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Sandra Mattavous-Frye, Esq.
People's Counsel

January 12, 2024

PUBLIC VERSION

Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 G Street, N.W., Suite 800
Washington, D.C. 20005

Re: Formal Case No. 1176, In the Matter of the Application of Potomac Electric Power Company for Authority to Implement a Multiyear Rate Plan for Electric Distribution Service in the District of Columbia

Dear Ms. Westbrook-Sedgwick:

Enclosed for filing in the above-referenced proceeding, pursuant to the procedural schedule outlined by the Commission, please find the public copy of the *Office of the People's Counsel for the District of Columbia's Direct Testimony of OPC Witnesses, Exhibits OPC (A) – (E).* Below is a list of the Office's witnesses:

OPC Exhibit (A) – David A. Dismukes
OPC Exhibit (B) – Michael P. Gorman
OPC Exhibit (C) – Christopher C. Walters
OPC Exhibit (D) – Brian C. Andrews
OPC Exhibit (E) – Kevin J. Mara

Additionally, OPC Witness Kevin Mara's confidential testimony filing and Witness David E. Dismukes's confidential exhibits will be filed under a separate cover. If there are any questions regarding this matter, please contact Ankush Nayar at 202.727.3071.

Sincerely,

/s/ Sandra Mattavous-Frye
Sandra Mattavous-Frye
People's Counsel

Enclosure

cc: Parties of Record

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BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In the Matter of	§	
	§	
The Application of Potomac Electric	§	
Power Company for Authority to	§	**Formal Case No. 1176**
Implement a Multiyear Rate Plan	§	
for Electric Distribution Service in	§	
the District of Columbia	§	

DIRECT TESTIMONY AND SUPPORTING EXHIBITS OF DAVID E. DISMUKES, PH.D.

Exhibit OPC (A)

On Behalf of the
Office of the People's Counsel
for the District of Columbia

January 12, 2024

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I. INTRODUCTION

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place, Suite 5-F, Baton Rouge, Louisiana, 70808. I am a Consulting Economist with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, which is located in Baton Rouge, Louisiana.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I hold M.S. and Ph.D. degrees in Economics from Florida State University. Over a career stretching more than three decades, I have been actively involved in research, government service, and consulting. My professional experience includes examination of economic, statistical, and public policy issues in energy and regulated industries. I previously served as a full Professor, Executive Director, and Director of Policy Analysis at the Center for Energy Studies at Louisiana State University ("LSU"). I was also a tenured Professor in the Department of Environmental Sciences and the Director of the Coastal Marine Institute in the College of the Coast and Environment at LSU. I also served as a member of the graduate research faculty at LSU directing and participating in M.S. theses and Ph.D. dissertation committees. On January 13, 2023, I retired from my active positions at LSU but continue to be involved in academic circles serving as a Professor Emeritus at LSU. I also serve on the program faculty and as a Senior Fellow at the Institute of Public Utilities at the Michigan State University teaching energy and regulatory professionals. Exhibit

OPC (A)-1 is my academic vitae, which includes a list of the proceedings in which I have testified, a list of all my publications, presentations, pre-filed expert witness testimony in other jurisdictions, expert reports, expert legislative testimony, and affidavits.

Q. PLEASE SUMMARIZE THE PURPOSE OF YOUR DIRECT TESTIMONY.

A. I have been retained by the Office of the People's Counsel ("OPC") to provide policy and technical analysis on the general issue of whether the Commission should continue to consider a move away from traditional ratemaking in favor of alternative forms of ratemaking ("AFORs"). More specifically, I was retained to analyze the Potomac Electric Power Company ("Pepco," or the "Company") assessment of the Multiyear Rate Plan Pilot ("MRP Pilot") that was approved in Formal Case No. 1156, and the merits of the Company's proposed Multiyear Rate Plan ("MYP") proposal in this case. I also provide an expert opinion regarding Pepco's proposed rate increase for the District of Columbia ("District"). My testimony will provide an overview OPC's case-in-chief and policy positions and will introduce each of OPC's expert witnesses and providing an overview of their testimony and recommendations. My testimony will also specifically address elements of the Company's proposed MYP, traditional test year filing ("TTYF") revenue distribution, and rate design. I will also address growing concerns regarding the affordability of rates in the District, and the Company's Bill Stabilization Adjustment ("BSA").

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE DISTRICT OF COLUMBIA PUBLIC SERVICE COMMISSION?

A. Yes and those are provided in Exhibit OPC (A)-1.

Q. WERE YOUR TESTIMONY AND EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized into the following sections:

- Section II: Scope and Summary of Testimony
- Section III: General Concerns Regarding Pepco's Application
- Section IV: Affordability Concerns in the District
- Section V: Revenue Distribution
- Section VI: Rate Design
- Section VII: Pepco's MYP Extension Request
- Section VIII: Bill Stabilization Adjustment
- Section IX: Conclusions and Recommendations

II. SCOPE AND SUMMARY OF TESTIMONY

A. Introduction of OPC Witnesses

Q. PLEASE INTRODUCE OPC'S EXPERT WITNESSES AND SUMMARIZE THE TOPICS OF THEIR RESPECTIVE TESTIMONIES.

A. In addition to my testimony, OPC is sponsoring the testimony of six additional expert witnesses in this proceeding, including:

- **Mr. Michael P. Gorman**, a managing principal of Brubacher & Associates, Inc., presents testimony in OPC Exhibit (B) regarding the Company's' overall revenue requirements for both its traditional rate year proposal and MYP proposal. Mr. Gorman recommends a number of adjustments to the Company's revenue requirements that are based on his own analyses, as well as supporting analyses provided by other OPC experts on such subjects as rate of return, depreciation, and capital spending.

- **Mr. Christopher C. Walters**, an associate with Brubacher & Associates, Inc., presents testimony in OPC Exhibit (C) related to Pepco's requested rate of return. Mr. Walters reviews and analyzes the regulatory utility industry's access to capital, credit rating trends and outlooks, as well as the overall trend in the authorized return on equity for utilities across the country.
- **Mr. Brian C. Andrews**, an associate with Brubacher & Associates, Inc., presents testimony in OPC Exhibit (D) assessing the propriety of, and recommending changes to Pepco's depreciation rates.
- **Mr. Kevin Mara**, an executive vice president at GDS Associates, presents testimony in OPC Exhibit (E) regarding Pepco's proposed construction and capital investment plans and related proposed test-year adjustments for Pepco's "traditional" rate filing and its proposed MYP. Mr. Mara also discusses a number of challenges associated with Pepco's new load forecasting and how the Company's forecasting methods impact capital spending. Finally, Mr. Mara reviews Pepco's proposed use of battery energy storage systems to delay capacity upgrades.

B. Overview of OPC's Positions and Recommendations

Q. PLEASE SUMMARIZE OPC'S CONCERNS AND RECOMMENDATIONS RELATED TO PEPCO'S TRADITIONAL TEST YEAR REVENUE REQUIREMENT PROPOSAL.

A. OPC witness Gorman finds that Pepco's traditional test year revenue deficiency of $108.2 million is overstated by $74.6 million and should, instead, be set at $33.6 million. Mr. Gorman's proposed reductions to Pepco's traditional test year revenue requirement are comprised of $20.0 million associated with a lower proposed return on equity, $40.9 million reduction to depreciation expense, a $10.3 million reduction attributable to Pepco's BSA deferral, and an assortment of additional reductions, including adjustments related to annualized revenues, deferred income taxes, regulatory asset amortization, and inflation.

Q. PLEASE SUMMARIZE OPC'S CONCERNS AND RECOMMENDATIONS RELATED TO PEPCO'S PROPOSED MYP REVENUE REQUIREMENT.

A. OPC witness Gorman finds that Pepco has overstated its proposed MYP revenue requirement by $76.1 million in 2024, $83.6 million in 2025, and $90.8 million in 2026. Mr. Gorman's proposed MYP revenue requirement reductions include:

- Cost of capital related reductions of $25 million to MRP Year 1; $26.8 million to MRP Year 2; and $28.3 million to MRP Year 3.
- Depreciation expense reductions of $46.8 million in 2024, $50 million in 2025, and $52.7 million in 2026.
- A variety of other revenue requirement reductions related to Pepco's sales forecast, service company cost escalation, deferred income taxes, and regulatory asset amortization.

Q. PLEASE SUMMARIZE OPC'S CONCERNS AND RECOMMENDATIONS RELATED TO PEPCO'S PROPOSED COST OF CAPITAL.

A. OPC witness Walters concludes that the recent trend in the authorized return on equity ("ROE") for regulated utilities has declined and remains below 10 percent recently. Mr.

Walters estimates that the current fair market ROE for Pepco is within the range of 9.20 percent to 9.90 percent and recommends the Commission adopt an ROE no greater than the midpoint of 9.55 percent under a traditional test year scenario without the BSA decoupling mechanism. Alternatively, in the event the Commission authorizes Pepco to continue under an MYP, with or without the BSA decoupling mechanism, then OPC witness Walters finds that a range of 9.20 percent to 9.55 percent is more appropriate and recommends the Commission authorize a ROE of no more than the mid-point of 9.30 percent. In addition, Mr. Walters concludes that Pepco's proposed 50 percent equity ratio (excluding short-term debt) significantly exceeds those observed for the proxy group used to estimate Pepco's cost of equity. Mr. Walters does not propose an adjustment to the capital structure but does incorporate the differences in financial risk among proxy group companies into consideration in making his recommendation.

Q. PLEASE SUMMARIZE OPC'S CONCERNS AND RECOMMENDATIONS RELATED TO PEPCO'S PROPOSED CLIMATE-RELATED CAPITAL SPENDING.

A. OPC witness Mara observes that over 90 percent of the projects identified as part of Pepco's "climate ready grid" modernization initiative are nothing more than routine reliability projects that any prudent utility would undertake. Based on this observation, Mr. Mara identifies a number of projects that could be delayed or eliminated without thwarting the District's climate goals.

Q. PLEASE SUMMARIZE OPC'S CONCERNS AND RECOMMENDATIONS RELATED TO PEPCO'S LOAD FORECASTING METHODOLOGIES.

A. OPC witness Mara finds that Pepco's proposed MYP capital budget is overstated and does not reflect the lower load growth suggested by the Company's new load forecasting methodologies. Mr. Mara notes that Pepco's new load forecasting methodologies suggest a slowdown in construction and energy use in the District, resulting in lower capital investment requirements. The lower load growth forecast leads Mr. Mara to recommend a delay in a number of proposed MYP capital projects that need to be removed from the proposed MYP test year including: (1) $635,610 associated with a fifth transformer at the Waterfront substation; (2) $6.1 million associated with two projects aimed at expanding capacity at the Alabama substation; (3) $6.3 million attributable to a battery energy storage system ("BESS") at the Alabama substation; and (4) a $4.5 million BESS-related investment at the Mt. Vernon substation.

Q. PLEASE SUMMARIZE OPC'S CONCERNS AND RECOMMENDATIONS RELATED TO PEPCO'S ALLOCATION OF SUB-TRANSMISSION COSTS.

A. OPC witness Mara an adjustment to account for Pepco's incorrect allocation of the costs of certain sub-transmission projects to the District. Mr. Mara also observes that Pepco has significantly changed its Downtown Resupply Project in its MRP proposal, resulting in a budget increase from $667 million to approximately $1.4 billion. OPC witness Mara finds that this increase is not justified and recommends a number of sub-projects related to the Downtown Resupply Project be eliminated from Pepco's MRP capital budget.

Q. PLEASE SUMMARIZE OPC'S CONCERNS AND RECOMMENDATIONS RELATED TO PEPCO'S DEPRECIATION EXPENSE CALCULATION.

A. OPC witness Andrews finds that Pepco's proposed depreciation expense amount is excessive. OPC witness Andrews challenges a number of Pepco proposed changes that will inflate net salvage values including (1) the Company's proposal to lengthen the average service life of nine plant accounts, (2) its proposal to reduce net salvage value for Account 362 by 30 percent; and (3) its proposal to use a uniform 2.5 percent inflation rate to discount future net salvage costs. Mr. Andrews recommends the Commission reduce the depreciation expense for the MYP by $46.8 million in 2024, $50.0 million in 2025, and $52.7 million in 2026, and that Pepco's proposed traditional test year depreciation expense should be reduced by $40.9 million.

C. Summary of Revenue Requirement, Rate Design and Regulatory Policy Recommendations

Q. WHAT ARE YOUR REVENUE DISTRIBUTION RECOMMENDATIONS?

A. I recommend that the Commission reject the Company's proposed revenue distribution allocation, which places a disproportionate amount of the rate increase on residential customers. Rate classes such as the residential class would see a rate increase of 2.3 times that of the system average. While the Commission has expressed a desire to address negative rates of return for the residential customer class, it has chosen to do so utilizing a policy of gradualism. Moreover, disproportionately allocating rate increases to residential ratepayers as Pepco proposes, has not proven effective in improving the overall rate of return for the residential class. I recommend that the Commission adopt a more reasonable revenue distribution allocation method that limits revenue increases to customer classes currently earning a relative rate of return (RROR) below 0.90 an increase equal to 1.25

times the overall system average increase in order to meet rate gradualism goals and to support electricity cost affordability in the District.

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS AND CONCLUSIONS?

A. I recommend that the Commission keep customer charge at their current levels. The Company's customer charges are already on the high side of other regional utilities and do not need to be increased any further. Additionally, residential customers have seen significant cumulative increases in customer charges over the past few rate cases.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE COMPANY'S PROPOSED MYP?

A. I recommend that the Commission reject the Company's requested MYP for multiple reasons. First, there has been no review of the previous MRP Pilot that the Commission approved in Formal Case No. 1156. As such, nothing in Pepco's pre-filed testimony or exhibits supports the conclusion that the pilot was successful and resulted in meaningful and measurable ratepayer benefits. Second, in Order No. 20737 (Formal Case No. 1156), the Commission established the framework by which it will review MYP proposals, and explained that it "will determine on a case-by-case basis whether the principles of the framework have been met in the proposed [alternative forms of ratemaking, i.e., AFOR] under the specific facts and circumstances of the case."[1] The Company has not provided sufficient evidence or analysis under this framework demonstrating that the MYP proposal

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1 *Formal Case No. 1156, In the Matter of the Application of Potomac Electric Power Company for Authority to Implement a Multiyear Rate Plan for Electric Distribution Service in the District of Columbia ("Formal Case No. 1156")*, Order No. 20737, ¶ 96, rel. December 20, 2019.

will provide any net public benefits or to be in the public interest. I will also discuss general concerns with multiyear plans such as the one proposed by Pepco and the fact that the Company fails to demonstrate the need for this form of regulation at this time.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S LOW-INCOME PROPOSALS AND ENERGY AFFORDABILITY IN THE DISTRICT?

A. I recommend that the Commission not approve the Company's proposed changes to its low-income programs at the current time and, instead, open a proceeding after the conclusion of the current rate case to examine low-income and affordability issues in a more holistic fashion. Changes to the Company's low-income programs could have important and potentially unintended consequences that affect other District-sponsored programs and other stakeholder initiatives.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S BSA?

A. I recommend the BSA be discontinued for several reasons: It is not fulfilling its original purpose and reduces incentives for prudent management by the Company. If the Commission approves some form of a multiyear rate plan, then this only further justifies discontinuing the BSA, as elements of the BSA are redundant of a multiyear rate plan. Finally, in the current energy transition environment, revenue decoupling's purpose is at odds with decarbonization and electrification.

Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION IF THE COMMISSION DECIDES TO RETAIN THE BSA?

A. Yes. If for any reason the Commission decides to retain the BSA, I recommend adoption of the Company's proposed BSA modifications.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED RATE BASE TREATMENT OF BSA DEFERRED BALANCES?

A. I recommend the Commission reject the Company's proposal to include its test year BSA deferred balance as an element of rate base, allowing the Company to earn a rate of return on this balance. Even ignoring the Company's admitted billing determinant error, which has contributed to the significant growth in these deferred balances over the past few years, the Commission should recognize that the Company had the opportunity to request changes to the BSA operations at any point in the mechanism's 14-year history. Accepting the Company's request to include BSA deferred balances as part of rate base now would effectively reward Pepco for not exercising prudent oversight of BSA operations.

Q. WHAT EVIDENCE HAS PEPCO PROVIDED TO SUPPORT A FINDING THAT IT HAS PRUDENTLY ADMINISTERED THE BSA?

A. None. Pepco does not provide any analysis to demonstrate that its administration of the BSA was prudent.

Q. DO YOU HAVE A RECOMMENDATION REGARDING THE CURRENT LARGE BSA DEFERRAL BALANCES FOR COMMERCIAL RATE CLASSES?

A. Yes. I recommend the Commission disallow the Company from recovering the portion of BSA deferral balances, associated with the Company's past administrative errors, from retail customers. Pepco has provided no analysis or evidence to support a finding of fact that it prudently operated the BSA despite the billing determinant error. The BSA mechanism should not function to immunize the Company from its own operational and business mistakes. I recommend the Commission remove $42.2 million of BSA deferral balance from ratepayer recovery, including $19.3 million from the Time Metered General Service-Low Voltage ("GTLV") rate class and $20.1 million from the Time Metered General Service-Low Voltage ("MGTLV") rate class. This removal is to account for the Company's previous acknowledged billing determinant mistake in Formal Case No. 1150 and its faulty GTLV normalization adjustment in the same proceeding.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE REGULATORY TREATMENT OF PANDEMIC-RELATED LOST REVENUES?

A. Yes. I recommend that the Commission consider alternative recovery options for pandemic related BSA deferral balance outside of the BSA such as mechanism already established by the Commission for recovery of pandemic-related expenses.

III. GENERAL CONCERNS REGARDING PEPCO'S APPLICATION

Q. PLEASE SUMMARIZE PEPCO'S RATE REQUEST.

A. On April 13, 2023, Pepco filed a request for approval of its MYP .[2] This follows a previous MRP Pilot approved on a pilot basis (called by Pepco at the time as a "Modified Enhanced Multiyear Rate Plan), by the Commission in 2021.[3] The currently proposed MYP will increase distribution revenues by $190.7 million over a three-year period starting February

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[2] *Formal Case No. 1176*, Application of Potomac Electric Power Company, p. 5, filed April 13, 2023 ("Application").

[3] *Formal Case No. 1156*, Order No. 20755, ¶ 142, rel. June 8, 2021.

15, 2024,[4] including $81.5 million (43 percent) to residential customers.[5] This proposed increase represented a 34.7 percent increase in system-wide distribution revenues, or an 80.0 percent increase in residential distribution revenues.[6]

Q. HAS THE COMMISSION MADE ANY RULINGS ON THE SUCCESSES, OR FAILURES OF THE CURRENTLY ACTIVE PILOT MYP?

A No. In adopting the MRP Pilot, the Commission explained that it would review the successes and failures of this new regulatory mechanism before considering any renewal or permanent plan.[7] That review did not occur before Pepco submitted its April 13, 2023 Application in Formal Case No. 1176, and I understand OPC is challenging the omission of that process on appeal. For purposes of my testimony, I note that Commission Order No. 21886 directed Pepco to file supplemental testimony explaining in quantitative and qualitative terms the benefits of, problems identified, and lessons learned from the MRP Pilot.[8] Order No. 21886 also directed Pepco to file a traditional one-year rate case with a test year ending December 31, 2023.[9] On August 31, 2023, Pepco filed supplemental testimony pursuant to Order No. 21886.[10] Likewise, on October 16, 2023, Pepco filed a

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4 *Formal Case No. 1176*, Application.

5 *Formal Case No. 1176*, Exhibit PEPCO (E)-3.

6 *Id.*

7 *See generally Formal Case No. 1176*, OPC's Motion for Limited Stay, filed November 13, 2023 (explaining the procedural background).

8 *Formal Case No. 1176,* Order No. 21886, ¶ 1, rel. July 28, 2023.

9 *Id.*

10 *See Formal Case No. 1176*, Exhibit PEPCO (2A), Supplemental Direct Testimony of Elizabeth M. D. O'Donnell.

one-year traditional test year compliance filing ("TTYCF") pursuant to Order No. 21886.[11] This supplemental TTYCF request would increase the Company's annual distribution revenues by $108.2 million, or $46.0 million to residential customers.[12] This represents a 19.8 percent increase in system-wide distribution revenues or a 45.4 percent increase in residential distribution revenues.[13]

Q. HAS THE COMMISSION PREVIOUSLY IDENTIFIED THE COMPLEXITY ASSOCIATED WITH MOVING FROM TRADITIONAL RATEMAKING TO AN MRP-BASED REGULATION?

A. Yes. The Commission recognizes the complexity of moving from traditional regulation to a regulation paradigm based on alternative forms of ratemaking ("AFOR"), noting that such considerations should be "deliberate, paying careful attention to the structure and framework for the evaluation of [alternative forms of regulation] so that unintended operational or financial outcomes are mitigated and managed."[14] The Commission ultimately noted that any move away from traditional ratemaking "may require multiple rate proceedings to fully implement."[15] However, to date, no such proceedings have arisen relative to assessing Pepco's MRP Pilot performance.

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11 *See Formal Case No. 1176*, Exhibit PEPCO (3A), Additional Supplemental Direct Testimony of Elizabeth M. D. O'Donnell.

12 *Formal Case No. 1176*, Exhibit PEPCO (2E)-2.

13 *Id.*

14 *Formal Case No. 1156*, Order No. 20273 at ¶86.

15 *Id.*

Q. ARE THERE PRACTICAL DIFFICULTIES IN REVIEWING THE PERFORMANCE OF THE MRP PILOT, THE PROPOSED MYP, AND A TTYCF IN THE SAME PROCEEDING?

A. Yes. The Commission should recognize that each of these three forms of regulatory oversight are complex that, by themselves, generally warrant a proceeding in and of themselves for the Commission and stakeholders to review. In this proceeding alone, Pepco has filed three sets of testimony covering (1) the Company's proposed rate increases under its proposed MYP; (2) the Company's supposed assessment of the MYP Pilot performance; and (3) the Company's proposed rate increases under its proposed TTYCF. Considering all three of these filings simultaneously places strain on the Commission and all stakeholders. Further, the Commission should recognize that there are separate and distinct rate implications for each of these regulatory mechanisms. Consideration of all issues poses difficulties in issuing and responding to discovery, composing pre-filed testimony, and conducting adequate evidentiary cross-examination within the limited timeframe associated with a single proceeding.

Q. DID PEPCO FILE TESTIMONY IN THE CURRENT PROCEEDING EMPIRICALLY ANALYSIS ASSESSING THE HISTORIC PERFORMANCE OF THE MYP RELATIVE TO TRADITIONAL REGULATION?

A. No. While the Company was required to file testimony reviewing the MRP Pilot, it did not quantify any benefits that are directly attributable to its MRP Pilot. More importantly, the Company did not show how the MRP Pilot led to benefits that would not have arisen under the counterfactual regulatory arrangement, which is traditional regulation.

Q. HOW WILL PEPCO'S CURRENT MYP PROPOSAL IMPACT A TYPICAL RESIDENTIAL CUSTOMER?

A. As will be outlined in my testimony further, the MYP proposal will impact residential retail customers, in general, and several subsets of these residential customers, adversely. My testimony will discuss in further detail how the proposal will, in particular, adversely impact energy affordability for some of the District's most vulnerable residential customers. Consider that the Company itself shows that its proposed MYP will result in a first-year typical residential bill increase (assuming 614 kWh/month) of $6.18 per month, or 6.37 percent on a total distribution bill basis.[16] This is over two time the going rate of inflation for normal household goods and services. But this is not the only increase that can be expected by the proposed MYP. Furthermore, the initial "year one" increase will be followed by "year two" and "year three" increases of $6.13 and $6.09 per month, respectively.[17] In total, the Company estimates that the typical residential customer will see monthly bill increases of $18.40 per month over the three-year MYP, or close to 19 percent on a total distribution bill basis.[18]

Q. HOW DOES THE PROPOSED RATE INCREASE FOR RATE YEAR 1 COMPARE TO PAST PEPCO RATE CASES?

A. This rate proceeding continues a long string of substantial rate increase requests made by the Company in the District. What is different about the Company's current MYP proposal

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16 *Formal Case No. 1176*, Application, at 2.

17 *Id.*

18 *Id.*

(relative to past "traditional regulation") is the considerable increase in rates that will be facilitated by this unnecessary AFOR. Consider that Pepco's proposed first year rate increase ($116.4 million) represents a 21.2 percent increase in rates. Figure 1, provided below, shows that, in total dollar terms, the Company's proposed one-year increase in this proceeding ($116.4 million) is nearly as large as the sum of the Commission-approved rate increases in the Company's last three rate cases (Formal Case Nos. 1156, 1139, and 1103).[19] Figure 1 illustrates the significance of these rate increases, affirming that the only quantifiable outcome they can expect from the MYP, if approved, is the "rate predictability" of very high electricity bills.

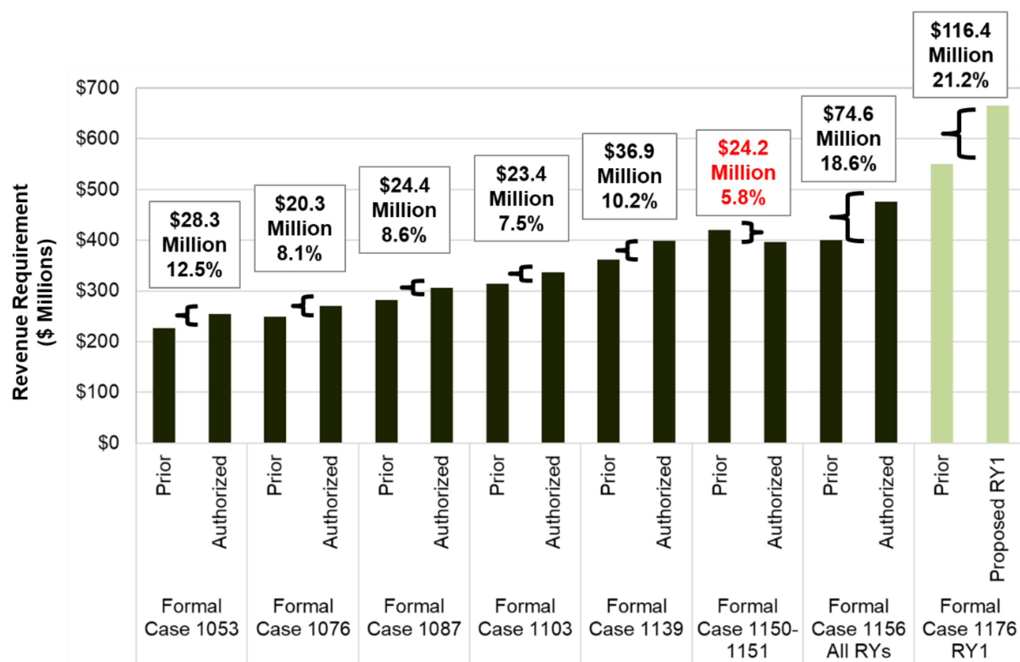

Figure 1: Comparison of Prior Pepco Rate Increases

19 I do not reference Formal Case Nos. 1150 and 1151 given the unique circumstances of those cases surrounding the effect of the Tax Cut and Jobs Act of 2017 ("2017 TCJA").

Q. WHAT HAS BEEN MOTIVATING THESE LARGE RATE INCREASE REQUESTS?

A. In prior cases, the Company claimed that these rate increases were motivated by infrastructure investments designed to improve customer service, system reliability, and customer satisfaction, as well as to advance the forward-focused policy goals of the District.[20] The Company notes that the current rate request is needed to support and advance decarbonization goals in the District through what the Company refers to as its "Climate Ready Grid" initiative.[21]

Q. WHAT ARE THE BIG PICTURE ISSUES INCENTING UTILITIES INTO MAKING SUCH LARGE CAPITAL INVESTMENTS?

A. Energy efficiency initiatives, federally mandated appliance standards, growth in behind-the-meter generation, and state/local building code changes have slowed growth in use per customer ("UPC"). This means that the only way utilities can grow earnings is to expand investments into areas that are either (a) not specific to load growth, or (b) heavily rely upon load growth. These include investments in efficiency, resilience, reliability, resource diversity, and decarbonization.

Q. HOW DO THESE CHANGES IN ENERGY USAGE IMPACT UTILITY COST RECOVERY?

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20 *See* Exhibit OPC (A)-20, *Formal Case No. 1150, In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service* ("*Formal Case No. 1150*"), Application of Potomac Electric Power Company at 3, filed December 19, 2017 ("FC 1150 Application"); Exhibit OPC (A)-21, *Formal Case No. 1150*, Exhibit PEPCO (A) (Dismukes) at 6:8-11; Exhibit OPC (A)-22, *Formal Case No. 1139*, Application of Potomac Electric Power Company at 3, filed June 30, 2016 ("FC 1139 Application"); and Exhibit OPC (A)-23, *Formal Case 1156*, Application at 7.

21 *Formal Case No. 1176*, Application, at 4.

A. Utility rates, in very general terms, are set using average costs which, themselves, are simply costs divided by output (or kWhs). If sales (the denominator) fall, then rates have to increase in order to assure cost recovery on both historic and incremental investments. Thus, for utilities like Pepco, increasing investments in non-revenue/non-load growth items like resiliency, reliability and sustainability, coupled with falling sales, results in very large and repetitive rate increases. The only way to stop these rate increases is to (a) reduce or stop capital expenditures and/or (b) grow sales.

Q. BY HOW MUCH WILL DISTRIBUTION RATES INCREASE OVER THE THREE YEAR PERIOD OF THE PROPOSED MYP?

A. Figure 2, provided below, shows that by the end of the MYP period, the Company's base distribution rates will have increased by more than $190.7 million, or by more than 34.7 percent when compared to existing rates over a mere three-year period. Thus, the Company's proposal will only exacerbate the sharp increase in rates that have been charged to District ratepayers.

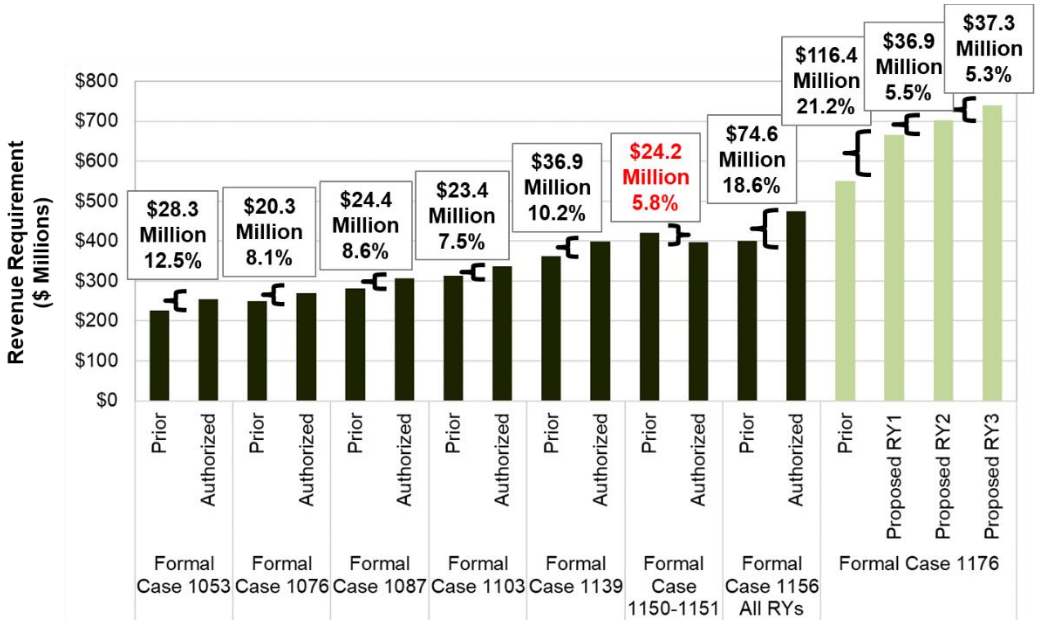

Figure 2: Comparison of Prior Pepco Rate Increases, with MRP

Q. WILL THE PROPOSED MYP PROVIDE RATEPAYERS WITH ANY RELIEF FROM THESE HISTORICALLY LARGE AND CONTINUALLY LARGE RATE INCREASE PROPOSALS?

A. No. Figure 2 shows that the Company's proposed MYP will not alleviate the historic pattern of large rate increases dating back to 2007 (FC 1053). The Company's MYP will not reduce the Company's capital investments, nor will it increase volumetric sales, meaning that this "new" approach to regulation will do nothing more than sustain the "old" trends in consistently large rate increases under an alternative regulatory framework.

Q. IS THERE REASON TO BELIEVE THAT THE COMPANY'S PROPOSED RATE INCREASE IN THIS PROCEEDING IS TOO LARGE?

A. Yes, particularly if past trends have any implication for the rate increase proposals in this proceeding. Figure 3 compares the Company's historic rate increase requests to those allowed by the Commission in its final order. The Commission has consistently contained rate increases to those that are between 42.1 and 60.6 percent of the amount originally requested by Pepco in its past applications. In short, it should be recognized that the efforts of the Commission, OPC, and other parties to carefully scrutinize Pepco's rate case applications have curtailed the Company's excessive rate increase requests.

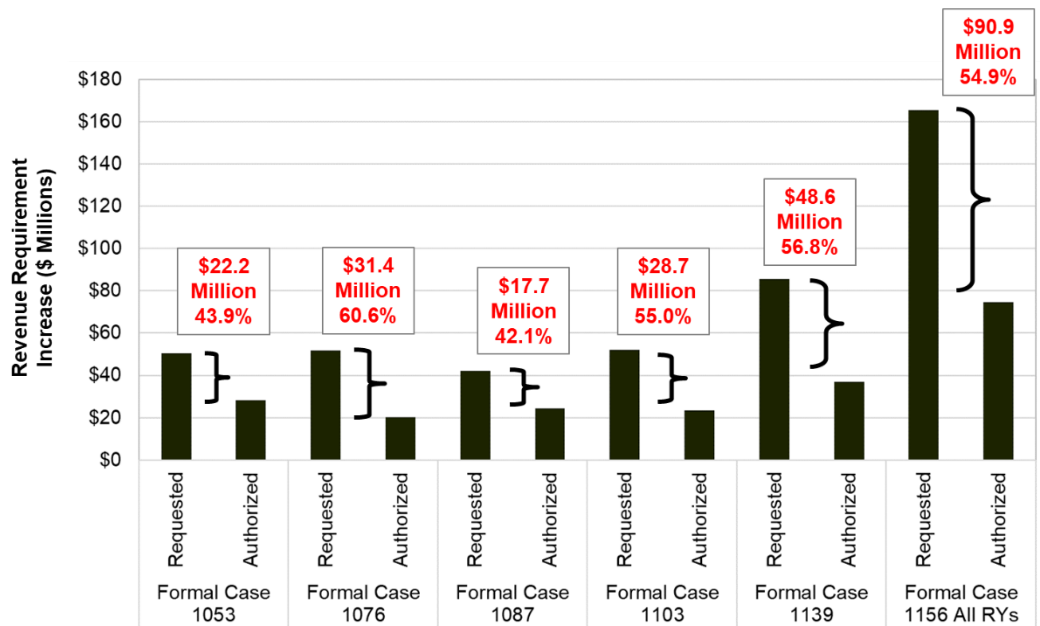

Figure 3: PEPCO Historic Requested to Authorized Revenue Requirements
Note: Formal Case 1150 and 1151 excluded due to effects of 2017 Tax Cuts and Jobs Act.

Q. HOW DOES THE COMPANY PROPOSE TO ALLOCATE ITS PROPOSED RATE INCREASE IN THIS PROCEEDING?

A. The Company proposes a revenue distribution that will increase rates for under-earning classes at a rate that is equal to 2.3, or 230 percent, its overall system-wide rate increase request.[22] This is while the Company proposes a 34.7 percent overall distribution rate

[22] Exhibit PEPCO (E) (Bonikowski) at 11:11-32 and 14:19-22.

increase for all customers during the course of the three-year MYP.[23] This means that the Company's proposal would lead to a substantial rate increase for residential customers of more than 80.0 percent over three years.[24] Again, it is hard to fathom how the proposed MYP will lead to any measurable or quantitative benefits with rate increases of these magnitudes.

Q. IS IT EQUITABLE FOR RESIDENTIAL CUSTOMERS TO BEAR SUCH A DISPROPORTIONATE BURDEN OF THE COMPANY'S PROPOSED RATE INCREASE?

A. No. The Company notes that the current rate request is needed to support and advance decarbonization goals in the District through what the Company refers to as its "Climate Ready Grid" initiative.[25] While the District has climate targets, the Commission has not approved a clear path forward in Formal Case No. 1167, which is the docket examining how utilities will move forward in light of those targets. That proceeding is also considering the Washington Gas and Light Company's ("WGL's") climate proposals, as well as stakeholder input on the plans submitted by both utilities, all of which have yet to be reconciled. Furthermore, OPC witness Mara raises serious questions about the nature of the Company's proposed capital investments and provides quantifiable evidence that over 95 percent of these proposed MYP investments are "business as usual" in nature, and cannot be matched to any reductions in greenhouse gas ("GHG") emissions, improve

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[23] Exhibit PEPCO (E)-3.

[24] Exhibit PEPCO (E)-1.

[25] *Formal Case No. 1176*, Application, at 4.

energy end use efficiencies, nor any operating or cost efficiencies that could translate into future rate reductions.

Q. IF THESE MYP INVESTMENTS PROVIDING SYSTEM-WIDE BENEFITS, AS SUGGESTED BY PEPCO, SHOULD THEIR COSTS BE PRIMARILY BORN BY RESIDENTIAL CUSTOMERS?

A. No. Even if true, the Company's claims about MYP infrastructure investments resulting in system-wide, even societal, benefits need to be recovered equally across all customer classes, and not disproportionately by any one specific class. However, the Company's revenue distribution proposal completely ignores this fact, placing the majority of the cost burden of these societal investments onto one customer class: residential customers.

Q. WHY IS THE COMPANY PROPOSING DISPROPORTIONATE RATE INCREASES FOR RESIDENTIAL CUSTOMERS?

A. The Company claims that its revenue distribution proposal is based upon the Commission's policy of addressing historical disparities in rate class-specific rates of return.[26] This policy was first established in Formal Case No. 1076, filed in May of 2009, more than a decade ago.[27] Since that time, residential customers have disproportionately borne the burden of the Company's proposed rate increases in the majority of subsequent rate filings. Yet, despite these disproportionate increases, there has been no improvement in these historic cross-subsidies until the current filing. Importantly, however, this recent improvement in

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26 Exhibit PEPCO (E) (Bonikowski) at 10:4-11.

27 *Formal Case No. 1076, In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service* ("*Formal Case No. 1076*"), Application of Potomac Electric Power Company ("1076 Application").

supposed rate disparities was accomplished after residential customers were assigned a lower-than-average rate increase in the Company's prior rate case filing in Formal Case No. 1156.

Q. HAVE YOU COMPARED THESE TRENDS IN RESIDENTIAL RATE INCREASES TO ANY OTHER METRICS?

A. Yes. Figure 4 compares the historic rate of growth in residential distribution rates to the overall rate of inflation in consumer goods as measured by the Consumer Price Index for Urban Consumers ("CPI-U"). This analysis shows that since September 2007, residential distribution rates have increased at nearly 2.4 times the rate of inflation. The increase in base rates is significantly more than increases in other consumer expenses.

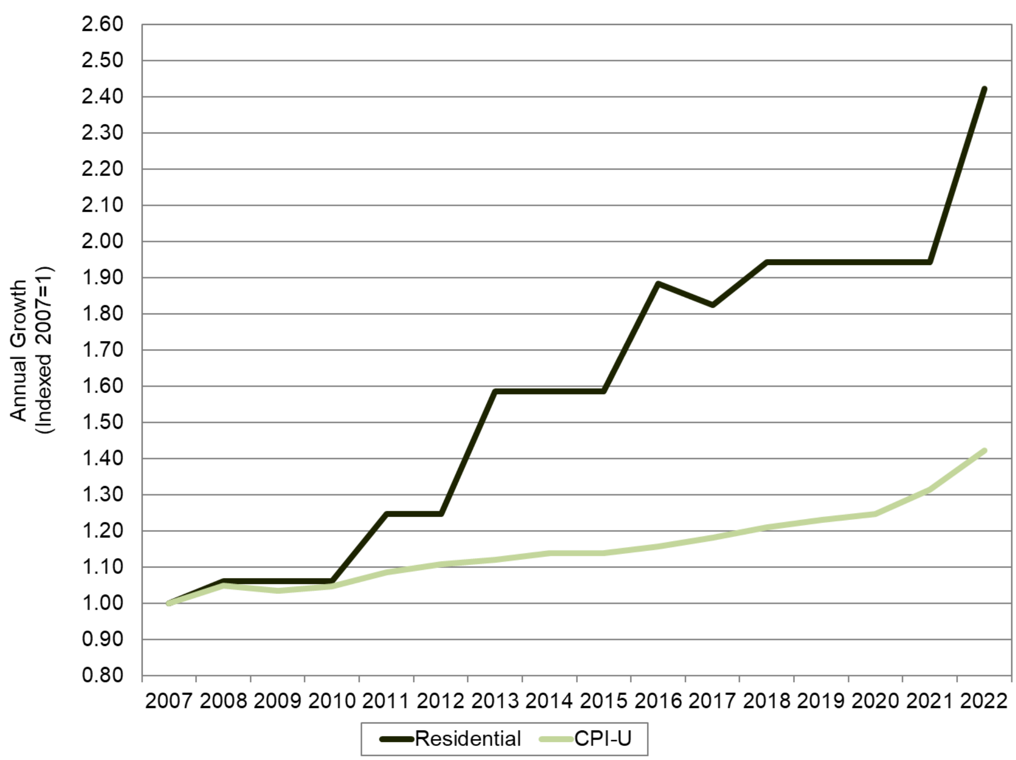

Figure 4: Residential Base Rate Growth to Consumer Price Index-Urban (CPI-U)

Q. WHY HAS THE POLICY OF DISPROPORTIONATE RATE INCREASES FOR RESIDENTIAL CUSTOMERS NOT ACCOMPLISHED THE STATED GOAL OF REMOVING HISTORIC CROSS-SUBSIDIES BETWEEN CUSTOMER CLASSES?

A. The Company's proposed capital expenditures, and the rate increases that support these investments, surpass any rate-rebalancing these prior revenue distribution policies could accomplish. In other words, the Commission's policy goals that support the Company's non-revenue generating investment proposals are in direct conflict with its goals to rebalance rates. This is only going to get worse, not better if the Commission approves the Company's MYP. I cannot envision a way in which the Commission can continue to support the level of MYP investments proposed by the Company and correct its long-standing ratemaking challenges at the same time. The more important of these two competing policy initiatives must be chosen, holding the other in abeyance until such time that the need for continued reliability, resiliency and sustainability investments have dissipated.

IV. <u>AFFORDABILITY</u>

Q. HOW DO YOU DEFINE ENERGY AFFORDABILITY?

A. Energy affordability reflects a fundamental household value proposition: it defines how expensive energy is relative to a household's income. Affordability, more generally, can be utilized as an index number to measure, among other things, the ability of a specific type of household to pay for essential utility services such as water, electric, and/or natural gas.

Q. ARE THERE ANY THRESHOLDS AT WHICH ENERGY SIMPLY BECOMES "UNAFFORDABLE" OR "BURDENSOME?"

A. Yes. The most accepted and utilized threshold at which utilities, and thus energy, becomes unaffordable or burdensome is when the percentage of income spent on energy exceeds six percent.[28] This threshold comes from the Fisher, Sheehan, and Colton's Home Energy Affordability Gap Study from 2011. The threshold is based on the premise that total shelter costs (including rent/mortgage and all utilities) should not exceed 30 percent of income, and that 20 percent of shelter costs should be allocated to energy bills. Thus, 20 percent of 30 percent yields a six percent affordable utility burden.[29] Utility burdens below six percent are classified as "affordable" and energy burdens above six percent are classified as "unaffordable".

Q. HOW DOES ACADEMIC LITERATURE EXAMINE UTILITY AFFORDABILITY?

A. The academic literature examines energy affordability through various metrics, but predominantly through utility and energy burden rates. Utility burden rates measure the impact of a utility bill on household income. The American Council for an Energy Efficient Economy (ACEEE)'s *Understanding Energy Affordability* Report best encapsulates what the academic literature has studied. Their report determines four drivers of high energy burdens: (1) physical (i.e. housing age and type, poor insulation, weather extremes); (2)

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[28] *See*, "Understanding Energy Affordability" ACEEE, 2015, page 2.

[29] Fisher, Sheehan, and Colton. "Home Energy Affordability in New York: The Affordability Gap 2008-2010", June 2011, page 2.

economic (i.e. chronic or sudden economic hardship); (3) behavioral (lack of access to information for bill payment assistance); and (4) policy (insufficient programs for bill assistance, high fixed customer charges).[30] It also examines utility burden rates throughout the United States, classifying any total utility burden above six percent as a household that experiences high energy burden.[31]

Q HOW IS THE CONCEPT OF ENERGY AFFORDABILITY RECOGNIZED IN REGULATION AND PUBLIC POLICY?

A. Energy affordability is increasingly becoming an important issue in regulatory policy with various states and local governments setting energy affordability targets. Recently, New York set a state-wide goal of achieving six percent energy burden.[32] Portland released a Ten-Year Plan to Reduce Energy Burden in Oregon Affordable Housing.[33] Adopting a three-phase process, the California Public Utilities Commission ("CPUC") developed the state's first energy affordability metric that tracks affordability for essential service level (electric, gas, water, and communications).[34] During the first phase, the CPUC defined affordability and established an affordability framework, setting residential household utility essential service levels and adopting the following three metrics to assess affordability of essential utility services: Affordability Ratio, Hours-at-Minimum-Wage,

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30 "Understanding Energy Affordability" ACEEE, 2015, page 2.

31 *Id*, page 3.

32 "Understanding and Alleviating Energy Cost Burden in New York City," (August 2019) NYC Mayor's Office of Sustainability and the Mayor's Office for Economic Opportunity, at p. 2.

33 "Reducing the Energy Burden in Oregon Affordable Housing – Ten-year Plan," (2018), Built Environment Energy Working Group.

34 California Public Utilities Commission Order 18-07-006, 2018.

and Socioeconomic Vulnerability Index.[35] In phase two, the CPUC focuses on implementation of the affordability framework through various efforts including rate cases, grants, and program assessments, while in the third phase of the order, the CPUC focuses on analyzing strategies to mitigate future rate increases based on the affordability metrics calculated.[36] On the other hand, the Pennsylvania Public Utility Commission ("PPUC") examined home energy burdens for low-income Pennsylvanians in its Home Energy Affordability 2019 report,[37] and subsequently issued a policy statement on March 21, 2020, establishing maximum energy burdens for customers.[38] The study found a wide disparity in the average percent of household income spent on natural gas and electric services by Customer Assistance Programs ("CAP") customers and non-CAP customers. CAP customers with gas heating and electric non-heating had a combined average energy burden of 12 to 14 percent or with electric heat eight to 10 percent.[39] In contrast, non-CAP customers had an average energy burden of six percent for gas heating and electric non-heating or four percent for electric heating.[40] These examples demonstrate that examining energy affordability has become paramount in utility regulation across the country.

Q. WHERE DOES THE DISTRICT OF COLUMBIA RANK NATIONALLY IN TERMS OF INCOME INEQUALITY?

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35 *Id*.

36 *Id*.

37 Exhibit OPC (A)-24, Home Energy Affordability for Low-Income Customers in Pennsylvania, (January 2019) Pennsylvania Public Utility Commission.

38 52 PA. Code Ch. 69.

39 Exhibit OPC (A)-24, page 109.

40 *Id*.

A. Wealth and income gaps in the District remain stark, with income inequality in the District being amongst the highest in the nation. Over the past decades, the District of Columbia has experienced economic growth, but this growth has been generally uneven.[41] One contributing factor to wealth inequality is the stagnant wages for low-to-moderate income households, while costs such as housing and utilities have increased significantly.[42] According to the U.S. Bureau of Labor Statistics, Consumer Price Index for transportation, food, and housing in the District of Columbia metro increased by 43 percent, 59 percent, and 70 percent respectively over the past 20 years.[43]

Q. IS HOUSING AFFORDABILITY A GROWING CONCERN IN THE DISTRICT?

A. Yes. Housing affordability is a critical issue that the District of Columbia faces. Over the last two decades, the number of affordable housing units has decreased while the number of high-cost housing units has multiplied.[44] In 2002, 40 percent of housing rented for less $800 per month, falling to 20 percent by 2013 and to less than 15 percent by 2021.[45] Moreover, the District of Columbia has the nation’s fourth highest “housing wage”, that is, the hourly wage needed to afford housing.[46] District of Columbia follows Hawaii,

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41 Ariel Drehobl, Diana Hernández, Roxana Ayala, and Lauren Ross. “An Examination of District Residents’ Experiences with Utility Burdens and Affordability Programs.” American Council for an Energy-Efficient Economy, March 2021, page 4.

42 *Id*.

43 *Id*.

44 *Id*.

45 *Id*.; Sophia, Wedeen (July 6, 2023), “Low-Cost Rentals Have Decreased in Every State,” Joint Center for Housing Studies of Harvard University.

46 Ariel Drehobl, Diana Hernández, Roxana Ayala, and Lauren Ross. “An Examination of District Residents’ Experiences with Utility Burdens and Affordability Programs.” American Council for an Energy-Efficient Economy, March 2021, page 4.

California, and Massachusetts in the "housing wage" ranking.[47] The increase in housing costs has made it difficult for low-income residents to afford basic necessities, even foregoing resources needed for a healthy lifestyle and living in substandard housing.[48]

Q. HAVE HOUSEHOLD ELECTRICITY COSTS RISEN OVER THE PAST TWO DECADES?

A Yes. From 2000 to 2019, the average electric bill for a resident in the District of Columbia increased 78 percent, from $55 to $98 per month.[49] D.C. water bills have also increased significantly over the years.[50] These increases exacerbate financial pressures for low-income residents, leading them to seek assistance. From April 2019 to June 2020 alone, the OPC received over 450 complaints about high water bills, disconnections, and payment disputes. OPC also received 912 complaints for PEPCO, 444 complaints for Washington Gas, and 164 complaints for third-party providers during FY 2019.[51] The significant number of formal complaints filed by residents underscores the severity of utility unaffordability.[52]

Q. HOW HAS ENERGY AFFORDABILITY CHANGED OVER THE PAST SEVERAL YEARS IN THE DISTRICT?

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[47] *Id*.

[48] *Id*, page 5.

[49] *Id*.

[50] *Id*.

[51] *Id*, page 6.

[52] *Id*.

A. As shown in Exhibit OPC (A)-2, costs associated with essential electric use will have increased 32 percent if the Company's proposed MYP is approved. Residential rate increases have far outpaced inflation at an average rate of nine percent per year since 2007.

Q HOW WOULD THE COMPANY'S MYP IMPACT ENERGY AFFORDABILITY?

A. Exhibit OPC (A)-2 shows that Pepco's rates have continuously exceeded the six percent affordability threshold for the bottom 15 percent of income households in the District since at least 2015. Importantly, this metric includes only natural gas and electric utility expenses and thus only includes a subset of total utility burden (which also includes water, sewer, and telecommunication utility expenses) used in academic literature when examining utility burden. The Company's proposed rate increases through its proposed MYP will only exacerbate this situation with energy expenditures constituting approximately nine percent of these household disposable income by 2026. Exhibit OPC (A)-2 finds that, if approved by the Commission, the Company's proposal will result in unaffordable residential rates for at least the bottom 20 percent of District households, one-fifth of all households in the District.

Q. WHAT RESIDENTIAL CUSTOMER ASSISTANCE PROGRAMS DOES THE COMPANY CURRENTLY OFFER?

A. The Company offers a Residential Aid Discount ("RAD") Program that provides eligible customers with a monthly credit for their full monthly distribution charges.[53] This credit is known as the Residential Aid Credit ("RAC"). To qualify for the RAD Program, customers must apply and receive certification of income eligibility from the District of

53 Direct Testimony of M.J. Bonikowski, page 31, 21-22.

Columbia Department of Energy and the Environment ("DOEE").[54] The RAC, pursuant to Order No. 18059 in Formal Case No. 1120, offsets the amount of the distribution customer charge, distribution energy charge, RAD Surcharge, Sustainable Energy Trust Fund Surcharge, and Energy Assistance Trust Fund Surcharge for RAD participants. In addition to this program, the Arrearage Management Program (AMP) allows qualifying Pepco customers in the District of Columbia the option of reducing or eliminating outstanding balances on residential accounts by making qualifying payments on budget billing one enrolled into the program. To be eligible to participate in the AMP, customers must be enrolled in the RAD Program and have a minimum balance of $300 that is at least 60 days past due and have a balance at or below $3,600.[55]

Q. WHAT OTHER ASSISTANCE PROGRAMS ARE AVAILABLE FOR LOW TO MODERATE INCOME HOUSEHOLDS IN THE COMPANY'S JURISDICTION?

A. There are four energy utility assistance programs administered by DOEE that serves low to moderate income residents in Washington D.C: (1) Low-Income Home Energy Assistance Program (LIHEAP); (2) Utility Discount Program (UDP); (3) Weatherization Assistance Program (WAP); and (4) Solar for All (SFA).[56]

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54 *Id*.

55 PEPCO Energy Assistance Website. https://thesource.pepcoholdings.com/what-energy-assistance-options-are-available/#:~:text=In%20addition%20to%20these%20programs,outstanding%20balances%20on%20residential%20accounts.

56 Ariel Drehobl, Diana Hernández, Roxana Ayala, and Lauren Ross. "An Examination of District Residents' Experiences with Utility Burdens and Affordability Programs." American Council for an Energy-Efficient Economy, March 2021, page 1.

Q. WHAT ASSISTANCE DOES THE LOW-INCOME HOME ENERGY ASSISTANCE PROGRAM ("LIHEAP") OFFER?

A. LIHEAP offers a one-time energy bill assistance between $250 and $1,800. The exact discount varies by various factors such as household size, total household income, heating source, and dwelling type.[57] To qualify for LIHEAP, customers need to be at or below 60 percent of the state median income. In fiscal year 2020, LIHEAP had total funding of $14,769,286 and served 9,654 households.[58] The state-eligible population in fiscal year 2020 was 76,602, meaning that LIHEAP served 12 percent of income-eligible households.[59] These numbers show that while important, the federal LIHEAP program has its limitations in addressing the needs of District consumers as it only serves a small percentage of income-eligible households.

Q. WHAT ASSISTANCE DOES THE UTILITY DISCOUNT PROGRAM ("UDP") OFFER?

A. The UDP offers a yearly bill discount of up to $475 on electric bills and $276 for gas heating bills, and/or over $962 on water and sewer bills to low-income District of Columbia residents.[60] To qualify for UDP, there is a maximum annual income limit: $79,700 for a household size of 1, $91,100 for a household size of 2, $102,500 for a household size of 3,

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57 *Id*.

58 District of Columbia LIHEAP FY2020 State Profile.

59 *Id*.

60 Department of Energy and Environment UDP Homepage

and $113,850 for a household size of 4.[61] These income limits are annually established by the U.S. Department of Health and Human Services.[62]

Q. WHAT ASSISTANCE DOES SOLAR FOR ALL ("SFA") OFFER?

A. SFA seeks to increase access to solar energy for low-income customers. Those who are at or below 80 percent of the state median income are eligible for free installation of PV systems on their home or eligible to participate in community solar.[63] Participants of Solar for All save about $500 per year on their electric bills. 3,103 residents participated in the SFA program in FY 2020.[64]

Q. WHAT ASSISTANCE DOES THE WEATHERIZATION ASSISTANCE PROGRAM ("WAP") OFFER?

A. This program supports customers with weatherization assistance. This assistance includes measures such as insulation, duct sealing, heating and cooling systems repair or replacement, air infiltration mitigation, and ENERGY STAR lighting and appliances, home energy efficiency, lowers bills, and improves home comfort.[65] 297 residents participated in WAP in FY 2020.[66]

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS AMP PROGRAM?

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[61] *Id*. There are additional income limits for household sizes of 5,6,7, and 8, $125,250, $136,650, $148,050, and $159,400 respectively.

[62] *Id*.

[63] Ariel Drehobl, Diana Hernández, Roxana Ayala, and Lauren Ross. "An Examination of District Residents' Experiences with Utility Burdens and Affordability Programs". American Council for an Energy-Efficient Economy, March 2021, page 1.

[64] *Id*, page 14.

[65] *Id*, page 1.

[66] *Id*, page 14.

A. The Company proposes to adopt the automatic enrollment feature that the Commission approved for Washington Gas Light Company ("WGL") in Formal Case No. 1164 in Order No. 21536.[67] This means that any RAD customer will be automatically enrolled into AMP if they meet eligibility requirements.[68] By lowering this barrier to entry, the Company hopes to increase accessibility of this assistance program. In addition, consistent with the approach approved for WGL, the Company will notify customers within 15 days of enrollment and these customers will have 45 days to opt out of the program.[69] A customer who fails to complete the program requirements will not be negatively impacted: there will be no retroactive removal for earned AMP credits and the customer will still be able to enter a deferred payment arrangement.[70]

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS RAD PROGRAM?

A. The Company proposes to expand the RAD program through additional marketing and outreach as well as expanding current eligibility requirements.[71] These new eligibility requirements will allow the Company to qualify any customers who has already been qualified by any District of Columbia governmental agency for low-income assistance.[72] In addition, because the AMP requires customers to be enrolled in the RAD program to qualify, AMP enrollment will likely increase of the pool of eligible RAD customers is

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67 Direct Testimony of Elizabeth O'Donnell, page 21, 5-9.

68 *Id*.

69 Direct Testimony of Morton Bell-Izzard, page 33,18, to page 34, 4.

70 *Id*.

71 Direct Testimony of Elizabeth O'Donnell, page 19, 5-9.

72 *Id*.

increased.[73] The Company plans to commit to additional marketing and outreach, broader advertising campaigns, and working with third party stakeholders to achieve this goal.[74]

Q. HOW MUCH WILL THE RAD PROGRAM PROPOSAL COST?

A. The Company estimates that the increased outreach effort for its RAD program will cost $900,000.[75] In addition, the Company anticipated an additional incremental cost of $160,000 per year associated with personnel engaged in application processing.[76] With the expected increase in enrollment, the RAD surcharge is likely to increase if the proposed changes are approved by the Commission.[77]

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S RAD PROPOSAL?

A. I recommend that the Commission not approve the Company's proposal at the current time and, instead, open a proceeding after the conclusion of the current rate case to look at low-income and affordability issues in a more holistic fashion. Changes to the RAD program could have important and potentially unintended consequences that affect other DOEE offered programs and other stakeholder initiatives. A more focused, stand-alone proceeding seems to be the better venue to consider such issues and develop an approach for consistent measurement and monitoring of energy affordability in the District.

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[73] *Id*, page 20, 4-6.

[74] Direct Testimony of Morton Bell-Izzard, page 30, 4-13.

[75] *Id*, page 32, 10-16.

[76] *Id*.

[77] *Id*.

V. <u>REVENUE DISTRIBUTION</u>

A. Revenue Distribution Objectives

Q. PLEASE EXPLAIN THE PURPOSE OF THE REVENUE DISTRIBUTION PROCESS IN SETTING RATES.

A. The revenue distribution process allocates a utility's overall revenue deficiency across customer classes, which in turn, is used to establish a new set of retail rates. The revenue distribution process often uses the results from the class cost of service study ("CCOSS") as its starting point but not necessarily as its ending point. Class-specific revenue responsibilities are established by allocating the system-wide revenue deficiency to classes that are under-earning, relative to their estimated rate of return ("ROR"), and assigning, at least in theory, revenue decreases to those classes that are over-earning relative to their CCOSS-estimated class returns. The final class revenue responsibilities are then used, in conjunction with the billing determinants for each class, to determine rates. In summary, the revenue distribution process can be thought of as the initial step taken to establish rates.

Q. DOES THE REVENUE DISTRIBUTION PROCESS INCLUDE ANY POLICY CONSIDERATIONS?

A. Yes. The Commission has discretion in setting class revenue requirements.[78] As is the case in this proceeding, allocating the overall system-wide revenue deficiency entirely on a full cost of service basis can result in a very significant and adverse rate impact for certain under-earning classes. To avoid such a result, regulators often temper the revenue responsibilities assigned to various customer classes in order to meet a set of broad

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[78] *Formal Case No. 1156*, Order No. 20755, ¶ 388.

ratemaking policy goals. Each of these policy considerations requires consideration of the specific facts of case.

Q. WHAT ARE THE BROADER RATEMAKING POLICY GOALS?

A. There are several generally accepted rate-making principles used in utility regulation that include:

1) Rates should be fair, just, and reasonable, and not unduly discriminatory.
2) To the extent possible, gradualism should be used to protect customers from rate shock.
3) Rate continuity should be maintained.
4) Rates should be informed by costs, but class cost of service results need not be the only factor used in rate development.
5) Rates should be understandable to customers.

Q. HOW ARE THE ABOVE PRINCIPLES APPLIED IN DEVELOPING RATES FOR A REGULATED UTILITY?

A. It is important to consider all of the principles I mentioned above. However, any principle's relative weight can change depending upon the importance of certain policy goals. Rate design should strike a balance between policy goals and resulting rates that are fair, just, and reasonable. There is no pre-set or universally accepted formula for developing rates and, as a result, sound judgment is necessary to formulate a rate design that meets these objectives. And as explained above, the Commission needs to examine the specific facts of a case in applying these principles.

Q. HAS THE COMMISSION MADE SIMILAR FINDINGS AND CONCLUSIONS IN ADDRESSING RATE DESIGN?

A. Yes. The Commission has stated in the past that the appropriate determination of rates is "not a matter for the slide-rule,"[79] and involves judgment regarding a myriad of facts. As part of its inquiry, the Commission considers cost factors and non-cost factors, such as efficiency and a customer's value of service.[80] Within this general framework, the Commission has historically upheld a policy of gradualism in moving rates towards cost-causation.[81] However, the Commission has made it clear that this is a general policy, seeing no requirement of uniformity among class rates of return and that other "equitable considerations" such as value of service and ability to pay, the quality of service delivered, historical rate patterns, the need to conserve energy resources, and other market-place reliability must be also considered by the Commission in establishing just and reasonable rates.[82]

B. Company's Proposed Revenue Distribution

Q. PLEASE EXPLAIN HOW THE COMPANY PROPOSES TO DISTRIBUTE ITS CLASS REVENUE REQUIREMENTS.

A. The Company proposes a four-step revenue allocation methodology in the current proceeding.[83] In step one, the Company identified Schedules GS-3A and TN as rate schedules with unitized rate of return ("UROR"), or relative rate of return (i.e., RROR),

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79 *See Formal Case No. 1053, In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service* ("*Formal Case No. 1053*"), Order No. 14712, ¶ 308, rel. January 30, 2008 (citing *Washington Gas Light Co. v. Pub. Serv. Comm'n. of D.C.*, 450 A.2d 1187, 1206 (D.C. 1982)).

80 *See Formal Case No. 1053*, Order No. 14712, ¶ 308.

81 *See id.*, ¶ 309.

82 *Formal Case No. 1156*, Order No. 20755 ¶ 388.

83 *Formal Case No. 1176*, Exhibit PEPCO (E) (Bonikowski) at 10:4-9.

greater than three times the system average rate of return and excluded these classes from any distribution rate increase.[84] In step two, the Company defines a "steady state" RROR band of plus or minus 0.10 (or 0.90 to 1.10 RROR) to indicate rate classes with RORs relative close to system average rate of return.[85] In step three, the Company assigns rate classes with RRORs of 0.90 or less a distribution revenue increase of 2.3 times the proposed system average increase.[86] In step four, the remaining revenue requirement increase is assigned to remaining rate classes on an equal proportionate basis.[87] Exhibit OPC (A)-3 presents the Company's estimated class rates of return, and its proposed revenue distribution, under its current and proposed rates.

Q. DEFINE THE CONCEPT OF A RELATIVE RATE OF RETURN.

A. The RROR effectively standardizes the class-specific rate of return estimated by a CCOSS to the overall system average. In other words, it divides the estimated class ROR by the estimated system ROR. For instance, assume that the residential class is earning a class-specific eight percent ROR, and further assume that the system-wide average ROR estimated by the same CCOSS is also eight percent. The residential class, in this example, can be said to be earning a 1.0 RROR if the estimated ROR is the same as the overall system (*i.e.*, eight percent divided by eight percent equals 1.0). Put another way, any class earning a 1.0 RROR can be said to be making its full contribution to the system's overall

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[84] *Formal Case No. 1176*, Exhibit PEPCO (E) (Bonikowski) at 11:2-4, 13:14-20, and 17, Table 3.

[85] *Formal Case No. 1176*, Exhibit PEPCO (E) (Bonikowski) at 11:5-10 and 14:11-16; notably, no rate classes were found by the Company to have current RROR existing within the defined steady state range.

[86] *Formal Case No. 1176*, Exhibit PEPCO (E) (Bonikowski) at 11:11-23 and 14:19-22.

[87] *Formal Case No. 1176*, Exhibit PEPCO (E) (Bonikowski) at 12:1-7.

ROR (*i.e.*, there is no cross-subsidy). A RROR that is greater than 1.0 indicates that a particular class is contributing more than the system average contribution to the Company's overall return. Likewise, a class that earns a RROR less than 1.0 but greater than zero can be said to be making a less-than-average contribution to the overall system.

Q. HOW ARE THE VARIOUS RATE YEAR INCREASES ALLOCATED ACROSS CUSTOMER CLASSES?

A. The Company proposes to allocate each rate year increase on a relative allocation basis, with the total revenue increase assigned to an individual rate class over the proposed MYP being equal to the Company's proposed allocation multiplied by the total proposed MYP incremental revenue requirement increase.[88] For example, the Company proposes that Schedule MGT LV be allocated 22.92 percent of all its MYP revenue increases.[89] Thus, Schedule MGT LV customers will be assigned 22.92 percent of any individual rate year increase. However, the exception to this proposal is Schedule R customers wherein the Company proposes spread the total proposed MYP allocated revenue requirement increase equally across all three rate years on an equal monetary basis.[90] This will result in roughly a $27 million annual increase to Schedule R customers each year across the full duration of the proposed MYP.[91]

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[88] *Formal Case No. 1176*, Exhibit PEPCO (E) (Bonikowski) at 20:11-19.

[89] *Formal Case No. 1176*, Exhibit PEPCO (E)-2

[90] *Formal Case No. 1176*, Exhibit PEPCO (E)-3.

[91] *Formal Case No. 1176*, Exhibit PEPCO (E)-3.

Q. DOES THE COMPANY'S TTYCF PROPOSED REVENUE ALLOCATION DIFFER FROM ITS PROPOSED ALLOCATION UNDER THE PROPOSED MYP?

A. Yes, slightly. The Company proposes to allocate 42.52 percent of its proposed TTYCF rate increase to residential customers,[92] compared to the proposed 42.73 percent under its proposed MYP.[93] However, these differences are solely due to the Company's proposed lower overall requested base revenue increase in its TTYCF ($63.7 million),[94] compared with its requested first year increase under the proposed MYP ($67.9 million),[95] and not any difference in proposed revenue allocation process.

Q. DO YOU AGREE THAT A CLASS RROR LESS THAN ONE IS PROBLEMATIC OR INEQUITABLE?

A. Not necessarily. Consistent with the principles identified above, there may be factual or policy reasons to support such a result that does not result in an inequitable cross-subsidization. For example, the presence and/or continuation of a RROR below 1.0 could be the result of a prior agreed-upon rate freeze that prevents class rates from increasing to correct the revenue deficiency (relative to cost of service). In this example, the presence of a RROR below 1.0 is simply a function of a prior policy decision, not necessarily the result of some arbitrary or intentionally designed inequity. Nonetheless, I understand the

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92 *Formal Case No. 1176*, Exhibit PEPCO (2E), Supplemental Direct Testimony of Matthew J. Bonikowski at 7, Table 2.

93 *Formal Case No. 1176*, Exhibit PEPCO (E), Direct Testimony of Matthew J. Bonikowski at 17, Table 3.

94 *Formal Case No. 1176*, Exhibit PEPCO (2E)-2.

95 *Formal Case No. 1176*, Exhibit PEPCO (E)-2.

Commission has a stated goal of ending negative class RORs over a series of Pepco rate cases.

Q. HOW DOES THE COMPANY PROPOSE TO INCREASE RATES FOR ITS UNDER-EARNING CLASSES?

A. The Company proposes a revenue distribution that will increase rates for classes earning less than 0.90 RRORs that is equal to 2.3 times the overall system-wide percentage increase.[96] The Company is also proposing to increase rates at a system-wide average of 34.8 percent in order to recover its estimated revenue deficiency.[97] Thus, the Company's proposal for classes with RRORs of less than 0.9 will see rate increases that are, in absolute percentage terms, approximately 80 percent (i.e., 2.3 times 34.7 percent) across the full term of the proposed MYP.[98] Exhibit OPC (A)-4 presents a summary of the Company's proposed total rate increase by rate schedule for the entirety of the proposed MYP.

Q. WHAT HAVE BEEN THE COMMISSION'S PAST POLICIES REGARDING RESIDENTIAL CLASS NEGATIVE RELATIVE RETURNS?

A. The Commission has stated that it is committed to "moving in a deliberate and reasonable fashion to eliminate negative class RORs."[99] It first recognized the issue in Formal Case Nos. 1087 and 1103. The Commission began taking corrective action to eliminate disparities in customer class RORs in Formal Case No. 1103, assigning $11.11 million, or

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96 *Formal Case No. 1176*, Exhibit PEPCO (E) (Bonikowski) at 11:11-23, 14:19-22, and 17, Table 3.

97 *Formal Case No. 1176*, Exhibit PEPCO (E)-3.

98 *Id.*

99 *Formal Case No. 1103*, *In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service* ("*Formal Case No. 1103*"), Order No. 17424 ¶ 437, rel. March 26, 2014.

47 percent of the proposed jurisdictional increase, to the residential class.[100] Nothing in its policy, however, requires completely eliminating all such disparities within the context of a single rate case.[101]

Q. DID THE COMMISSION REINFORCE A POLICY PREFERENCE FOR ADDRESSING THE NEGATIVE RROR FOR THE RESIDENTIAL CLASSES IN SUBSEQUENT RATE CASES?

A. Yes, to an extent. In Formal Case No. 1139, the Commission reiterated that it has historically had a policy of gradually lessening the disparities in RRORs between rate classes.[102] However, the Commission noted that there is no requirement of uniformity among ROR from different customer classes, and that equity considerations such as value of service and ability to pay, among others, may be considered in setting both customer class revenue requirements and in determining appropriate rate design.[103] These are factual questions the Commission must consider in evaluating application of its general policy.

Q. HOW DID THE COMMISSION ALLOCATE THE RATE INCREASE TO THE RESIDENTIAL RATE CLASS IN THE COMPANY'S LAST RATE CASE, FORMAL CASE NO. 1156?

A. Given the uncertainty associated with potential impacts of the pandemic on the local economy, the Commission decided to adopt a more uniform revenue allocation across rate

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100 *Id.*

101 *Id.* at ¶ 438.

102 *See Formal Case No. 1139*, Order No. 18846, ¶ 453.

103 *Id*.

classes, with residential and SL-E customers receiving rate increases approximately equal to 0.89 times the system average increase.[104] In approving a less than system average increase the Commission noted that it recognized that the approved revenue allocation "only marginally address[ed] the commercial class's subsidization of the residential class's costs."[105]

Q. WILL PEPCO'S PROPOSAL SUCCEED IN ELIMINATING NEGATIVE CLASS RORS?

A. No, it is not likely that these negative class returns will be eliminated. I have examined the historic trends in the Company's allowed revenue distribution, and those trends show that over the several years the Commission has allocated a greater than average share of the Company's past rate increases to the residential rate classes, the residential class's RROR did not improve. Indeed, the only improvement in the residential classes' RROR occurred after the Company's most recent rate case filing. Exhibit OPC (A)-5 examines the Commission's authorized revenue allocations across customer classes, going back to Formal Case No. 1053 decided in 2007, more than a decade ago. In the subsequent three rate cases Formal Case Nos. 1076, 1087, and 1103, the Commission approved increases to base rates for residential customers that were between 2.21 and 2.48 times the system average rate increases. In other words, residential base rate increases for these classes were more than double the rate increases that were approved at the overall system level. Yet,

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[104] *Formal Case No. 1156*, Order No. 20755, ¶ 394.

[105] *Id.*, ¶ 395.

these disproportionate, larger-than-average rate increases did not improve the estimated RRORs for the residential classes.

Q. PLEASE EXPLAIN.

A. Exhibit OPC (A)-5 shows that in Formal Case No. 1076, the first rate case in which the Commission articulated its policy of eliminating negative RRORs, the total residential customer class was estimated to be earning a RROR of -0.47. Later, in Formal Case No. 1087, the estimated RROR decreased to -0.54 despite the fact that residential customers were assessed with a rate increase that was 2.21 times the system average. In the following rate case (Formal Case No. 1103), residential customers were estimated to be earning a RROR of -0.41. While this RROR increased slightly from the prior rate case, this moderate change in the RROR was paid for with a disproportionately large rate increase that was 2.48 times the overall system average. Subsequent cases continued this trend, with the Company reporting residential RRORs that were worse than previous years, despite the fact that the residential class received a rate increase consistent with the system average rate increase in Formal Case No. 1139, and received a disproportionately small rate decrease in the Company’s last rate case that incorporated operating savings due to the passage of the 2017 TCJA, namely Formal Case Nos. 1150/1151. .

Q. HAS THE RESIDENTIAL RROR IMPROVED RECENTLY?

A. Yes. In Formal Case No. 1156, the Company estimated that residential customers were earning a RROR of -1.00. However, in the current proceeding the Company estimates that earnings from residential customers has improved to a RROR of -0.68. This represents an approximate one-third reduction in negative RROR for residential customers since the

Company's last rate case. Rather than "only marginally address[ing] the commercial class' subsidization of the residential class' costs,"[106] as stated by the Commission in its Order, the Commission's approval of a less than average rate increase for residential customer has led to the most substantial improvement in class subsidization since at least Formal Case No. 1053.

Q. HAVE YOU CONDUCTED ANY OTHER ANALYSES THAT EXAMINE THE HISTORIC TRENDS IN THE COMPANY'S ALLOWED REVENUES ON A PER CUSTOMER CLASS BASIS?

A. Yes, I have provided this analysis in Exhibit OPC (A)-6. This analysis examines a number of different ratemaking statistics, on a per customer class basis, dating back to Formal Case No. 1053. I have analyzed statistics including number of customers, energy sales, revenues, and revenues per kWh sold. The analysis clearly shows that the total residential class has received allowed revenue increases of 189.3 percent over the past 17 years compared to the 137.5 percent for other commercial classes. If the Company's proposed rate case is approved as filed, residential customers will have seen rate increases of **402.2 percent** since Formal Case No. 1053. Compare this to the other customer classes, over a comparable time period, that will have only seen a 195.2 percent increase. The residential classes' combined per kWh revenue has grown from $0.0178 per kWh in 2006 (Formal Case No. 1053) to $0.0432 per kWh, and if the Company's current proposals are accepted in their entirety in this rate case, will grow to $0.0748 per kWh by 2025. Thus, continuing a policy of saddling residential customers with exceptionally large rate increases, in hopes

[106] *Formal Case No. 1156*, Order No. 20755, ¶ 395.

of solving what appears to be some kind of systemic rate design problem, appears to be fruitless.

Q. WHY WON'T THE COMPANY'S PROPOSED REVENUE DISTRIBUTION RESOLVE THE NEGATIVE RROR PROBLEM?

A. The Company's revenue distribution proposal will not resolve the problem because it is based upon a static, and not dynamic view, of the Company's cost trends and CCOSS results. The results of the analysis I described above suggest that costs historically were simply increasing at rates faster than those that could be reasonably allocated to residential customers.

Q. HOW SHOULD THE COMMISSION RECONCILE ITS GOAL OF ELIMINATING NEGATIVE CLASS RORS WITH THE FACT THAT RATES ARE INCREASING FASTER THAN WHAT CAN BE REASONABLY ASSIGNED TO RESIDENTIAL CUSTOMERS?

A. These goals cannot be reconciled. Therefore, I recommend that the Commission re-consider its policy of assigning relatively higher portions of any revenue increase in an attempt to eliminate negative RRORs at this time given the facts of this case and the experience from recent rate cases. I cannot envision a way in which the Commission can financially support the Company's efforts to improve reliability or other policy directives in the District at the current rate of spending and correct its long-standing ratemaking challenges at the same time. If the Commission does not adopt my recommendation, it should explain to the District's ratepayers how these two policy objectives can be met simultaneously and why they should be confident that circumstances will be different this time in light of the experience in recent rate cases.

C. Revenue Distribution Recommendations

Q. DOES THE COMPANY'S PROPOSED REVENUE DISTRIBUTION DIFFER FROM THAT PROPOSED BY THE COMPANY IN PRIOR RATE CASES?

A. Yes. In Formal Case No. 1139, the Company proposed to allocate revenues to the main residential classes[107] by one third of the difference between these customer classes' then-current respective rates of return and a zero percent rate of return.[108] In this manner, the Company stated that it would move the ROR for the main residential classes to a zero percent ROR over three successive rate cases.[109]

Q. DID THE COMMISSION APPROVE THE COMPANY'S PROPOSED REVENUE DISTRIBUTION APPROACH IN FORMAL CASE NO. 1139?

A. No. While the Commission did accept the Company's proposal to allocate $7.45 million of the approved $36.888 million increase to the residential class, it importantly rejected the Company's proposed three-step plan.[110] In its decision, the Commission found that increasing residential rates by the amount thought to be needed to eliminate the estimated negative RRORs over the course of two or three cases would result in rate increases that could potentially lead to rate shock.[111]

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[107] Residential ("R") and Residential-All Electric ("R-AE") classes. These tariff classes have been merged for Cost of Service purposes in the current proceeding as simply the "R" customer class.

[108] *See Formal Case No. 1139*, Exhibit PEPCO (G) (Janocha) at 4:20-22.

[109] *Id*. at 7:6-9.

[110] *See Formal Case No. 1139*, Order No. 18846, ¶ 455.

[111] *Id*., ¶ 456.

> We make this revenue requirement allocation recognizing that adopting Pepco's 20% residential allocation marginally impacts the commercial class' subsidization of the residential class' costs. We are reducing Pepco's total request by 52% and providing a corresponding bill reduction to the estimated $3.84 residential bill increase Pepco estimated in its Application, resulting in a $209 average increase to residents. Further, we have decided not to move as aggressively towards reducing the negative rate of return as we have in the past or as AOBA has suggested. If we moved to reduce the commercial class subsidization of residential class customers so that residential RORs reach zero in two or three rate cases, the rate impact in this proceeding would have been $6.46 per month (for two rate cases) or $4.32 (for three rate cases). Therefore, Pepco's rate increase is being distributed among the customer classes in a manner that continues to *gradually* adjust rate structures so that rates move closer to being cost-based for all customer classes while minimizing rate shock in this proceeding.[112]

Q. IS THE COMPANY'S PROPOSED REVENUE DISTRIBUTION CONSISTENT WITH ITS RECOMMENDATIONS IN PAST RATE CASES?

A. Yes. While the Company does not state in its current application or testimony that it is proposing to increase rates to under-earning classes by an amount thought to be needed to eliminate current negative RRORs over a series of cases, the Company's proposal appears to be designed around a similar intention. As shown in Exhibit OPC (A)-3, the Company finds that residential customers would require an additional $161.6 million in allocated revenue requirement in order to eliminate existing negative earnings to the customer class. The Company's proposed revenue distribution would increase residential customer rates by $27.2 million per year for each year of the proposed MYP, or $54.3 million within the first two years of the MYP. Effectively, the Company is continuing to advocate for its

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112 *Id*.

failed previous proposals of increasing rates to under-earning rate classes by an amount thought to be needed to eliminate the estimated negative RRORs over the course of multiple cases. The only difference in the current proceeding is the Company's use of its proposed MRP as a singular conduit for this proposal since the MRP includes three separate rate increases over a three-year time period.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED REVENUE DISTRIBUTION?

A. I recommend that the Company's proposed revenue distribution allocating an increase of 2.3 times the system average for customer classes currently earning RROR less than 0.90 be rejected. In place of the Company's proposal, I recommend that the Commission adopt a more reasonable revenue distribution allocation method that assigns customer classes currently earning RROR lower than 0.90 a revenue increase equal to 1.25 times the overall system average increase. High allocations of any rate increase onto under-earning rate classes, as proposed by Pepco, should not be approved until the Commission can be assured that any enhanced residential revenue responsibility allocation will lead to an improvement in its estimated RROR. Over the past several years, the Commission has allocated a significant share of the Company's requested rate increase to the residential classes, and, despite those increases, the residential classes' RRORs have not improved. There is no reason to assume that pursuing the same revenue distribution strategy in this rate case will result in any differing results, and it is likely that the Commission will not be successful in addressing this RROR challenge until such time that the Company's infrastructure investment growth slows.

Q. HAVE YOU PREPARED A SUMMARY OF THE EFFECTS OF YOUR PROPOSED REVENUE DISTRIBUTION?

A. Yes. My proposed alternative revenue distribution is presented in Exhibit OPC (A)-7. My proposed revenue distribution would lower the proposed increase in base rates to residential customers to 15.5 percent, compared to the Company's proposed increase to these same customers of 28.53 percent.

VI. RATE DESIGN

A. Rate Design Objectives

Q. WHAT ARE THE COMPANY'S RATE DESIGN GOALS?

A. The Company states that the guiding principles used in the development of its distribution rate design reflect the directives given by the Commission in Formal Case Nos. 1139, 1103, 1087, 1076, and 1156.[113] Specifically, the Company finds that past Commission rulings have presented a position that the Commission desires rates to have a greater emphasis on customer charges and demand rates, and less emphasis on volumetric charges.[114]

Q. HOW SHOULD POLICY BALANCE RATE DESIGN GOALS BETWEEN SETTING APPROPRIATE CUSTOMER CHARGES AND VOLUMETRIC RATES?

A. Modern utility pricing theory is primarily concerned with the development of optimal tariff design, which over the years has become dominated by a form of pricing referred to as a "two-part tariff," sometimes referred to more technically as a non-linear (or non-uniform)

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113 *Formal Case No. 1176*, Exhibit PEPCO (E) (Bonikowski) at 23:19-21.

114 *Id.* at 23:21-24:3.

pricing approach. Once a class revenue requirement is established, the goal for regulators should be one that sets the most appropriate rates based upon various efficiency and equity considerations. Balancing the weight of how costs are recovered between fixed rates, variable rates, block rates, and seasonal rates are all integrated parts of that process.

Q. WHAT IS THE APPROPRIATE ROLE OF COSTS IN SETTING RATES BASED UPON A TWO-PART TARIFF?

A. Costs can be instructive in establishing a baseline upon which prices may be set, but costs do not need to serve as the sole or exclusive basis for rates in order for them to be set optimally (i.e., fixed charges do not need to strictly equal fixed costs, variable rates need not strictly equal variable costs). Unfortunately, repeated discussions regarding the "fixed charge-equals-fixed cost" philosophy can often drown out meaningful discussions about other equally important considerations in setting rates in imperfect markets. In fact, appropriate rate setting in the context of a two-part tariff typically has more to do with consumer demand than it does with cost.

B. Customer Charge Proposals

Q. PLEASE DISCUSS THE COMPANY'S RESIDENTIAL CUSTOMER CHARGE PROPOSAL.

A. A summary of the Company's current and proposed customer charges under both its proposed MYP and TTYCF are provided in Exhibit OPC (A)-8. The Company proposes to increase the residential customer charge by $1.00 in each rate year (RY1, RY2, and RY3).[115] Collectively, such changes represent a $3.00 increase from the current residential

[115] *Id.* at 31:7-8.

customer charge of $16.09, and would, in effect, raise existing customer charges by 18.6 percent. In its TTYCF request, the Company proposes to immediately increase the residential customer charge by $2.76, or 17.2 percent. As can be seen in Exhibit OPC (A)-8, the Company's proposed changes to customer charges in its TTYCF approximate its proposed changes in its MYP .

Q. IS THE COMPANY PROPOSING TO INCREASE ANY OTHER CLASS' CUSTOMER CHARGES?

A. Yes. I identify those increases in Exhibit OPC (A)-8. In summary, the Company is proposing the following customer charge increases by RY3:[116]

- An increase in customer charge for its General Service - Secondary ("GS ND") class of 16.4 percent.
- An increase in customer charge for its General Service - Temporal ("T") class of 16.4 percent.
- An increase in customer charge for its Time Metered General Service - Low Voltage ("GT LV") class of 60.9 percent.
- An increase in customer charge for its Time Metered General Service - Primary ("GT 3A") class of 21.0 percent.
- An increase in customer charge for its Rapid Transit Service ("RT") class of 23.2 percent.

Q. IS THE COMPANY PROPOSING TO DECREASE THE CUSTOMER CHARGES OF ANY OF ITS RATE CLASSES?

A. Yes. Pepco is proposing to decrease the customer charge for its Master Metered Apartments ("MMA") class from $5.44 to $1.78, or by approximately 67.3 percent.[117] The Company is also proposing to reduce the monthly customer charge for the General Service

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116 *Formal Case No. 1176*, Exhibit PEPCO (E)-5.

117 *Formal Case No. 1176*, Exhibit PEPCO (E)-5.

- Low Voltage ("GSLV") class by 1.2 percent, the Time Metered Medium General Service - Low Voltage (i.e., MGTLV) class by 11.2 percent, and its Time Metered General Service - Sub-Transmission (i.e., GT3B) class by 36.6 percent.[118]

Q. HAVE YOU COMPARED THE COMPANY'S RESIDENTIAL CUSTOMER CHARGES TO OTHER REGIONAL ELECTRIC UTILITIES?

A. Yes, and this analysis is presented in Exhibit OPC (A)-9. This analysis shows that the Company's current residential customer charge of $16.09 per month is noticeably greater than the regional average of $11.36 per month. This schedule surveys current residential and small commercial customer charges for major electric distribution companies operating in the Mid-Atlantic region. There are only five (out of 16) electric distribution utilities in the survey with residential customer charges greater than the Company's $16.09 per month. Further, Pepco's Maryland residential customer charges are 49 percent lower than the customer charges in the District.

Q. HAVE YOU COMPARED THE COMPANY'S COMMERCIAL CUSTOMER CHARGES TO OTHER REGIONAL ELECTRIC UTILITIES?

A. The Company's current small commercial customer charge of $32.88 per month is far greater than the average small commercial customer charge of $15.75 for other regional utilities. Furthermore, out of 16 electric distribution companies in the survey referenced earlier, none have a customer charge for small commercial customers that is greater than the Company's proposed $38.28 per month. Pepco's Maryland small commercial customer charges are 63 percent lower than the customer charges in the District.

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[118] *Formal Case No. 1176*, Exhibit PEPCO (E)-5.

Q. DID YOU PREPARE AN ANALYSIS OF COSTS COMMONLY ASSOCIATED WITH CUSTOMER CHARGES?

A. Yes. That analysis is provided in Exhibit OPC (A)-10 and summarized in Figure 5 below. "Customer-related" expense accounts are those typically allocated on the basis of customers and can include: removing and setting meters; maintenance of meters; services expense; maintenance of service drops; meter reading expense; dispatch applications and orders; customer records and collections; customer billing and accounting; customer service and information; and sales expense. These costs can also include the depreciation expense associated with the service drop and meter plant accounts and property taxes, as well as the carrying charges (at the Company's requested rate of return) for the customer portion of services investment and 100 percent of the meters investment.

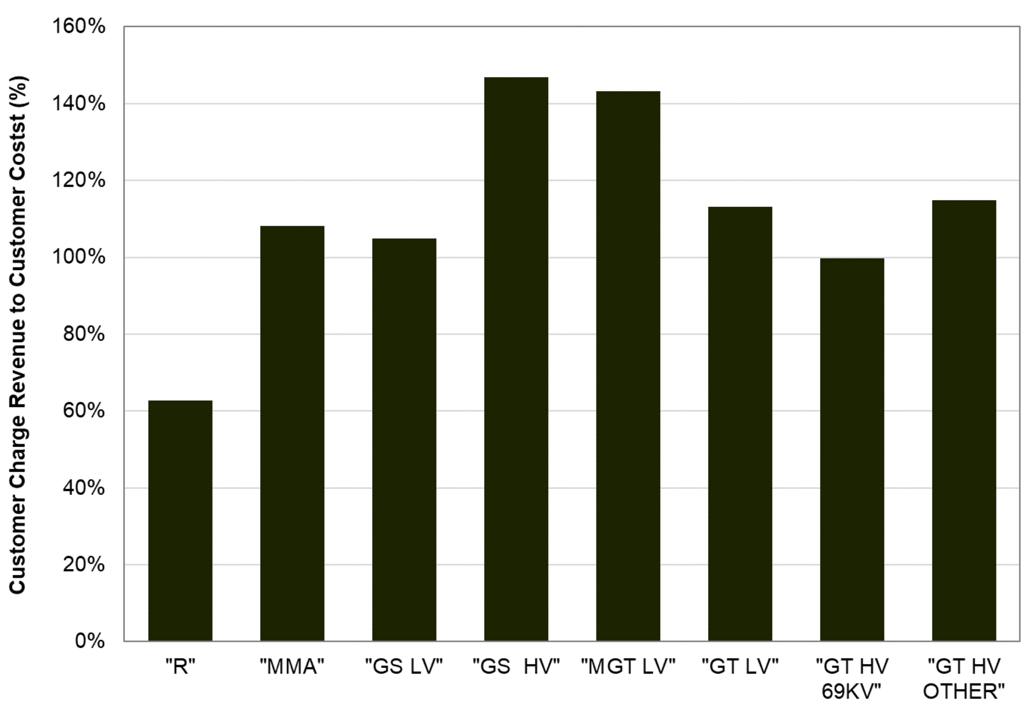

Figure 5: Summary of Customer Charge Revenues to Customer-Related Costs

Q. HOW DO THE COMPANY'S RESIDENTIAL CUSTOMER CHARGE REVENUES COMPARE WITH THE RESULTS OF ITS CCOSS?

A. As shown in Exhibit OPC (A)-10 the customer charge revenue associated with the R and MMA rate classes is 63 percent and 108 percent, respectively, of their class cost responsibility.

Q. HOW DO THE COMPANY'S GENERAL SERVICE CUSTOMER CHARGES COMPARE WITH THE RESULTS OF ITS CCOSS?

A. The results of the Company's non-residential classes' revenues are also shown in Exhibit OPC (A)-10. The Company's customer charge revenues for the GSLV and GSHV classes, respectively, are 105 percent and 147 percent of their class cost responsibility. The customer charge revenue for the Time Metered Secondary Service (MGT-LV) and Time Metered General Service low-voltage class (GTLV) are 143.3 and 113 percent of its cost-of-service responsibilities, respectively. The Time Metered high voltage classes, GTHV-69kv and GT-HV-Other, have customer charge revenues of 100 percent and 115 percent of their respective class cost responsibility.

Q. DO THESE RESULTS INDICATE ANY PRESSING NEED TO MAKE AN IMMEDIATE AND DRASTIC INCREASE IN CUSTOMER CHARGES, PARTICULARLY FOR THE RESIDENTIAL CLASS?

A. No. Most of the classes cover their customer-related costs through the current customer charge. Current residential customer charges do not fully cover current customer-related costs, but even for these customers the Company's current customer charge is estimated to cover 63 percent of their customer-related costs, or nearly two-thirds and more than a majority of such expenses. Likewise, the residential MMA class is estimated to currently recover 108 percent of its customer-related costs.

Q. WOULD THE PROPOSED INCREASES TO THE RESIDENTIAL CUSTOMER CHARGE BE AFFECTED BY ANY OTHER COMPANY RATE DESIGN PROPOSAL?

A. Yes. In addition to the proposed increases to the customer charge for the residential customer class, the Company additionally proposes to increase the discounted volumetric block rate of 1.055¢ for the first 400 kwh of use to 2.647¢ by RY3. This is an increase of 151 percent over a three-year period.

Q. SHOULD THE COMMISSION BE MINDFUL OF THE EFFECT OF THE COMPANY'S PROPOSED RATE DESIGN ON LOW-USE RESIDENTIAL CUSTOMERS?

A. Yes. There are numerous studies in the academic literature supporting the hypothesis that electricity is a "normal good."[119] That is, the consumption of electricity is directly correlated with household income level, meaning that higher-use electrical customers are typically higher income individuals and lower-use electrical customers are typically lower

[119] *See*, Exhibit OPC (A)-25, Alberini, A., W. Gans, D. Velez-Lopez. 2011, "Residential consumption of gas and electricity in the U.S.: The role of prices and income," Energy Economics 33, 870-881; Bernard, J., D. Bolduc, N. Yameogo, 2011, "A pseudo-panel data model of household electricity demand," Resource and Energy Economics 33(1), 315-325; Dax, P. 1987, "Estimation of Income Elasticity from Cross-Section Data," Applied Economics 19 (11), 1471-1482; Fell, H., S. Li, A. Paul. 2010, "A New Look at Residential Electricity Demand Using Household Expenditure Data," RFF DP 10-57; Fullerton, T. D. Juarez, A. Walke. 2012, "Residential Electricity Consumption in Seattle," Energy Economics; Reiss. P.C., and M. W. White, 2005, "Household electricity demand revisited," Review of Economic Studies 72, 853-858; and Swan L.G., V. I. Ugursan, 2009, "Modeling of end-use energy consumption in the residential sector: A review of modeling techniques," Renewable and Sustainable Energy Reviews 13, 1819-1835.

income individuals. These are important factual considerations the Commission should bear in mind.

Q. HAVE YOU CONDUCTED ANY ANALYSES EXAMINING THE RELATIONSHIP OF ELECTRICITY USAGE AND INCOME?

A. Yes, I am providing factual and analytical support for the Commission to consider. Page 1 of Exhibit OPC (A)-11 provides the results of an analysis I have performed using data from the 2020 Residential Electricity Consumption Survey ("RECS") produced by the United States Energy Information Administration ("EIA") and household data from the Census division in which the District is located.[120] The results show a positive relationship between electricity consumption (in kWh terms) and income. This clearly shows that as income increases, electricity consumption increases, and vice versa: as income decreases, electricity usage decreases.

Q. ARE THERE LOW-INCOME CUSTOMERS WHO WILL NOT BE AFFECTED BY THE COMPANY'S PROPOSED RATE CHANGES?

A. Yes. The Company states in its filing that its proposed rate increase for residential service customers will not affect customers receiving service under the RAD Program.[121] RAD provides a monthly credit (the RAC) that offsets the full customer and volumetric distribution charges of eligible residential customers who receive certification of income eligibility from the District's DOEE.[122]

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[120] This census division also includes the states of Delaware, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, and West Virginia. This is the most detailed level of aggregation available in the RECS.

[121] *Formal Case No. 1176*, Exhibit PEPCO (E) (Bonikowski) at 32:6-9.

[122] *Id.* at 31:21-32:6.

Q. SHOULD THE COMMISSION IGNORE THE POTENTIAL EFFECT OF THE COMPANY'S PROPOSED RATE INCREASE ON LOW-INCOME RESIDENTIAL CUSTOMERS BECAUSE OF THE RAD PROGRAM?

A. No, this is an important factual and policy issue that the Commission should not ignore. As noted above, the RAD Program is income-restricted. Specifically, it is restricted to only those households that meet federal LIHEAP eligibility standards.[123] For the District, this amounts to $95,797 for a family of four and as little as $49,814 for a single occupant household.[124] Indeed, the Company reported an average of 37,850 customers in low-income programs the District in 2022,[125] with 25,814 of these customers specifically enrolled in RAD.[126] This means that nearly 13 percent of the Company's entire residential customer base is enrolled in some form of low-assistance program. There are many low-income persons living in the District that do not receive benefits through the RAD Program, and the Commission should not ignore this important fact.

Q. DO LOW INCOME HOUSEHOLDS SPEND PROPORTIONATELY MORE IN ELECTRICITY THAN HIGHER INCOME HOUSEHOLDS?

A. Yes. Lower income households spend a larger share of their income on electricity than higher income households. In other words, while households consume more electricity as

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123 *District of Columbia LIHEAP Energy Burden Analysis* (September 2020), Department of Energy and Environment at 3.1.

124 "Receive Assistance With Your Utility Bills," Department of Energy and Environment, available at: https://doee.dc.gov/liheap.

125 Exhibit OPC (A)-26, Response to OPC Discovery Request 3-34.

126 Exhibit OPC (A)-27, Response to OPC Discovery Request 3-45.

income increases, the share of their income they spend on electricity decreases as their income increases.

Q. WHAT DO THESE FINDINGS MEAN FOR LOWER-INCOME HOUSEHOLDS UNDER THE COMPANY'S RATE DESIGN PROPOSALS?

A. Lower-income households will likely be impacted negatively and in a fashion disproportionate to higher income households. As I noted earlier, electricity use increases as income increases, meaning that low-income households will likely use less, rather than more, electricity than their upper income counterparts. Therefore, the Company's proposal to increase volumetric rates will disproportionately impact those with lower usage and incomes in the District. Indeed, the Company's Conditional Demand Analysis ("CDA") based on its most recent appliance saturation study confirms my conclusions.[127]

Q. ARE THERE OTHER CONCERNS REGARDING THE PROPOSED INCREASES IN RESIDENTIAL CUSTOMER CHARGE?

A. Yes. The Company's proposal is inconsistent with the promotion of energy efficiency and conservation in the District for the simple reason that it places more costs into the fixed component of rates than in the variable component. This reduces economic incentives for ratepayers to control monthly utility bills through energy efficiency and conservation efforts, because only the variable component of bills is avoidable.

Q. HAVE OTHER COMMISSIONS RECOGNIZED THE DETRIMENTAL EFFECT INCREASED FIXED CHARGES HAVE ON ENERGY EFFICIENCY?

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[127] *Formal Case No. 1176*, PEPCO (E)-16.

A. Yes. In rejecting a request by Northern States Power Company to increase customer charges[128] as part of a larger rate design proposal, the Minnesota Public Utilities Commission recognized the need to allow customers the opportunity to control their monthly bills by reducing energy usage.

> Monthly customer charges are an important component of the Company's Residential and Small General Service rates by facilitating recovery of the costs caused by each customer that do not vary with the amount of energy used. However, higher fixed customer charges discourage customers from conserving energy and investing in renewable energy by reducing the impact of these efforts on the customers' bills. Customer charges also tend to confuse and alienate customers by impairing customer understanding of their energy bills. The Commission notes that Minn. Stat. §216B.03 requires the Commission to design rates to encourage energy conservation and renewable-energy use to "the maximum reasonable extent." Considering this statutory mandate and the evidence submitted by the parties, the Commission agrees with the ALJ that it is reasonable and appropriate to lower the monthly customer charge for the Residential and Small General Service classes to $ 6.00.[129]

Q. IS THE MINNESOTA COMMISSION ALONE IN ITS BELIEF THAT HIGH FIXED CHARGES DISCOURAGE EFFICIENT USE OF ENERGY?

A. No. A research document presented for consideration by the membership of the National Association of Regulatory Utility Commissioners ("NARUC") lists Straight-Fixed Variable ("SFV") rate design as an alternative to delink utility revenue from sales. A SFV places all fixed-related costs to fixed charges while relegating only variable charges to

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128 *In the Matter of the Application of Northern States Power Company, dba Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota*, Minnesota Public Utilities Commission, Docket No. E-002/GR-21-630, Findings of Fact, Conclusions, and Order, at 114 (July 17, 2023).

129 *Id.*at 116-117.

volumetric rates. The NARUC research noted this type of rate design was problematic because of its effects on customer incentives to conserve energy:

> **Straight-Fixed Variable Rate Design.** This mechanism eliminates all variable distribution charges and costs are recovered through a fixed delivery services charge or an increase in the fixed customer charge alone. With this approach, it is assumed that a utility's revenues would be unaffected by changes in sales levels if all its overhead or fixed costs are recovered in the fixed portion of customers' bills. <u>This approach has been criticized for having the unintended effect of reducing customers' incentive to use less electricity or gas by eliminating their volumetric charges and billing a fixed monthly rate, regardless of how much customers consume</u>.[130]

Q. HAS ANY NATIONAL PUBLIC POLICY ANALYSIS NOTED THE EFFICIENCY DISINCENTIVES ASSOCIATED WITH SFV-TYPE RATE DESIGNS?

A. Yes. The National Action Plan for Energy Efficiency ("NAPEE"), a joint venture of the U.S. Department of Energy and U.S. Environmental Protection Agency, published a whitepaper on various rate design effects on encouraging energy efficient behaviors. The NAPEE postulated that SFV had a detrimental effect on economic signals to encourage customers to change energy usage behavior and investments in energy efficiency devices, and specifically noted that such disincentives persist even when applied to individual components of a customer's utility bill, such as SFV for strictly distribution services:

> Because [SFV] tends to shift costs out of volumetric charges, it tends to reduce customers' efficiency incentive, because the marginal price of additional consumption is reduced. <u>While SFV rates are being considered to better reflect the utility's costs behind the rate, these rates do not encourage customers to change energy usage behavior or invest in</u>

[130] "Decoupling for Electric & Gas Utilities: Frequently Asked Questions (FAQ)" (September 2007), Grants & Research Department, National Association of Regulatory Utility Commissioners, p. 5. (Emphasis added).

> efficiency technologies. Such customer disincentives persist even when SFV rates are applied to individual components of the bill, such as charges for distribution service.[131]

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS AND CONCLUSIONS?

A. Given the important factual and policy considerations involved, I recommend that the Commission direct the Company to maintain customer charges at their current levels.

Q. PLEASE EXPLAIN WHY YOU RECOMMEND THAT THE COMMISSION DIRECT THE COMPANY TO MAINTAIN CUSTOMER CHARGES AT THEIR CURRENT LEVELS.

A. I make this recommendation in part because the Company's customer charges are already on the high side of other regional utilities and do not need to be increased any further. Additionally, residential customers have seen significant cumulative increases in customer charges over the past few rate cases. Since Formal Case No. 1053 in 2006, residential customers have seen fixed customer charges increases of a whopping 705 percent, from $2.00 per month to $16.09 per month. These significant and ongoing increases have left the District's residential customer charges at a level noticeably higher than the equivalent charges for residential customers living in the Company's Maryland service territory. Furthermore, District ratepayers will not be able to mitigate these increases in fixed

[131] National Action Plan for Energy Efficiency, "Customer Incentives for Energy Efficiency Through Electric and Natural Gas Rate Design" at 13-14, prepared by William Prindle, ICF International, Inc. (September 2009) (emphasis added), available at https://www.epa.gov/sites/production/files/2015-08/documents/rate_design.pdf.

customer charges through participation in District energy efficiency programs or other conservation efforts.

VII. PEPCO'S MYP REQUEST

A. Overview of MYP

Q. PLEASE DESCRIBE THE MYP.

A. The MYP was originally proposed in Formal Case No. 1156 under the premise that it would assist the Company in making significant long-term investments to meet the District's policy goals and changing needs of its customers,[132] with a particular emphasis on investments in grid modernization and infrastructure required to facilitate District goals of climate action, transportation electrification, and increased resilience.[133] The MYP was originally proposed as a three-year mechanism (2020-2022) and included a set of proposed PIMs to incentivize performance and compliance with policy objectives.[134] The original proposal was ultimately "enhanced" in the last base rate case ("enhanced MYP") in order to reduce proposed near-term rate increases and to provide an increased set of residential and commercial customer assistance programs.[135]

Q. DID THE COMMISSION APPROVE THE COMPANY'S PROPOSED MYP IN FORMAL CASE NO. 1156?

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[132] Exhibit OPC (A)-28, *Formal Case No. 1156,* Exhibit PEPCO (A), Direct Testimony of David M. Velazquez at 8:4-5.

[133] *Id.* at 8:21 to 9:2.

[134] *Id.* at 8:13-17.

[135] Exhibit OPC (A)-29, *Formal Case No. 1156,* Exhibit PEPCO (5B) (McGowan) at 15:19-22.

A. No. The Commission rejected both Pepco's original MYP and its enhanced MYP as proposed.[136] Instead, the Commission approved a modified enhanced MYP with a reduced revenue requirement recognizing the regulatory mechanism's reduced financial risk.[137] The Commission's modified enhanced MYP also required additional Pepco shareholder-funded customer benefit programs for residential, small commercial, and streetlight customers in the District,[138] and a revised set of tracking PIMs focused on the District's climate and clean energy goals.[139]

Q. WAS THE MODIFIED ENHANCED MYP APPROVED AS A PERMANENT CHANGE IN REGULATORY METHODS IN THE DISTRICT?

A. No. The Commission was clear in Formal Case No. 1156 that the modified enhanced MYP was approved as a pilot program and that there would be an explicit process by which overall performance and effectiveness of the MYP would be evaluated.[140]

> With respect to customer benefits, the Modified [Enhanced MYP] is designed to among other things, make rates more predictable for customers, with rate increases spread gradually over multiple years. In this case, the prolonged proceeding and the exigency of the COVID pandemic led the Commission to <u>approve a pilot 18-month [Enhanced MYP]</u> with offsets through 2022 that lessons the impact of Pepco's [Enhanced MYP] rate increase. <u>Adopting the Modified [Enhanced MYP] as a pilot program provides the Commission, the Parties, and other stakeholders with an opportunity to improve the [MYP] process and prudently</u>

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136 *Formal Case No. 1156*, Order No. 20755, ¶ 142.

137 *Id.*

138 *Id.*

139 *Id.*

140 *Id.*, ¶ 474.

> evaluate the overall performance and effectiveness of the Modified [Enhanced MYP].[141]

The Commission also explained that it "will determine on a case-by-case basis whether the principles of the framework have been met in the proposed AFOR under the specific facts and circumstances of the case."[142]

Q. DID THE COMMISSION PROVIDE ANY GUIDANCE ON CONSIDERATION OF MYP OR SIMILAR MECHANISMS IN FORMAL CASE NO. 1156?

A. Yes. The Commission's decision was based upon broad considerations regarding "paradigm shifts" away from traditional ratemaking toward AFORs.[143] The Commission concluded that review of any AFOR, not just an MYP, must be deliberative in nature due to the potential scope of changes, and recognized that such changes may require multiple rate proceedings to fully implement.[144]

> While the statute permits the Commission to adopt AFORs, the Commission's review of any changes to the traditional ratemaking methodology must be deliberative, paying careful attention to the structure and framework for the evaluation of AFORs so that unintended operational or financial outcomes are mitigated and managed. The District's electric and natural gas utilities combined, as of their last fully litigated rate case, collect from ratepayers $691.45 million per year to support the safe and reliable operations of energy distribution systems valued at $1.9 billion. In considering and implementing changes as to how the costs of these systems are accounted for and recovered from ratepayers, the Commission must carefully consider how its actions impact the operational incentives of the utilities, ensure that it maintains the financial stability and

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141 *Id., emphasis added.*

142 *Formal Case No. 1156,* Order No. 20737, ¶ 96.

143 *Formal Case No. 1156*, Order No. 20755, ¶ 473.

144 *Formal Case No. 1156*, Order No. 20273, ¶ 86.

> flexibility of the utilities, and promote the utilities' continued safe and reliable operations over time. The Commission recognizes that there will not be quick or rapid changes in rate review and recovery given the importance of utility operations to the District and the scope of their operations. We believe that any changes to the traditional ratemaking methodology may require multiple rate proceedings to fully implement AFORs.[145]

Q. WHAT SPECIFIC GUIDANCE DID THE COMMISSION PROVIDE REGARDING AFORS IN FC 1156?

A. The Commission established an overarching framework as a starting point for which AFOR proposals would be reviewed including the consideration of PIMs, that advance or otherwise align with District public policy goals,[146] and indeed the Commission held that "any [MYP] that is adopted should be accompanied by PIMs."[147]

Q. WERE PIMS PART OF THE ORIGINAL PILOT PROGRAM APPROVAL?

A. No, since the Commission rejected the Company's originally proposed PIMs which mainly focused on promoting service reliability. The Commission found such a limited set of PIMs unnecessary since it already has Electric Quality of Service Standards ("EQSS") governing reliability performance.[148] Instead, the Commission approved a set of initial tracking (or "reporting-only") PIMs that, once properly designed, could be turned into fully functioning PIMs with financial penalties associated with poor performance.[149] The Commission ordered Pepco to reconvene an existing PIMs Working Group to collaborate

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[145] *Formal Case No. 1156*, Order No. 20273, ¶ 86, emphasis added.

[146] *Id.*, ¶ 94.

[147] *Id.*, ¶ 108, *emphasis added.*

[148] *Formal Case No. 1156*, Order No. 20755, ¶ 166.

[149] *Id.*, ¶ 169.

with interested parties on appropriate data measurement methodologies for the approved tracking PIMs, and implied that it envisioned this collaborative process being an ongoing process to develop additional financial/tracking PIMs as needed in the future.[150]

Q. HAS THE COMMISSION OR THE PIMS WORKING GROUP DEVELOPED FULLY FUNCTION PIMS FOR USE WITH THE COMPANY'S MYP?

A. No, there are no approved PIMS in place at the current time. To date, the PIMs Working Group has not only been unable to develop a comprehensive set of working PIMs, it has still yet to finalize appropriate data measurement methodology associated with the Commission-implemented tracking PIMs from the last base rate case.

Q. WAS A REVIEW PROCESS ENVISIONED FOR THE MODIFIED ENHANCED MYP?

A. Yes. The current procedural schedule clearly states that the existing MYP was approved as a pilot mechanism and that further review of the lessons learned and experiences with the program would be important in considering any proposed new MYP mechanism.[151]

B. Evaluation of Existing Pepco's MYP Mechanism

Q. WHAT POTENTIAL MYP BENEFITS WERE IDENTIFIED IN FC 1156?

A. Ten quantitative and qualitative benefits were purported to arise from adoption of the MYP including: (1) facilitating investments that support the District's energy policy goals; (2) providing customers, the Commission, and interested parties a longer-term view of future capital investments and O&M plans before the utility makes those investments; (3)

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[150] *Id.*, ¶ 173.

[151] *Id.*

providing customers with rate predictability over the MYP's term; (4) providing a decrease in the administrative burden and cost for the Commission and stakeholders by reducing the frequency of annual rate case filings; (5) protecting customers and provide incentives to the Company to reduce costs and improve operational efficiency through the proposed Annual Reconciliation Filing; (6) aligning customer rates and reflect the current cost of providing service to customers; (7) increase the level of transparency and reporting to customers, the Commission, and stakeholders; (8) enhancing Commission oversight through advance review of the Company's total capital investment plan and proposed performance levels, with annual reporting and reviews of certain variances to those approved plans over the term of the MYP and again at its conclusion; (9) providing for significant automatic financial penalties if the Company did not meet Commission-approved performance criteria; and (10) enhancing certainty of spending for the MYP's term, leading to improved investment planning that would create jobs and promote economic development.[152]

Q. HAS THE COMPANY "PROVED UP" ANY OF THESE ASSERTED BENEFITS IN ITS CURRENT FILING?

A. No, Pepco has not provided evidence or analysis to support a finding of fact that its proposal will provide these benefits. Rather, the Company provides open-ended assertions regarding MYP performance including statements like "the MYP has allowed for more

152 *Formal Case No. 1176*, Exhibit PEPCO (2A), Direct Testimony of Elizabeth M. D. O'Donnell at 3:1 to 4:4; *citing*, *Formal Case No. 1156*, Exhibit PEPCO (3B), McGowan Additional Supplemental Direct Testimony at 9-21, submitted January 21, 2020, and *Formal Case No. 1156*, Exhibit PEPCO (4B), McGowan Rebuttal Testimony at 9-17, submitted April 8, 2020.

timely recovery of investments over the MYP," that the MYP has allowed the Company to "invest at the pace required to meet the District of Columbia's and the Commission's decarbonization and clean energy goals."[153] The Company also states that the MYP provided a longer-term, forward-looking view of proposed business and capital investment plans[154] and rate predictability for customers during its term.[155] Importantly, however, the Company did not provide any quantifiable and measurable review of supposed historic benefits of the MYP, even while claiming that the MYP's reduction in administrative burden and costs associated with annual rate case filings was "quantitative and measurable."[156] The one exception to this, was a report, prepared by NERA, that purports to show the economic benefits of the MYP on the District's economy.

Q. PLEASE EXPLAIN THIS NERA REPORT OF PURPORTED MYP BENEFITS.

A. The Company provided an economic benefits study conducted by NERA Economic Consulting (hereafter "NERA Report") estimating the economic impact of the Company's actual investments in 2022 and proposed capital investments from 2023 through 2026.[157] This analysis supposedly found that Pepco's plan is estimated to support over 3,800 full-time equivalent jobs, contribute more than $580 million in value added to gross domestic product and $26 million in tax revenue in the District.[158]

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153 *Formal Case No. 1176*, Exhibit PEPCO (2A), Direct Testimony of Elizabeth M. D. O'Donnell at 4:13-16.

154 *Id.* at 5-12.

155 *Id.* at 6:9-13.

156 *Id.* at 7:12.

157 *Formal Case No. 1176*, Exhibit PEPCO (A), Direct Testimony of Elizabeth M. D. O'Donnell at 23:3-9; *see also*, Exhibit PEPCO (A)-1 CONFIDENTIAL.

158 *Id.*

Q. HOW CAN LARGE CAPITAL INVESTMENTS IMPACT A LOCAL ECONOMY?

A. Capital investment programs like those purportedly "facilitated" by the MYP can lead to both positive and negative economic impacts. For instance, capital investments can lead to a number of construction, engineering, and other employment opportunities in the local economy. These capital expenditures can lead to ripple "multiplier" effects since every dollar spent in the local economy is supported by a variety of other activities and investments.

Q. DO PROGRAMS SUCH AS THE MYP COME WITH ANY COSTS?

A. Yes, this is an important factual issue that the NERA Report fails to consider. Capital investment programs, like those purportedly facilitated by the MYP, need to be financed, and that financial support, in the case of regulated utility investment, comes from the rates paid by retail ratepayers. These rate increases, however, represent a cost since they reduce household disposable income and increase costs to businesses and industries. Reductions in household income and increases in business costs, in turn, reduce the amount of money spent on goods and services, which in turn, leads to negative ripple or multiplier effects in a regional economy, in same way program-related expenditures result in positive ripple effects. A complete review of the MYP, therefore, needs to consider the "net benefits" of overall program costs and benefits. While the NERA Report considered the local "benefits" of these purportedly MYP-facilitated capital investments, the study does not offset such benefits with the costs of the investment program, namely, the rate impacts.

Q. HAVE YOU ESTIMATED THE NET BENEFITS OF THE COMPANY'S PURPORTED MYP INVESTMENT PROGRAM?

A. Yes, and this is presented in Confidential Exhibit OPC (A)-12 and pages 18-23 show that the Company's MRP Pilot has led to, and will continue to lead to, negative net economic benefits. My findings are that the MRP Pilot in conjunction with the MYP proposal will have the following economic effects:

- A contraction of economic output of over $2.7 billion on a net-present value ("NPV") basis.
- An employment reduction of 41,000 job-years;
- A $1 billion reduction in overall wages; and
- A $1.2 billion reduction in local GDP.

C. Evaluation of Alternative Regulation in General

Q. HAS THE COMPANY COMPARED ITS PERFORMANCE TO OTHER AFORS?

A. No. The Company has conducted no specific analysis looking at any of the ten different benefits that purportedly have arisen from the MYP nor have they compared/contrasted their AFOR performance with best practices in other regulatory jurisdictions. My experience, however, is that, to date, few AFORs have led to results that provide clear and unequivocal ratepayer benefits.

Q. HAVE YOU EXAMINED AFOR PERFORMANCE IN OTHER JURISDICTIONS?

A. Yes, and that analysis is provided in Exhibit OPC (A)-13. For purposes of this analysis, AFORs are limited to the major "paradigm shifting" forms of regulation that include formula rate plans ("FRPs"), performance-based ratemaking ("PBR") and MYP mechanisms. My analysis finds that, to date, no major form of AFOR has led to meaningful or measurable ratepayer benefits, including no sustainable or distinctly measurable improvement in reliability or quality of service.

Q. WHAT CONCLUSIONS DO YOU REACH FROM THIS ANALYSIS?

A. As shown in Exhibit OPC (A)-13, no major form of AFOR has led to any meaningful or measurable ratepayer benefits in other jurisdictions. Indeed, no one single state adopting an AFOR has shown outcomes that can be held out as an unequivocal "success" for ratepayers. Specifically, AFORs have generally led to:

- Deterioration in utility capital investment discipline with significant increases in rate base;
- Large rate increases with very few rate decreases or earning sharing opportunities;
- No measurable or sustainable improvement in utility operating cost efficiencies; and
- No sustainable or distinctly measurable improvement in reliability or quality of service.

D. Review of the Company's MRP Pilot

Q. DID YOU REVIEW SUPPLEMENTAL TESTIMONY IN THIS CASE RELATED TO THE MRP PILOT?

A. Yes, I reviewed the Supplemental Testimony submitted by Pepco on August 31, 2023, which the Company was required to submit per Order 21886. This supplemental filing reviewed the MRP Pilot, including lessons learned by the Company, as well as an explanation, in quantitative and qualitative terms, as to the benefits of the MRP Pilot.

Q. BASED ON YOUR REVIEW OF PEPCO'S TESTIMONY AND FILING REGARDING THE MRP PILOT SHOULD THE COMMISSION ADOPT A MULTIYEAR PLAN?

A. No. Pepco's pre-filed testimony and exhibits contain no analysis or support for findings that (a) the MRP pilot, to date, has provided any ratepayer benefits and (b) that moving to the proposed MYP will result in any *bona fide* and measurable public benefits. To date, the Commission has no PIMs to govern a future MYP and will likely not have any by the conclusion of this proceeding. Failure to adopt PIMs or any other form of performance accountability in this proceeding is inequitable since it provides clear and unequivocal benefits to the Company and its shareholders but no measurable benefits to the District's ratepayers. It is virtually impossible to establish a set of rates that are fair, just, and reasonable under such conditions and under a framework like that proposed by the Company. Therefore, the Commission must also reject the proposed MYP at the current time.

Q. WHAT KIND OF BENEFITS SHOULD RATEPAYERS EXPECT TO SEE FROM A MULTIYEAR PLAN?

A. Ultimately, the set of performance metrics for a multiyear plan, such as the MRP Pilot and the proposed MYP, should be straightforward, measurable, and transparent and should focus on big-pictures goals: lower and/or more affordable rates; greater operating and cost efficiencies; and lower GHG emissions, particularly Pepco's own Scope 1 GHG emissions.

Q. WILL ENERGY AFFORDABILITY IMPROVE IF THE COMPANY'S MRP PILOT IS CONTINUED ON A PERMANENT BASIS?

A. No, and I discussed this outcome in my discussion of affordability earlier in my testimony. Figure 6 below comes from the affordability analysis I conducted for the District (OPC Exhibit (A)-2) and shows that some of the District's most vulnerable ratepayers will be adversely impacted if the MYP is approved.

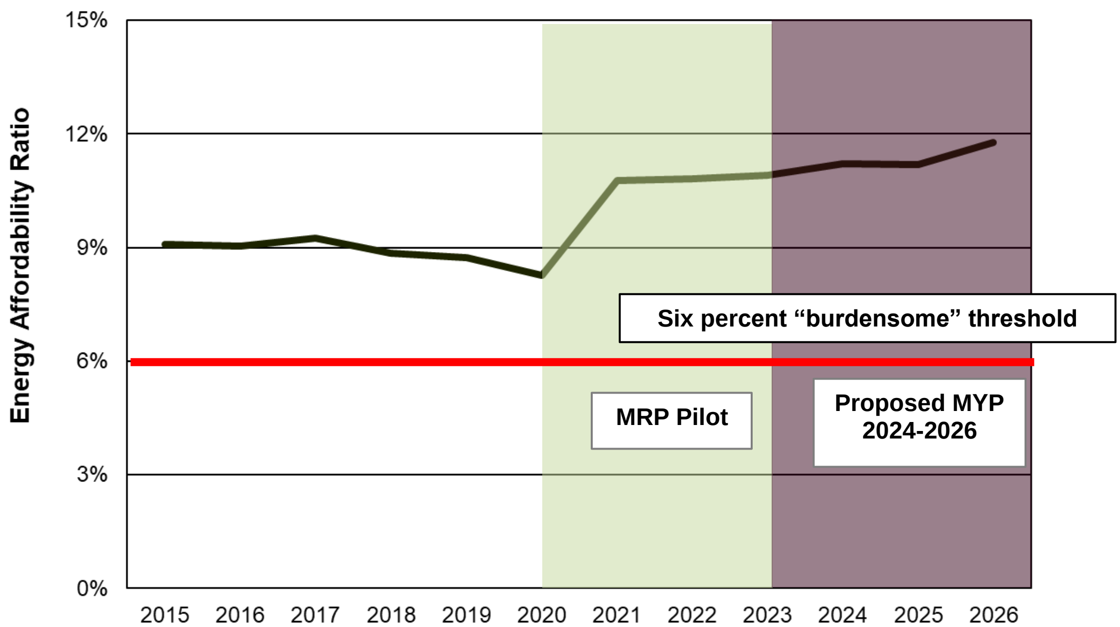

Figure 6: Energy Affordability Ratio for Customers at or below 15th income percentile

Q. DID PEPCO'S RATE COMPETITIVENESS IMPROVE DURING THE MRP PILOT?

A. No. Exhibit OPC (A)-13 includes a section examining a number of different metrics (prices, costs, capital investments) before and during the MRP Pilot. These metrics have been compiled for both the Company and other regional peer investor-owned utilities ("IOUs"). Pages 63 to 69 provide a comparison of the Company's residential and commercial retail rates (average non-fuel revenues) relative to peer utilities. The table and charts on these pages show that Pepco's retail rates have not improved during the MRP Pilot period. Specifically, Pepco has consistently had the 9th highest residential rates in the region (out of a peer group of 14 utilities) since 2017. Pepco's commercial rates have grown during the MRP Pilot period such that the Company has the 12th highest rates in the region.

Q. DID PEPCO SEE ANY IMPROVEMENTS IN ITS OPERATING COST EFFICIENCIES DURING THE MRP PILOT?

A. No. Pages 70 to 76 of Exhibit OPC (A)-13 show a variety of comparisons of both the Company's O&M and A&G costs. Over the past year of available information, Pepco has not seen demonstrative improvement in its O&M costs relative to peer utilities and, in fact, has seen its ranking deteriorate recently. While the Company's A&G performance has improved, that improvement seems highly correlated with its prior merger and, if anything, recent trends suggest a halt in those A&G cost improvements over the past year of available information.

Q. DID PEPCO SEE ANY IMPROVEMENTS IN ITS CAPITAL COST EFFICIENCIES OVER THE MRP PILOT PERIOD?

A. No. As shown in pages 77 to 81 of Exhibit OPC(A)-13, Company growth in net distribution plant in service has constantly outpaced regional peer utilities since 2013. In recent years Company net distribution plant per MWh of load has grown to the highest of all regional peer utilities, without any sign of moderation from the MRP Pilot.

Q. IS THERE ANY EVIDENCE TO SUGGEST THAT GHG EMISSIONS IN THE DISTRICT IMPROVED DUE TO THE MRP PILOT?

A. No. Page 83 of Exhibit OPC (A)-13 show that GHG emissions in the District have been steadily declining through the entirety of the period 2010 through 2020. Page 84 of Exhibit OPC (A)-13 furthermore shows that non-residential GHG emissions in the district fell from approximately 4.2 million metric tons of CO_2 equivalents ("MMTCO2e") in 2010 to approximately 2.1 MMTCO2e in 2020, a 50 percent decline over the course of the decade without any utility intervention. So, while it is possible that the District saw reduced GHG emissions during the course of the MRP Pilot, there is little evidence to suggest these reductions were due to the MRP Pilot.

E. The MYP in Relation to Climate and Clean Energy Goals

Q. ARE THERE ANY OTHER REASONS TO REJECT THE COMPANY'S REQUESTED MYP?

A. Yes. The capital investments identified to be recovered through the MYP are not designed to meet the District's climate and clean energy goals, but, instead, appear to be designed to meet its normal public service obligations. OPC's engineering expert, Mr. Kevin Mara, notes that several of the Company's proposed MYP capital investment programs are comparable to those he has seen repeatedly over the past several years, up to, and including those in which the Company was regulated using "traditional" cost of service methods. Mr. Mara shows in his direct testimony that over 90 percent of the Company's proposed MYP investments are dedicated to the replacement of aged infrastructure and other "business as usual" investments, not those dedicated to clean energy or reducing GHG emissions. There is no showing that these business-as-usual and "like for like" investments cannot be facilitated thought traditional regulation, much like they were prior to the MRP Pilot.

Q. IS PEPCO ABLE TO MATCH ITS PROPOSED MYP INVESTMENTS TO SPECIFIC CLEAN ENERGY OR CLIMATE GOALS?

A. No. Pepco has not been able to identify which of its MYP capital investments are specifically designed to meet the District's climate and clean energy goals[159] nor, more importantly, has the Company been able to identify how it will measure the success of such investments in meeting these climate and clean energy goals.[160]

Q. HAS THE COMMISSION RECENTLY EXPRESSED ANY RESERVATIONS ABOUT THE APPROVAL OF ILL-DEFINED CLIMATE-RELATED INVESTMENTS?

A. Yes. The Commission recently considered, and ultimately rejected, Washington Gas Light Company's ("WGL's") proposal to fund six future climate initiatives through a new Climate Action Recovery Tariff ("CART").[161] The Commission based its rejection of the CART proposal on the premature nature of WGL's request, observing:

> Until projects have been approved by the Commission, whether in *Formal Case No. 1167* or other proceedings, according to the mechanism approved in *GD2019-04-M*, there should be no cost recovery for these unapproved programs at this time.[162]

Q. COULD CERTAIN INVESTMENTS PROPOSED BY THE COMPANY BE USEFUL FOR GRID MODERNIZATION AND IMPROVING THE DISTRICT'S CLEAN ENERGY CAPABILITIES?

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[159] Exhibit OPC (A)-30, Pepco's Response to OPC Data Request 4-1(b).

[160] Exhibit OPC (A)-30, Pepco's Response to OPC Data Request 4-1(a).

[161] *Formal Case No. 1169, In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Natural Gas Service,* ("Formal Case No. 1168"), Order No. 21939 at ¶ 430, rel. December 22, 2023 ("Order No. 21939").

[162] Order No. 21939, ¶ 430.

A. Mr. Mara notes that the Advanced Distribution Management System ("ADMS") has the ability to make important contributions to grid modernization but, to date, there is not clear linking of specific and quantifiable annual benefits and costs needed to attain those benefits. Furthermore, the Company has not clearly shown how its clean energy and climate investments cannot be facilitated under traditional forms of regulation.

Q. WHAT CONCERNS DO YOU HAVE WITH PEPCO'S ADMS PROPOSAL WITHIN THE CONTEXT OF A REGULATORY FRAMEWORK?

A. If anything, the Company's inability to show any unique need nor performance standard for its clean energy investments, including the ADMS, begs for a tighter form of traditional regulation, not a MYP. The Company's ADMS alone serves as a good reason why the Commission should utilize traditional regulation and not an MYP:

- The ADMS is small relative to the Company's proposed MYP capital investments.
- The Company cannot specifically identify and quantify the ADMS benefits, many of which may not start to materialize until as late as 2029.
- There is no well-defined process by which these investments will be rolled out, their composition, and the input that stakeholders, including the Commission, will have in this process.

Q. HOW LARGE ARE THE ADMS INVESTMENTS RELATIVE TO THE COMPANY'S TOTAL PROPOSED MYP CAPITAL SPENDING AMOUNTS?

A. Table 1 below compares the Company's annual ADMS investment levels relative to its total proposed MYP capital budget. The ADMS is relatively small, less than one percent of total capital spending, on average, over the MYP period. There is nothing in the ADMS investment levels that are large or volatile enough to justify some form of alternative regulation nor some alternative to a MYP such as a special, limited one-time capital tracker to address the goals of this program alone.

Table 1: Comparison of Annual ADMS to Total MYP Capital Budget

	2024	2025	2026	Total MYP
	($000)			
Advanced Distribution Management System (ADMS)				
Project 268: ADMS Implementation	$ 3,845	$ 3,460	$ 1,640	$ 8,945
Project 294: ADMS Covergence-Stage 2	-	-	3,485	3,485
Total ADMS	**$ 3,845**	**$ 3,460**	**$ 5,126**	**$ 12,430**
Total Executive Capital Budgeted Through MYP Period	**$ 456,190**	**$ 476,906**	**$ 489,551**	**$ 1,422,647**
Percent ADMS of Total Capital Budgeted	**0.84%**	**0.73%**	**1.05%**	**0.87%**

Q. HAVE THE DETAILS AND FUNCTIONALITIES OF THIS PROPOSED INVESTMENT BEEN CLEARLY DEFINED?

A. No. Mr. Mara notes that many of the ADMS functionalities could help to facilitate distributed energy resource ("DER") development in the District. For instance, the Enterprise Asset Management Program is expected to be a precursor for the Company's Distributed Energy Management System ("DERMS") and purportedly will allow for the interconnection and control of various different technologies and resource ownership models. However, DERMS itself is part of a future phase of the ADMS implementation that is not projected for deployment until 2029. Thus, the details and functionalities of this program are yet to be fully scoped or defined.[163] Furthermore, Mr. Mara notes that the

[163] Exhibit OPC (A)-31, Pepco's Response to OPC Data Request 6-20.

ratepayer benefits of this program, from an engineering perspective, cannot be assessed at the current time.

Q. DOES A MYP FACILITATE STAKEHOLDER PARTICIPATION AND ACCOUNTABILITY?

A. No. The MYP does not include nor assure a proper framework for the Commission, OPC, and other stakeholders to assure that investments made by the Company are prudent, will not lead to technologies and processes that will be quickly obsolete and stranded, nor will a MYP facilitate the kind of interconnection and diversity of ownership envisioned in grids of the future. This later consideration is important, particularly as it relates to investments facilitating the future deployment of the DERMS. The DERMS is purportedly designed to facilitate various different technologies and ownership types, so it is incumbent that stakeholder input, of all types, be facilitated. Such input requires more regulation, not less regulation typical of a MYP and other AFORs. .

Q. WHAT IS THE BEST FORM OF REGULATION TO ADDRESS THE DISTRICT'S CLIMATE CHANGE GOALS?

A. The goals of today's clean energy agenda require greater regulatory oversight and input to assure that a wide range of resource options, participants, and potential outcomes are considered. The goals of most clean energy agendas are societal in nature, and have been, and should continue to be determined by public policy, not by regulated utilities and their shareholders. AFORs effectively decouple prices from costs and allow utilities (and by default, their shareholders) to establish priorities that maximize profits, not necessarily a clean energy/climate agenda. AFORS allow prices to change, with little to no ongoing regulatory oversight and input. Once the "cast-off" rates are set, regulators are put in a passive position to hope that positive regulatory outcomes, assuring ratepayer benefits, are attained. This is particularly problematic if no *ex-ante* performance standards or benchmarks (with penalties for negative outcomes) are established.

Q. DOES A "HANDS-OFF" FORM OF REGULATION WORK WELL AT ASSURING PERFORMANCE GOALS ARE MET?

A. No. This is not the 1980s, and in the absence of very clearly defined standards, with penalties and other forms of accountability, regulators need to be more actively engaged to assure that ratepayers are protected and that other clean energy goals, including GHG emission reductions, are met. To date, the Commission itself has had a difficult time defining what performance standards it wants from Pepco placing all performance risk of the MRP Pilot exclusively upon ratepayers. If the Commission does that once again, by approving the Company's proposed MYP, without a clearly defined, fully vetted set of performance standards agreed upon by a diverse group of impacted stakeholders, it will be difficult to assure that rates are fair, just, and reasonable.

Q. WHAT REGULATORY APPROACH DO YOU RECOMMEND THE COMMISSION ADOPT IN ORDER TO HELP ACHIEVE THE DISTRICT'S CLIMATE

A. To assure both forward movement on the District's clean energy agenda, and the protection of ratepayers, a return to traditional regulation is the best option. Pepco's pre-filed testimony and exhibits contain nothing that would suggest, much less demonstrate, that moving back to traditional regulation will be harmful to that clean energy agenda. A return to traditional oversight methods will ensure that rates are set in a fashion consistent with their public policy requirements.

VIII. BILL STABILIZATION ADJUSTMENT

A. BSA Background

Q. PLEASE DESCRIBE THE BSA.

A. The BSA is a rider adjustment that is designed to recover differences between authorized test year RPC and actual base RPC collected by the Company. In proposing the BSA in 2009, the Company claimed that the mechanism would "decouple revenues from variation in kWh sales per customer."[164] The BSA is designed to provide the Company with stable revenue streams based on test year revenue requirements,[165] by insulating the Company from changes in sales resulting from weather, price elasticity, building standards, expanded energy efficiency programs, and changes in appliance efficiency.[166] The BSA, it was argued, would increase the stability of customer bills and reduce the Company's financial risk, eliminate the disincentive for the Company to promote energy efficiency, and help ensure fixed-cost recovery.[167]

Q. HOW IS THE BSA CALCULATED?

A. The BSA is computed by comparing the normalized per-customer monthly test year revenues from the Company's base rate case proceeding for each customer class, with the actual per-customer revenues, adjusted for any major service outages. This difference,

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164 *See Formal Case No. 1053*, Order No. 14712, ¶ 340.

165 *Id.*

166 *Id.*, ¶ 341.

167 *Id.*, ¶ 343.

along with any over or under-collections from previous months, is divided by forecasted kWh sales to derive a volumetric adjustment for the BSA.

Q. HOW DOES THE BSA COMPARE TO OTHER DECOUPLING MECHANISMS USED BY SOME UTILITIES ACROSS THE COUNTRY?

A. The BSA is an RPC-based form of revenue decoupling that allows the Company to adjust revenues between rate cases. An RPC-based revenue decoupling mechanism uses a commission-authorized revenue requirement as the numerator, and test year customers, as the denominator. Weather-normalized actual RPC collected by the utilities are then compared against this authorized RPC benchmark, with revenue surpluses credited to customers and revenue deficiencies assessed as a surcharge on customer bills. With respect to Pepco, this comparison is done on a monthly basis, though other utilities have revenue decoupling mechanisms that are reconciled on a quarterly or annual period.

Q. HAVE YOU REVIEWED THE HISTORIC PERFORMANCE OF THE COMPANY'S BSA?

A. Yes. Exhibit OPC (A)-14 presents historical BSA credits and debits from December 2009, when the adjustment first went into effect, to July 2023. This analysis shows that in general, revenues recovered through the BSA have grown significantly since it was first implemented in late 2009. The BSA recovered less than $3.2 million in 2010 then grew substantially, recovering almost $16.2 million in 2015. While the $16.2 million figure from 2015 was down from the total BSA adjustment for 2014 of nearly $22.0 million, revenues recovered through the BSA continued to grow after 2015. In 2018 the BSA recovered more than $26.2 million, and by 2022, the mechanism recovered nearly $36.1

million. In just the first eleven months of 2023 the BSA has totaled nearly $40.1 million in recoveries. Over the entire history of the BSA, the Company has recovered an astounding **<u>$294.0 million</u>** from ratepayers.

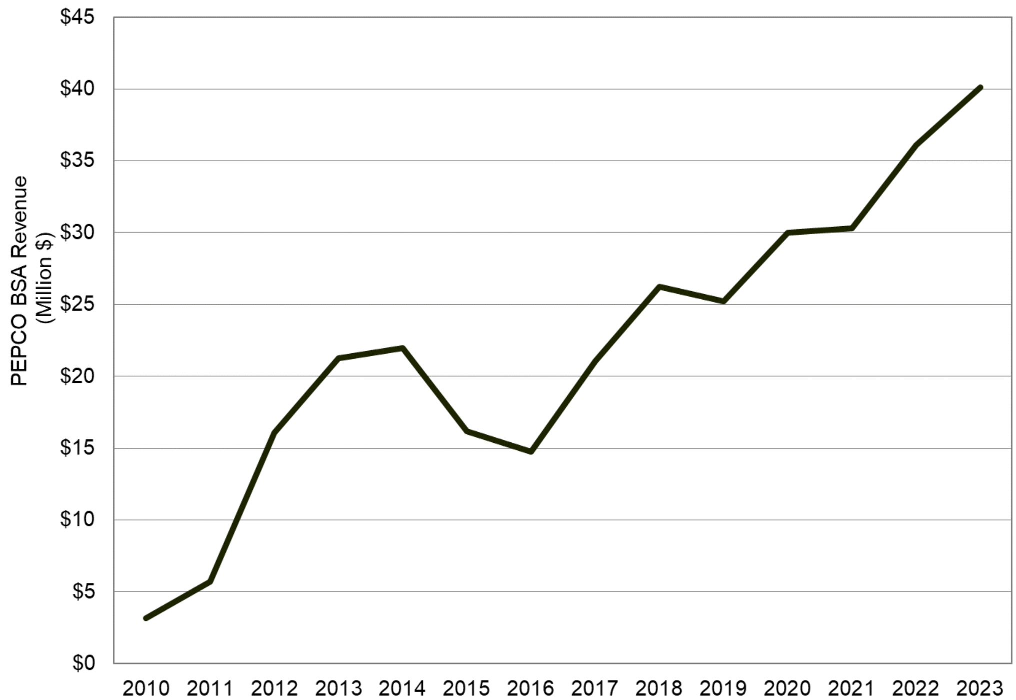

Figure 7: Historic Total BSA Revenues

Q. HAVE THE LEVEL OF SURCHARGES AND REFUNDS BEEN COMPARABLE SINCE THE BSA WAS PUT INTO PLACE?

A. No. Between 2009 and 2011, the Company collected total revenues (across all customer classes) in excess of its benchmark on eight different months (32 percent of the time). However, in the 139 months since 2011 (i.e., January 2012 – July 2023), the Company has reported a net revenue surplus (for all customer classes) in only one month.

Q. HAVE YOU REVIEWED HISTORIC BSA CREDITS AND DEBITS BY RATE CLASS?

A. Yes. Exhibit OPC (A)-15 provides historic BSA revenue balances by rate class and year since 2009. This analysis shows that very little of the Company's revenue volatility stems from residential customers. In fact, less than $19.6 million (6.7 percent) of the overall $294 million in BSA shortfalls can be attributable to residential customers. Most of the BSA shortfalls can be attributed to time metered general service ("GT") rate classes to the tune of $268.9 million, as well as the GT-LV rate class totaling $144.0 million.

Q. HAVE YOU EXAMINED THE COMPANY'S CUSTOMER COUNT AND USAGE BY RATE SCHEDULE?

A. Yes. Exhibit OPC (A)-16 provides historic use per customer ("UPC") by rate class and year since 2010. Most major Company rate classes have seen declining UPC in recent years. For example, estimated residential UPC for the Company has fallen from 0.64 MWh per year in 2010 to 0.62 MWh per year in 2022, a decrease of approximately 2.1 percent. This decline in UPC is even more noticeable for commercial customers, with estimated UPC for the GT-LV and MGT-LV class falling from 149.55 MWh per year in 2010 to 94.56 MWh per year, a decrease of 36.8 percent. However, the Company has seen its residential customer counts grow from 2.79 million to 3.6 million a 30.7 percent growth over this same time period while GT-LV and MGT-LV customer counts have grown by 39.4 percent during the same period. These new customers have offset the reduction in Company sales of electricity caused by falling UPC.

Q. HOW DOES THIS INFORMATION IMPACT THE OPERATIONS OF THE BSA?

A. These are important facts the Commission should consider in evaluating, as a policy matter, whether the BSA should be continued. While the BSA was originally implemented as a revenue decoupling mechanism to insulate the Company from changes in revenues due to a variety of factors including weather and increased energy efficiency, the mechanism now effectively operates as an attrition adjustment to insulate the Company from declining electric use primarily by GT rate class customers. In fact, the Company has admitted as much in a past proceeding before the Commission, claiming that the rationale supporting the continued use of the BSA has likely increased since the mechanism was originally approved.[168] Specifically the Company noted in part that its total energy consumption has been declining over the past decade, increasing the likelihood that the Company will be unable to recover Commission-approved cost of service without the BSA.[169] However, the purpose of the BSA was not to serve as an attrition adjustment but to move the District's energy efficiency initiatives forward.

B. BSA Deferrals and Prior Billing Determinant Error

Q. HOW ARE BILLING DETERMINANTS USED IN THE RATEMAKING PROCESS?

A. Billing determinants are customer data recorded in billing records, such as customer usage information and customer counts. This information is used both to bill customers and to develop future individual rates for utility service during rate cases. Incorrect billing determinants can lead to inaccurate billing. Errors in the internal reporting of billing information can lead to development of inaccurate rates during rate case proceedings, since

168 *See* Exhibit OPC (A)-32, *Formal Case No. 1139*, Exhibit PEPCO (L) (Chamberlin) at 11:20-22.

169 *Id.* at 6:9-12.

the amount of revenue expected to be generated from a developed tariff (rate) will be inaccurate.

Q. PLEASE EXPLAIN THE NATURE OF PEPCO'S BILLING DETERMINANTS ERROR AND ITS RELATIONSHIP WITH THE BSA.

A. The Company has previously stated that the demand billing determinants used in Formal Case Nos. 1139 and 1150 were "generally over-stated in the applicable test periods."[170] According to the Company, this billing determinant error resulted in an under-recovery of revenue that the Company then partially recovered through the operations of its BSA.[171] This means that demand rates for applicable rate classes were incorrectly established for the period between when approved rates resulting from Formal Case No. 1139 were effective (August 2017) until modified rates resulting from Formal Case No. 1156 were effective (July 2021).

Q. WHEN DID THE COMPANY FIRST NOTIFY PARTIES AND THE COMMISSION ABOUT ITS BILLING DETERMINANT ERROR?

A. The Company filed rebuttal testimony in Formal Case No. 1156 on April 8, 2020, to address issues raised by OPC[172] and AOBA[173] regarding the BSA and particularly its application to commercial customers taking service on Schedules MGTLV and GTLV. These two customer classes repeatedly reported consistently large under-recoveries of their class-specific authorized revenues, indicating a potential BSA-related problem. The

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[170] *Formal Case No. 1156*, Exhibit PEPCO (4F) (Blazunas) at 17:19-21.

[171] *Id.* at 18:1-7; *see also Formal Case No. 1156*, Exhibit OPC (5A)-3.

[172] *See Formal Case No. 1156*, Exhibit OPC (A) (Dismukes) at 57.

[173] *See Formal Case No. 1156*, Exhibit AOBA (A) (B. Oliver) at 17:1-4.

Company's rebuttal noted that it had "identified an issue that it believes has contributed to the accumulation of the deferred BSA balances for these two classes."[174] The Company at the time noted that it had addressed the identified issue and that the proposed MRP Pilot avoided the identified issue by using forecasted billing determinants.[175]

Q. DID THE COMPANY SUBSEQUENTLY REVISE THIS POSITION?

A. Yes. Nearly four months later, on July 28, 2020, the Company filed errata to portions of its rebuttal testimony in Formal Case No. 1156. The errata reversed the Company's prior position that the proposed MRP was unaffected by the historic demand billing determinant error.[176] Instead, the Company noted that forecasted demand billing determinants used to design MRP rates were calculated using load factors derived from actual billing determinants in the test year.[177] A few days later on July 31, 2020, the Company filed a third round of supplemental testimony addressing its July 28, 2020 errata filing. In its third supplemental testimony filing, the Company explained that currently effective base distribution rates (from the last base rate case) were designed utilizing incorrect actual demand billing determinants, resulting in billed distribution demand revenues that were lower than actually collected.[178] The incorrectly constructed rates resulted in larger monthly BSA adjustments for the demand rates for commercial customers, thus increasing

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174 *Formal Case No. 1156*, Exhibit Pepco (4F) at 17:17-18.

175 *Formal Case No. 1156*, Exhibit Pepco (4F) at 18:9-14.

176 *Formal Case No. 1156*, Errata to Rebuttal Testimony of Company Witness Blazunas at 1, filed July 28, 2020.

177 *Id.*

178 *Formal Case No. 1156*, Exhibit PEPCO (6F) (Blazunas) at 4:20 to 5:2.

BSA deferral balances.[179] The Company estimated that the error resulted in an annual $12.7 million under-recovery, or $20.8 million in total for the period August 2018 through March 2020.[180] This supplemental testimony marked the first instance where Pepco acknowledged the likely full extent of the identified error's impact on historical rates.

Q. DID THE COMPANY LATER BRIEF PARTIES CONCERNING THE EXTENT OF THE BILLING DETERMINANT ERROR?

A. Yes. On September 10, 2020, the Company held a technical conference on Pepco's BSA-related billing determinant errors as required by the Commission in Order No. 20617.[181] At the conference, the Company explained that in February of 2020, it was made aware by an employee of a regulated utility affiliate (later identified as Atlantic City Electric and Delmarva Power),[182] that an error in an internal report the Company used to collect kW demand information "double counted" customer demand in instances where a rate change occurred in the middle of a month.[183] This double-counting error had the effect of inflating customer demand information that was also used by the Company in its design of rates in its prior base rate cases (Formal Case Nos. 1139 and 1150). Because of the double counting error, retail commercial demand charges were set at inappropriate levels resulting in

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179 *Id.* at 5:6-8.

180 *Id.* at 5:9-19.

181 *Formal Case No. 1156*, Order No. 20617, rel. August 21, 2020.

182 *Formal Case No. 1156,* Pepco Response to OPC Data Request No. 61-7 (Exhibit OPC 33).

183 The Office of the People's Counsel Response to the September 10 Technical Conference and Renewal of the Joint Motion to Dismiss Pepco's MRP Enhanced Proposal, to Direct Withdrawal of Pepco's Rate Case Application, and for Additional Relief at 3; *see also Formal Case No. 1156,* Pepco Response to OPC Data Request No. 61-3 (Exhibit OPC (A)-34) (explaining that "the error is a demand billing determinant report that double counted demand in the months with a "time slice" (such as a month with a rate change). A 'time slice' occurs when there are multiple price values within a bill period, and that price is setup to be prorated within that period.")

consistent under-recoveries in the BSA.[184] At the time, the Company informed parties that the total impact of the billing determinant error through December 2020 would be approximately $30.3 million.[185]

Q. DID ANY RATE CLASS EXPERIENCE ADVERSE CUSTOMER RATE IMPACTS FROM THIS BILLING DETERMINANT ERROR?

A. Yes. Effectively all Pepco commercial customers taking service on rate schedules that include demand rates were negatively affected by the Company's double counting error. The Company's double counting error not only understated demand charges, and demand charge revenues, but likely overstated volumetric rates set in prior base rate cases in order to reconcile overall class revenues. This outcome likely resulted in a cross-subsidization between customers within the rate class since higher load factor ratepayers (i.e. lower demand relative to energy use) were incorrectly receiving discounted service while customers with lower load factors (i.e. higher demand relative to energy use) were being charged higher than intended rates.

Q. WHY DID THE COMPANY'S BILLING DETERMINANT ERROR RESULT IN THE ACCUMULATION OF SIGNIFICANT BSA DEFERRAL BALANCES?

A. The BSA includes a ratepayer protection provision that limits any change in volumetric surcharges (the rate per kWh) to no more than 10 percent; any amount over this 10 percent cap is deferred for recovery in future periods. The Company's double counting error likely

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184 *Id.*

185 *Formal Case No. 1156*, Pepco Response to Staff Data Request No. 19-16 (Exhibit OPC (A)-35).

contributed significantly to the accrual, over this time period, of sizeable deferred BSA balances for the relevant commercial rate classes.

Q. HAS THE COMPANY PROPOSED TO TAKE ANY FISCAL RESPONSIBILITY FOR ITS DOUBLE COUNTING ERROR?

A. No. Pepco has not assumed any responsibility nor offered to shoulder or share in the responsibility for the revenue shortfall that resulted from its failure to accurately implement the BSA or catch its double counting error in a timely manner.[186]

Q. HAS THE COMPANY PROVIDE ANY ANALYSIS TO SUPPORT A CONCLUSION THAT ITS OPERATION OF THE BSA WAS PRUDENT DESPITE THE BILLING DETERMINANT ERROR?

A. No. Pepco was explicitly asked to provide all documents and analyses that it had prepared related to the prudent (1) administration of the BSA, (2) incurrence of BSA deferral balances related to erroneous billing determinants, and (3) recover of erroneous deferral balances caused by the erroneous billing determinants.[187] The Company provided no such documents or analyses.

Q. HAVE YOU EXAMINED BSA DEFERRAL BALANCES?

A. Yes. Figure 8 shows the growth in BSA deferral balances over time. Prior to 2017, the total deferral balance associated with the BSA was never greater than $6 million. However, since 2017 BSA deferral balances have continuously been greater than $6 million every

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[186] *See Formal Case No. 1156*, Pepco Response to OPC Data Request No. 61-17 (Exhibit OPC (A)-36) (stating that "the BSA deferral balances appropriately represent amounts approved for collection by the Company but not yet billed.")

[187] Exhibit OPC (A)-37, Pepco Response to OPC Data Request 10-6.

month, and furthermore continue to grow. As of November 2023, the Company reported a total BSA deferral balance of more than $111 million.

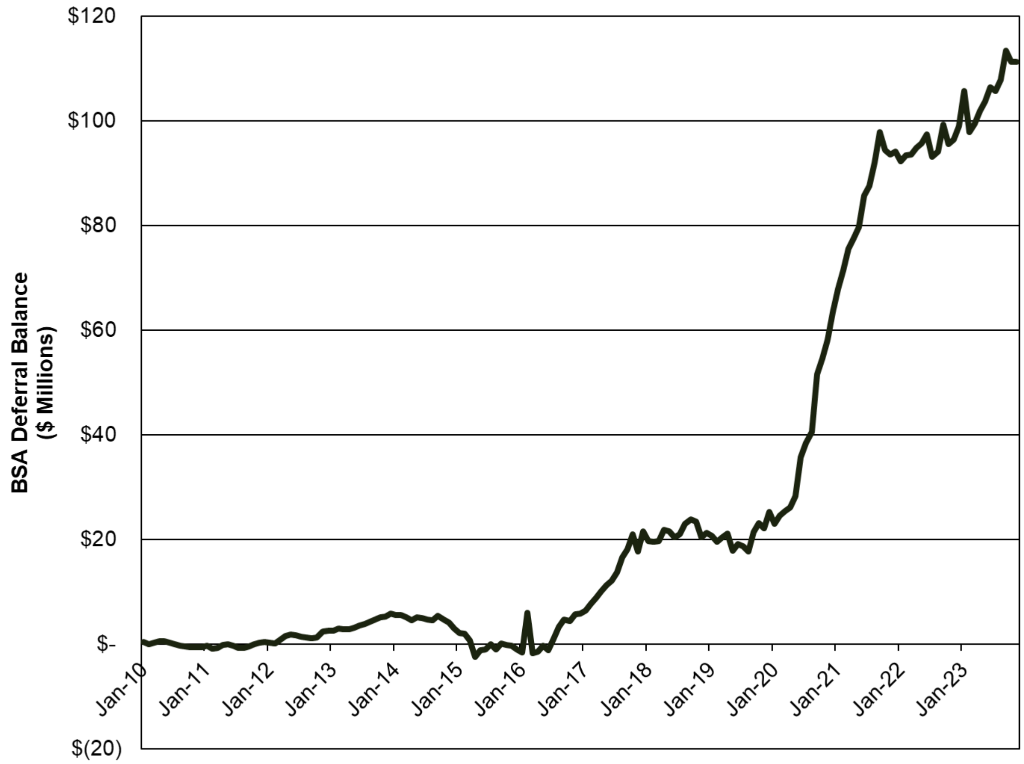

Figure 8: Historic Total BSA Deferral Balance

Q. DO RESIDENTIAL CUSTOMERS COMPRISE THE MAJORITY OF THESE DEFERRED BALANCES?

A. No. As shown in Figure 7, in the Company's November 2023 BSA filing all residential customers combined totaled $630,411 in BSA deferred balances of the total BSA deferred balance of more than $111 million. This means that residential customers comprised less than 0.6 percent (or six tenths of one percent) of the Company's total deferred BSA balance. The vast majority of deferred balances were associated with Timed General Services rate schedules, which combined totaled more than $108 million of the $111 million deferred balance. The GTLV rate schedule alone comprised nearly $87 million of the $111 million deferred balance.

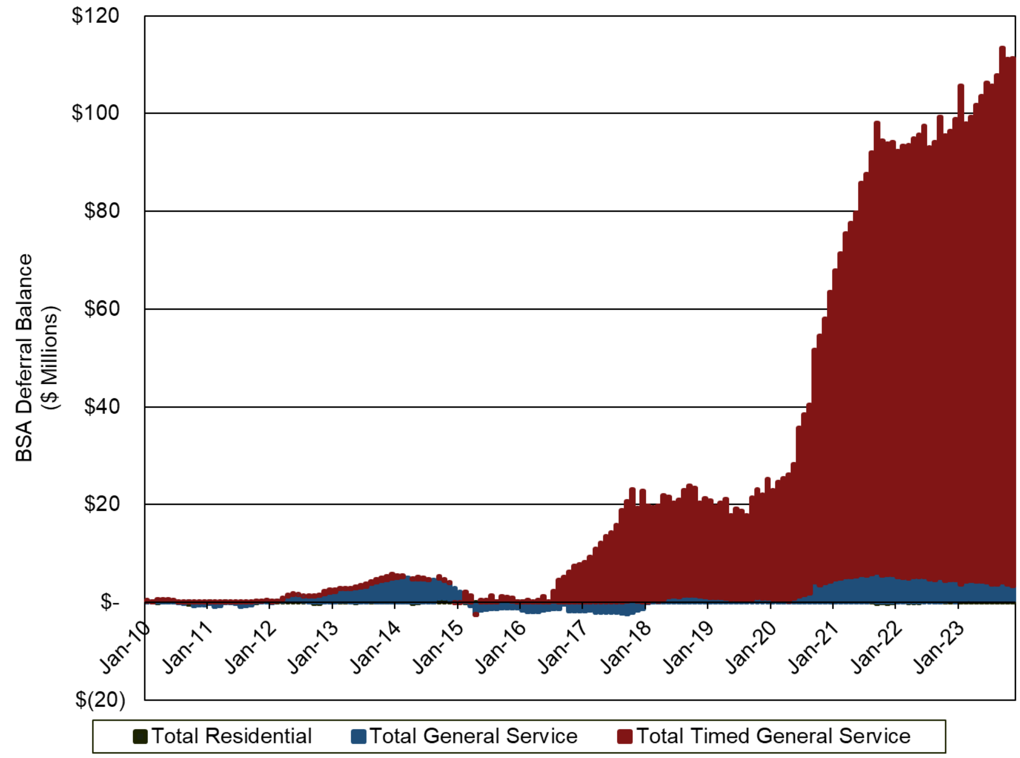

Figure 9: Historic Total BSA Deferral Balances by Customer Class

Q. HAVE YOU EXAMINED THE HISTORIC ACCURACY OF PEPCO'S DEMAND REPORTS?

A. Yes. Confidential Exhibit OPC (A)-17 estimates the impact of the Company's double counting error. The analysis shows notable impacts across various months, particularly in August 2018, the month in which rates approved in Formal Case No. 1150 become effective.[188] Confidential Exhibit OPC (A)-17 furthermore highlights the extent of Pepco's

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188 *Formal Case No. 1156,* The Office of the People's Counsel Response to the September 10 Technical Conference and Renewal of the Joint Motion to Dismiss Pepco's MRP Enhanced Proposal, to Direct Withdrawal of Pepco's Rate Case Application, and for Additional Relief at 3.

mismanagement of the BSA since a cursory review of billing data should have raised concerns due to the extent of the Company's double counting mistake.

Q. DID COMMISSION STAFF HOST ANY TECHNICAL CONFERENCES REGARDING THE BSA AFTER THE CONCLUSION OF FORMAL CASE 1156?

A. Yes. Pursuant to Order No. 20755,[189] Commission Staff hosted three technical conferences after the conclusion of Formal Case No. 1156 which discussed structural deficiencies in the BSA and BSA deferments. The first of these was held November 19, 2021, the second was held December 9, 2021, while the third was held January 20, 2022.

Q. DID THE COMPANY DISCUSS ITS BSA DEFERRAL BALANCES AT ANY OF THESE TECHNICAL CONFERENCES?

A. Yes. At the second BSA technical conference, the Company updated parties on the status and causes of its BSA deferrals.[190] The Company confirmed that as of the end of October 2021, $98.5 million, or 99.72 percent, of the Company's BSA deferral balances were comprised of just four rate classes: GTLV ($55.2 million); MGTLV ($29.8 million); GT3A ($7.5 million); and GSLV ($5.7 million).[191] Furthermore, of the $98.5 million deferral balances at the time, the Company estimated that only $2.5 million would be recovered in the upcoming monthly BSA reconciliation, with the remaining $95.9 million being deferred to several months into the future.[192] The Company furthermore revealed that over

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[189] *Formal Case No. 1156,* Order No. 20755 at ¶ 316.

[190] *Formal Case No. 1156,* "BSA Deferral Balances," Pepco Holdings presentation at Technical Workshop dated December 9, 2021.

[191] *Id.* at 13.

[192] *Id.*

the six year period from 2016 through 2021, it saw approximately $220 million in monthly BSA under-collections.[193]

Q. WHAT DRIVERS OF BSA COLLECTIONS DID THE COMPANY ANALYZE?

A. The Company analyzed five drivers of historic BSA under-collections – (1) changes in usage per customer ("UPC"); (2) changes in customer counts; (3) weather variation; (4) the previously noted billing determinant error; and (5) a normalization adjustment for the GTLV class in Formal Case No. 1150.[194] The Company furthermore estimated three sub-categories of changes in UPC including: changes in UPC due to the Covid-19 pandemic; changes in UPC due to District energy efficiency programs; and all other non-Covid-19 related causes of changes in UPC.[195]

Q. WHAT WERE THE RESULTS OF THE COMPANY'S ANALYSIS OF DRIVERS OF BSA UNDER-COLLECTIONS?

A. Exhibit OPC (A)-18 shows the results of the Company's analysis of historic BSA under-collections. The Company found that non-Covid-related changes in customer UPC accounted for the majority of historic BSA under-collections, comprising approximately 40 percent of historic BSA under-collections. The second largest driver was changes in customer UPC caused by the economic downturn resulting from the Covid-19 pandemic, which the Company estimated accounted for $48.2 million, or approximately 22 percent, of historic BSA under collections.

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193 *Id.* at 21.

194 *Id.* at 20.

195 *Id.*

Q. DID THE COMPANY PROVIDE A REVISED ESTIMATE OF DOUBLE COUNTING ERRORS?

A. Yes. The Company, at the December 2021 technical conference, stated that its revised analysis of drivers of historic BSA under-collections found that its double counting error only resulted in $15.3 million in cumulative BSA under-collections over the five-year period from 2017 through 2021.[196] This represents a notable reduction in the Company's prior estimates of $20.8 million during the period from August 2018 through March 2020,[197] or the estimated $30.3 million the Company claimed would raise through December 2020.[198]

Q. HOW DID THE COMPANY EXPLAIN THESE CHANGING ESTIMATES?

A. The Company stated that, upon further analysis, its prior double counting error estimates were inclusive of two separate regulatory errors arising from Formal Case Nos. 1136 and 1150.[199] The first being the previously discussed billing determinant mistake and the second being a "normalization adjustment" for the GTLV class that was included in Formal Case No. 1150.[200] The Company estimated that this second normalization adjustment resulted in total BSA under collections of $20.3 million over the four year period from

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196 *Id.*

197 *Formal Case No. 1156*, Exhibit PEPCO (6F) (Blazunas) at 5:9-19.

198 *Formal Case No. 1156,* Pepco Response to Staff Data Request No. 19-16 (Exhibit OPC (A)-35).

199 *Formal Case No. 1156,* "BSA Deferral Balances," Pepco Holdings presentation at Technical Workshop dated December 9, 2021, at 35.

200 *Id.*

2018 through 2021.[201] Combined, the Company estimated regulatory errors of $35.6 million in BSA under collections through June 2021.[202].[203]

Q. EXPLAIN THE GTLV NORMALIZATION ADJUSTMENT?

A. In final negotiations to develop a Settlement Agreement between parties to Formal Case No. 1150, Pepco and AOBA agreed to a normalization adjustment of the GTLV rate class. OPC was not involved in this discussion since it applied to the GTLV and not residential or small commercial rate classes. However, it is my understanding that this adjustment was intended to account for expected customer growth in the GTLV rate class based on historic trends.[204] However, it because apparent later, after the settlement, that the Company was seeing far fewer new GTLV customers than it anticipated, causing an estimated $12.3 million shortfall in annual GTLV annual revenues at the time.[205]

Q. HAS ANY OTHER PARTY EXAMINED THE DRIVERS OF THE COMPANY'S LARGE BSA UNDER-COLLECTIONS AND DEFERRED BALANCES?

A. Yes. In Order No. 20755, the Commission directed that an independent audit be conducted.[206] Atrium Economics ("Atrium") was selected as the Commission's independent auditor and issued its Final Report on July 7, 2023.[207] As part of their analysis,

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201 *Id.*

202 *Id.*

203 The date at which these mistakes were removed, coincident with the effective date of new retail rates arising from Formal Case No. 1156

204 *See Id.* at 37, and *Formal Case No. 1150,* Exhibit PEPCO (3E)-1 at 10; interestingly this normalization adjustment was inaccurately labelled a "weather normalization" adjustment to GTLV customer counts in Pepco's Settlement Testimony exhibits in Formal Case No. 1150.

205 *Formal Case No. 1150*, Motion to Clarify at ¶ 4.

206 *Formal Case No. 1156*, Order No. 20755, at ¶ 316.

207 *Formal Case No. 1156*, "Pepco DC Bill Stabilization Adjustment Audit Report," (July 7, 2023).

Atrium evaluated Pepco's BSA deferral drivers analysis presented to parties at the December 2022 technical conference.[208]

Q. WHAT WERE THE FINDINGS OF THE ATRIUM REPORT REGARDING THE DRIVERS OF HISTORIC BSA UNDER-COLLECTIONS?

A. Atrium found that the billing determinant error was isolated to Case No. 1150[209] and did not extend to Case No. 1139 as represented by the Company in both Formal Case No. 1156 and during the December 2022 Technical Conference. Atrium, however, did largely confirm the Company's estimated BSA under-collections caused by the double counting mistake. Specifically, Atrium estimated that the impact of the mistake was $15.1 million (compared to the Company's estimated $15.3 million presented to parties at the December 2022 Technical Conference) over the four-year period 2018 through 2021.[210] Atrium also found that the Company significantly under-estimated the impact of the Formal Case No. 1150 GTLV normalization adjustment by only accounting for the error in demand charges caused by the adjustment without also accounting for the similar error in volumetric charges. Atrium found that the Formal Case No. 1150 GTLV normalization adjustment caused $27.1 million in BSA under-collections (compared to the Company's estimated $20.3 million presented to parties at the December 2022 Technical Conference).[211] Combined, Atrium found that the two regulatory errors accounted for $42.2 million in BSA under-collections.

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208 *Id.* at 32.

209 *Id.* at 36-37.

210 *Id.* at 37.

211 *Id.* at 48.

Q. HAS PEPCO RESPONDED TO CONCERNS RAISED BY PARTIES AFTER REVIEW OF THE ATRIUM REPORT?

A. Yes. In recent Reply Comments responding to parties criticism of its administration of the BSA, Pepco claims that it has "consistently administered and executed the BSA in the manner approved by the Commission since the mechanism's inception,"[212] and that a large portion of deferred BSA balances are caused by the fact that billing determinants change between rate cases.[213] The Company highlights its current billing determinants used in BSA reconciliations which are based off of forecasts using data that is more than five years old.[214]

Q. DO YOU AGREE THAT THE COMPANY HAS IDENTIFIED A VALID CONCERN?

A. No. The Commission should recognize that Pepco has full control over when it decides to file base rate cases with the Commission. Indeed, the staleness of existing billing determinates from its Formal Case No. 1156 filing emphases the inappropriateness of the Company's proposed MYP in the context of rapidly changing customer base.

Q. WHAT IS YOUR CONCLUSION REGARDING THE PRESENCE OF LARGE BSA DEFERRAL BALANCES?

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212 *Formal Case No. 1156*, Reply Comments of Potomac Electric Power Company on Atrium Final Report at page 8.

213 *Id.*

214 *Id.*

A. The current large BSA deferral balances demonstrate a major problem associated with the current BSA: that is, the mechanisms allow the Company to recovery any revenue deficiency regardless of the rationale for that shortcoming, up to and including Company created-double counting errors. The BSA also allows for the recovery of lost revenues resulting from economic contractions such as those associated with the Covid-19 pandemic. The BSA has the effect of reducing incentives for the Company to closely monitor its billing practices since it suffers no financial harm if such practices are in error, as evidenced by the large deferrals arising from the various Company errors identified in the Atrium Report.

C. Proposed Changes to the BSA Mechanism

Q. HAS THE COMMISSION EVER DISCUSSED THE APPROPRIATENESS OF THE BSA?

A. Yes, in Formal Case 1156. The Commission acknowledged at the time that the BSA protects Pepco from **any** difference between actual versus forecasted sales on a per-customer basis regardless of the source.[215] However, the Commission ultimately stated that it was not persuaded by parties to eliminate the BSA, in part, because such mechanisms continue to be credit-positive features that help the Company maintain its investment grade credit rating. The Commission, furthermore, noted that it shared parties concerned regarding the operations of the BSA – including the significant BSA deferrals – and noted its view that the BSA could be improved.[216] The Commission, thus, ordered the convening

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215 *Formal Case No. 1156*, Order 20755, ¶ 314.

216 *Id.*, ¶ 315.

of technical conferences previously discussed to explore possible reforms of the BSA to address revenue pressures unrelated to the Company's energy efficiency efforts.[217]

Q. DOES THE COMPANY PROPOSE ANY CHANGES TO THE BSA IN THE CURRENT PROCEEDING?

A. Yes. In response to discussions with stakeholders through the BSA technical conferences, and its own research into decoupling best practices from other states, the Company proposes a series of four "enhancements" to better align the BSA with its proposed MYP.[218] These include: (1) a change in the structure of the BSA from RPC targets to flat class revenue targets; (2) a change in the structure of the BSA from monthly reconciliations and surcharges to an annual process; (3) incorporation of demand surcharges for demand-metered classes; and (4) displaying of BSA surcharges as separate line items on customer bills.[219]

Q. WHY DOES THE COMPANY PROPOSE TO CHANGE FROM AN RPC BSA TO A TOTAL CLASS REVENUE BSA?

A. The Company states that there are two notable limitations associated with the current BSA revenue target structure. First, the Company states that the RPC structure assumes that any new customer added to a rate class will have approximately the same cost of service as the class average customers.[220] This assumption is problematic for large commercial classes

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217 *Id.*, ¶ 316.

218 *Formal Case No. 1176*, Exhibit PEPCO (E) (Bonikowski) at 60:4-9.

219 *Id.* at 61:5-11.

220 *Id.* at 62:3-5.

with fewer customer counts and greater customer load diversity.[221] The Company further states that, to the extent new customers have lower cost of service than class average, the existing BSA RPC framework has the potential to exacerbate existing interclass subsidies.[222] Second, the Company notes that under an MYP ratemaking structure the Company's rates and revenue requirement are based on forecasted data which includes expected customer and cost of service growth.[223]

Q. WHY DOES THE COMPANY PROPOSE TO MOVE FROM MONTHLY TO ANNUAL BSA SURCHARGE FILINGS?

A. The Company states that the current monthly BSA structure has introduced high degrees of customer bill volatility[224] which, interestingly, contravenes one of the oft-cited reasons for adopting revenue decoupling by utilities (i.e., reducing ratepayer bill volatility and increasing revenue stability)[225] and indeed the "stability" nature of the BSA. For example, the Company notes that Schedule GT 3B has only one customer, which means that rate schedule can sometime appear to have a significant under-recovery of 100 percent in a given month to be followed by significant over-recovery or 200 percent the next depending on billing cycles relative to calendar months.[226]

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221 *Id.* at 62:5-8.

222 *Id.* at 62:11-13.

223 *Id.* at 62:14-18.

224 *Id.* at 63:7-10.

225 *See*, *Formal Case No. 1053*, Order No. 15556, ¶ 5, citing *Formal Case No. 1053*, Exhibit Pepco (H) at 18.

226 *Formal Case No. 1176*, Exhibit PEPCO (E) (Bonikowski) at 63:10-14.

Q. WHY DOES THE COMPANY PROPOSE TO IMPLEMENT DEMAND-BASED BSA SURCHARGE RATES FOR DEMAND-METERED CLASSES?

A. The existing BSA currently is designed as a volumetric dollar-per-kWh charge for all rate classes. The Company is concerned that this structure can lead to intraclass equity concerns by shifting revenue responsibility towards high load factor customers from low load factor customers without a rate class.[227]

Q. WHY DOES THE COMPANY PROPOSE TO IMPLEMENT NEW BSA SURCHARGES AS A SEPARATE LINE ITEM ON CUSTOMER'S MONTHLY BILL?

A. The existing BSA surcharge is not implemented as a separate line item on customers' monthly bill, and instead is aggregated within a single "Energy Charge" line item with other volumetric charges. In the interest of addressing parties' concerns about the lack of transparency, the Company proposes to separate the BSA surcharge onto a separate line item going forward.[228]

D. Proposed Rate Base Accounting for Deferred Balances

Q. DID THE COMPANY INCLUDE ANY ADDITIONAL RECOMMENDATIONS REGARDING THE BSA IN ITS TTYCF?

A. Yes. While not included in its MYP case-in-chief, the Company in its TTYCF requested that the Commission approve the establishment of a regulatory asset that would allow the

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[227] *Id.* at 65:14-20.

[228] *Id.* at 66:14-18.

Company to include BSA deferred balances in rate base for its proposed TTYCF.[229] Specifically, the proposed regulatory asset and ratemaking adjustment would increase the Company's test year rate base by nearly $113.8 million, reflecting the estimated BSA deferred balance on December 31, 2023.[230]

Q. WHAT IS THE COMPANY'S RATIONALE FOR INCLUDING THE PROPOSED BSA REGULATORY ASSET?

A. The Company notes that Atrium recommended in its report that the Commission continue to monitor Pepco's credit quality for signs of deterioration and consider implementing credit support measures such as allowing a return on BSA deferral balances.[231] The Company states that the current large BSA deferral balance put additional cash flow burdens on the Company and negatively impacts its earned ROE.[232] The Company did not propose such a measure in its MYP rate case proposal since Pepco's proposed MYP and updated billing determinants will improve the overall financial health of the Company.[233]

E. BSA Recommendations

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S BSA?

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[229] *Formal Case No. 1176*, Exhibit PEPCO (3A)-1, Additional Supplemental Direct Testimony of Elizabeth M. D. O'Donnell at 5:9-12.

[230] *Formal Case No. 1176*, Exhibit PEPCO (2B)-1.

[231] *Formal Case No. 1176*, Exhibit PEPCO (3A)-1, Additional Supplemental Direct Testimony of Elizabeth M. D. O'Donnell at 4:14-18.

[232] *Id.* at 5:3-12.

[233] *Id.*

A. I recommend the BSA be discontinued. The BSA is not functioning as intended. The BSA allows the Company to recover revenues shortfalls regardless of the source, and therefore inherently reduces incentives for the Company to prudently manage its operations and insulates the Company from a wide range of business risk that can include the economic contraction caused by the Covid-19 pandemic. Furthermore, to the extent the Commission approves the Company's proposed MYP, even the Company recognizes that elements of the BSA are now duplicative of elements of the MYP.[234] Specifically, the proposed MYP is based off forecasted billing determinants such as forecasted customer counts and volumetric sales, and thus is already designed to reflect forecasted changes in customer usage.

Q. HAS THE COMMISSION RECENTLY EXPRESSED CAUTION REGARDING THE USE OF REVENUE DECOUPLING BY JURISDICTIONAL UTILITIES?

A. Yes. The Commission recently rejected a WGL revenue decoupling proposal offered in its last base rate case.[235] The Commission noted that it is currently considering possible reform of Pepco's BSA and that approval of WGL's revenue decoupling proposal would be inappropriate. The Commission identified specific issues with the Pepco decoupling mechanism including: (a) how Pepco's BSA impacts ratepayers; (b) whether the BSA insulates Pepco's revenues from the impact of weather and economic changes as well as

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[234] *Id.* at 62:14-18.

[235] Order No. 21939 at ¶ 370.

reducing a utility's disincentive for energy efficiency; and (c) how Pepco's BSA will interact with future electrification efforts.[236]

Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION IF THE COMMISSION DECIDES TO RETAIN THE BSA?

A. Yes. Elsewhere, I have recommended that the Commission not extend the Company's MYP. If the Commission does not accept this MYP recommendation, or, if for any other reason, the Commission decides to retain the BSA, I recommend adoption of the Company's proposed BSA modifications. These proposed BSA modifications will reduce several known problematic elements of the BSA including the mechanism's problematic monthly reconciliations, which produces clearly anomalous BSA adjustments for small commercial rate classes, and the current RPC framework which unnecessarily adds complexity to the mechanism while allowing Company revenues to increase beyond those approved in prior base rates.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED RATE BASE TREATMENT OF BSA DEFERRED BALANCES?

A. I recommend the Commission reject the Company's proposal to include its test year BSA deferred balance as an element of rate base, allowing the Company to earn a rate of return on this balance. The Company in the current proceeding notes several structure concerns associated with the calculations of existing BSA surcharges.[237] However, even ignoring the Company's admitted billing determinant error which has contributed to the significant

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[236] *Id.*

[237] *See Formal Case No. 1176*, Exhibit PEPCO (E) (Bonikowski) at 61:3-10.

growth in these deferred balances over the past few years, the Commission should recognize that the Company had the opportunity to request changes to the BSA operations at any point in the mechanism's 14-year history. Accepting the Company's request to include BSA deferred balances as part of rate base would effectively reward Pepco for not exercising appropriate oversight of BSA operations.

Q. DO YOU HAVE A RECOMMENDATION REGARDING THE CURRENT LARGE BSA DEFERRAL BALANCES FOR COMMERCIAL RATE CLASSES?

A. Yes. I recommend that the Commission recognize the portion of BSA deferral balances associated with the Company's past administrative errors be disallowed from recovery by retail customers. The BSA mechanism should not function to immunize the Company from its own mistakes.

Q. HAS THE COMMISSION PREVIOUSLY RECOGNIZED THE IMPORTANCE OF HOLDING PEPCO ACCOUNTABLE FOR ITS OWN MISTAKES?

A. Yes. The Commission earlier this year found that Pepco is currently or has been in violation of relevant laws and regulations pertaining to the installation of Community Renewable Energy Facility ("CREF") meters.[238] The Commission declined to impose any financial penalties on the Company and give "Pepco the benefit of the doubt that its flawed reading of the law and [the Commission's] regulations [were] not a deliberate attempt to undermine them."[239] However, the Commission also made it clear that the Commission's decision to not establish a direct financial penalty shielded it from bearing the

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[238] *Formal Case No. 1171*, Order No. 21649 at ¶ 3, citing Order No. 21600 at ¶ 1.

[239] *Formal Case No. 1171*, Order No. 21649 at ¶ 9.

consequences of its own erroneous reading of relevant laws and regulations, and that Pepco should not be allowed to dump these consequences on the backs of ratepayers.[240]

> In Order No. 21600, we declined to impose a financial penalty because we gave Pepco the benefit of the doubt that its flawed reading of the law and our regulations was not a deliberate attempt to undermine them. **However, the fact that we saw no reason to punish Pepco with a financial penalty does not create a shield against a claim that Pepco should be prohibited from dumping the consequences of the Company's error onto the backs of ratepayers.** When it comes to assigning costs to ratepayers, Pepco must first show that the shift in costs is just and reasonable and that showing has not, and cannot, be made (at least under these circumstances).[241]

Q. HAVE YOU ESTIMATED THE SPECIFIC BSA DEFERRAL BALANCES TO BE REMOVED FROM RATE RECOVERY?

A. Yes. Exhibit OPC (A)-19 presents detailed calculations of rate-specific BSA deferral balances to be removed from rate recovery. These calculations are based on the findings of the Atrium Report estimates of the impact of the Formal Case No. 1150 billing determinant mistake and GTLV normalization adjustment. In total, I recommend that $42.2 million of BSA deferral balance be removed from ratepayer recovery, including $19.3 million from the GTLV rate class and $20.1 million from ratepayer recovery for the MGTLV rate class.

Q. DO YOU HAVE ANY ADDITIONAL RECOMMENDATION REGARDING BSA DEFERRAL BALANCES?

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240 *Id.*

241 *Id.*, emphasis added.

A. Yes. The Atrium Report found that approximately 25 percent of BSA deferral balances, totaling $69.5 million, are due to revenue under-recoveries resulting from the effects of the Covid-19 pandemic.[242] The Commission should consider alternative recovery options for these balances outside of the BSA, including inclusion of these Covid-related balances within the proposed regulatory asset for pandemic-related expenses.[243]

IX. CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED REVENUE DISTRIBUTION?

A. I recommend that the Commission reject the Company's proposed revenue distribution, which places an increase of 2.3 times the system average on residential ratepayers. Until the Commission can receive assurances that increasing residential revenue responsibility will improve its relative rate of return, I recommend the Commission reevaluate its policy of eliminating negative class rates of return. Instead, the Commission should adopt a more reasonable increase to currently underearning classes equal to 1.25 times the overall system average.

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS AND CONCLUSIONS?

A. I recommend that the Commission direct the Company to maintain customer charges at their current levels.

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242 *Formal Case No. 1156*, "Pepco DC Bill Stabilization Adjustment Audit Report," (July 7, 2023) at 50.

243 *Formal Case No. 1176*, Exhibit PEPCO (B) (Leming) at 61:11-13.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE COMPANY'S PROPOSED MYP?

A. I recommend that the Commission reject the Company's requested MYP. There is no evidence to support a finding that the Company's MRP pilot provided any net public benefits or was in the public interest. The Company has provided no detailed information in this proceeding to support claims that this proposal would produce those benefits or advance the public interest.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S BSA?

A. I recommend the BSA be discontinued, as it is not functioning as intended. Moreover, should the Commission approve a multiyear plan, the BSA should be discontinued as it is duplicative of elements in a multiyear plan. Specifically, the proposed MYP is based off forecasted billing determinants such as forecasted customer counts and volumetric sales, and thus is already designed to reflect forecasted changes in customer usage.

Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION IF THE COMMISSION DECIDES TO RETAIN THE BSA?

A. Yes. If for any reason the Commission decides to retain the BSA, I recommend adoption of the Company's proposed BSA modifications.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED RATE BASE TREATMENT OF BSA DEFERRED BALANCES?

A. I recommend the Commission reject the Company's proposal in its TTYF of including the BSA deferred balance in the rate base. This would unfairly allow the Company to earn a rate of return on this balance, which solely stems from its own imprudence.

Q. DO YOU HAVE A RECOMMENDATION REGARDING THE CURRENT LARGE BSA DEFERRAL BALANCES FOR COMMERCIAL RATE CLASSES?

A. Yes. I recommend that the Commission recognize the portion of BSA deferral balances associated with the Company's past administrative errors be disallowed from recovery by retail customers. The BSA mechanism should not function to immunize the Company from its own mistakes.

Q. DO YOU HAVE ANY ADDITIONAL RECOMMENDATION REGARDING BSA DEFERRAL BALANCES?

A. Yes. I recommend that the Commission consider alternative recovery options for Covid-19 related BSA deferral balance outside of the BSA, including inclusion of these Covid-related balances within the proposed regulatory asset for pandemic-related expenses.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In the Matter of the	)	
	)	
Application of Potomac Electric Power Company	)	**Formal Case No. 1176**
for Authority to Implement a Multiyear Rate	)	
Plan for Electric Distribution Service	)	
in the District of Columbia	)	

AFFIDAVIT

I declare under penalty of perjury that the foregoing testimony was prepared by me or under my direction and is true and correct to the best of my knowledge, information, and belief.

David E. Dismukes, Ph.D.

Date: January 10, 2024

Subscribed and sworn to before me

This 10 day of January, 2024.

State of Louisiana
East Baton Rouge Parish

MELISSA MCMANUS
NOTARY PUBLIC ID #157216
STATE OF LOUISIANA
MY COMMISSION IS FOR LIFE

Notary Public

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EDUCATION

Ph.D., Economics, Florida State University, 1995.
M.S., Economics, Florida State University, 1992.
M.S., International Affairs, Florida State University, 1988.
B.A., History, University of West Florida, 1987.
A.A., Liberal Arts, Pensacola State College, 1985.

Master's Thesis: *Nuclear Power Project Disallowances: A Discrete Choice Model of Regulatory Decisions*

Ph.D. Dissertation: *An Empirical Examination of Environmental Externalities and the Least-Cost Selection of Electric Generation Facilities*

ACADEMIC APPOINTMENTS

Louisiana State University, Baton Rouge, Louisiana

Center for Energy Studies

2023-Current	Professor Emeritus
2014-2023	Executive Director (Retired in 2023)
2007-2023	Director, Division of Policy Analysis
2006-2023	Professor
2003-2014	Associate Executive Director
2001-2006	Associate Professor
1999-2001	Research Fellow and Adjunct Assistant Professor
1995-2000	Assistant Professor

College of the Coast and the Environment (Department of Environmental Studies)

2014-2023	Professor (Joint Appointment with CES)
2010-2023	Director, Coastal Marine Institute
2010-2014	Adjunct Professor

E.J. Ourso College of Business Administration (Department of Economics)

2006-2023	Adjunct Professor

2001-2006	Adjunct Associate Professor
1999-2000	Adjunct Assistant Professor

Michigan State University, East Lansing, Michigan

Institute of Public Utilities

2018-Current	Senior Fellow

Florida State University, Tallahassee, Florida

College of Social Sciences, Department of Economics

1995	Instructor

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

2001-Current	Consulting Economist/Principal
1995-1999	Consulting Economist/Principal

Econ One Research, Inc., Houston, Texas

1999-2001	Senior Economist

Florida Public Service Commission, Tallahassee, Florida

Division of Communications, Policy Analysis Section

1995	Planning & Research Economist

Division of Auditing & Financial Analysis, Forecasting Section

1993	Planning & Research Economist
1992-1993	Economist

Project for an Energy Efficient Florida/FlaSEIA, Tallahassee, Florida

1994	Energy Economist

Ben Johnson Associates, Inc., Tallahassee, Florida

1991-1992	Research Associate
1989-1991	Senior Research Analyst
1988-1989	Research Analyst

GOVERNMENT & ADVISORY APPOINTMENTS

2023 – Current	Distinguished Fellow & Senior Economist Institute For Energy Research Washington, D.C.
2017 -- Current	Member, National Petroleum Council. U.S. Department of Energy.

2020-2023	Co-Chairperson, Energy Advisory Committee, World Trade Center New Orleans, Louisiana.
2007-2023	Louisiana Representative, Interstate Oil and Gas Compact Commission; Energy Resources, Research & Technology Committee.
2007-2023	Louisiana Representative, University Advisory Board Representative; Energy Council (Center for Energy, Environmental and Legislative Research).
2005	Member, Task Force on Energy Sector Workforce and Economic Development (HCR 322).
2003-2005	Member, Energy and Basic Industries Task Force, Louisiana Economic Development Council
2001-2003	Member, Louisiana Comprehensive Energy Policy Commission.

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2. *Co-Principal Investigator*. (2021). With Gregory B. Upton Jr. Estimating the benefits of underground carbon dioxide storage investments. Funded by Gulf Coast Sequestration. Total Funding: $124,835. Status: In Progress.

3. *Principal Investigator*. (2021). Louisiana Greenhouse Gas Inventory Update and Report. Governor's Office of Coastal Affairs. Total Funding $65,830. Status: Completed.

4. *Principal Investigator*. (2021). Estimating Louisiana's power generation greenhouse gas emissions. The Nature Conservancy. Total Funding: $9,994. Status: Completed.

5. *Co-Principal Investigator*. (2021). With Gregory B. Upton. Estimating the economic impacts of methanol investments in St. James Parish. Koch Industries. Total Funding: $37,457. Status: Completed.

6. *Co-Principal Investigator*. (2019). With Gregory B. Upton Estimating the economic impact of TransCanada pipeline investments. TransCanada Pipelines. Total Funding: $40,798. Status: Completed.

7. *Co-Principal Investigator*. (2018). With Gregory B. Upton. Estimating the economic impact of Enable Pipeline Investments. Total Funding: $49,798. Status: Completed.

8. *Co-investigator*. Estimating offshore Gulf of Mexico carbon capture, sequestration, and utilization opportunities. (2018). With Southern States Energy Board, Advanced Resources International, Argonne Laboratories, University of Alabama, University of South Carolina, and Oklahoma State University. U.S. Department of Energy, National Energy Technology Laboratory. Total funding: $731,031 (LSU share of $4.0 million project, three years, in progress).

9. *Co-Principal Investigator*. Planning Grant: Engineering Research Center for Resiliency Enhancement and Disaster-Impact Interception ("READII") in the Manufacturing Sector. (2018). With Mahmoud El-Halwagi, Mark Stadtherr, Heshmat Aglan, Efstratos Postikopoulus. National Science Foundation (#1840512). Total Funding: $100,000 (one year). Status: Completed.

10. *Principal Investigator*. Understanding MISO long term infrastructure needs and stakeholder positions. (2017). Midcontinent Independent System Operator. Total Project: $9,500, six months. Status: Completed.

11. *Principal Investigator*. Offshore oil and gas activity impacts on ecosystem services in the Gulf of Mexico. (2017). With Brian F, Snyder. U.S. Department of the Interior, Bureau of Ocean Energy Management. Total Project: $240,982, two years. Status: Completed.

12. *Principal Investigator*. Economic Impacts of the Bayou Bridge pipeline. (2017). With Gregory B, Upton, Jr., Energy Transfer Corporation. $9,900. Status: Completed.

13. *Principal Investigator*. Integrated carbon capture, storage and utilization in the Louisiana chemical corridor. (2017). U.S, Department of Energy/National Energy Technology Laboratory. Total funding: $1,300,000 (18 months). Status: Completed.

14. *Co-Principal Investigator*. Gulf coast energy outlook and analysis. (2016). With Gregory B. Upton and Mallory Vachon. Regions Bank. Total funding: $20,000, one year. Status: Completed.

15. *Principal Investigator*. GOM energy infrastructure trends and factbook update. (2016). With Gregory B. Upton and Mallory Vachon. U.S. Department of the Interior, Bureau of Ocean Energy Management ("BOEM"). Total funding: $224,995, two years. Status: In progress.

16. *Principal Investigator*. Examining Louisiana's Industrial Carbon Sequestration Potential. Phase 2: Follow-up and estimation. (2016). With Brian F. Snyder. Southern States Energy Board. Total Project: $69,990, three months. Status: Completed.

17. *Principal Investigator*. Examining Louisiana's Industrial Carbon Sequestration Potential. Phase 1: Scoping and Identification. (2016). With Brian F. Snyder. Southern States Energy Board. Total Project: $29,919, three months. Status: Completed.

18. *Principal Investigator*. Energy efficiency building codes for Louisiana. (2016). With Brian F. Snyder. Louisiana Department of Natural Resources. Total Project: $50,000, one year. Status: Completed.

19. *Principal Investigator*. An update of Louisiana's combined heat and power potentials, current utilizations, and barriers to improved operating efficiencies. (2016). Louisiana Department of Natural Resources. Total Project: $90,000, one year. Status: Completed.

20. *Principal Investigator*. Combined Heat and Power Stakeholder Meeting. (2016). Southeastern Energy Efficiency Council. Total Project $9,160, two months. Status: Completed.

21. *Co-Investigator*. "Expanding Ecosystem Service Provisioning from Coastal Restoration to Minimize Environmental and Energy Constraints" (2015). With John Day and Chris D'Elia. Gulf Research Program. Total Project: $147,937. Status: Completed.

22. *Principal Investigator*. "Coastal Marine Institute Administrative Grant" (2104). U.S. Department of the Interior. Total Project $45,000. Status: Completed.

23. *Principal Investigator*. "Analysis of the Potential for Combined Heat and Power (CHP) in Louisiana." (2013). Louisiana Department of Natural Resources. Total Project: $90,000. Status: Completed.

24. *Co-Investigator*. "CNH: A Tale of Two Louisianas: Coupled Natural-Human Dynamics in a Vulnerable Coastal System" (2013) With Nina Lam, Margaret Reams, Kam-Biu Liu, Victor Rivera, Yi-Jun Xu and Kelley Pace. National Science Foundation. Total Project: $1.5 million. Status: Completed (Sept 2012-Feb 2017).

25. *Principal Investigator*. "Examination of Unconventional Natural Gas and Industrial Economic Development" (2012). America's Natural Gas Alliance. Total Project: $48,210. Status: Completed.

26. *Principal Investigator*. "Investigation of the Potential Economic Impacts Associated with Shell's Proposed Gas-To-Liquids Project" (2012). Shell Oil Company, North America. Total Project: $76,708. Status: Completed.

27. *Principal Investigator*. "Analysis of the Federal Wind Energy Production Tax Credit." American Energy Alliance. Total Project: $20,000. Status: Completed.

28. *Principal Investigator*. "Energy Sector Impacts Associated with the Deepwater Horizon Oil Spill." Louisiana Department of Economic Development. Total Project: approximately $50,000. Status: Completed.

29. *Principal Investigator*. "Economic Contributions and Benefits Support by the Port of Venice." Port of Venice Coalition. Total Project: $20,000. Status: Completed.

30. *Principal Investigator.* "Energy Policy Development in Louisiana." Louisiana Department of Natural Resources. Total Project: $150,000. Status: Completed.

31. *Principal Investigator.* "Preparing Louisiana for the Possible Federal Regulation of Greenhouse Gas Regulation." With Michael D. McDaniel. Louisiana Department of Economic Development. Total Project: $98,543. Status: Completed.

32. *Principal Investigator*. "OCS Studies Review: Louisiana and Texas Oil and Gas Activity and Production Forecast; Pipeline Position Paper; and Geographical Units for Observing and Modeling Socioeconomic Impact of Offshore Activity." (2008). With Mark J. Kaiser and Allan G. Pulsipher. U.S. Department of the Interior, Minerals Management Service.

Total Project: $377,917 (3 years). Status: Completed.

33. *Principal Investigator*. "State and Local Level Fiscal Effects of the Offshore Petroleum Industry." (2007). With Loren C. Scott. U.S. Department of the Interior, Minerals Management Service. Total Project: $241,216 (2.5 years). Status: Completed.

34. *Principal Investigator*. "Understanding Current and Projected Gulf OCS Labor and Ports Needs." (2007). With Allan. G. Pulsipher, Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $169,906. (one year). Status: Completed.

35. *Principal Investigator*. "Structural Shifts and Concentration of Regional Economic Activity Supporting GOM Offshore Oil and Gas Activities." (2007). With Allan. G. Pulsipher, Michelle Barnett. U.S. Department of the Interior, Minerals Management Service. Total Project: $78,374 (one year). Status: Awarded, Completed.

36. *Principal Investigator*. "Plaquemine Parish's Role in Supporting Critical Energy Infrastructure and Production." (2006). With Seth Cureington. Plaquemines Parish Government, Office of the Parish President and Plaquemines Association of Business and Industry. Total Project: $18,267. Status: Completed.

37. *Principal Investigator*. "Diversifying Energy Industry Risk in the Gulf of Mexico." (2006). With Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $65,302 (two years). Status: Awarded, Completed.

38. *Principal Investigator*. "Post-Hurricane Assessment of OCS-Related Infrastructure and Communities in the Gulf of Mexico Region." (2006). U.S. Department of the Interior, Minerals Management Service. Total Project Funding: $244,837. Status: Completed.

39. *Principal Investigator*. "Ultra-Deepwater Road Mapping Process." (2005). With Kristi A. R. Darby, Subcontract with the Texas A&M University, Department of Petroleum Engineering. Funded by the Gas Technology Institute. Total Project Funding: $15,000. Status: Completed.

40. *Principal Investigator*. "An Examination of the Opportunities for Drilling Incentives on State Leases." (2004). With Robert H. Baumann and Kristi A. R. Darby. Louisiana Office of Mineral Resources. Total Project Funding: $75,000. Status: Completed.

41. *Principal Investigator*. " An Examination on the Development of Liquefied Natural Gas Facilities on the Gulf of Mexico." (2004). With Dmitry V. Mesyanzhinov and Mark J. Kaiser. U.S. Department of the Interior, Minerals Management Service. Total Project Funding $101,054. Status: Completed.

42. *Principal Investigator*. "Examination of the Economic Impacts Associated with Large Customer, Industrial Retail Choice." (2004). With Dmitry V. Mesyanzhinov. Louisiana Mid-Continent Oil and Gas Association. Total Project Funding: $37,000. Status: Completed.

43. *Principal Investigator*. "Economic Opportunities from LNG Development in Louisiana." (2003). With Dmitry V. Mesyanzhinov. Metrovision/New Orleans Chamber of Commerce and the Louisiana Department of Economic Development. Total Project Funding: $25,000. Status: Completed.

44. *Principal Investigator*. "Marginal Oil and Gas Properties on State Leases in Louisiana: An Empirical Examination and Policy Mechanisms for Stimulating Additional Production." (2002). With Robert H. Baumann and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $72,000. Status: Completed.

45. *Principal Investigator*. "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $557,744. Status: Awarded, In Progress.

46. *Co-Principal Investigator*. "An Analysis of the Economic Impacts of Drilling and Production Activities on State Leases." (2002). With Robert H. Baumann, Allan G. Pulsipher, and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $8,000. Status: Completed.

47. *Principal Investigator*. "Cost Profiles and Cost Functions for Gulf of Mexico Oil and Gas Development Phases for Input Output Modeling." (1998). With Dmitry Mesyanzhinov and Allan G. Pulsipher. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $244,956. Status: Completed.

48. *Principal Investigator*. "An Economic Impact Analysis of OCS Activities on Coastal Louisiana." (1998). With Dmitry Mesyanzhinov and David Hughes. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $190,166. Status: Completed.

49. *Principal Investigator*. "Energy Conservation and Electric Restructuring in Louisiana." (1997). Louisiana Department of Natural Resources." Petroleum Violation Escrow Program Funds. Total Project Funding: $43,169. Status: Completed.

50. *Principal Investigator*. "The Industrial Supply of Electricity: Commercial Generation, Self-Generation, and Industry Restructuring." (1996). With Andrew Kleit. Louisiana Energy Enhancement Program, LSU Office of Research and Development. Total Project Funding: $19,948. Status: Completed.

51. *Co-Principal Investigator*. "Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, Grant Number 95-0056. Total Project Funding: $109,361. Status: Completed.

ACADEMIC CONFERENCE PAPERS/PRESENTATIONS

1. "The changing nature of Gulf of Mexico energy infrastructure." (2017). Session 3B: New Directions in Social Science Research. 27th Gulf of Mexico Region Information Technology Meetings. U.S. Department of the Interior, Bureau of Ocean Energy Management, Environmental Studies Program. New Orleans, LA. August 24.

2. "Capacity utilization, efficiency trends, and economic risks for modern CHP installations." (2017). U.S. Department of Energy, 2017 Industrial Energy Technology Conference, New Orleans, LA June 21.

3. “Vulnerability assessment of the central Gulf of Mexico coast using a multi-dimensional approach.” (2016). With Siddhartha Narra. Eighth International Conference on Environmental Science and Technology. June 6-10, Houston, TX.

4. “The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and Leaks.” (2015). With Gregory Upton. Southern Economic Association Meeting 2015. New Orleans, Louisiana. November 23.

5. “The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and Leaks” (2015). With Gregory Upton. 38th IAEE International Conference, Antalya, Turkey. May 26.

6. “Modifying Renewables Policies to Sustain Positive Economic and Environmental Change” (2015). IEEE Annual Green Technologies (“Greentech”) Conference. April 17.

7. “The Gulf Coast Industrial Investment Renaissance and New CHP Development Opportunities.” (2014). Industrial Energy and Technology Conference, New Orleans, Louisiana. May 20.

8. “Estimating Critical Energy Infrastructure Value at Risk from Coastal Erosion” (2014). With Siddhartha Narra. American’s Estuaries: 7th Annual Summit on Coastal and Estuarine Habitat Restoration. Washington, D.C., November 3-6.

9. “Economies of Scale, Learning Curves, and Offshore Wind Development Costs” (2012). With Gregory Upton. Southern Economic Association Annual Conference, New Orleans, LA November 17.

10. “Analysis of Risk and Post-Hurricane Reaction.” (2009). 25th Annual Information Transfer Meeting. U.S. Department of the Interior, Minerals Management Service. January 7.

11. “Legacy Litigation, Regulation, and Other Determinants of Interstate Drilling Activity Differentials.” (2008). With Christopher Peters and Mark Kaiser. 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3.

12. “Gulf Coast Energy Infrastructure Renaissance: Overview.” (2008). 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3.

13. “Understanding the Impacts of Katrina and Rita on Energy Industry Infrastructure.” (2008). American Chemical Society National Meetings, New Orleans, Louisiana. April 7.

14. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2007). With Kristi A. R. Darby and Michelle Barnett. International Association for Energy Economics, Wellington, New Zealand, February 19.

15. “Regulatory Issues in Rate Design, Incentives, and Energy Efficiency.” (2007). 34th Annual Public Utilities Research Center Conference, University of Florida. Gainesville, FL. February 16.

16. “An Examination of LNG Development on the Gulf of Mexico.” (2007). With Kristi A.R. Darby. US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 9.

17. "OCS-Related Infrastructure on the GOM: Update and Summary of Impacts." (2007). U.S. Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 10.

18. "The Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006). With Michelle Barnett. Third National Conference on Coastal and Estuarine Habitat Restoration. Restore America's Estuaries. New Orleans, Louisiana, December 11.

19. "The Impact of Implementing a 20 Percent Renewable Portfolio Standard in New Jersey." (2006). With Seth E. Cureington. Mid-Continent Regional Science Association 37th Annual Conference, Purdue University, Lafayette, Indiana, June 9.

20. "The Impacts of Hurricane Katrina and Rita on Energy infrastructure Along the Gulf Coast." (2006). Environment Canada: 2006 Artic and Marine Oilspill Program. Vancouver, British Columbia, Canada.

21. "Hurricanes, Energy Markets, and Energy Infrastructure in the Gulf of Mexico: Experiences and Lessons Learned." (2006). With Kristi A.R. Darby and Seth E. Cureington. 29th Annual IAEE International Conference, Potsdam, Germany, June 9.

22. "An Examination of the Opportunities for Drilling Incentives on State Leases in Louisiana." (2005). With Kristi A.R. Darby. 28th Annual IAEE International Conference, Taipei, Taiwan (June).

23. "Fiscal Mechanisms for Stimulating Oil and Gas Production on Marginal Leases." (2004). With Jeffrey M. Burke. International Association of Energy Economics Annual Conference, Washington, D.C. (July).

24. "GIS and Applied Economic Analysis: The Case of Alaska Residential Natural Gas Demand." (2003). With Dmitry V. Mesyanzhinov. Presented at the Joint Meeting of the East Lakes and West Lakes Divisions of the Association of American Geographers in Kalamazoo, MI, October 16-18.

25. "Are There Any In-State Uses for Alaska Natural Gas?" (2002). With Dmitry V. Mesyanzhinov and William E. Nebesky. IAEE/USAEE 22nd Annual North American Conference: "Energy Markets in Turmoil: Making Sense of It All." Vancouver, British Columbia, Canada. October 7.

26. "The Economic Impact of State Oil and Gas Leases on Louisiana." (2002). With Dmitry V. Mesyanzhinov. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

27. "Moving to the Front of the Lines: The Economic Impact of Independent Power Plant Development in Louisiana." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

28. "New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities in the Gulf of Mexico." (2002). With Vicki Zatarain. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

29. “Distributed Energy Resources, Energy Efficiency, and Electric Power Industry Restructuring.” (1999). American Society of Environmental Science Fourth Annual Conference. Baton Rouge, Louisiana. December.
30. “Estimating Efficiency Opportunities for Coal Fired Electric Power Generation: A DEA Approach.” (1999). With Williams O. Olatubi. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November.
31. "Applied Approaches to Modeling Regional Power Markets." (1999.) With Robert F. Cope. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November 1999.
32. “Parametric and Non-Parametric Approaches to Measuring Efficiency Potentials in Electric Power Generation.” (1999). With Williams O. Olatubi. International Atlantic Economic Society Annual Conference, Montreal, October.
33. “Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry.” (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. International Association of Energy Economics Annual Conference. Orlando, Florida. August.
34. “Modeling Regional Power Markets and Market Power.” (1999). With Robert F. Cope. Western Economic Association Annual Conference. San Diego, California. July.
35. “Economic Impact of Offshore Oil and Gas Activities on Coastal Louisiana” (1999). With Dmitry Mesyanzhinov. Annual Meeting of the Association of American Geographers. Honolulu, Hawaii. March.
36. “Empirical Issues in Electric Power Transmission and Distribution Cost Modeling.” (1998). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association. Sixty-Eighth Annual Conference. Baltimore, Maryland. November.
37. “Modeling Electric Power Markets in a Restructured Environment.” (1998). With Robert F. Cope and Dan Rinks. International Association for Energy Economics Annual Conference. Albuquerque, New Mexico. October.
38. “Benchmarking Electric Utility Distribution Performance.” (1998) With Robert F. Cope and Dmitry Mesyanzhinov. Western Economic Association, Seventy-sixth Annual Conference. Lake Tahoe, Nevada. June.
39. “Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry.” (1998). With Fred I. Denny. IEEE Large Engineering Systems Conference on Power Engineering. Nova Scotia, Canada. June.
40. “Benchmarking Electric Utility Transmission Performance.” (1997). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-seventh Annual Conference. Atlanta, Georgia. November 21-24.
41. “A Non-Linear Programming Model to Estimate Stranded Generation Investments in a Deregulated Electric Utility Industry.” (1997). With Robert F. Cope and Dan Rinks. Institute for Operations Research and Management Science Annual Conference. Dallas Texas. October 26-29.

42. "New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. International Association of Science and Technology for Development, High Technology in the Power Industry Conference. Orlando, Florida. October 27-30

43. "Cogeneration and Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Western Economic Association, Seventy-fifth Annual Conference. Seattle, Washington. July 9-13.

44. "The Unintended Consequences of the Public Utilities Regulatory Policies Act of 1978." (1997). National Policy History Conference on the Unintended Consequences of Policy Decisions. Bowling Green State University. Bowling Green, Ohio. June 5-7.

45. "Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 16th Annual Information Transfer Meeting. New Orleans, Louisiana.

46. "Empirical Modeling of the Risk of a Petroleum Spill During E&P Operations: A Case Study of the Gulf of Mexico OCS." (1996). With Omowumi Iledare, Allan Pulsipher, and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

47. "Input Price Fluctuations, Total Factor Productivity, and Price Cap Regulation in the Telecommunications Industry" (1996). With Farhad Niami. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

48. "Recovery of Stranded Investments: Comparing the Electric Utility Industry to Other Recently Deregulated Industries" (1996). With Farhad Niami and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

49. "Spatial Perspectives on the Forthcoming Deregulation of the U.S. Electric Utility Industry." (1996) With Dmitry Mesyanzhinov. Southwest Association of American Geographers Annual Meeting. Norman, Oklahoma.

50. "Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators." (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 15th Annual Information Transfer Meeting. New Orleans, Louisiana.

51. "Empirical Determinants of Nuclear Power Plant Disallowances." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

52. "A Cross-Sectional Model of IntraLATA MTS Demand." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

ACADEMIC SEMINARS AND PRESENTATIONS

1. Panelist. "Fuel Security, Resource Adequacy & Value of Transmission." (2019). 6th Annual Electricity Dialogue at Northwestern University: Energy and Capacity: Transitions? Northwestern University Center of Law, Regulation, and Economic Growth.

2. “Air Emissions Regulation and Policy: The Recently Proposed Cross State Air Pollution Rule and the Implications for Louisiana Power Generation.” Lecture before School of the Coast & Environment. November 5, 2011.
3. “Energy Regulation: Overview of Power and Gas Regulation.” Lecture before School of the Coast & Environment, Course in Energy Policy and Law. October 5, 2009.
4. “Trends and Issues in Renewable Energy.” Presentation before the School of the Coast & Environment, Louisiana State University. Spring Guest Lecture Series. May 4, 2007.
5. “CES Research Projects and Status.” Presentation before the U.S. Department of the Interior, Minerals Management Service, Outer Continental Shelf Scientific Committee Meeting, New Orleans, LA May 22, 2007.
6. “Hurricane Impacts on Energy Production and Infrastructure.” Presentation Before the 53rd Mineral Law Institute, Louisiana State University. April 7, 2006.
7. “Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) 51st Mineral Law Institute, Louisiana State University, Baton Rouge, LA. April 2, 2004.
8. “Electric Restructuring and Conservation.” (2001). Presentation before the Department of Electrical Engineering, McNesse State University. Lake Charles, Louisiana. May 2, 2001.
9. “Electric Restructuring and the Environment.” (1998). Environment 98: Science, Law, and Public Policy. Tulane University. Tulane Environmental Law Clinic. March 7, New Orleans, Louisiana.
10. “Electric Restructuring and Nuclear Power.” (1997). Louisiana State University. Department of Nuclear Science. November 7, Baton Rouge, Louisiana.
11. “The Empirical Determinants of Co-generated Electricity: Implications for Electric Power Industry Restructuring.” (1997). With Andrew N. Kleit. Florida State University. Department of Economics: Applied Microeconomics Workshop Series. October 17, Tallahassee, Florida.

PROFESSIONAL AND CIVIC PRESENTATIONS

1. “Gulf Coast Energy Outlook 2024.” (2023). LSU Center for Energy Studies, Baton Rouge, LA, Fall 2023.
2. “Louisiana clean, green industry: reconciling industrial decarbonization, capital formation, and growth.” (2023). Louisiana State Bar Association, Public Utility Section. December 1, 2023.
3. “Expert witness training: considerations for preparation and effective execution during public utility regulatory hearings and proceedings.” (2023). On the Behalf of the National Association of State Utility Consumer Advocates, Accounting and Finance Subcommittee. September 21, 2023.

4. “Gulf cost energy outlook: traditional resources and the energy transition.” (2023). AAPL/Gulf Coast Land Institute Meetings. April 26, 2023.

5. “Ratepayer considerations in the promotion of clean energy.” (2023). Public Utility Law Section Roundtable Discussion. April 21, 2023.

6. “Gulf coast energy outlook: traditional resources and the energy transition.” (2023). Louisiana Engineering Society. April 19, 2023.

7. “Carbon capture & storage: three thoughts and considerations.” (2023). Gulf Coast Power Association. 9th Annual MISO/SPP Conference. March 9, 2023.

8. “Natural gas markets: prices; trends; and ratepayer impacts.” (2023). Maryland Energy Advocates Virtual Monthly Meeting. February 17, 2023.

9. “Hydrogen overview and its role in Louisiana decarbonization.” (2022). Louisiana Public Service Commission Monthly Business & Executive Meeting. November 17, 2022.

10. “High winter natural gas prices and ratepayer impacts.” (2022). National Association of State Utility Consumer Advocates (“NASUCA”) Annual Conference. November 14, 2022.

11. “Facing the future together: the Louisiana energy transition, industrial decarbonization, and capital formation trends.” (2022). Louisiana Chemical Association: Annual Meeting 2022. October 27, 2022.

12. “Louisiana and the energy transition: reconciling industrial decarbonization, capital formation, and growth.” (2022). Louisiana Air and Waste Management 2022 Annual Meeting. October 26, 2022.

13. “The Louisiana energy transition, industrial decarbonization, and industrial capital formation trends.” (2022). Postlethwaite & Netterville: 2022 Governmental Update. August 4, 2022.

14. “Identifying and mapping regulatory requirements for CCUS projects.” (2022). SECARB Offshore GOM Gulf Regulator Workshop. New Orleans LA. May 16, 2022.

15. “Louisiana industrial decarbonization opportunities.” (2022). Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Meeting. May 11, 2022. Baton Rouge, LA.

16. “Natural Gas outlook, 2022: supply, demand, and geopolitical considerations.” (2022). National Association of State Utility Consumer Advocates (“NASUCA”) Monthly Natural Gas Committee Webinar. March 30, 2022.

17. “Louisiana industrial decarbonization opportunities.” (2022). LSU Law School, Journal of Energy Law and Resources Symposium on Energy Transitions. February 4, 2022. Baton Rouge, LA.

18. Panelist. Grid Resiliency in the Era of Extreme Weather. Gulf Coast Power Association 8th Annual MISO/SPP Regional Meeting. February 9, 2022. New Orleans, LA.

19. Panelist. Natural Gas Industry Update. (2022). National Association of State Utility Consumer Advocates Annual Meeting. (virtual). November 8, 2021.

20. “Overview of Louisiana’s greenhouse gas emissions and trends.” (2021). Louisiana Energy Users Group (“LEUG”) Meeting. November 11, 2021.

21. “State of energy in Louisiana: a preview of the 2021 Gulf Coast Energy Outlook.” (2021). Financial Planning Association of Baton Rouge. November 10, 2021.

22. “Replacing natural gas and industrial decarbonization: utility and ratemaking issues.” (2021). Virtual Joint Annual Meeting: Virginia Committee for Fair Utility Rates, Old Dominion Committee for Fair Utility Rates, and Virginia Industrial Gas Users Group Workshop. September 8, 2021.

23. “Louisiana 2021 GHG Inventory: Update and summary of preliminary findings.” (2021). Presentation before the Climate Initiative Task Force. July 29, 2021.

24. “Opportunities for the development of a hydrogen economy in Louisiana.” (2021). Louisiana Energy Climate Solutions Workshop. June 15, 2021.

25. “Natural gas: Building gas system resilience. Overview of the 2021 polar vortex and its implications for gas resiliency.” (2021). National Association of State Utility Consumer Advocates (“NASUCA”). Virtual mid-year meeting. June 14, 2021.

26. “Status and briefing on the Louisiana greenhouse gas inventory and emissions analysis.” (2021). Scientific Advisory Group (“SAG”) Meeting, Governor’s Climate Initiative Task Force. March 29, 2021.

27. “Louisiana carbon capture: sinks; sources; and the role of transportation in industrial applications.” (2021). LSU Journal of Energy Law & Resources Symposium on Carbon Capture and Solutions. February 5, 2021.

28. “Natural gas outlook, 2021: production, demand, pandemic and policy.” (2021). National Association of State Utility Consumer Advocates (“NASUCA”) Monthly Natural Gas Committee Webinar. January 20, 2021.

29. “Consumer Perspectives on the Rate Design of the Future.” (2020). National Association of State Utility Consumer Advocates (“NASUCA”). Annual Conference, November 10.

30. “Evaluation of Louisiana’s Depleted Gas Reservoirs for Geological Carbon Sequestration.” (2020). Louisiana Mid-Continent Oil and Gas Association (“LMOGA”) Carbon Capture and Underground Storage (“CCUS”) Committee Meeting. August 25.

31. “The 2020 Gulf Coast Energy Outlook: COVID-19 update.” (2020). Baton Rouge Area Chamber of Commerce Business Webinar. COVID-19 and Global Supply Impacts on the Capital Region and Louisiana Economies. Baton Rouge, LA. June 3.

32. “Ratepayer benefits of reforming PURPA”. (2020). Harvard Electricity Policy Group Webinar. PURPA: A time to reform or reduce its role? March 26.

33. “Pipeline industry: economic trends and outlook”. (2020). Joint Industry Association Annual Meeting. Louisiana Mid-Continent Oil and Gas Association (“LMOGA”) and the Louisiana Oil and Gas Association (“LOGA”). Lake Charles, LA March 5.

34. “The outlook for natural gas: storm clouds ahead?” (2020). National Association of State Utility Consumer Advocates (“NASUCA”). Natural Gas Committee Webinar, February 26.

35. “The 2020 Gulf Coast Energy Outlook”. (2020). University of Louisiana Lafayette, Southern Unconventional Resources Center for Excellence. Lafayette, LA February 16.

36. “Opportunities for carbon capture, utilization, and storage in the Louisiana chemical corridor”. (2020). Air and Waste Management Association, Louisiana Section Luncheon. Gonzales, LA January 16.

37. Panelist. (2020). Baton Route Advocate, 2020 Economic Outlook Summit. Baton Rouge Advocate. January 8.

38. “2020 Louisiana business climate outlook: the view from the energy sector.” (2019). American Council of Engineering Companies Fall Conference. November 21, 2019. Baton Rouge, LA

39. “The urgency of PURPA reform in protecting ratepayers.” (2019). Americans for Tax Reform, Fall 2019 Coalition Leaders Summit, November 14, 2019. New Orleans, LA.

40. “Louisiana’s coast and the energy industry.” (2019). 2019 API Delta Chapter Joint Society Luncheon Meeting. November 12, 2019, New Orleans, LA.

41. “Reforming PURPA: implications for ratepayers.” (2019). Thomas Jefferson Institute for Public Policy, Annual Energy Summit, State Policy Network Annual Meeting. Colorado Springs, CO, October 28.

42. “Natural gas outlook: supply, demand and prices.” (2019). National Association of State Utility Consumer Advocates, Natural Gas Committee Monthly Meeting. July 30, 2019.

43. “The economic impacts and outlook for LNG development on the Gulf Coast.” (2019). 73rd Annual Meeting of the Southern Legislative Conference of the Council of State Governments. New Orleans, LA, July 14. (prepared presentation, hurricane cancellation)

44. “Natural gas outlook: supply, demand, and prices.” (2019). NASUCA Mid-Year Meeting. Portland, OR, June 20.

45. “Overview of Louisiana LNG issues and trends.” (2019). Berlin: LNG, Energy Security, and Diversity Reporting Tour, LSU Center for Energy Studies. Baton Rouge, LA, May 9.

46. “Overview of Louisiana energy issues and outlook.” (2019). Australian Media Visit, Greater New Orleans, Inc./Baton Rouge Area Foundation. Baton Rouge, LA, April 29.

47. “Gulf Coast Energy Outlook 2019: Regional trends and outlook.” (2019). Women’s Energy Network. Baton Rouge, LA, April 23.

48. “MISO Grid Vision 2033.” (2019). 2019 Spring Regulator and Policymaker Forum. New Orleans, LA, April 15-16.

49. “Ratepayer benefits of reforming PURPA.” (2019). LSU Center for Energy Studies Industry Advisory Council Meeting. March 27.

50. “Incentives, risk, and the changing nature of regulation.” (2019). NASUCA Water Committee monthly meeting/webinar. March 13.

51. “Gulf Coast Energy Outlook 2019: Production, trade and infrastructure trends.” (2019). 66th Annual Mineral Board Institute Meetings. Baton Rouge, LA, March 14.

52. "A golden age: energy outlook 2019." (2019). Engineering News Record Webinar. February 13.
53. Panelist. (2019). Baton Route Advocate, 2019 Economic Outlook Summit. Baton Rouge Advocate. January 8.
54. "MISO Grid Vision 2033." (2018). 2018 Winter Regulatory and Policymaker Forum. New Orleans, LA, December 11.
55. "Gulf Coast Energy Outlook 2019." (2018). LSU Center for Energy Studies, Baton Rouge, LA, Fall 2018.
56. "How LNG is transforming Louisiana's energy economy." (2018). Louisiana State Bar Association, Public Utility Section. Baton Rouge, LA, November 30.
57. "Overview of Louisiana LNG issues and trends." (2018). Kean Miller Law Firm: Energy and Environmental Practice Group. Baton Rouge, LA, November 28.
58. "Infrastructure and capacity: challenges for development." (2018). Society of Utility and Regulatory Financial Analysts (SURFA) Annual Meeting, New Orleans, LA, April 20.
59. "Louisiana industrial cogeneration trends." (2018). Annual Louisiana Solid Waste Association Conference, Lafayette, LA, March 16.
60. "Gulf Coast industrial development: overview of trends and issues." (2018). Gulf Coast Power Association Meetings, New Orleans, LA, February 8.
61. "Energy outlook – reflection on market trends and Louisiana implications." (2017). IberiaBank Corporation Bank Board of Directors Meeting, New Orleans, LA. November 15.
62. "Integrated carbon capture and storage in the Louisiana chemical corridor." (2017). Industry Associates Advisory Council Meeting, Baton Rouge, LA. November 7.
63. "The outlook for natural gas and energy development on the Gulf Coast." (2017). Louisiana Chemical Association, Annual Meeting, New Orleans, LA. October 26.
64. "Critical energy infrastructure: the big picture on resiliency research." (2017). National Academies of Science, Engineering, and Medicine. New Orleans, LA. September 18.
65. "The changing nature of Gulf of Mexico energy infrastructure." (2017). 27th Gulf of Mexico Region Information Technology Meetings, New Orleans, LA, August 24.
66. "Capacity utilization, efficiency trends, and economic risks for modern CHP installations." (2017). Industrial Energy Technology Conference, New Orleans, LA. June 21.
67. "Crude oil and natural gas outlook: Where are we and where are we going?" (2017). CCREDC Economic Trends Panel. Corpus Christi, TX, June 15.
68. "Navigating through the energy landscape." (2017). Baton Rouge Rotary Luncheon. Baton Rouge, LA, May 24.
69. "The 2017-2018 Louisiana energy outlook." (2017). Junior Achievement of Greater New Orleans, JA BizTown Speaker Series. New Orleans, LA, May 12.

70. "The Gulf Coast energy economy: trends and outlook." (2017). Society for Municipal Analysts. New Orleans, LA, April 21.

71. "Gulf coast energy outlook." (2017). E.J. Ourso College of Business, Dean's Advisory Council, Energy Committee Meeting. Baton Rouge, LA, March 31.

72. "Recent trends in energy: overview and impact for the banking community." (2017). Oil and Gas Industry Update, Louisiana Bankers Association. Baton Rouge, LA, March 24.

73. "How supply, demand and prices have influenced unconventional development." (2016). Energy Annual Meeting, CLEER-University Advisory Board Lecture. New Orleans, LA, September 17.

74. "The Basics of Natural Gas Production, Transportation, and Markets." (2016). Center for Energy Studies. Baton Rouge, LA, August 1.

75. "Gulf Coast industrial development: trends and outlook." (2016). Investor Relations Group Meeting, Edison Electric Institute. New Orleans, LA, June 23.

76. "The future of policy and regulation: Unlocking the Treasures of Utility Regulation." (2016). Annual Meeting, National Conference of Regulatory Attorneys. Tampa, FL, June 20.

77. "Utility mergers: where's the beef?". (2016). National Association of State Utility Consumer Advocates Mid-Year Meetings. New Orleans, LA, June 6.

78. "Overview of the Clean Power Plan and its application to Louisiana." (2016). Shell Oil Company Internal Meeting. April 12.

79. "Energy and economic development on the Gulf Coast: trends and emerging challenges." (2016). Gas Processors Association Meeting. New Orleans, LA, April 11.

80. "Unconventional Oil and Gas Drilling Trends and Issues." (2016). French Delegation Visit, LSU Center for Energy Studies. March 16.

81. "Gulf Coast Industrial Growth: Passing clouds or storms on the horizon?" (2016). Gulf Coast Power Association Meetings. New Orleans, LA, February 18.

82. "The Transition to Crisis: What do the recent changes in energy markets mean for Louisiana?" (2016). Louisiana Independent Study Group. February 2.

83. "Regulatory and Ratepayer Issues in the Analysis of Utility Natural Gas Reserves Purchases" (2016). National Association of State Utility Consumer Advocates Gas Consumer Monthly Meeting. January 25.

84. "Emerging Issues in Fuel Procurement: Opportunities & Challenges in Natural Gas Reserves Investment." (2015). National Association of State Utility Consumer Advocates Annual Meeting. Austin, Texas. November 9.

85. "Trends and Issues in Net Metering and Solar Generation." (2015). Louisiana Rural Electric Cooperative Meeting. November 5.

86. "Electric Power: Industry Overview, Organization, and Federal/State Distinctions." (2015). EUCI. October 16.

87. "Natural Gas 101: The Basics of Natural Gas Production, Transportation, and Markets."

(2015). Council of State Governments Special Meeting on Gas Markets. New Orleans, LA. October 14.

88. "Update and General Business Matters." (2015). CES Industry Associates Meeting. Baton Rouge, Louisiana. Fall 2015.

89. "The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and Leaks." (2015). 38th IAEE 2015 International Conference. Antalya, Turkey. May 26.

90. "Industry on the Move – What's Next?" (2015). Event Sponsored by Regional Bank and 1012 Industry Report. May 5.

91. "The State of the Energy Industry and Other Emerging Issues." (2015). Lex Mundi Energy & Natural Resources Practice Group Global Meeting. May 5.

92. "Energy, Louisiana, and LSU." (2015). LSU Science Café. Baton Rouge, Louisiana. April 28.

93. "Energy Market Changes and Impacts for Louisiana." (2015). Kinetica Partners Shippers Meeting, New Orleans, Louisiana. April 22.

94. "Incentives, Risk and the Changing Nature of Utility Regulation." (2015). NARUC Staff Subcommittee on Accounting and Finance Meetings, New Orleans, Louisiana. April 22.

95. "Modifying Renewables Policies to Sustain Positive and Economic Change." (2015). IEEE Annual Green Technologies ("Greentech Conference"). April 17.

96. "Louisiana's Changing Energy Environment." (2015). John P. Laborde Energy Law Center Advisory Board Spring Meeting, Baton Rouge, Louisiana. March 27.

97. "The Latest and the Long on Energy: Outlooks and Implications for Louisiana." (2015). Iberia Bank Advisory Board Meeting, Baton Rouge, Louisiana. February 23.

98. "A Survey of Recent Energy Market Changes and their Potential Implications for Louisiana." (2015). Vistage Group, New Orleans, Louisiana. February 4.

99. "Energy Prices and the Outlook for the Tuscaloosa Marine Shale." (2015). Baton Rouge Rotary Club, Baton Rouge, Louisiana. January 28.

100. "Trends in Energy & Energy-Related Economic Development." (2014). Miller and Thompson Presentation, Baton Rouge, Louisiana. December 30.

101. "Overview EPA's Proposed Rule Under Section 111(d) of the Clean Air Act: Impacts for Louisiana." (2014). Louisiana State Bar: Utility Section CLE Annual Meeting, Baton Rouge, Louisiana. November 7.

102. "Overview EPA's Proposed Clean Power Plan and Impacts for Louisiana." (2014). Clean Cities Coalition Meeting, Baton Rouge, Louisiana. November 5.

103. "Impacts on Louisiana from EPA's Proposed Clean Power Plan." (2014). Air & Waste Management Annual Environmental Conference (Louisiana Chapter), Baton Rouge, Louisiana. October 29, 2014.

104. "A Look at America's Growing Demand for Natural Gas." (2014). Louisiana Chemical Association Annual Meeting, New Orleans, Louisiana. October 23.

105. "Trends in Energy & Energy-Related Economic Development." (2014). 2014 Government Finance Officer Association Meetings, Baton Rouge, Louisiana. October 9.

106. "The Conventional Wisdom Associated with Unconventional Resource Development." (2014). National Association for Business Economics Annual Conference, Chicago, Illinois. September 28.

107. Unconventional Oil & Natural Gas: Overview of Resources, Economics & Policy Issues. (2014). Society of Environmental Journalists Annual Meeting. New Orleans, Louisiana. September 4.

108. "Natural Gas Leveraged Economic Development in the South." (2014). Southern Governors Association Meeting, Little Rock, Arkansas. August 16.

109. "The Past, Present and Future of CHP Development in Louisiana." (2014). Louisiana Public Service Commission CHP Workshop, Baton Rouge, Louisiana. June 25.

110. "Regional Natural Gas Demand Growth: Industrial and Power Generation Trends." (2014). Kinetica Partners Shippers Meeting, New Orleans, Louisiana. April 30.

111. "The Technical and Economic Potential for CHP in Louisiana and the Impact of the Industrial Investment Renaissance on New CHP Capacity Development." (2014). Electric Power 2014, New Orleans, Louisiana. April 1.

112. "Industry Investments and the Economic Development of Unconventional Development." (2014). Tuscaloosa Marine Shale Conference & Expo, Natchez, Mississippi. March 31.

113. Discussion Panelist. Energy Outlook 2035: The Global Energy Industry and Its Impact on Louisiana, (2014). Grow Louisiana Coalition, Baton Rouge, Louisiana. March 18.

114. "Natural Gas and the Polar Vortex: Has Recent Weather Led to a Structural Change in Natural Gas Markets?" (2014). National Association of State Utility Consumer Advocates Monthly Gas Committee Meeting. February 19.

115. "Some Unconventional Thoughts on Regional Unconventional Gas and Power Generation Requirements." (2014). Gulf Coast Power Association Special Briefing, New Orleans, Louisiana. February 6.

116. "Leveraging Energy for Industrial Development." (2013). 2013 Governor's Energy Summit, Jackson, Mississippi. December 5.

117. "Natural Gas Line Extension Policies: Ratepayer Issues and Considerations." (2013). National Association of State Utility Consumer Advocates Annual Meeting, Orlando, Florida. November 19.

118. "Replacement, Reliability & Resiliency: Infrastructure & Ratemaking Issues in the Power & Natural Gas Distribution Industries." (2013). Louisiana State Bar, Public Utility Section Meetings. November 15.

119. "Natural Gas Markets: Leveraging the Production Revolution into an Industrial Renaissance." (2013). International Technical Conference, Houston, TX. October 11.

120. "Natural Gas, Coal & Power Generation Issues and Trends." (2013). Southeast Labor and Management Public Affairs Committee Conference, Chattanooga, Tennessee.

September 27.

121. "Recent Trends in Pipeline Replacement Trackers." (2013). National Association of State Utility Consumer Advocates Monthly Gas Committee Meeting. September 19.

122. Discussion Panelist (2013). Think About Energy Summit, America's Natural Gas Alliance, Columbus Ohio. September 16-17.

123. "Future Test Years: Issues to Consider." (2013). National Regulatory Research Institute, Teleseminar on Future Test Years. August 28.

124. "Industrial Development Outlook for Louisiana." (2013). Louisiana Water Synergy Project Meetings, Jones Walker Law Firm, Baton Rouge, Louisiana. July 30.

125. "Natural Gas & Electric Power Coordination Issues and Challenges." (2013). Utilities State Government Organization Conference, Pointe Clear, Alabama. July 9.

126. "Natural Gas Market Issues & Trends." (2013). Western Conference of Public Service Commissioners, Santa Fe, New Mexico. June 3.

127. "Louisiana Unconventional Natural Gas and Industrial Redevelopment." (2013). Louisiana Chemical Association/Louisiana Chemical Industry Alliance Annual Legislative Conference, Baton Rouge, Louisiana. May 8.

128. "Infrastructure Cost Recovery Mechanism: Overview of Issues." (2013). Energy Bar Association Annual Meeting, Washington, D.C. May 1.

129. "GOM Offshore Oil and Gas." (2013). Energy Executive Roundtable, New Orleans, Louisiana. March 27.

130. "Louisiana Unconventional Natural Gas and Industrial Redevelopment." (2013). Risk Management Association Luncheon, March 21.

131. "Natural Gas Market Update and Emerging Issues." (2013). NASUCA Gas Committee Conference Call/Webinar, March 12.

132. "Unconventional Resources and Louisiana's Manufacturing Development Renaissance." (2013). Baton Rouge Press Club, De La Ronde Hall, Baton Rouge, LA, January 28.

133. "New Industrial Operations Leveraged by Unconventional Natural Gas." (2013) American Petroleum Institute-Louisiana Chapter. Lafayette, LA, Petroleum Club, January 14.

134. "What's Going on with Energy? How Unconventional Oil and Gas Development is Impacting Renewables, Efficiency, Power Markets, and All that Other Stuff." (2012). Atlanta Economics Club Monthly Meeting. Atlanta, GA. December 11.

135. "Trends, Issues, and Market Changes for Crude Oil and Natural Gas." (2012). East Iberville Community Advisory Panel Meeting. St. Gabriel, LA. September 26.

136. "Game Changers in Crude and Natural Gas Markets." (2012). Chevron Community Advisory Panel Meeting. Belle Chase, LA, September 17.

137. "The Outlook for Renewables in a Changing Power and Natural Gas Market." (2012). Louisiana Biofuels and Bioprocessing Summit. Baton Rouge, LA. September 11.

138. "The Changing Dynamics of Crude and Natural Gas Markets." (2012). Chalmette Refining Community Advisory Panel Meeting. Chalmette, LA, September 11.

139. "The Really Big Game Changer: Crude Oil Production from Shale Resources and the Tuscaloosa Marine Shale." (2012). Baton Rouge Chamber of Commerce Board Meeting. Baton Rouge, LA, June 27.

140. "The Impact of Changing Natural Gas Prices on Renewables and Energy Efficiency." (2012). NASUCA Gas Committee Conference Call/Webinar. 12 June 2012.

141. "Issues in Gas-Renewables Coordination: How Changes in Natural Gas Markets Potentially Impact Renewable Development" (2012). Energy Bar Association, Louisiana Chapter, Annual Meeting, New Orleans, LA. April 12, 2012.

142. "Issues in Natural Gas End-Uses: Are We Really Focusing on the Real Opportunities?" (2012). Energy Bar Association, Louisiana Chapter, Annual Meeting, New Orleans, LA. April 12, 2012.

143. "The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana." (2012). Louisiana Oil and Gas Association Annual Meeting, Lake Charles, LA. February 27, 2012.

144. "The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana." (2012) Louisiana Oil and Gas Association Annual Meeting. Lake Charles, Louisiana. February 27, 2012.

145. "Louisiana's Unconventional Plays: Economic Opportunities, Policy Challenges. Louisiana Mid-Continent Oil and Gas Association 2012 Annual Meeting. (2012) New Orleans, Louisiana. January 26, 2012.

146. "EPA's Recently Proposed Cross State Air Pollution Rule ("CSAPR") and Its Impacts on Louisiana." (2011). Bossier Chamber of Commerce. November 18, 2011.

147. "Facilitating the Growth of America's Natural Gas Advantage." (2011). BASF U.S. Shale Gas Workshop Management Meeting. Florham Park, New Jersey. November 1, 2011.

148. "CSAPR and EPA Regulations Impacting Louisiana Power Generation." (2011). Air and Waste Management Association (Louisiana Section) Fall Conference. Environmental Focus 2011: a Multi-Media Forum. Baton Rouge, LA. October 25, 2011.

149. "Natural Gas Trends and Impact on Industrial Development." (2011). Central Gulf Coast Industrial Alliance Conference. Arthur R. Outlaw Convention Center. Mobile, AL. September 22, 2011.

150. "Energy Market Changes and Policy Challenges." (2011). Southeast Manpower Tripartite Alliance ("SEMTA") Summer Conference. Nashville, TN September 2, 2011.

151. "EPA Regulations, Rates & Costs: Implications for U.S. Ratepayers." (2011). Workshop: "A Smarter Approach to Improving Our Environment." 38th Annual American Legislative Exchange Council ("ALEC") Meetings. New Orleans, LA. August 5, 2011.

152. Panelist/Moderator. Workshop: "Why Wait? Start Energy Independence Today." 38th Annual American Legislative Exchange Council ("ALEC") Meetings. New Orleans, LA.

August 4, 2011.

153. "Facilitating the Growth of America's Natural Gas Advantage." Texas Chemical Council, Board of Directors Summer Meeting. San Antonio, TX. July 28, 2011.

154. "Creating Ratepayer Benefits by Reconciling Recent Gas Supply Opportunities with Past Policy Initiatives." National Association of State Utility Consumer Advocates ("NASUCA"), Monthly Gas Committee Meeting. July 12, 2011.

155. "Energy Market Trends and Policies: Implications for Louisiana." (2011). Lakeshore Lion's Club Monthly Meeting. Baton Rouge, Louisiana. June 20, 2011.

156. "America's Natural Gas Advantage: Securing Benefits for Ratepayers Through Paradigm Shifts in Policy." Southeastern Association of Regulatory Commissioners ("SEARUC") Annual Meeting. Nashville, Tennessee. June 14, 2011.

157. "Learning Together: Building Utility and Clean Energy Industry Partnerships in the Southeast." (2011). American Solar Energy Society National Solar Conference. Raleigh Convention Center, Raleigh, North Carolina. May 20, 2011.

158. "Louisiana Energy Outlook and Trends." (2011). Executive Briefing. Counsul General of Canada. LSU Center for Energy Studies, Baton Rouge, Louisiana. May 24, 2011.

159. "Louisiana's Natural Gas Advantage: Can We Hold It? Grow It? Or Do We Need to be Worrying About Other Problems?" (2011). Louisiana Chemical Association Annual Legislative Conference, Baton Rouge, Louisiana, May 5, 2011.

160. "Energy Outlook and Trends: Implications for Louisiana. (2011). Executive Briefing, Legislative Staff, Congressman William Cassidy. LSU Center for Energy Studies, Baton Rouge, Louisiana. March 25, 2011.

161. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2011). Gas Committee, National Association of State Utility Consumer Advocates ("NASUCA"). February 15, 2011.

162. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2010). 2010 Annual Meeting, National Association of State Utility Consumer Advocates ("NASUCA"), Omni at CNN Center, Atlanta, Georgia, November 16, 2010.

163. "How Current and Proposed Energy Policy Impacts Consumers and Ratepayers." (2010). 122nd Annual Meeting, National Association of Regulatory Utility Commissioners ("NARUC"), Omni at CNN Center, Atlanta, Georgia, November 15, 2010.

164. "Energy Outlook: Trends and Policies." (2010). 2010 Tri-State Member Service Conference; Arkansas, Louisiana, and Mississippi Electric Cooperatives. L'Auberge du Lac Casino Resort, Lake Charles, Louisiana, October 14, 2010.

165. "Deepwater Moratorium and Louisiana Impacts." (2010). The Energy Council Annual Meeting. Gulf of Mexico Deepwater Horizon Accident, Response, and Policy. Beau Rivage Conference Center. Biloxi, Mississippi. September 25, 2010.

166. "Overview on Offshore Drilling and Production Activities in the Aftermath of Deepwater Horizon." (2010) Jones Walker Banking Symposium. The Oil Spill: What Will it Mean for

Banks in the Region? New Orleans, Louisiana. August 31, 2010.

167. "Long-Term Energy Sector Impacts from the Oil Spill." (2010). Second Annual Louisiana Oil & Gas Symposium. The BP Gulf Oil Spill: Long-Term Impacts and Strategies. Baton Rouge Geological Society. August 16, 2010.

168. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Global Interdependence Meeting on Energy Issues. Baton Rouge, LA. August 12, 2010.

169. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Regional Roundtable Webinar. National Association for Business Economics. August 10, 2010.

170. "Deepwater Moratorium: Overview of Impacts for Louisiana." Louisiana Association of Business and Industry Meeting. Baton Rouge, LA. June 25, 2010.

171. Moderator. Senior Executive Roundtable on Industrial Energy Efficiency. U.S. Department of Energy Conference on Industrial Efficiency. Office of Renewable Energy and Energy Efficiency. Royal Sonesta Hotel, New Orleans, LA. May 21, 2010.

172. "The Energy Outlook: Trends and Policies Impacting Southeastern Natural Gas Supply and Demand Growth." Second Annual Local Economic Analysis and Research Network ("LEARN") Conference. Federal Reserve Bank of Atlanta. March 29, 2010.

173. "Natural Gas Supply Issues: Gulf Coast Supply Trends and Implications for Louisiana." Energy Bar Association, New Orleans Chapter Meeting. Jones Walker Law Firm. January 28, 2010, New Orleans, LA.

174. "Potential Impacts of Federal Greenhouse Gas Legislation on Louisiana Industry." LCA Government Affairs Committee Meeting. November 10, 2009. Baton Rouge, LA

175. "Regulatory and Ratemaking Issues Associated with Cost and Revenue Tracker Mechanisms." National Association of State Utility Consumer Advocates ("NASUCA") Annual Meeting. November 10, 2009.

176. "Louisiana's Stakes in the Greenhouse Gas Debate." Louisiana Chemical Association and Louisiana Chemical Industry Alliance Annual Meeting: The Billing Dollar Budget Crisis: Catastrophe or Change? New Orleans, LA.

177. "Gulf Coast Energy Outlook: Issues and Trends." Women's Energy Network, Louisiana Chapter. September 17, 2009. Baton Rouge, LA.

178. "Gulf Coast Energy Outlook: Issues and Trends." Natchez Area Association of Energy Service Companies. September 15, 2009, Natchez, MS.

179. "The Small Picture: The Cost of Climate Change to Louisiana." Louisiana Association of Business and Industry, U.S. Chamber of Commerce, Louisiana Oil and Gas Association, and LSU Center for Energy Studies Conference: Can Louisiana Make a Buck After Climate Change Legislation? August 21, 2009. Baton Rouge, LA.

180. "Carbon Legislation and Clean Energy Markets: Policy and Impacts." National Association of Conservation Districts, South Central Region Meeting. August 14, 2009. Baton Rouge, LA.

181. "Evolving Carbon and Clean Energy Markets." The Carbon Emissions Continuum: From

Production to Consumption." Jones Walker Law Firm and LSU Center for Energy Studies Workshop. June 23, 2009. Baton Rouge, LA

182. "Potential Impacts of Cap and Trade on Louisiana Ratepayers: Preliminary Results." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

183. "Natural Gas Outlook." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

184. "Gulf Coast Energy Outlook: Issues and Trends." (2009). ISA-Lafayette Technical Conference & Expo. Cajundome Conference Center. Lafayette, Louisiana. March 12, 2009.

185. "The Cost of Energy Independence, Climate Change, and Clean Energy Initiatives on Utility Ratepayers." (2009). National Association of Business Economics (NABE). 25th Annual Washington Economic Policy Conference: Restoring Financial and Economic Stability. Arlington, VA March 2, 2009.

186. Panelist, "Expanding Exploration of the U.S. OCS" (2009). Deep Offshore Technology International Conference and Exhibition. PennWell. New Orleans, Louisiana. February 4, 2009.

187. "Gulf Coast Energy Outlook." (2008.) Atmos Energy Regional Management Meeting. Louisiana and Mississippi Division. New Orleans, Louisiana. October 8, 2008.

188. "Background, Issues, and Trends in Underground Hydrocarbon Storage." (2008). Presentation before the LSU Center for Energy Studies Industry Advisory Board Meeting. Baton Rouge, Louisiana. August 27, 2008.

189. "Greenhouse Gas Regulations and Policy: Implications for Louisiana." (2008). Presentation before the Praxair Customer Seminar. Houston, Texas, August 14, 2008.

190. "Market and Regulatory Issues in Alternative Energy and Louisiana Initiatives." (2008). Presentation before the 2008 Statewide Clean Cities Coalition Conference: Making Sense of Alternative Fuels and Advanced Technologies. New Orleans, Louisiana, March 27, 2008.

191. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007) Presentation before the New Hampshire Public Utilities Commission. Workshop on Energy Efficiency and Revenue Decoupling. November 7, 2007.

192. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives, and Energy Efficiency." (2007). National Association of State Utility Consumer Advocates, Mid-Year Meeting. June 12, 2007.

193. "Regulatory and Policy Issues in Nuclear Power Plant Development." (2007). LSU Center for Energy Studies Industry Advisory Council Meeting. Baton Rouge, LA. March 23, 2007.

194. "Oil and Gas in the Gulf of Mexico: A North American Perspective." (2007). Canadian Consulate, Heads of Mission EnerNet Workshop, Houston, Texas. March 20, 2007.

195. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives & Energy

Efficiency. (2007). National Association of State Utility Consumer Advocates ("NASUCA") Gas Committee Monthly Meeting. February 13, 2006.

196. "Recent Trends in Natural Gas Markets." (2006). National Association of Regulatory Utility Commissioners, 118th Annual Convention. Miami, FL November 14, 2006.

197. "Energy Markets: Recent Trends, Issues & Outlook." (2006). Association of Energy Service Companies (AESC) Meeting. Petroleum Club, Lafayette, LA, November 8, 2006.

198. "Energy Outlook" (2006). National Business Economics Issues Council. Quarterly Meeting, Nashville, TN, November 1-2, 2006.

199. "Global and U.S. Energy Outlook." (2006). Energy Virginia Conference. Virginia Military Institute, Lexington, VA October 17, 2006.

200. "Interdependence of Critical Energy Infrastructure Systems." (2006). Cross Border Forum on Energy Issues: Security and Assurance of North American Energy Systems. Woodrow Wilson Center for International Scholars. Washington, DC, October 13, 2006.

201. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006) The Economic and Market Impacts of Coastal Restoration: America's Wetland Economic Forum II. Washington, DC September 28, 2006.

202. "Relationships between Power and Other Critical Energy Infrastructure." (2006). Rebuilding the New Orleans Region: Infrastructure Systems and Technology Innovation Forum. United Engineering Foundation. New Orleans, LA, September 24-25, 2006.

203. "Outlook, Issues, and Trends in Energy Supplies and Prices." (2006.) Presentation to the Southern States Energy Board, Associate Members Meeting. New Orleans, Louisiana. July 14, 2006.

204. "Energy Sector Outlook." (2006). Baton Rouge Country Club Meeting. Baton Rouge, Louisiana. July 11, 2006.

205. "Oil and Gas Industry Post 2005 Storm Events." (2006). American Petroleum Institute, Teche Chapter. Production, Operations, and Regulations Annual Meeting. Lafayette, Louisiana. June 29, 2006.

206. "Concentration of Energy Infrastructure in Hurricane Regions." (2006). Presentation before the National Commission on Energy Policy Forum: Ending the Stalemate on LNG Facility Siting. Washington, DC. June 21, 2006.

207. "LNG—A Premier." (2006). Presentation Given to the U.S. Department of Energy's "LNG Forums." Los Angeles, California. June 1, 2006.

208. "Regional Energy Infrastructure, Production and Outlook." (2006). Executive Briefing for Board of Directors, Louisiana Oil and Gas Plc., Enhanced Exploration, Inc. and Energy Self-Service, Inc. Covington, Louisiana, May 12, 2006.

209. "The Impacts of the Recent Hurricane Season on Energy Production and Infrastructure and Future Outlook." Presentation before the Industrial Energy Technology Conference 2006. New Orleans, Louisiana, May 9, 2006.

210. "Update on Regional Energy Infrastructure and Production." (2006). Executive Briefing

for Delegation Participating in U.S. Department of Commerce Gulf Coast Business Investment Mission. Baton Rouge, Louisiana May 5, 2006.

211. "Hurricane Impacts on Energy Production and Infrastructure." (2006). Presentation before the Interstate Natural Gas Association of America Mid-Year Meeting. Hyatt Regency Hill Country. April 21, 2006.

212. "LNG—A Premier." Presentation Given to the U.S. Department of Energy's "LNG Forums." Astoria, Washington. April 28, 2006.

213. Natural Gas Market Outlook. Invited Presentation Given to the Georgia Public Service Commission and Staff. Georgia Institute of Technology, Atlanta, Georgia. March 10, 2006.

214. The Impacts of Hurricanes Katrina and Rita on Louisiana's Energy Industry. Presentation to the Louisiana Economic Development Council. Baton Rouge, Louisiana. March 8, 2006.

215. Energy Markets: Hurricane Impacts and Outlook. Presentation to the 2006 Louisiana Independent Oil and Gas Association Annual Conference. L'Auberge du Lac Resort and Casino. Lake Charles, Louisiana. March 6, 2006

216. Energy Market Outlook and Update on Hurricane Damage to Energy Infrastructure. Presentation to the Energy Council 2005 Global Energy and Environmental Issues Conference. Santa Fe, New Mexico, December 10, 2005.

217. "Putting Our Energy Infrastructure Back Together Again." Presentation Before the 117th Annual Convention of the National Association of Regulatory Utility Commissioners (NARUC). November 15, 2005. Palm Springs, CA

218. "Hurricanes and the Outlook for Energy Markets." Presentation before the Baton Rouge Rotary Club. November 9, 2005, Baton Rouge, LA.

219. "Hurricanes, Energy Supplies and Prices." Presentation before the Louisiana Department of Natural Resources and Atchafalaya Basin Committee Meeting. November 8, 2005. Baton Rouge, LA.

220. "The Impact of the Recent Hurricane's on Louisiana's Energy Industry." Presentation before the Louisiana Independent Oil and Gas Association Board of Directors Meeting. November 8, 2005. Baton Rouge, LA.

221. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before the Baton Rouge City Club Distinguished Speaker Series. October 13, 2005. Baton Rouge, LA.

222. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before Powering Up: A Discussion About the Future of Louisiana's Energy Industry. Special Lecture Series Sponsored by the Kean Miller Law Firm. October 13, 2005. Baton Rouge, LA.

223. "The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Special Lecture on Hurricane Impacts, LSU Center for Energy Studies, September 29, 2005.

224. "Louisiana Power Industry Overview." Presentation before the Clean Air Interstate Rule Implementation Stakeholders Meeting. August 11, 2005. Louisiana Department of Environmental Quality.

225. "CES 2005 Legislative Support and Outlook for Energy Markets and Policy." Presentation before the LMOGA/LCA Annual Post-Session Legislative Committee Meeting. August 10-13, 2005. Perdido Key, Florida.

226. "Electric Restructuring: Past, Present, and Future." Presentation to the Southeastern Association of Tax Administrators Annual Conference. Sheraton Hotel and Conference Facility. New Orleans, LA July 12, 2005.

227. "The Outlook for Energy." Lagniappe Studies Continuing Education Course. Baton Rouge, LA. July 11, 2005.

228. "The Outlook for Energy." Sunshine Rotary Club. Baton Rouge, LA. April 27, 2005.

229. "Background and Overview of LNG Development." Energy Council Workshop on LNG/CNG. Biloxi, Ms: Beau Rivage Resort and Hotel, April 9, 2005.

230. "Natural Gas Supply, Prices, and LNG: Implications for Louisiana Industry." Cytec Corporation Community Advisory Panel. Fortier, LA January 14, 2005.

231. "The Economic Opportunities for a Limited Industrial Retail Choice Plan." Louisiana Department of Economic Development. Baton Rouge, Louisiana. November 19, 2004.

232. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Association of Business and Industry, Energy Council Meeting. Baton Rouge, Louisiana. October 11, 2004.

233. "Energy Issues for Industrial Customers of Gas and Power." Annual Meeting of the Louisiana Chemical Association and the Louisiana Chemical Industry Alliance. Point Clear, Alabama. October 8, 2004.

234. "Energy Issues for Industrial Customers of Gas and Power." American Institute of Chemical Engineers – New Orleans Section. New Orleans, LA. September 22, 2004.

235. "Natural Gas Supply, Prices and LNG: Implications for Louisiana Industry." Dow Chemical Company Community Advisory Panel Meeting. Plaquemine, LA. August 9, 2004.

236. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Chemical Association Post-Legislative Meeting. Springfield, LA. August 9, 2004.

237. "LNG In Louisiana." Joint Meeting of the Louisiana Economic Development Council and the Governors Cabinet Advisory Council. Baton Rouge, LA. August 5, 2004.

238. "Louisiana Energy Issues." Louisiana Mid-Continent Oil and Gas Association Post Legislative Meetings. Sandestin, Florida. July 28, 2004.

239. "The Gulf South: Economic Opportunities Related to LNG." Presentation before the Energy Council's 2004 State and Provincial Energy and Environmental Trends Conference. Point Clear, AL, June 26, 2004.

240. "Natural Gas and LNG Issues for Louisiana." Presentation before the Rhodia Community Advisory Panel. May 20, 2004, Baton Rouge, LA.

241. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association Plant Managers Meeting. May 27, 2004. Baton Rouge, LA.

242. The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Conference. May 26, 2004. Baton Rouge, LA.

243. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Petrochemical Industry Cluster, Greater New Orleans, Inc. May 19, 2004, Destrehan, LA.

244. "Industry Development Issues for Louisiana: LNG, Retail Choice, and Energy." Presentation before the LSU Center for Energy Studies Industry Associates. May 14, 2004, Baton Rouge, LA.

245. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Board of Directors, Greater New Orleans, Inc. May 13, 2004, New Orleans, LA.

246. "Natural Gas Outlook: Trends and Issues for Louisiana." Presentation before the Louisiana Joint Agricultural Association Meetings. January 14, 2004, Hotel Acadiana, Lafayette, Louisiana.

247. "Natural Gas Outlook" Presentation before the St. James Parish Community Advisory Panel Meeting. January 7, 2004, IMC Production Facility, Convent, Louisiana.

248. "Competitive Bidding in the Electric Power Industry." Presentation before the Association of Energy Engineers. Business Energy Solutions Expo. December 11-12, 2003, New Orleans, Louisiana.

249. "Regional Transmission Organization in the South: The Demise of SeTrans" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. December 9, 2003. Baton Rouge, Louisiana.

250. "Affordable Energy: The Key Component to a Strong Economy." Presentation before the National Association of Regulatory Utility Commissioners ("NARUC"), November 18, 2003, Atlanta, Georgia.

251. "Natural Gas Outlook." Presentation before the Louisiana Chemical Association, October 17, 2003, Pointe Clear, Alabama.

252. "Issues and Opportunities with Distributed Energy Resources." Presentation before the Louisiana Biomass Council. April 17, 2003, Baton Rouge, Louisiana.

253. "What's Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. November 12, 2002. Baton Rouge, Louisiana.

254. "An Introduction to Distributed Energy Resources." Presentation before the U.S. Department of Energy, Office of Renewable Energy and Energy Efficiency, State Energy Program/Rebuild America Conference, August 1, 2002, New Orleans, Louisiana.

255. "Merchant Energy Development Issues in Louisiana." Presentation before the Program Committee of the Center for Legislative, Energy, and Environmental Research (CLEER), Energy Council. April 19, 2002.

256. "Merchant Power Plants and Deregulation: Issues and Impacts." Presentation before 24th Annual Conference on Waste and the Environment. Sponsored by the Louisiana Department of Environmental Quality. Lafayette, Louisiana, Cajundome. March 18, 2002.

257. "Merchant Power and Deregulation: Issues and Impacts." Presentation before the Air and Waste Management Association Annual Meeting. Baton Rouge, LA, November 15, 2001.

258. "Moving to the Front of the Lines: The Economic Impact of Independent Power Production in Louisiana." Presentation before the LSU Center for Energy Studies Merchant Power Generation and Transmission Conference, Baton Rouge, LA. October 11, 2001.

259. "Economic Impacts of Merchant Power Plant Development in Mississippi." Presentation before the U.S. Oil and Gas Association Annual Oil and Gas Forum. Jackson, Mississippi. October 10, 2001.

260. "Economic Opportunities for Merchant Power Development in the South." Presentation before the Southern Governor's Association/Southern State Energy Board Meetings. Lexington, KY. September 9, 2001.

261. "The Changing Nature of the Electric Power Business in Louisiana." Presentation before the Louisiana Department of Environmental Quality. Baton Rouge, LA, August 27, 2001.

262. "Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Interagency Group on Merchant Power Development . Baton Rouge, LA, July 16, 2001.

263. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Office of the Governor. Baton Rouge, LA, July 16, 2001.

264. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Department of Economic Development. Baton Rouge, LA, July 3, 2001.

265. "The Economic Impacts of Merchant Power Plant Development In Mississippi." Presentation before the Mississippi Public Service Commission. Jackson, Mississippi, March 20, 2001.

266. "Energy Conservation and Electric Restructuring." With Ritchie D. Priddy. Presentation before the Louisiana Department of Natural Resources. Baton Rouge, Louisiana, October 23, 2000.

267. "Pricing and Regulatory Issues Associated with Distributed Energy." Joint Conference by Econ One Research, Inc., the Louisiana State University Distributed Energy Resources

Initiative, and the University of Houston Energy Institute: "Is the Window Closing for Distributed Energy?" Houston, Texas, October 13, 2000.

268. "Electric Reliability and Merchant Power Development Issues." Technical Meetings of the Louisiana Public Service Commission. Baton Rouge, LA. August 29, 2000.

269. "A Introduction to Distributed Energy Resources." Summer Meetings, Southeastern Association of Regulatory Utility Commissioners (SEARUC). New Orleans, LA. June 27, 2000.

270. Roundtable Moderator/Discussant. Mid-South Electric Reliability Summit. U.S. Department of Energy. New Orleans, Louisiana. April 24, 2000.

271. "Electricity 101: Definitions, Precedents, and Issues." Energy Council's 2000 Federal Energy and Environmental Matters Conference. Loews L'Enfant Plaza Hotel, Washington, D.C. March 11-13, 2000.

272. "LSU/CES Distributed Energy Resources Initiatives." Los Alamos National Laboratories. Office of Energy and Sustainable Systems. Los Alamos, New Mexico. February 16, 2000.

273. "Distributed Energy Resources Initiatives." Louisiana State University, Center for Energy Studies Industry Associates Meeting. Baton Rouge, Louisiana. December 15, 1999.

274. "Merchant Power Opportunities in Louisiana." Louisiana Mid-Continent Oil and Gas Association (LMOGA) Power Generation Committee Meetings. Baton Rouge, Louisiana. November 10, 1999.

275. Roundtable Discussant. "Environmental Regulation in a Restructured Market" The Big E: How to Successfully Manage the Environment in the Era of Competitive Energy. PUR Conference. New Orleans, Louisiana. May 24, 1999.

276. "The Political Economy of Electric Restructuring In the South" Southeastern Electric Exchange, Rate Section Annual Conference. New Orleans, Louisiana. May 7, 1999.

277. "The Dynamics of Electric Restructuring in Louisiana." Joint Meeting of the American Association of Energy Engineers and the International Association of Facilities Managers. Metairie, Louisiana. April 29, 1999.

278. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Lafayette, Louisiana, March 24, 1999.

279. "What's Happened to Electricity Restructuring in Louisiana?" Louisiana State University, Center for Energy Studies Industry Associates Meeting. March 22, 1999.

280. "A Short Course on Electric Restructuring." Central Louisiana Electric Company. Sales and Marketing Division. Mandeville, Louisiana, October 22, 1998.

281. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Shreveport, Louisiana, October 13, 1998.

282. "How Will Utility Deregulation Affect Tourism." Louisiana Travel Promotion Association Annual Meeting, Alexandria, Louisiana. January 15, 1998.

283. "Reflections and Predictions on Electric Utility Restructuring in Louisiana." With Fred I. Denny. Louisiana State University, Center for Energy Studies Industry Associates Meeting. November 20, 1997.

284. "Electric Utility Restructuring in Louisiana." Hammond Chamber of Commerce, Hammond, Louisiana. October 30, 1997.

285. "Electric Utility Restructuring." Louisiana Association of Energy Engineers. Baton Rouge, Louisiana. September 11, 1997.

286. "Electric Utility Restructuring: Issues and Trends for Louisiana." Opelousas Chamber of Commerce, Opelousas, Louisiana. June 24, 1997.

287. "The Electric Utility Restructuring Debate In Louisiana: An Overview of the Issues." Annual Conference of the Public Affairs Research Council of Louisiana. Baton Rouge, Louisiana. March 25, 1997.

288. "Electric Restructuring: Louisiana Issues and Outlook for 1997." Louisiana State University, Center for Energy Studies Industry Associates Meeting, Baton Rouge, Louisiana, January 15, 1997.

289. "Restructuring the Electric Utility Industry." Louisiana Propane Gas Association Annual Meeting, Alexandria, Louisiana, December 12, 1996.

290. "Deregulating the Electric Utility Industry." Eighth Annual Economic Development Summit, Baton Rouge, Louisiana, November 21, 1996.

291. "Electric Utility Restructuring in Louisiana." Jennings Rotary Club, Jennings, Louisiana, November 19, 1996.

292. "Electric Utility Restructuring in Louisiana." Entergy Services, Transmission and Distribution Division, Energy Centre, New Orleans, Louisiana, September 12, 1996

293. "Electric Utility Restructuring" Louisiana Electric Cooperative Association, Baton Rouge, Louisiana, August 27, 1996.

294. "Electric Utility Restructuring -- Background and Overview." Louisiana Public Service Commission, Baton Rouge, Louisiana, August 14, 1996.

295. "Electric Utility Restructuring." Sunshine Rotary Club Meetings, Baton Rouge, Louisiana, August 8, 1996.

296. Roundtable Moderator, "Stakeholder Perspectives on Electric Utility Stranded Costs." Louisiana State University, Center for Energy Studies Seminar on Electric Utility Restructuring in Louisiana, Baton Rouge, May 29, 1996.

297. Panelist, "Deregulation and Competition." American Nuclear Society: Second Annual Joint Louisiana and Mississippi Section Meetings, Baton Rouge, Louisiana, April 20, 1996.

EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS

1. Expert Testimony. Docket No. DPU 23-81. (2023). Before the Commonwealth of

Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil (Gas Division), pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Gas Service and a Performance-Based Ratemaking Plan.* On Behalf of the Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy. Issues: alternative regulation performance-based ratemaking, cost of service, revenue distribution, rate design.

2. Expert Testimony. Docket No. DPU 23-80. (2023). Before the Commonwealth of Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil (Electric Division), pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance-Based Ratemaking Plan.* On Behalf of the Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy. Issues: alternative regulation performance-based ratemaking, cost of service, revenue distribution, rate design.

3. Expert Testimony. Cause No. 45933 (2023). Before the Indiana Utility Regulatory Commission. *Petition of Indiana Michigan Power Company an Indiana Corporation, for authority to increase rates and charges for electric utility service through a phase in rate adjustment; and for approval of related relief including: (1) revised depreciation rates, including cost of removal less salvage, and updated depreciation expense; (2) accounting relief, including deferrals and amortization; (3) inclusion of capital investment; (4) rate adjustment mechanism proposals, including new grant projects rider and modified tax rider; (5) a voluntary residential customer powerpay program; (6) waiver or declination of jurisdiction with respect to certain rules to facilitate implementation of the powerpay program; (7) cost recovery for cook plant subsequent license renewal evaluation project; and (8) new schedules of rates, rules and regulations.* On Behalf of Indiana Office of Utility Consumer Counselor. Issues: cost of service, rate design, revenue distribution, service fees.

4. Expert Report. (2023). *Alternative regulation deficiencies and potential ratepayer harms*. On Behalf of the Office of the Consumer Advocate of Iowa. October 3, 2023.

5. Expert Testimony. Docket No. 2023.06.057. (2023). Before the Public Service Commission of the State of Montana. *In the Matter of Energy West Montana's Application for Approval of Gas Cost Hedging Plan for West Yellowstone.* On Behalf of the Montana Consumer Counsel. Issues: gas hedging program.

6. Legislative Testimony. (2023). Ratepayer harms from alternative regulation in Oklahoma. Appearing on the Behalf of the Petroleum Alliance of Oklahoma. October 23, 2023.

7. Expert Testimony. Cause No. 45911. (2023). Before the State of Indiana Utility Regulatory Commission. *Petition of Indianapolis Power & Light Company D/B/A AES Indiana ("AES Indiana") for authority to increase rates and charges for electric utility service, and for approval of related relief, including (1) revised depreciation rates, (2) accounting relief, including deferrals and amortizations, (3) inclusion of capital investments, (4) rate adjustment mechanism proposals, including new economic development rider, (5) remote disconnect/reconnect process and (6) new schedules of rates, rules and regulations for service*. On Behalf of Indiana Office of Utility Consumer Counselor. Direct and Cross-Answering. Issues: allocated cost of service, revenue distribution, rate design, trackers.

8. Expert Testimony. Docket No. 23-06007. (2023). Before the Public Utilities Commission of Nevada. *In the Matter of the Application by Nevada Power Company D/B/A NV Energy, filed pursuant to NRS 704.110(3) and NRS 704.110(4), addressing its annual revenue requirement for general rates charged to all classes of electric customers.* On Behalf of the Nevada Bureau of Consumer Protection. Issues: marginal cost of service study, embedded cost of service study, revenue distribution, rate design.

9. Expert Testimony. Docket No. UE-230172. (2023). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission, Complainant v. Pacificorp dba Pacific Power & Light Company, Respondent.* On Behalf of the Washington State Office of the Attorney General Public Counsel Unit. Issues: rate design, revenue distribution, cost of service.

10. Expert Testimony. Case No. U-21389. (2023). Before the Michigan Public Service Commission. *In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for other Relief.* On Behalf of the Michigan Department of the Attorney General. Issues: capital expenditure adjustments, overview of proposal.

11. Expert Report. Case No. 22-1094-WW-AIR. (2023). *Audit of the Application to Increase Rates of Aqua Ohio, Inc. For the Period July 1, 2022 through June 30, 2023.* Prepared for the Public Utilities Commission of Ohio. Issues: cost of service, billing determinants, revenue distribution, rate design.

12. Expert Report. Case No. 22-1096-ST-AIR. (2023). *Audit of the Application to Increase Rates of Aqua Ohio Wastewater, Inc. For the period July 1, 2022 through June 30, 2023.* Prepared for the Public Utilities Commission of Ohio. Issues: cost of service, billing determinants, revenue distribution, rate design.

13. Expert Report. *Analysis of the effectiveness and ratepayer impacts regarding the Natural Gas Rate Stabilization Act of 2005. (S.C. Code Ann. Section 58-5-410).* On Behalf of the South Carolina Department of Consumer Affairs. July 27, 2023.

14. Expert Testimony. Docket No. 2023-70-G. (2023). Before the Public Service Commission of South Carolina. *In the Matter of: Dominion Energy South Carolina, Inc's application for adjustments in its natural gas rate schedules and tariffs.* On Behalf of the South Carolina Department of Consumer Affairs. Issues: revenue credit, revenue distribution, rate design. Direct and Surrebuttal.

15. Expert Testimony. Docket No. E-01345A-22-0144. (2023). Before the Arizona Corporation Commission. *In the Matter of the Application of Arizona Public Service Company for a hearing to determine the fair value of the utility property of the company for ratemaking purposes, to fix a just and reasonable rate of return thereon, and to approve rate schedules designed to develop such return. On Behalf of the Utilities Division Arizona Corporation Commission.* Issues: cost of service, revenue distribution, rate design. Direct and Surrebuttal.

16. Expert Testimony. Docket No. 23-0068 (consol.) 23-0069. (2023). Before the Illinois Commerce Commission. *North Shore Gas Company, The Peoples Gas Light and Coke Company Proposed general increase in rates and revisions to service classifications,*

riders and terms and conditions of service. On Behalf of the People of the State of Illinois. Issues: integrity management, infrastructure metrics, natural gas policy, state gas policy.

17. Expert Testimony. Docket No. 23-067. (2023). Before the Illinois Commerce Commission. *Ameren Illinois Company Proposed general increase in gas delivery service rates.* On Behalf of the Illinois Attorney General. Issues: integrity management, infrastructure metrics, natural gas policy, state gas policy.

18. Expert Testimony. Docket No. 23-066. (2023). Before the Illinois Commerce Commission. *Northern Illinois Gas Company d/b/a Nicor Gas Company Proposed general increase in gas rates.* On Behalf of the People of the State of Illinois. Issues: integrity management, infrastructure metrics, natural gas policy, state gas policy.

19. Expert Testimony. Docket No. U-22-081. (2023). Before the Regulatory Commission of Alaska. *In the Matter of the Revenue Requirement Study Designated as TA334-4 Filed by Enstar Natural Gas Company, A Division of SEMCO Energy, Inc.* On Behalf of the Attorney General, Regulatory Affairs & Public Advocacy Section. Issues: cost of service, rate design, revenue distribution.

20. Expert Testimony. Docket No. U-22-078. (2023). Before the Regulatory Commission of Alaska. *In the Matter of the Revenue Requirement Study and Tariff Filing Designated as TA510-1 Filed by Alaska Electric Light & Power Company.* On Behalf of the Office of the Attorney General, Regulatory Affairs & Public Advocacy Section. Issues: cost of service, rate design, seasonal rates, revenue allocation, customer charge.

21. Expert Testimony. Docket No. 2022.11.099. (2023). Before the Department of Public Service Regulation. *In the Matter of Montana-Dakota Utilities Co. for Authority to Establish Increased Rates for Electric Service.* On Behalf of the Montana Consumer Counsel. Direct and Cross-Answering. Issues: rate increase, cost of service study, marginal cost of service, revenue allocation, rate design.

22. Expert Testimony. Docket No. U-22-078. (2023). Before the Regulatory Commission of Alaska. *In the Matter of the Revenue Requirement Study and Tariff Filing Designated as TA510-1 Filed by Alaska Electric Light & Power Company.* On Behalf of the Office of the Attorney General, Regulatory Affairs & Public Advocacy Section. Issues: rate design, cost of service, revenue allocation, seasonal rates.

23. Expert Testimony. Docket No. U-21193. (2023). Before the Michigan Public Service Commission. *In the matter of the Application of DTE Electric Company for Approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief.* On Behalf of the Michigan Department of the Attorney General. Issues: Resource planning, coal retirements, asset amortization, financial compensation mechanism.

24. Expert Testimony. Docket No. RP22-1033. (2023). Before the Federal Energy Regulatory Commission. *Northern Natural Gas Company.* On Behalf of the Northern Municipal Distributors Group and the Midwest Region Gas Task Force Association. Issues: tariff provisions, rate analysis, discount adjustment.

25. Expert Testimony. Docket No. 22-061-U. (2023). Before the Arkansas Public Service Commission. *In the Matter of an Investigation into Potential Cost Shifting Associated with*

Net Metering. On Behalf of the Office of Tim Griffin, Attorney General of Arkansas. Issues: policy, net metering background.

26. Expert Testimony. Docket No. 22F-0263EG. (2023). Before the Public Utility Commission of the State of Colorado. *Olson's Greenhouses of Colorado, LLC. Complainant, v. Public Service Company of Colorado Respondent*. On Behalf of Olson's Greenhouses of Colorado, LLC. Issues: reliability, system upgrades, weather normalization.

27. Expert Testimony. Docket No. 2022.07.078. (2022). Before the Public Service Commission of the State of Montana. *In the Matter of NorthWestern Energy's Application for Authority to Increase Retail Electric and Natural Gas Utility Rates and for Approval of Electric and Natural Gas Service Schedules and Rules and Allocated Cost of Service and Rate Design.* On Behalf of the Montana Consumer Counsel. Direct and Cross-Intervenor. Issues: riders, fixed cost recovery mechanism, power cost adjustment, cost of service, revenue distribution.

28. Expert Testimony. Docket No 2022-254-E. (2022). Before the Public Service Commission of South Carolina. *In the Matter of: Application of Duke Energy Progress, LLC for Authority to Adjust and Increase its Electric Rates and Charges.* On Behalf of South Carolina Department of Consumer Affairs. Direct and Surrebuttal. Issues: Cost of service, revenue allocation, rate design.

29. Expert Testimony Docket No. 22-06014. (2022). *Before the Public Utilities Commission of Nevada. In the Matter of the Application by Sierra Pacific Power Company D/B/A NV Energy, filed pursuant to NRS 704.110(3) and NRS 704.110(4), addressing its annual revenue requirement for general rates charged to all classes of electric customers*. On Behalf of the Nevada Bureau of Consumer Protection. Issues: rate design, cost of services, marginal cost of service, revenue distribution.

30. Expert Testimony Docket No. 2022.06.067. (2022). *Before the Public Service Commission of the State of Montana. In RE NorthWestern Energy's Application for an Advanced Metering Opt-Out Tariff.* On Behalf of the Montana Consumer Counsel. Direct and Rebuttal. Issues: meter issues, opt-out fees, tariffs options.

31. Expert Testimony Docket No. 16-036-FR. (2022). *Before the Arkansas Public Service Commission. In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, INC., Pursuant to APSC Docket NO. 15-015-U. On Behalf of the Arkansas Attorney General Leslie Rutledge.* Issues: Rate design, netting adjustment, performance standards, projected year adjustments.

32. Expert Testimony Formal Case No. 1169. (2022). *Before the Public Service Commission of the District of Columbia. In the Matter of the application of Washington Gas Light Company for authority to increase existing rates and charges for gas service.* On Behalf of the People's Counsel for the District of Columbia. Direct and Rebuttal. Issues: Revenue allocation, weather normalization, rate design.

33. Expert Testimony Case No. U-21224. (2022). *Before the Michigan Public Service Commission. In the Matter of the Application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief*. On Behalf of the Michigan Department of the Attorney General. Issues: cost of service,

revenue distribution, policy overview.

34. Expert Report. Case No. 695287. (2022). Before the Nineteenth Judicial District Court, The Parish of East Baton Rouge, State of Louisiana. *Washington-St. Tammany Electric Cooperative, Inc. and Claiborne Electric Cooperative, Inc., Plaintiff v. Louisiana Generating, L.L.C., Defendant.* On Behalf of Louisiana Generating, L.L.C. Issues: environmental regulations, re-fueling, regulatory rules, collateral benefits.

35. Expert Report. Case No. 0:20-cv-60981-AMC. (2022). *Café, Gelato & Panini LLC, d/b/a Café Gelato Panini, on behalf of itself and all others similarly situated, Plaintiff v. Simon Property Group, Inc., Simon Property Group, L.P., M. S. Management Associates, Inc. And The Town Center at Boca Raton Trust, Defendant.* On Behalf of Simon Property Group, Inc.

36. Expert Testimony Case No. U-20836. (2022). *Before the Michigan Public Service Commission. In the Matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.* On Behalf of the Michigan Department of the Attorney General. Issues: cost of service, revenue distribution, peer comparison.

37. Expert Testimony. D.P.U. 22-22. (2022*). Before the Department of Public Utilities of the Commonwealth of Massachusetts. Petition of NSTAR Electric Company d/b/a Eversource Energy for Approval of a Performance-Based Ratemaking Plan and Increase in Base Distribution Rates for Electric Service Pursuant to G.L. c. 164, §94 and 220 C.M.R. §5.00.* On Behalf of Massachusetts Office of the Attorney General Office of Ratepayer Advocacy. Issues: rate design, TFP analysis, rate increases, benchmark analysis, revenue distribution. Direct and Surrebuttal.

38. Expert Testimony. Docket No. 21-097-U. (2022). In the Matter of the Application of Black Hills Energy Arkansas, Inc. for Approval of a General Change in Rates and Tariffs. On Behalf of the Office of Arkansas Attorney General. Issues: cost of service, rate design, reliability, billing determinant adjustment.

39. Expert Testimony. Docket No. 2021-361-G. (2022). Before the Public Service Commission of South Carolina. *In the Matter of: Dominion Energy South Carolina, Inc.'s Request for Approval of New Natural Gas Energy Efficiency Programs*. On Behalf of South Carolina Department of Consumer Affairs. Issues: DSM Rider, energy efficiency, shared savings. Direct and Surrebuttal.

40. Expert Report. Case No. 21-596-ST-AIR. (2022). *Audit of the Application to Increase Rates of Aqua Ohio Wastewater, Inc. For the Period January 1, 2021 through December 31, 2021*. Prepared for Public Utilities Commission of Ohio. Issues: rate design, cost of service, revenue distribution.

41. Expert Report. Case No. 21-595-WW-AIR. (2022). *Audit of the Application to Increase Rates of Aqua Ohio, Inc. For the Period January 1, 2021 through December 31, 2021.* Prepared for Public Utilities Commission of Ohio. Issues: rate design, cost of service, revenue distribution.

42. Expert Testimony. Docket No. 2021.09.112. (2022). *Before the Public Service Commission of the State of Montana. In the Matter of NorthWestern Energy's Annual PCCAM Filing and Application for Approval of Tariff Changes.* On Behalf of the Montana Consumer Counsel. Issues: wholesale energy hedging, market exposure, overview of PCCAM filing, demand side management costs.

43. Expert Affidavit. Docket No. 2:21-cv-1074. (2021). In the United States District Court for the Western District of Louisiana. *The State of Louisiana by and through its Attorney General, Jeff Landry et al. Plantiffs, v. Joseph R. Biden, Jr., in his official capacity as President of the United States; et al., Defendants.* On Behalf of the Attorney General of Louisiana. Issues: social cost of carbon, carbon tax, environmental policy.

44. Expert Testimony. Case No. U21090. (2021). *Before the Michigan Public Service Commission. In the matter of the application of Consumers Energy Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, certain accounting approvals, and for other relief*. On Behalf of the Michigan Department of the Attorney General. Issues: IRP, coal plant retirements, acquisition premiums, financial compensation mechanism.

45. Expert Testimony. Docket No 16-036-FR. (2021). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U*. On Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: netting adjustments, rate increases, projected year adjustments, reliability.

46. Expert Report. Docket JCCP No. 4861. (2021). Before the Superior Court of the State of California County of Los Angeles, Central Civil West. *Coordination Proceeding Special Title [Rule 3.550] Southern California Gas Leak Cases.* On Behalf of Toll Brothers. Issues: gas leak, public service obligation, integrity management.

47. Expert Testimony. Docket No. U-35927. (2021). Before the Louisiana Public Service Commission. *In Re: Application of 1803 Electric Cooperative, Inc. for Approval of Power Purchase Agreements and for Cost Recovery.* Direct and Cross-Answering. On Behalf of Cleco Cajun LLC. Issues: tolling agreements, generation acquisition, risk factors.

48. Expert Testimony. Docket No. 21-060-U. (2021). Before the Arkansas Public Service Commission. *In the Matter of Joint Application of Centerpoint Energy Resources Corp. and Summit Utilities Arkansas, Inc. For all Necessary Authorizations and Approvals for Summit Utilities Arkansas, Inc. To Acquire the Arkansas Assets of Centerpoint Energy Resources Corp. and for Approval of a Certificate of Public Convenience and necessity for Summit Utilities Arkansas, Inc.* Direct and Surrebuttal. On Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: asset acquisition, ratepayer benefits, acquisition synergies, Rider FRP.

49. Expert Affidavit. Civil Action No. 2:21-cv-00778 (2021). Before the United States District Court for the Western District of Louisiana. *The State of Louisiana v. Joseph R. Biden, Jr.* Issues: leasing and drilling moratorium, state revenue, coastal restoration, economic activity.

50. Expert Testimony. Docket No. 21-044-U (2021). Before the Arkansas Public Service Commission. *In the Matter of Centerpoint Energy Resources Corp. D/B/A Centerpoint*

Energy Arkansas Gas' Request to Extend Rider FRP. On Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: ratepayer benefits, service quality, cost of service, FRP extension.

51. Expert Testimony. Docket No. 17-010-FR (2021). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: rate increase, investment and expense trends, revenue deficiency, leak performance.

52. Expert Testimony. Case No. U-20963 (2021). Before the Michigan Public Service Commission. *In the Matter of the Application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief.* On Behalf of the Michigan Department of the Attorney General. Issues: cost of service, peak allocation, revenue distribution.

53. Expert Testimony. U-20-072, U-20-073, U-20-074. (2021). Before the Regulatory Commission of Alaska. *In the Matter of the Revenue Requirement study and Tariff Filing designated as TA886-2 filed by Alaska Power Company, In the Matter of the Revenue Requirement study and Tariff filing designated as TA6-521 filed by Goat Lake Hydro, Inc., In the Matter of the Revenue Requirement study and Tariff filing designated as TA4-573 filed by BBL Hydro, Inc.* On Behalf of the Alaska Office of Attorney General. Issues: rate groups, cost of service.

54. Expert Testimony. Docket No. P20-001. (2021). Before the Louisiana Pilotage Fee Commission. *In Re: Request for Increase in Approved Pilot Complement; Increased Funding for necessary Additional Manpower; Upward Adjustment of Estimated Average Annual Pilot Compensation; and Related Relief Pursuant to LA R.S. 34:112.* On Behalf of the Louisiana Chemical Association (LCA) and Louisiana Mid-Continent Oil & Gas Association (LMOGA). Issues: unreasonable requests, fee structure, economic impact, over earnings.

55. Expert Testimony. D.P.U. 20-120. (2021). Before the Commonwealth of Massachusetts Before the Department of Public Utilities. *Petition of Boston Gas Company d/b/a National Grid Pursuant to G.L. c. 164, 94 and 220 C.M.R. 5.00 for Approval of an Increase in Base Distribution Rates and Approval of a Performance-Based Ratemaking Plan.* On Behalf of the Massachusetts Office of the Attorney General Office of Ratepayer Advocacy. Issues: rate increase, accelerated depreciation, benchmarking analysis, performance incentive mechanism.

56. Expert Testimony. RPU-2020-0001. (2020). Before the Iowa Utilities Board. *In Re: Iowa-American Water Company.* On Behalf of the Office of Consumer Advocate. Issues: rate increase, test trackers, RSM accounting ratemaking construct.

57. Expert Testimony. BPU Docket Nos. QO19010040 and GO20090622. (2020). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Energy Efficiency Programs and the Associated Cost Recovery Mechanisms Pursuant to the Clean Energy Act, N.J.S.A. 48:3-87.8 et seq. and 48:3-98.1 et seq.* On behalf of the Division of Rate Counsel. Issues: CBA requirements,

capacity benefits, volatility benefits.

58. Expert Testimony. Docket No. 2020-125-E. (2020). Before the Public Service Commission of South Carolina. *In the Matter of: Application of Dominion Energy South Carolina, Incorporated for Adjustments of Rates and Charges (See Commission Order No. 2020-313).* On Behalf of the South Carolina department of Consumer Affairs. Issues: cost of service, revenue allocation, rate design.

59. Answering Testimony. Before the United States of America Federal Energy Regulatory Commission. Docket No. RP20-614-000 and RP20-618-000. (2020). *Transcontinental Gas Pile Line Company, LLC.* On Behalf of the North Carolina Utilities Commission. Issues: Tariff revisions, assessment of Transco claims.

60. Expert Testimony. Docket No. 16-036-FR. (2020). *Before the Arkansas Public Service Commission. In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U. Direct and Surrebuttal*. On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate increases, investment and expenses trends, load forecast, historic year netting adjustment, reliability issues.

61. Expert Testimony. Docket No. 2019.12.101. (2020). Before the Public Service Commission of the State of Montana. *In the Matter of NorthWestern Energy's Application for Approval of Capacity Resource Acquisition.* On the Behalf of the Montana Consumer Counsel. Issues: sale of capital asset, evaluation benefits, ratepayer cost exposure, reserve fund.

62. Expert Testimony. Formal Case No. 1162. (2020). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Service*. On Behalf of the Office of the People's Counsel. Issues: rate increase, revenue adjustment, weather normalization, rate design, revenue distribution.

63. Expert Testimony. Docket No. E-01345A-19-0236. (2020). Before the Arizona Corporation Commission. *In the Matter of the Application of Arizona Public Service Company for Ratemaking Purposes to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop such Return*. Direct and Surrebuttal. On Behalf of the Utilities Division of the Arizona Corporation Commission. Issues: Cost of Service, Revenue Distribution, Rate Design.

64. Expert Testimony. Docket No. 17-010-FR. (2020). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate increase, leak replacement and reduction, netting adjustment, revenue deficiency, accounting policy changes.

65. Expert Testimony. Case No. U-20697. (2020). Before the Michigan Public Service Commission. *In the Matter of the Application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief*. On Behalf of the Michigan Department of Attorney General. Issues: cost of service, revenue distribution, rate design.

66. Expert Testimony. Docket No. 2019.09.058. (2020). Before the Public Service Commission of the State of Montana. *In the Matter of NorthWestern Energy's Annual PCCAM Filing and Application for Approval of Tariff Changes*. On the Behalf of the Montana Consumer Counsel. Issues: purchase power expenses, cost sharing, PCAAM power cost.

67. Expert Testimony. Formal Case No. 1156. (2020). Before the Public Service Commission of the District of Columbia. *In the matter of Potomac Electric Power Company for authority to implement a multiyear rate plan for electric distribution service in the district of Columbia.* Direct, Rebuttal, Surrebuttal, Supplemental, and Second Supplemental. On Behalf of the Office of the People's Counsel. Issues: revenue distribution, rate design, customer charge, performance metric policies, performance metric incentives.

68. Expert Testimony. Case No. U-20561. (2019). Before the Michigan Public Service Commission. *In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority*. On Behalf of the Michigan Department of Attorney General. Issues: Cost of service, allocation of production plant, allocation of sub-transmission plant, revenue distribution.

69. Expert Testimony. Cause No. 45253. (2019). Before the Indiana Utility Regulatory Commission. *Petition of Duke Energy Indiana, LLC Pursuant to Ind. Code 8-1-2-42.7 and 8-1-2-61, for (1) Authority to Modify its Rates and Charges for Electric Utility Service through a Step-In of New Rates and Charges using a Forecasted Test Period; (2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders; (3) Approval of a Federal Mandate Certificate Under Ind. Code 8-1-8.4-1; (4) Approval of Revised Electric Depreciation Rates Applicable to its Electric Plant in Service; (5) Approval of Necessary and Appropriate Accounting Deferral Relief; and (6) Approval of a Revenue Decoupling Mechanism for Certain Customers Classes*. On Behalf of the Indiana Office of Utility Consumer Counsel. Issues: Decoupling, revenue decoupling mechanism and design, commission policy, benchmarking analysis.

70. Expert Testimony. Docket 19-019-U. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Petition of Entergy Arkansas, LLC for Approval of a Build-Own-Transfer Arrangement for a Renewable Resource and for all other Related Approvals.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: Solar investment, risk assessment, proposed rider.

71. Expert Testimony. Docket No. 16-036-FR. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate design, reliability, and formula rate plan.

72. Expert Testimony. Docket No. 19-019-U. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Petition of Entergy Arkansas, LLC for Approval of a Build-Own-Transfer Arrangement for a Renewable Resource and for all other Related Approvals*. On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: Solar project approval, ratepayer risk, cost allocation.

73. Expert Testimony. Docket No. 17-010-FR. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: retail rates, leak analysis, revenue deficiency, investments.

74. Expert Testimony. Case No. U-20471. (2019). Before the Michigan Public Service Commission. *In the matter of the Application of DTE Electric Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief.* On Behalf of the Michigan Department of Attorney General. Issues: load forecasting, least-cost system planning.

75. Expert Report. Docket No. 18-004422. (2019). Before the State of Florida Division of Administrative Hearings. *Peoples Gas System vs. South Sumter Gas Company, LLC and the City of Leesburg.* On Behalf of the City of Leesburg. Issues: retail rates, customer growth, sales trends and forecasts, policy, cost of service, socio-economic trends and forecasts.

76. Expert Testimony. Docket Nos. GO18101112 and EO18101113. (2019). Before the New Jersey Board of Public Utilities. *In the Matter of the Public Service Electric and Gas Company for Approval of its Clean Energy Future-Energy Efficiency ("CEF-EE") Program on a Regulated Basis.* On behalf of the Division of Rate Counsel. Issues: economic impact, cost benefit analysis, decoupling mechanisms.

77. Expert Testimony. Docket Nos. EO18060629 and GO18060630. (2019). Before the New Jersey Board of Public Utilities. *In the Matter of the Public Service Electric and Gas Company for Approval of the Second Energy Strong Program (Energy Strong II)*. On behalf of the Division of Rate Counsel. Issues: economic impact, cost benefit analysis, infrastructure replacement, cost recovery tracker mechanisms.

78. Expert Report. Docket No. 2011-AD-2. (2019). On Behalf of the Mississippi Public Service Commission. *Order Establishing Docket to Investigate the Development and Implementation of Net Metering Programs and Standards.* On Behalf of the Mississippi Public Utilities Staff. Issues: Net-metering, distributed generation.

79. Expert Testimony. Docket No. D2018.2.12. (2018). Before the Public Service Commission of the State of Montana. *In the Matter of NorthWestern Energy's Application for Authority to Increase Retail Electric Utility Service Rates and for Approval of Electric Service Schedules and Rules and Allocated Cost of Service and Rate Design.* On Behalf of the Montana Consumer Counsel. Issues: Net-metering, cost of service, revenue distribution, rate design.

80. Expert Testimony. Docket No. 19-SEPE-054-MER. (2018). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Sunflower Electric Power Corporation and Mid-Kansas Electric Company, Inc. for an Order Approving the Merger of Mid-Kansas Electric Company, Inc. into Sunflower Electric Power Corporation*. On the Behalf of the Kansas Electric Power Cooperative, Inc. Issues: merger impacts, rates, tariffs.

81. Expert Testimony. Docket No. 18-046-FR. (2018). Before the Arkansas Public Service

Commission. *In the Matter of the Formula Rate Plan Filings of Oklahoma Gas and Electric Company Pursuant to APSC Docket No. 16-052-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: formula rate plan, plant investment and expenses benchmarking analysis, reliability.

82. Expert Testimony. Docket No. 16-036-FR. (2018). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate design, reliability, and formula rate plan.

83. Expert Testimony. Docket No. 2017-AD-0112. (2018). Before the Mississippi Public Service Commission. *In Re: Encouraging Stipulation of Matters in Connection with the Kemper County IGCC Project.* On Behalf of the Mississippi Public Utilities Staff. Issues: cost of service and rate design.

84. Expert Affidavit. Docket No. 87011-E. (2018). Before the 16th Judicial District Court Parish of St. Martin State of Louisiana. *Bayou Bridge Pipeline, LLC versus 38.00 Acres, More or Less, Located in St. Martin Parish; Barry Scott Carline, et al.* Issues: economic impacts.

85. Expert Testimony. Docket No. QO18080843. (2018). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Nautilus Offshore Wind, LLC for the Approval of the State Waters Wind Project and Authorizing Offshore Wind Renewable Energy Certificates.* On behalf of the Division of Rate Counsel. Issues: regulatory policy and cost-benefit analyses.

86. Expert Testimony. Docket No. ER18010029 and GR18010030. (2018). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief.* On behalf of the Division of Rate Counsel. Issues: rate proposal, revenue decoupling, regulatory policy, cost benchmarking.

87. Expert Testimony. Docket No. T-34695. (2018). Before the Louisiana Public Service Commission. *In re: Application for a rate increase on service originating at Grand isle and termination at St. James for Crude Petroleum as currently outlined in LPSC Tariff No. 75.2*. On Behalf of Energy XXI GOM, LLC. Issues: cost of service, rate design, and alternative regulation.

88. Expert Testimony. Docket No. 17-071-U. (2018). Before the Arkansas Public Service Commission*. In the Matter of the Application of Black Hills Energy Arkansas, Inc. for Approval of a General Change in Rates and Tariffs*. On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, billing determinates.

89. Expert Testimony. Docket No. 17-010-FR. (2018). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filing of CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, alternative regulation, formula rate plan.

90. Expert Testimony. Case No. PU-17-398. (2018). Before the North Dakota Public Service Commission. *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in North Dakota*. On Behalf of the North Dakota Service Commission Advocacy Staff. Issues: cost of service, marginal cost of service, and rate design.

91. Expert Testimony. Docket No. 20170179-GU. (2018). Before the Florida Public Service Commission. *In re: Petition for rate increase and approval of depreciation study by Florida City Gas.* On Behalf of the Citizens of the State of Florida. Issues: policy issues concerning long-term gas capacity procurement.

92. Expert Testimony. Docket No. 18-KCPE-095-MER. (2018). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Merger of Westar, Inc. and Great Plains Energy Incorporated.* On the Behalf of the Kansas Electric Power Cooperative, Inc. Issues: merger/acquisition policy, financial risk, and ring-fencing.

93. Expert Testimony. Docket No. GR17070776. (2018). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP II"). On behalf of the Division of Rate Counsel. Issues: economic impact, infrastructure replacement program rider, pipeline replacement, leak rate comparisons and cost benefit analysis.

94. Expert Affidavit. Case No. 18-489. (2018). Before the Civil District Court for the Parish of Orleans, State of Louisiana. *Bayou Bridge Pipeline, LLC versus The White Castle Lumber and Shingle Company Limited and Jeanerette Lumber & Shingle CO. L.L.C.* Issues: economic impact of crude oil pipeline development.

95. Expert Testimony. Docket No. 16-036-FR. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U*. On behalf of the Office of the Arkansas Attorney General Leslie Rutledge. Issue: cost of service, rate design, alternative regulation, formula rate plan.

96. Expert Testimony. Docket No. 2017-AD-0112. (2017). Before the Mississippi Public Service Commission. *In re: Encouraging Stipulation of Matters in Connection with the Kemper County IGCC Project*. On Behalf of the Mississippi Public Utilities Staff. Issues: financial analysis, rates and cost trends, economic impacts of proposal.

97. Expert Testimony. Case No. 2017-00179. (2017). Before the Public Service Commission, Commonwealth of Kentucky. *Electronic Application of Kentucky power Company For (1) A General Adjustment of Its Rates for Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs and Riders; (4) An Order Approving Accounting Practices to Establish a Regulatory Asset or Liability Related to the Big Sandy 1 Operation Rider; and (5) An Order Granting All Other Required Approvals and Relief.* On Behalf of the Office of the Kentucky Attorney General. Issues: rate design, revenue allocation, economic development.

98. Expert Testimony. Docket No. 17-010-FR. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filing of CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, alternative regulation, formula rate plan.

99. Expert Testimony. Formal Case No. 1142. (2017). Before the Public Service Commission of the District of Columbia. *In the Matter of the Merger of AltaGas Ltd. and WGL Holdings, Inc.* On Behalf of the Office of the People's Counsel. Issues: merger/acquisition policy, financial risk, ring-fencing, and reliability.

100. Expert Testimony. D.P.U. 17-05. (2017). Before the Massachusetts Department of Public Utilities. *Petition of NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy for Approval of an Increase in Base Distribution Rates for Electric Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00*. On Behalf of the Massachusetts Office of the Attorney General Office of Ratepayer Advocacy. Issues: performance-based ratemaking, multi-factor productivity estimation.

101. Deposition and Testimony. (2017) Before the Nebraska Section 70, Article 13 Arbitration Panel. *Northeast Nebraska Public Power District, City of South Sioux City Nebraska; City of Wayne, Nebraska; City of Valentine, Nebraska; City of Beatrice, Nebraska; City of Scribner, Nebraska; Village of Walthill, Nebraska, vs. Nebraska Public Power District.* On the Behalf of Baird Holm LLP for the Plaintiffs. Issues: rate discounts; cost of service; utility regulation, economic harm.

102. Expert Testimony. Docket No. 16-052-U. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Application of the Oklahoma Gas and Electric Company for Approval of a General Change in Rates, Charges and Tariffs.* On the Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, alternative regulation, formula rate plan.

103. Expert Testimony. Docket No. 16-KCPE-593-ACQ. (2016). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Acquisition of Westar, Inc. by Great Plains Energy Incorporated.* On the Behalf of the Kansas Electric Power Cooperative, Inc. Issues: merger/acquisition policy, financial risk, and ring-fencing.

104. Expert Testimony. Formal Case No. 1139. (2016). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service.* On the Behalf of the Office of the People's Counsel for the District of Columbia. Issues: cost of service, rate design, alternative regulation.

105. Expert Affidavit. Docket No. CP15-558-000 (2016). Before the United States of America Federal Energy Regulatory Commission. *PennEast Pipeline Company, LLC*. Affidavit and Reply Affidavit. On the Behalf of the New Jersey Division of Rate Counsel. Issues: pipeline capacity, peak day requirements.

106. Expert Testimony. Docket No. RPU-2016-0002. (2016). Before the Iowa Utilities Board. *In re: Iowa American Water Company application for revision of rates.* On behalf of the Office of Consumer Advocate. Issue: revenue stabilization mechanism, revenue decoupling.

107. Expert Testimony. Docket No. 15-015-U. (2016). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U*. On behalf of the Office of the Arkansas Attorney General Leslie Rutledge. Issue: formula rate plan evaluation.

108. Expert Testimony. Docket Nos. 160021-EI, 160061-EI, 160062-EI, and 160088-EI. (2016). Before the Florida Public Service Commission. *In re: Petition for rate increase by Florida Power & Light Company (consolidated).* On behalf of the Citizens of the State of Florida. Issue: load forecasting.

109. Expert Testimony. Docket Nos. 160021-EI, 160061-EI, 160062-EI, and 160088-EI. (2016). Before the Florida Public Service Commission. *In re: Petition for rate increase by Florida Power & Light Company (consolidated).* On behalf of the Citizens of the State of Florida. Issue: off-system sales incentives.

110. Expert Testimony. Project No. 5-103. (2016). United States of America Federal Energy Regulatory Commission. *Confederated Salish and Kootenai Tribes Energy Keepers, Incorporated*. On behalf of the Flathead, Mission, and Jocko Valley Irrigation Districts and the Flathead Joint Board of Control of the Flathead, Mission, and Jocko Valley Irrigation Districts.

111. Expert Testimony. Docket No. 15-098-U. (2016). Before the Arkansas Public Service Commission. *In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas for a General Change or Modification in its Rates, Charges and Tariffs.* On behalf of the Office of the Arkansas Attorney General. Issues: formula rate plan, cost of service and rate design.

112. Expert Testimony. BPU Docket No. GM15101196. (2016). *In the Matter of the Merger of Southern Company and AGL Resources, Inc*. On behalf of the New Jersey Division of Rate Counsel. Issues: merger standards of review, customer dividend contributions, synergy savings and costs to achieve, ratemaking treatment of merger-related costs.

113. Expert Testimony. Docket No. 15-078-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Joint Application of SourceGas Inc., SourceGas LLC, SourceGas Holdings LLC and Black Hills Utility Holdings, Inc. for all Necessary Authorizations and Approvals for Black Hills Utility Holdings, Inc. to Acquire SourceGas Holdings LLC.* On behalf of the Office of the Arkansas Attorney General. Issues: public policy and regulatory policy associated with the acquisition.

114. Expert Testimony. Docket No. 15-031-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Application of SourceGas Arkansas Inc. for an Order Approving the Acquisition of Certain Storage Facilities and the Recovery of Investments and Expenses Associated Therewith.* On behalf of the Office of the Arkansas Attorney General. Issues: cost-benefit analysis, transmission cost analysis, and a due diligence analysis.

115. Expert Testimony. Docket No. 15-015-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service.* On behalf of the Office of the Arkansas Attorney General. Issues: economic development riders and production plant cost allocation.

116. Expert Testimony. Docket No. 7970. (2015). Before the Vermont Public Service Board. *Petition of Vermont Gas Systems, Inc., for a certificate of public good pursuant to 30 V.S.A.§ 248, authorizing the construction of the "Addison Natural Gas Project" consisting of approximately 43 miles of new natural gas transmission pipeline in Chittenden and Addison Counties, approximately 5 miles of new distribution mainlines in Addison County, together with three new gate stations in Williston, New Haven, and Middlebury, Vermont*. On behalf of AARP-Vermont. Issues: net economic benefits of proposed natural gas transmission project.

117. Expert Testimony. File No. ER-2014-0370 (2015). Before the Public Service Commission of the State of Missouri. *In the Matter of Kansas City Power & Light Company for Authority Implement A General Rate Increase for Electric Service*. On behalf of the Missouri Office of the People's Counsel. Issues: customer charges, rate design, revenue distribution, class cost of service, and policy and ratemaking considerations in connection with electric vehicle charging stations.

118. Expert Testimony. File No. ER-2014-0351 (2015). Before the Public Service Commission of the State of Missouri. *In the Matter of The Empire District Electric Company for Authority To File Tariffs Increasing Rates for Electric Service Provided to Customers In the Company's Missouri Service Area*. On behalf of the Missouri Office of the People's Counsel. Issues: customer charges, rate design, revenue distribution, and class cost of service.

119. Expert Testimony. D.P.U. 14-130 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval by the Department of Public Utilities of the Company's 2015 Gas System Enhancement Program Plan, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015.* On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

120. Expert Testimony. D.P.U. 14-131 (2015). Before the Massachusetts Department of Public Utilities. *Petition of The Berkshire Gas Company for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

121. Expert Testimony. D.P.U. 14-132 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for approval by the Department of Public Utilities of the Companies' Gas System Enhancement Program for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

122. Expert Testimony. D.P.U. 14-133 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Liberty Utilities for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

123. Expert Testimony. D.P.U. 14-134 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates to be effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

124. Expert Testimony. D.P.U. 14-135 (2015). Before the Massachusetts Department of Public Utilities. *Petition of NSTAR Gas Company for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates to be effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

125. Expert Report. Docket No. X-33192 (2015). Before the Louisiana Public Service Commission. *Examination of the Comprehensive Costs and Benefits of Net Metering in Louisiana.* On behalf of the Louisiana Public Service Commission. Issues: cost-benefit, cost of service, rate impact.

126. Expert Testimony. F.C. 1119 (2014). Before the District of Columbia Public Service Commission. *In the Matter of the Merger of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC, and new Special Purpose Entity, LLC*. On behalf of the Office of the People's Counsel. Issues: economic impact analysis, reliability, consumer investment fund, regulatory oversight, impacts to competitive electricity markets.

127. Expert Report. Civil Action 1:08-cv-0046 (2014). Before the U.S. District Court for the Southern District of Ohio. *Anthony Williams, et al., v. Duke Energy International, Inc., et al.* On behalf of Markovits, Stock & DeMarco, Attorneys & Counselors at Law. Issues: public utility regulation, electric power markets, economic harm.

128. Expert Testimony. D.P.U. 14-64 (2014). Before the Massachusetts Department of Public Utilities. *NSTAR Gas Company/HOPCO Gas Services Agreement. On behalf of the Office of the Public Advocate*. Issues: certain ratemaking features associated with the proposed Gas Service Agreement.

129. Expert Testimony. Docket Nos. 14-0224 and 14-0225 (2014). Before the Illinois Commerce Commission. *In the Matter of the Peoples Gas Light and Coke Company and North Shore Gas Company Proposed General Increase in Rates for Gas Service (consolidated)*. On behalf of the People of the State of Illinois. Issues: test year expenses, cost benchmarking analysis, pipeline replacement, and leak rate comparisons.

130. Expert Testimony. Docket 8191 (2014). Before the Vermont Public Service Board. *In Re: Petition of Green Mountain Power Corporation for Approval of a Successor Alternative*

Regulation Plan. On the behalf of AARP-Vermont. Issues: Alternative Regulation.

131. Expert Testimony. Docket No. 2013-00168 (2014). Before the Maine Public Utilities Commission. *In the Matter of the Request for Approval of an Alternative Rate Plan (ARP 2014) Pertaining to Central Maine Power Company*. On behalf of the Office of the Public Advocate. Issues: class cost of service study, marginal cost of service study, revenue distribution and rate design.

132. Expert Testimony. D.P.U. 13-90 (2013). Before the Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company (Electric Division) d/b/a Unitil to the Department of Public Utilities for approval of the rates and charges and increase in base distribution rates for electric service.* On behalf of the Office of the Ratepayer Advocate. Issues: capital cost adjustment mechanism and performance-based regulation.

133. Expert Testimony. BPU Docket Nos. EO13020155 and GO13020156. (2013). Before the State of New Jersey Board of Public Utilities. *I/M/O The Petition of Public Service Electric & Gas Company for the Approval of the Energy Strong Program.* On behalf of the Division of Rate Counsel. Issues: economic impact, infrastructure replacement program rider, pipeline replacement, leak rate comparisons and cost benefit analysis.

134. Expert Testimony. D.P.U. 13-75 (2013). Before the Massachusetts Department of Public Utilities. *Investigation by the Department of Public Utilities on its Own Motion as to the Propriety of the Rates and Charges by Bay State Gas Company d/b/a Columbia Gas of Massachusetts set forth in Tariffs M.D.P.U. Nos. 140 through 173, and Approval of an Increase in Base Distribution Rates for Gas Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., filed with the Department on April 16, 2013, to be effective May 1, 2013*. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Target infrastructure replacement program rider, pipeline replacement, and leak rate comparisons; environmental benefits analysis; O&M offset; and cost benchmarking analysis.

135. Expert Testimony. Docket No. 13-115 (2013). Before the Delaware Public Service Commission. *In the Matter of the Application of Delmarva Power & Light Company FOR an Increase in Electric Base Rates and Miscellaneous Tariff Changes* (Filed March 22, 2013). On the Behalf of Division of the Public Advocate. Issues: pro forma infrastructure proposal, class cost of service study, revenue distribution, and rate design.

136. Expert Testimony. Formal Case No. 1103 (2013). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*. On the Behalf of the Office of the People's Counsel of the District of Columbia. Issues: Pro forma adjustment for reliability investments.

137. Expert Testimony. Case No. 9326 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Electric Reliability Investment ("ERI") initiatives, pro forma gas infrastructure proposal, tracker mechanisms, class cost of service study, revenue

distribution, and rate design

138. Rulemaking Testimony. (2013). Before the Louisiana Tax Commission. Examination of Louisiana Assessors' Association Well Diameter Analysis, economic development policies regarding midstream assets and industrial development.

139. Expert Testimony. Case No. 9317 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Delmarva Power & Light Company for Adjustments to its Retail Rates for the Distribution of Electric Energy*. Direct, and Surrebuttal. On the Behalf of the Maryland Office of the People's Counsel. Issues: Grid Resiliency Charge, tracker mechanisms, pipeline replacement, class cost of service study, revenue distribution, and rate design.

140. Expert Testimony. Case No. 9311 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Potomac Electric Power Company for an Increase in its Retail Rates for the Distribution of Electric Energy*. Direct, and Surrebuttal. On the Behalf of the Maryland Office of the People's Counsel. Issues: Grid Resiliency Charge, tracker mechanisms, pipeline replacement, class cost of service study, revenue distribution, and rate design.

141. Expert Testimony. Docket No. 12AL-1268G (2013). Before the Public Utilities Commission of the State of Colorado. *In the Matter of the Tariff Sheets Filed by Public Service Company of Colorado with Advice No. 830 – Gas. Answer*. On the Behalf of the Colorado Office of Consumer Counsel. Issues: Pipeline System Integrity Adjustment, tracker mechanisms, pipeline replacement and leak rate comparisons.

142. Expert Testimony. BPU Docket No. EO12080721 (2013). Before the New Jersey Board of Public Utilities. *In the Matter of the Public Service Electric & Gas Company for Approval of an Extension of Solar Generation Program*. On the Behalf of the New Jersey Division of Rate Counsel. Direct, Rebuttal, Surrebuttal. Issues: solar energy market design, solar energy market conditions, solar energy program design and net economic benefits.

143. Expert Testimony. BPU Docket No. EO12080726 (2013). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Loan III Program.* On the Behalf of the New Jersey Division of Rate Counsel. Direct, Rebuttal and Surrebuttal. Issues: solar energy market design, solar energy market conditions, solar energy program design.

144. Expert Testimony. BPU Docket No. EO11050314V. (2012). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Fishermen's Atlantic City Windfarm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates*. On the Behalf of the New Jersey Division of Rate Counsel. December 17, 2012. Issues: approval of offshore wind project and ratepayer financial support for the proposed project.

145. Expert Testimony. D.P.U. 12-25. (2012). Before the Massachusetts Department of Public Utilities. *In the Matter of Bay State Gas Company d/b/a/ Columbia Gas Company of Massachusetts Request for Increase in Rates*. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Target infrastructure replacement program rider, pipeline replacement and leak rate comparisons.

146. Expert Testimony. Docket Nos. UE-120436, et.al. (consolidated). (2012). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities*. On the Behalf of the Washington Attorney General, Office of the Public Counsel. Issues: Revenue Decoupling, lost revenues, tracker mechanisms, attrition adjustments.

147. Expert Testimony. Case No. 9286. (2012) Before the Public Service Commission of Maryland. *In Re: Potomac Electric Power Company ("Pepco") General Rate Case*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Capital tracker mechanisms/reliability investment mechanisms, reliability issues, regulatory lag, class cost of service, revenue distribution, rate design.

148. Expert Testimony. Case No 9285. (2012) Before the Public Service Commission of Maryland. *In Re: the Delmarva Power and Light Company General Rate Case*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Capital tracker mechanisms/reliability investment mechanisms, reliability issues, regulatory lag, class cost of service, revenue distribution, rate design.

149. Expert Testimony. Docket Nos. UE-110876 and UG-110877 (consolidated). (2012). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities*. On the Behalf of the Washington Attorney General, Office of the Public Counsel. Issues: Revenue Decoupling, lost revenues, tracker mechanisms.

150. Expert Testimony. BPU Docket No. EO11050314V. (2012). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Fishermen's Atlantic City Windfarm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates*. On the Behalf of the New Jersey Division of Rate Counsel. February 3, 2012. Issues: approval of offshore wind project and ratepayer financial support for the proposed project.

151. Expert Testimony. Docket No. NG 0067. (2012). Before the Public Service Commission of Nebraska. *In the Matter of the Application of SourceGas Distribution, LLC Approval of a General Rate Increase*. On the Behalf of the Public Advocate. January 31, 2012. Issues: Revenue Decoupling, Customer Adjustments, Weather Normalization Adjustments, Class Cost of Service Study, Rate Design.

152. Expert Testimony. Docket No. G-04204A-11-0158. (2011). Before the Arizona Corporation Commission. On the Behalf of the Arizona Corporation Commission Staff. *In the Matter of the Application of UNS Gas, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Arizona Properties*. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

153. Expert Testimony. Formal Case Number 1087. (2011). Before the Public Service Commission of the District of Columbia. On the Behalf of the Office of the People's Counsel of the District of Columbia. *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*. Issues: Regulatory lag, ratemaking principles, reliability-related

capital expenditure tracker proposals.

154. Expert Affidavit. Case No. 11-1364. (2011). *The State of Louisiana, the Louisiana Department of Environmental Quality, and the Louisiana Public Service Commission v. United States Environmental Protection Agency and Lisa P. Jackson.* Before the United States Court of Appeals for the District of Columbia Circuit. On the behalf of the State of Louisiana, the Louisiana Department of Environmental Quality, and the Louisiana Public Service Commission. Issues: Impacts of environmental costs on electric utilities, compliance requirements, investment cost of mitigation equipment, multi-area dispatch modeling and plant retirements.

155. Expert Affidavit. Docket No. EPA-HQ-OAR-2009-0491. (2011). Before the U.S. Environmental Protection Agency. *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals*. On the Behalf of the Louisiana Public Service Commission. Issues: Impacts of environmental costs on electric utilities, compliance requirements, investment cost of mitigation equipment, multi-area dispatch modeling and plant retirements.

156. Expert Testimony. Case No. 9296. (2011). Before the Maryland Public Service Commission. *On the Behalf of the Maryland Office of People's Counsel. In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges and Revise its Terms and Conditions for Gas Service*. Issues: Infrastructure Cost Recovery Rider; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

157. Expert Testimony. Docket No. G-01551A-10-0458. (2011). Before the Arizona Corporation Commission. On the Behalf of the Arizona Corporation Commission Staff. *In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of its Properties throughout Arizona*. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

158. Expert Testimony. Docket No. 11-0280 and 11-0281. (2011). Before the Illinois Commerce Commission. On the Behalf of the Illinois Attorney General, the Citizens Utility Board, and the City of Chicago, Illinois. *In re: Peoples Gas Light and Coke Company and North Shore Natural Gas Company*. Issues: Revenue Decoupling and Rate Design. (Direct and Rebuttal)

159. Expert Testimony. D.P.U. 11-01. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. *Petition of the Fitchburg Electric and Gas Company (Electric Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism*. Issues: Capital Cost Rider, Revenue Decoupling.

160. Expert Testimony. D.P.U. 11-02. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. *Petition of the Fitchburg Electric and Gas Company (Gas Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism*. Issues: Pipeline Replacement Rider, Revenue Decoupling.

161. Expert Affidavit. Docket No. EL-11-13 (2011). Before the Federal Energy Regulatory

Commission. Petition for Preliminary Ruling, Atlantic Grid Operations. On the Behalf of the New Jersey Division of Rate Counsel. Issues: Offshore wind generation development, offshore wind transmission development, ratemaking treatment of development costs, transmission development incentives.

162. Expert Opinion. Case No. CI06-195. (2011). Before the District Court of Jefferson County, Nebraska. On the Behalf of the City of Fairbury, Nebraska and Michael Beachler. In re: Endicott Clay Products Co. vs. City of Fairbury, Nebraska and Michael Beachler. Issues: rate design and ratemaking, time of use and time differentiated rate structures, empirical analysis of demand and usage trends for tariff eligibility requirements.

163. Expert Testimony. D.P.U. 10-114. (2010). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the New England Gas Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: infrastructure replacement rider.

164. Expert Testimony. D.P.U. 10-70. (2010). Before the Massachusetts Department of Public Utilities. Petition of the Western Massachusetts Electric Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure replacement rider; performance-based regulation; inflation adjustment mechanisms; and rate design.

165. Expert Testimony. G.U.D. Nos. 998 & 9992. (2010). Before the Texas Railroad Commission. In the Matter of the Rate Case Petition of Texas Gas Services, Inc. On the Behalf of the City of El Paso, Texas. Issues: Cost of service, revenue distribution, rate design, and weather normalization.

166. Expert Testimony. B.P.U Docket No. GR10030225. (2010). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Regional Greenhouse Gas Initiative Programs and Associated Cost Recovery Mechanisms Pursuant to N.J.S.A. 48:3-98.1. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy proposals, solar securitization issues, solar energy policy issues.

167. Expert Testimony. D.P.U. 10-55. (2010). Before the Massachusetts Department of Public Utilities. Investigation Into the Propriety of Proposed Tariff Changes for Boston Gas Company, Essex Gas Company, and Colonial Gas Company. (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; pipeline-replacement rider; performance-based regulation; partial productivity factor estimates, inflation adjustment mechanisms; and rate design.

168. Expert Testimony. Cause No.43839. (2010). Before the Indiana Utility Regulatory Commission. In the Matter of Southern Indiana Gas and Electric Company d/b/a/ Vectren Energy Delivery of Indiana, Inc. (Vectren South-Electric). On the behalf of the Indiana Office of Utility Consumer Counselor (OUCC). Issues: revenue decoupling, variable production cost riders, gains on off-system sales, transmission cost riders.

169. Congressional Testimony. Before the United States Congress. (2010). U.S. House of

Representatives, Committee on Natural Resources. Hearing on the Consolidated Land, Energy, and Aquatic Resources Act. June 30, 2010.

170. Expert Testimony. Before the City Counsel of El Paso, Texas; Public Utility Regulatory Board. (2010). On the Behalf of the City of El Paso. In Re: Rate Application of Texas Gas Services, Inc. Issues: class cost of service study (minimum system and zero intercept analysis), rate design proposals, weather normalization adjustment, and its cost of service adjustment clause, conservation adjustment clause proposals, and other cost tracker policy issues.

171. Expert Testimony. Docket 09-00183. (2010). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Chattanooga Gas Company for a General Rate Increase, Implementation of the EnergySMART Conservation Programs, and Implementation of a Revenue Decoupling Mechanism. On the Behalf of Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling and energy efficiency program review and cost effectiveness analysis.

172. Expert Testimony and Exhibits. Docket No. 10-240. (2010). Before the Louisiana Office of Conservation. In Re: Cadeville Gas Storage, LLC. On the Behalf of Cardinal Gas Storage, LLC. Issues: alternative uses and relative economic benefits of conversion of depleted hydrocarbon reservoir for natural gas storage purposes.

173. Expert Testimony. Docket No. 09505-EI. (2010). Before the Florida Public Service Commission. In Re: Review of Replacement Fuel Costs Associated with the February 26, 2008 outage on Florida Power & Light's Electrical System. On the Behalf of the Florida Office of Public Counsel for the Citizens of the State of Florida. Issues: Replacement costs for power outage, regulatory policy/generation development incentives, renewable and energy efficiency incentives.

174. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29380-A, ex parte, (2009). Before the Louisiana Public Service Commission. In re: Environmental Adjustment Clause and Environmental Certification for Electric Power Generation Resources. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: environmental regulation and cost recovery; allowance allocations and air credit markets cost recovery treatment; other generation planning issues.

175. Expert Testimony. Docket 09-00104. (2009). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Piedmont Natural Gas Company, Inc. to Implement a Margin Decoupling Tracker Rider and Related Energy Efficiency and Conservation Programs. On the Behalf of the Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling, energy efficiency program review, weather normalization.

176. Expert Testimony. Docket Number NG-0060. (2009). Before the Nebraska Public Service Commission. In the Matter of SourceGas Distribution, LLC Approval for a General Rate Increase. On the Behalf of the Nebraska Public Advocate. October 29, 2009. Issues: revenue decoupling, inflation trackers, infrastructure replacement riders, customer adjustment rider, weather normalization rider, weather normalization adjustments, estimation of normal weather for ratemaking purposes.

177. Expert Report and Deposition. Before the 23rd Judicial District Court, Parish of Assumption, State of Louisiana. On the Behalf of Dow Hydrocarbons and Resources, Inc. September 1, 2009. (Deposition, November 23-24, 2009). Issues: replacement and repair costs for underground salt cavern hydrocarbon storage.

178. Expert Testimony. D.P.U. 09-39. Before the Massachusetts Department of Public Utilities. (2009). Investigation Into the Propriety of Proposed Tariff Changes for Massachusetts Electric Company and Nantucket Electric Company (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure rider; performance-based regulation; inflation adjustment mechanisms; revenue distribution; and rate design.

179. Expert Testimony. D.P.U. 09-30. Before the Massachusetts Department of Public Utilities. (2009). In the Matter of Bay State Gas Company Request for Increase in Rates. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; target infrastructure replacement program rider; revenue distribution; and rate design.

180. Expert Testimony. Docket EO09030249. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of a Solar Loan II Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design, renewable portfolio standards, solar energy, and renewable financing/loan program design.

181. Expert Testimony. Docket EO0920097. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Verified Petition of Rockland Electric Company for Approval of an SREC-Based Financing Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design; renewable energy portfolio standards; solar energy.

182. Expert Rebuttal Report. Civil Action No.: 2:07-CV-2165. (2009). Before the U.S. District Court, Western Division of Louisiana, Lake Charles Division. Prepared on the Behalf of the Transcontinental Pipeline Corporation. Issues: expropriation and industrial use of property.

183. Expert Testimony. Docket EO06100744. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Atlantic City Electric Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

184. Expert Testimony. Docket EO08090840. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Jersey Central Power & Light Company). On the Behalf of the

Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

185. Expert Testimony. Docket UG-080546. (2008). Before the Washington Utilities and Transportation Commission. On the Behalf of the Washington Attorney General (Public Counsel Section). Issues: Rate Design, Cost of Service, Revenue Decoupling, Weather Normalization.

186. Congressional Testimony. (2008). Senate Republican Conference: Panel on Offshore Drilling in the Restricted Areas of the Outer Continental Shelf. September 18, 2008.

187. Expert Testimony. Appeal Number 2007-125 and 2007-299. (2008). Before the Louisiana Tax Commission. On the Behalf of Jefferson Island Storage and Hub, LLC (AGL Resources). Issues: Valuation Methodologies, Underground Storage Valuation, LTC Guidelines and Policies, Public Purpose of Natural Gas Storage. July 15, 2008 and August 20, 2008.

188. Expert Testimony. Docket Number 07-057-13. (2008). Before the Utah Public Service Commission. In the Matter of the Application of Questar Gas Company to File a General Rate Case. On the Behalf of the Utah Committee of Consumer Services. Issues: Cost of Service, Rate Design. August 18, 2008 (Direct, Rebuttal, Surrebuttal).

189. Rulemaking Testimony. (2008). Before the Louisiana Tax Commission. Examination of Replacement Cost Tables, Depreciation and Useful Lives for Oil and Gas Properties. Chapter 9 (Oil and Gas Properties) Section. August 5, 2008.

190. Legislative Testimony. (2008). Examination of Proposal to Change Offshore Natural Gas Severance Taxes (HB 326 and Amendments). Joint Finance and Appropriations Committee of the Alabama Legislature. March 13, 2008.

191. Public Testimony. (2007). Issues in Environmental Regulation. Testimony before Gubernatorial Transition Committee on Environmental Regulation (Governor-Elect Bobby Jindal). December 17, 2007.

192. Public Testimony. (2007). Trends and Issues in Alternative Energy: Opportunities for Louisiana. Testimony before Gubernatorial Transition Committee on Natural Resources (Governor-Elect Bobby Jindal). December 13, 2007.

193. Expert Report and Recommendation: Docket Number S-30336 (2007). Before the Louisiana Public Service Commission. In re: Entergy Gulf States, Inc. Application for Approval of Advanced Metering Pilot Program. Issues: pilot program for demand response programs and advanced metering systems.

194. Expert Testimony. Docket EO07040278 (2007). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Energy Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: renewable energy market development, solar energy development, SREC markets, rate impact analysis, cost recovery issues.

195. Expert Testimony: Docket Number 05-057-T01 (2007). Before the Utah Public Service

Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Direct, Rebuttal, and Surrebuttal Testimony)

196. Expert Testimony (Non-sworn rulemaking testimony) Docket Number RR-2008, (2007). Before the Louisiana Tax Commission. In re: Commission Consideration of Amendment and/or Adoption of Tax Commission Real/Personal Property Rules and Regulations. Issues: Louisiana oil and natural gas production trends, appropriate cost measures for wells and subsurface property, economic lives and production decline curve trends.

197. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29213 & 29213-A, ex parte, (2007). Before the Louisiana Public Service Commission. In re: In re: Investigation to determine if it is appropriate for LPSC jurisdictional electric utilities to provide and install time-based meters and communication devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: demand response programs, advanced meter systems, cost recovery issues, energy efficiency issues, regulatory issues.

198. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29712, ex parte, (2007) Before the Louisiana Public Service Commission. In re: Investigation into the ratemaking and generation planning implications of nuclear construction in Louisiana. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: nuclear cost power plant development, generation planning issues, and cost recovery issues.

199. Expert Testimony, Case Number U-14893, (2006). Before the Michigan Public Service Commission. In the Matter of SEMCO Energy Gas Company for Authority to Redesign and Increase Its Rates for the Sale and Transportation of Natural Gas In its MPSC Division and for Other Relief. On the behalf of the Michigan Attorney General. Issues: Rate Design, revenue decoupling, financial analysis, demand-side management program and energy efficiency policy. (Direct and Rebuttal Testimony).

200. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29380, ex parte, (2006). Before the Louisiana Public Service Commission. In re: An Investigation Into the Ratemaking and Generation Planning Implications of the U.S. EPA Clean Air Interstate Rule. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: environmental regulation and cost recovery; allowance allocations and air credit markets; ratepayer impacts of new environmental regulations.

201. Expert Affidavit Before the Louisiana Tax Commission (2006). On behalf of ANR Pipeline, Tennessee Gas Transmission and Southern Natural Gas Company. Issues: Competitive nature of interstate and intrastate transportation services.

202. Expert Affidavit Before the 19th Judicial District Court (2006). Suit Number 491, 453 Section 26. On behalf of Transcontinental Pipeline Corporation, et.al. Issues: Competitive

nature of interstate and intrastate transportation services.

203. Expert Testimony: Docket Number 05-057-T01 (2006). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Rebuttal and Supplemental Rebuttal Testimony)

204. Legislative Testimony (2006). Senate Committee on Natural Resources. Senate Bill 655 Regarding Remediation of Oil and Gas Sites, Legacy Lawsuits, and the Deterioration of State Drilling.

205. Expert Report: Rulemaking Docket (2005). Before the New Jersey Bureau of Public Utilities. In re: Proposed Rulemaking Changes Associated with New Jersey's Renewable Portfolio Standard. Expert Report. The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard. On behalf of the New Jersey Office of Ratepayer Advocate. Issues: Renewable Portfolio Standards, rate impacts, economic impacts, technology cost forecasts.

206. Expert Testimony: Docket Number 2005-191-E. (2005). Before the South Carolina Public Service Commission. On behalf of NewSouth Energy LLC. In re: General Investigation Examining the Development of RFP Rules for Electric Utilities. Issues: Competitive bidding; merchant development. (Direct and Rebuttal Testimony).

207. Expert Testimony: Docket No. 05-UA-323. (2005). Before the Mississippi Public Service Commission. On the behalf of Calpine Corporation. In re: Entergy Mississippi's Proposed Acquisition of the Attala Generation Facility. Issues: Asset acquisition; merchant power development; competitive bidding.

208. Expert Testimony: Docket Number 050045-EI and 050188-EI. (2005). Before the Florida Public Service Commission. On the behalf of the Citizens of the State of Florida. In re: Petition for Rate Increase by Florida Power & Light Company. Issues: Load forecasting; O&M forecasting and benchmarking; incentive returns/regulation.

209. Expert Testimony (non-sworn, rulemaking): Comments on Decreased Drilling Activities in Louisiana and the Role of Incentives. (2005). Louisiana Mineral Board Monthly Docket and Lease Sale. July 13, 2005

210. Legislative Testimony (2005). Background and Impact of LNG Facilities on Louisiana. Joint Meeting of Senate and House Natural Resources Committee. Louisiana Legislature. May 19, 2005.

211. Public Testimony. Docket No. U-21453. (2005). Technical Conference before the Louisiana Public Service Commission on an Investigation for a Limited Industrial Retail Choice Plan.

212. Expert Testimony: Docket No. 2003-K-1876. (2005). On Behalf of Columbia Gas Transmission. Expert Testimony on the Competitive Market Structure for Gas Transportation Service in Ohio. Before the Ohio Board of Tax Appeals.

213. Expert Report and Testimony: Docket No. 99-4490-J, *Lafayette City-Parish Consolidated*

Government, et. al. v. Entergy Gulf States Utilities, Inc. et. al. (2005, 2006). On behalf of the City of Lafayette, Louisiana and the Lafayette Utilities Services. Expert Rebuttal Report of the Harborfront Consulting Group Valuation Analysis of the LUS Expropriation. Filed before 15th Judicial District Court, Lafayette, Louisiana.

214. Expert Testimony: ANR Pipeline Company v. Louisiana Tax Commission (2005), Number 468,417 Section 22, 19th Judicial District Court, Parish of East Baton Rouge, State of Louisiana Consolidated with Docket Numbers: 480,159; 489,776;480,160; 480,161; 480,162; 480,163; 480,373; 489,776; 489,777; 489,778;489,779; 489,780; 489,803; 491,530; 491,744; 491,745; 491,746; 491,912;503,466; 503,468; 503,469; 503,470; 515,414; 515,415; and 515,416. In re: Market structure issues and competitive implications of tax differentials and valuation methods in natural gas transportation markets for interstate and intrastate pipelines.

215. Expert Report and Recommendation: Docket No. U-27159. (2004). On Behalf of the Louisiana Public Service Commission Staff. Expert Report on Overcharges Assessed by Network Operator Services, Inc. Before the Louisiana Public Service Commission.

216. Expert Testimony: Docket Number 2004-178-E. (2004). Before the South Carolina Public Service Commission. On behalf of Columbia Energy LLC. In re: Rate Increase Request of South Carolina Electric and Gas. (Direct and Surrebuttal Testimony)

217. Expert Testimony: Docket Number 040001-EI. (2004). Before the Florida Public Service Commission. On behalf of Power Manufacturing Systems LLC, Thomas K. Churbuck, and the Florida Industrial Power Users Group. In re: Fuel Adjustment Proceedings; Request for Approval of New Purchase Power Agreements. Company examined: Florida Power & Light Company.

218. Expert Affidavit: Docket Number 27363. (2004). Before the Public Utilities Commission of Texas. Joint Affidavit on Behalf of the Cities of Texas and the Staff of the Public Utilities Commission of Texas Regarding Certified Issues. In Re: Application of Valor Telecommunications, L.P. For Authority to Establish Extended Local Calling Service (ELCS) Surcharges For Recovery of ELCS Surcharge.

219. Expert Report and Testimony. Docket 1997-4665-PV, 1998-4206-PV, 1999-7380-PV, 2000-5958-PV, 2001-6039-PV, 2002-64680-PV, 2003-6231-PV. (2003) Before the Kansas Board of Tax Appeals. (2003). In the Matter of the Appeals of CIG Field Services Company from orders of the Division of Property Valuation. On the Behalf of CIG Field Services. Issues: the competitive nature of natural gas gathering in Kansas.

220. Expert Report and Testimony: Docket Number U-22407. Before the Louisiana Public Service Commission (2002). On the Behalf of the Louisiana Public Service Commission Staff. Company examined: Louisiana Gas Services, Inc. Issues: Purchased Gas Acquisition audit, fuel procurement and planning practices.

221. Expert Testimony: Docket Number 000824-EI. Before the Florida Public Service Commission. (2002). On the Behalf of the Citizens of the State of Florida. Company examined: Florida Power Corporation. Issues: Load Forecasts and Billing Determinants for the Projected Test Year.

222. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic Impacts of Merchant Power Generation.

223. Expert Testimony: Docket Number 24468. (2001). On the Behalf of the Texas Office of Public Utility Counsel. Public Utility Commission of Texas Staff's Petition to Determine Readiness for Retail Competition in the Portion of Texas Within the Southwest Power Pool. Company examined: AEP-SWEPCO.

224. Expert Report. (2001) On Behalf of David Liou and Pacific Richland Products, Inc. to Review Cogeneration Issues Associated with Dupont Dow Elastomers, L.L.C. (DDE) and the Dow Chemical Company (Dow).

225. Expert Testimony: Docket Number 01-1049, Docket Number 01-3001. (2001) On behalf the Nevada Office of Attorney General, Bureau of Consumer Protection. Petition of Central Telephone Company-Nevada D/b/a Sprint of Nevada and Sprint Communications L.P. for Review and Approval of Proposed Revised Performance Measures and Review and Approval of Performance Measurement Incentive Plans. Before the Public Utilities Commission of Nevada.

226. Expert Affidavit: Multiple Dockets (2001). Before the Louisiana Tax Commission. On the Behalf of Louisiana Interstate Pipeline Companies. Testimony on the Competitive Nature of Natural Gas Transportation Services in Louisiana.

227. Expert Affidavit before the Federal District Court, Middle District of Louisiana (2001). Issues: Competitive Nature of the Natural Gas Transportation Market in Louisiana. On behalf of a Consortium of Interstate Natural Gas Transportation Companies.

228. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic and Ratepayer Benefits of Merchant Power Generation and Issues Associated with Tax Incentives on Merchant Power Generation and Transmission.

229. Expert Testimony: Docket Number 01-1048 (2001). Before the Public Utilities Commission of Nevada. On the Behalf of the Nevada Office of the Attorney General, Bureau of Consumer Protection. Company analyzed: Nevada Bell Telephone Company. Issues: Statistical Issues Associated with Performance Incentive Plans.

230. Expert Testimony: Docket 22351 (2001). Before the Public Utility Commission of Texas. On the Behalf of the City of Amarillo. Company analyzed: Southwestern Public Service Company. Issues: Unbundled cost of service, affiliate transactions, load forecasting.

231. Expert Testimony: Docket 991779-EI (2000). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Competitive Nature of Wholesale Markets, Regional Power Markets, and Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

232. Expert Testimony: Docket 990001-EI (1999). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Regulatory Treatment of Incentive Returns on Gains

from Economic Energy Sales.

233. Expert Testimony: Docket 950495-WS (1996). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Company analyzed: Southern States Utilities, Inc. Issues: Revenue Repression Adjustment, Residential and Commercial Demand for Water Service.

234. Legislative Testimony. Louisiana House of Representatives, Special Subcommittee on Utility Deregulation. (1997). On Behalf of the Louisiana Public Service Commission Staff. Issue: Electric Restructuring.

235. Expert Testimony: Docket 940448-EG -- 940551-EG (1994). Before the Florida Public Service Commission. On the Behalf of the Legal Environmental Assistance Foundation. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Comparison of Forecasted Cost-Effective Conservation Potentials for Florida.

236. Expert Testimony: Docket 920260-TL, (1993). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: BellSouth Communications, Inc. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

237. Expert Testimony: Docket 920188-TL, (1992). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: GTE-Florida. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

REFEREE AND EDITORIAL APPOINTMENTS

Contributor, 2014-2018, *Wall Street Journal*, *Journal Reports*, Energy

Editorial Board Member, 2015-2017, *Utilities Policy*

Referee, 2014-Current, *Utilities Policy*

Referee, 2010-Current, *Economics of Energy & Environmental Policy*

Referee, 1995-Current*, Energy Journal*

Contributing Editor, 2000-2005, *Oil, Gas and Energy Quarterly*

Referee, 2005, *Energy Policy*

Referee, 2004, *Southern Economic Journal*

Referee, 2002, *Resource & Energy Economics*

Committee Member, IAEE/USAEE Student Paper Scholarship Award Committee, 2003

PROPOSAL TECHNICAL REVIEWER

California Energy Commission, Public Interest Energy Research (PIER) Program (1999).

PROFESSIONAL ASSOCIATIONS

American Economic Association, American Statistical Association, Southern Economic Association, Western Economic Association, International Association of Energy Economists ("IAEE"), United States Association of Energy Economics ("USAEE"), the National Association for Business Economics ("NABE"), and the Energy Bar Association (National and Louisiana Chapter; current Board member of LA chapter).

HONORS AND AWARDS

Baton Rouge Business Report, Selected as one of the "Capital Region 500" (2023).

National Association of Regulatory Utility Commissioners (NARUC). Best Paper Award for papers published in the *Journal of Applied Regulation* (2004).

Baton Rouge Business Report, Selected as "Top 40 Under 40" (2003).

Omicron Delta Epsilon (1992-Current).

Interstate Oil and Gas Compact Commission (IOGCC) "Best Practice" Award for Research on the Economic Impact of Oil and Gas Activities on State Leases for the Louisiana Department of Natural Resources (2003).

Distinguished Research Award, Academy of Legal, Ethical and Regulatory Issues, Allied Academics (2002).

Florida Public Service Commission, Staff Excellence Award for Assistance in the Analysis of Local Exchange Competition Legislation (1995).

TEACHING EXPERIENCE

Energy and the Environment (Survey Course)

Principles of Microeconomic Theory

Principles of Macroeconomic Theory

Lecturer, Environmental Management and Permitting. Lecture in Natural Gas Industry, LNG and Markets.

Lecturer, Electric Power Industry Environmental Issues, Field Course on Energy and the Environment. (Dept. of Environmental Studies).

Lecturer, Electric Power Industry Trends, Principles Course in Power Engineering (Dept. of Electric Engineering).

Lecturer, LSU Honors College, Senior Course on "Society and the Coast."

Continuing Education. Electric Power Industry Restructuring for Energy Professionals.

"The Gulf Coast Energy Situation: Outlook for Production and Consumption." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, New Orleans, LA, December 2, 2004

"The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, Houston, TX, September 13, 2005.

"Forecasting for Regulators: Current Issues and Trends in the Use of Forecasts, Statistical, and Empirical Analyses in Energy Regulation." Instructional Course for State Regulatory Commission Staff. Institute of Public Utilities, Kellogg Center, Michigan State University. July 8-9, 2010.

"Regulatory and Ratemaking Issues with Cost and Revenue Trackers." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 29, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 30, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities, Forecasting Workshop, Charleston, SC. March 7-9, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 7-11, 2011.

"Regulatory and Ratemaking Issues Associated with Cost and Expense Adjustment Mechanisms." Michigan State University, Institute of Public Utilities, Advanced Regulatory Studies Program. Lansing, Michigan. September 28, 2011.

"Utility Incentives, Decoupling, and Renewable Energy Programs." Michigan State University, Institute of Public Utilities, Advanced Regulatory Studies Program. Lansing, Michigan. September 29, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 6-8, 2012.

"Traditional and Incentive Ratemaking Workshop." New Mexico Public Utilities Commission Staff. Santa Fe, NM October 18, 2012.

"Traditional and Incentive Ratemaking Workshop." New Jersey Board of Public Utilities Staff. Newark, NJ. March 1, 2013.

"Natural Gas Issues and Recent Market Trends." Michigan State University Institute of Public Utilities, GridSchool Regulatory Studies Program, East Lansing, Mich., March 29, 2017.

"Gas Supply Planning and Procurement: Regulatory Overview and issues." Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 17, 2017.

"Natural Gas Supply Issues and Challenges." Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 17, 2017.

"Incentives, Risk and Changes in the Nature of Regulation." Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 18, 2017.

"Traditional and Alternative Forms of Regulation: Background and Overview." Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

"Traditional and Alternative Forms of Regulation: Utility and policy motivations for risk and change." Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

"Traditional and Alternative Forms of Regulation: Incentives and Formula Based Methods." Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

THESIS/DISSERTATIONS COMMITTEES

Active:
1 Thesis Committee Memberships (Environmental Studies)
2 Ph.D. Dissertation Committee (Economics)
Completed:
8 Thesis Committee Memberships (Environmental Studies, Geography)
4 Doctoral Committee Memberships (Information Systems & Decision Sciences, Agricultural and Resource Economics, Economics, Education and Workforce Development).
2 Doctoral Examination Committee Membership (Information Systems & Decision Sciences, Education and Workforce Development)
1 Senior Honors Thesis (Journalism, Loyola University)

LSU SERVICE AND COMMITTEE MEMBERSHIPS

Committee Member, Energy Education Curriculum Committee. E.J. Ourso College of Business. LSU (2016-Current).

Chairman, LSU Energy Initiative/LSU Energy Council (2014-Current).

Co-Director & Steering Committee Member, LSU Coastal Marine Institute (2009-2014).

CES Promotion Committee, Division of Radiation Safety (2006).

Search Committee Chair (2006), Research Associate 4 Position.

Search Committee Member (2005), Research Associate 4 Position.

Search Committee Member (2005), CES Communications Manager.

LSU Graduate Research Faculty, Associate Member (1997-2004); Full Member (2004-2010); Affiliate Member with Full Directional Rights (2011-2014); Full Member (2014-current).

LSU Faculty Senate (2003-2006).

Conference Coordinator. (2005-Current) Center for Energy Studies Conference on Alternative Energy.

LSU CES/SCE Public Art Selection Committee (2003-2005).

Conference Coordinator. Center for Energy Studies Annual Energy Conference/Summit. (2003-Current).

Conference Coordinator. Center for Energy Studies Seminar Series on Electric Utility Restructuring and Wholesale Competition. (1996-2003).

Co-Chairman, Review Committee, Louisiana Port Construction and Development Priority Program Rules and Regulations, On Behalf of the LSU Ports and Waterways Institute. (1997).

LSU Main Campus Cogeneration/Turbine Project, (1999-2000).

LSU InterCollege Environmental Cooperative. (1999-2001).

LSU Faculty Senate Committee on Public Relations (1997-1999).

LSU Faculty Senate Committee on Student Retention and Recruitment (1999-2003).

PROFESSIONAL SERVICE

Board Member (2018). Energy Bar Association, Louisiana Chapter.

Program Committee Member (2017). Gulf Coast Power Association Conference. New Orleans.

Program Committee Member (2016). Gulf Coast Power Association Conference. New Orleans.

Program Committee Member (2015). Gulf Coast Power Association Workshop/Special Briefing. "Gulf Coast Disaster Readiness: A Past, Present and Future Look at Power and Industry Readiness in MISO South."

Advisor (2008). National Association of Regulatory Utility Commissioners. Study Committee on the Impact of Executive Drilling Moratoria on Federal Lands.

Steering Committee Member, Louisiana Representative (2008-Current). Southeast Agriculture & Forestry Energy Resources Alliance. Southern Policies Growth Board.

Advisor (2007-Current). National Association of State Utility Consumer Advocates ("NASUCA"), Natural Gas Committee.

Program Committee Chairman (2007-2008). U.S. Association of Energy Economics ("USAEE") Annual Conference, New Orleans, LA

Finance Committee Chairman (2007-2008). USAEE Annual Conference, New Orleans, LA

Committee Member (2006), International Association for Energy Economics Nominating Committee.

Founding President (2005-2007) Louisiana Chapter, USAEE.

Secretary (2001) Houston Chapter, USAEE.

Advisor, Louisiana LNG Buyers/Developers Summit, Office of the Governor/Louisiana

Department of Economic Development/Louisiana Department of Natural Resources, and Greater New Orleans, Inc. (2004).

ACADIAN
CONSULTING GROUP

Affordability Issues in Pepco Base Rate Case

Prepared on the behalf of the District of Columbia, Office of the People's Counsel

David E. Dismukes, Ph.D.
Acadian Consulting Group

January 12, 2024

Introduction

Study purpose and findings

The Acadian Consulting Group, LLC ("ACG") has been asked by the District of Columbia, Office of the Peoples Counsel ("OPC) to **examine affordability issues in the District.**

The purpose of this analysis is **to examine electricity affordability and how that has changed since the approval of Pepco's multi-year rate plan pilot ("MRP Pilot") program.** The analysis here **focusses on electricity affordability measures at both aggregate and detailed census/zip code levels information.**

The analysis finds that <u>Pepco's consistent and large rate increases had jeopardized electricity affordability</u>, particularly for those least advantaged communities in the District. **<u>The Commission's policies</u>** of allocating ever increasing shares of these rate increases to residential customers **<u>has exacerbated these affordability challenges</u>.**

While Pepco does have low-income support programs, these **programs fail to reach an overwhelming portion of low-income households/residents**, **nor do they offset the increases** that have arisen from the MRP Pilot.

Recommendations

ACG makes the following recommendations:

- **Do not approve the proposed multi-year rate plan ("MYP")**. The current MRP Pilot has done nothing but make electricity more expensive in the District.
- **Limit Pepco's proposed annual capital expenditures** to levels that are more sustainable and consistent with affordability concerns.
- Require Pepco to **regularly examine and file affordability analyses**.
- **Review the Pepco's low-income proposals** for:

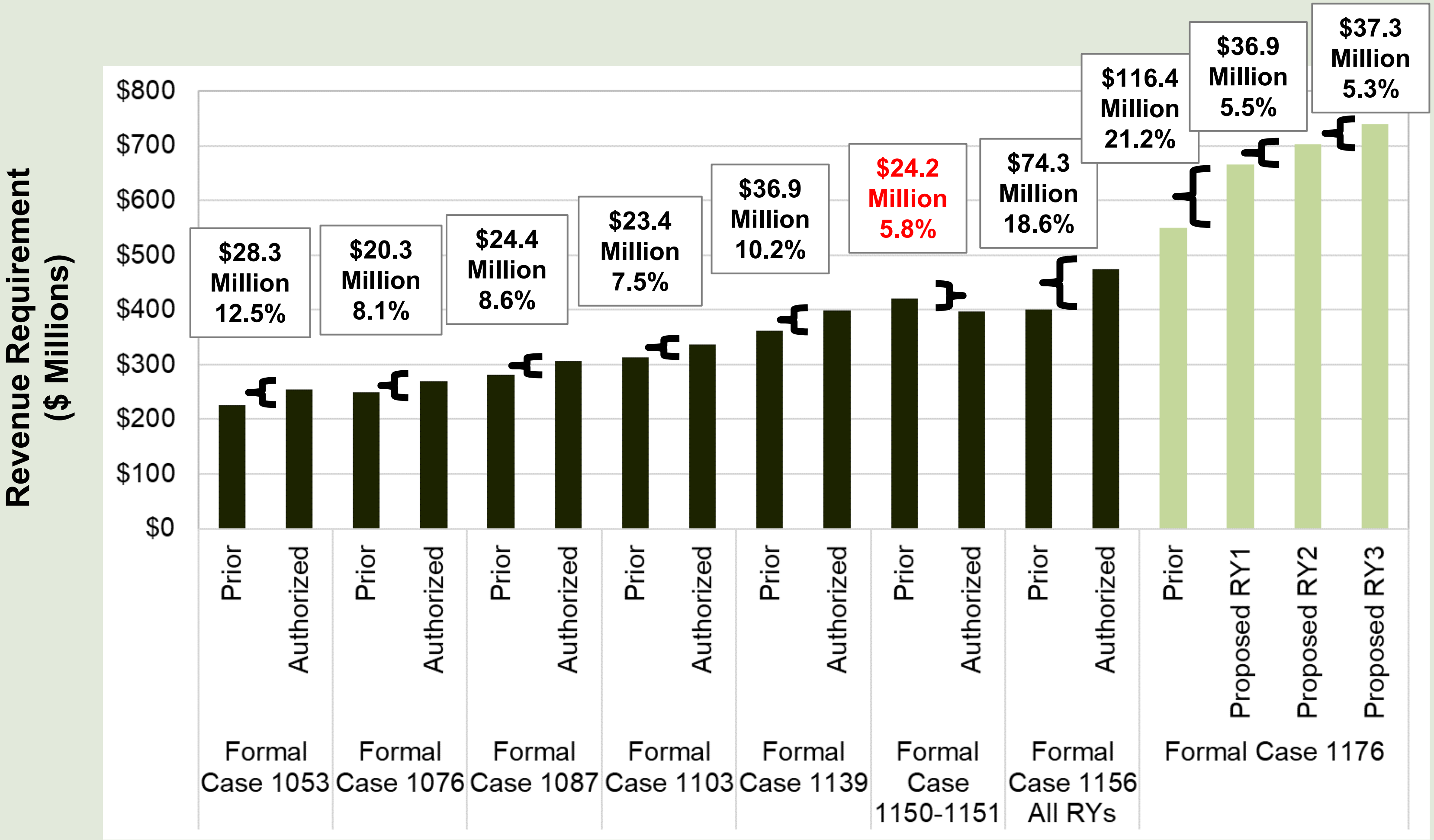
  (a) potential modifications that **expand coverage** to a larger number of eligible households and

  (b) **means test and scale financial assistance levels** to assure adequacy, minimize adverse rate impacts on other supporting customers, and to get the "biggest bang for the buck" in low-income assistance.

Pepco's rate increases are harming ratepayers

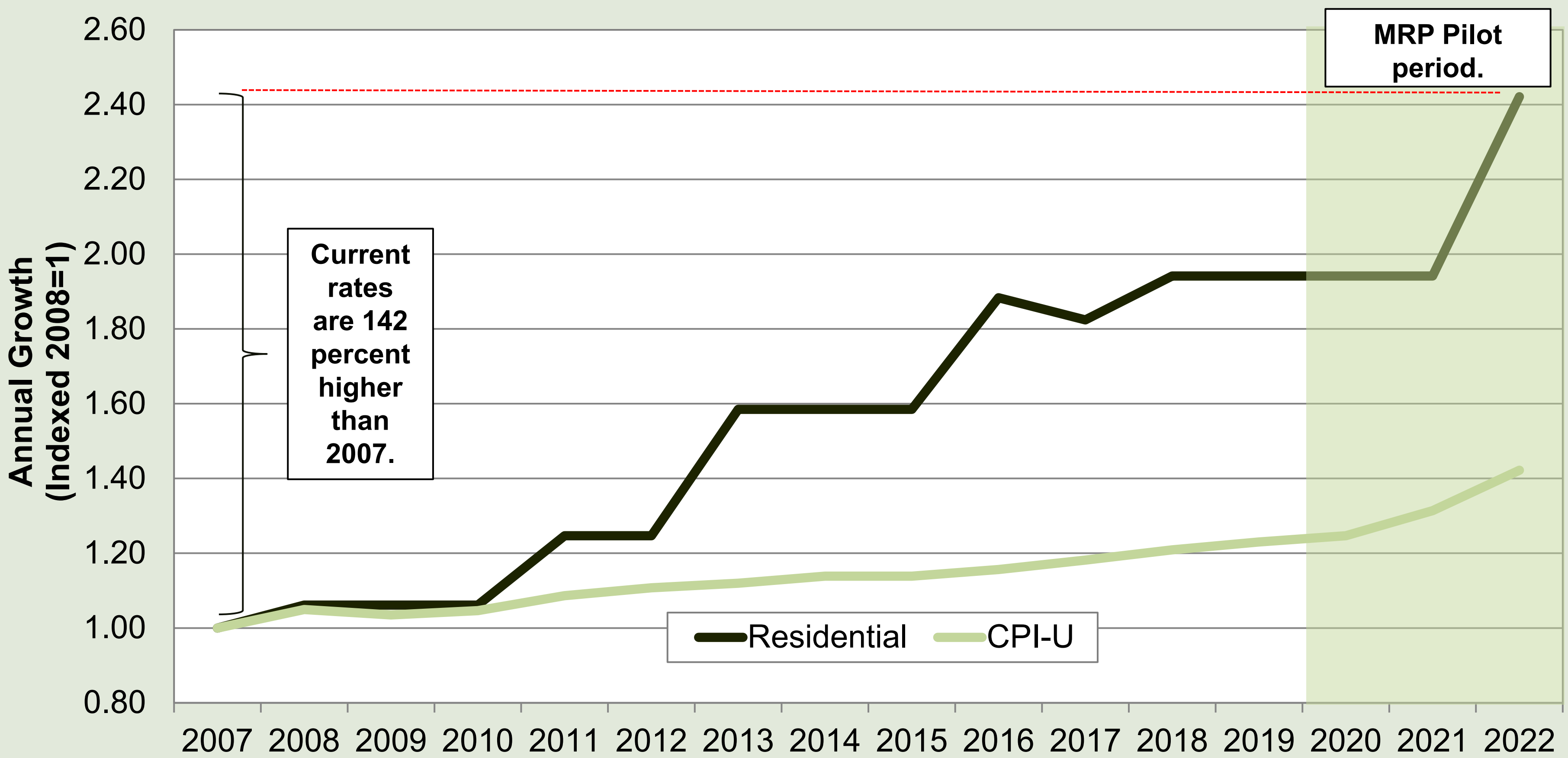
Historic PEPCO revenue requirements with proposed MYP

PEPCO proposes **two-year rate increases of $74.3 million** ~ 85 percent greater than rates prior to FC 1156 (2019) and **double rate levels in FC 1053 (2006).**



Growth in residential rates relative to inflation

PEPCO **residential rates have far outpaced inflation** at **over nine percent per year**.



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David E. Dismukes, Ph.D.
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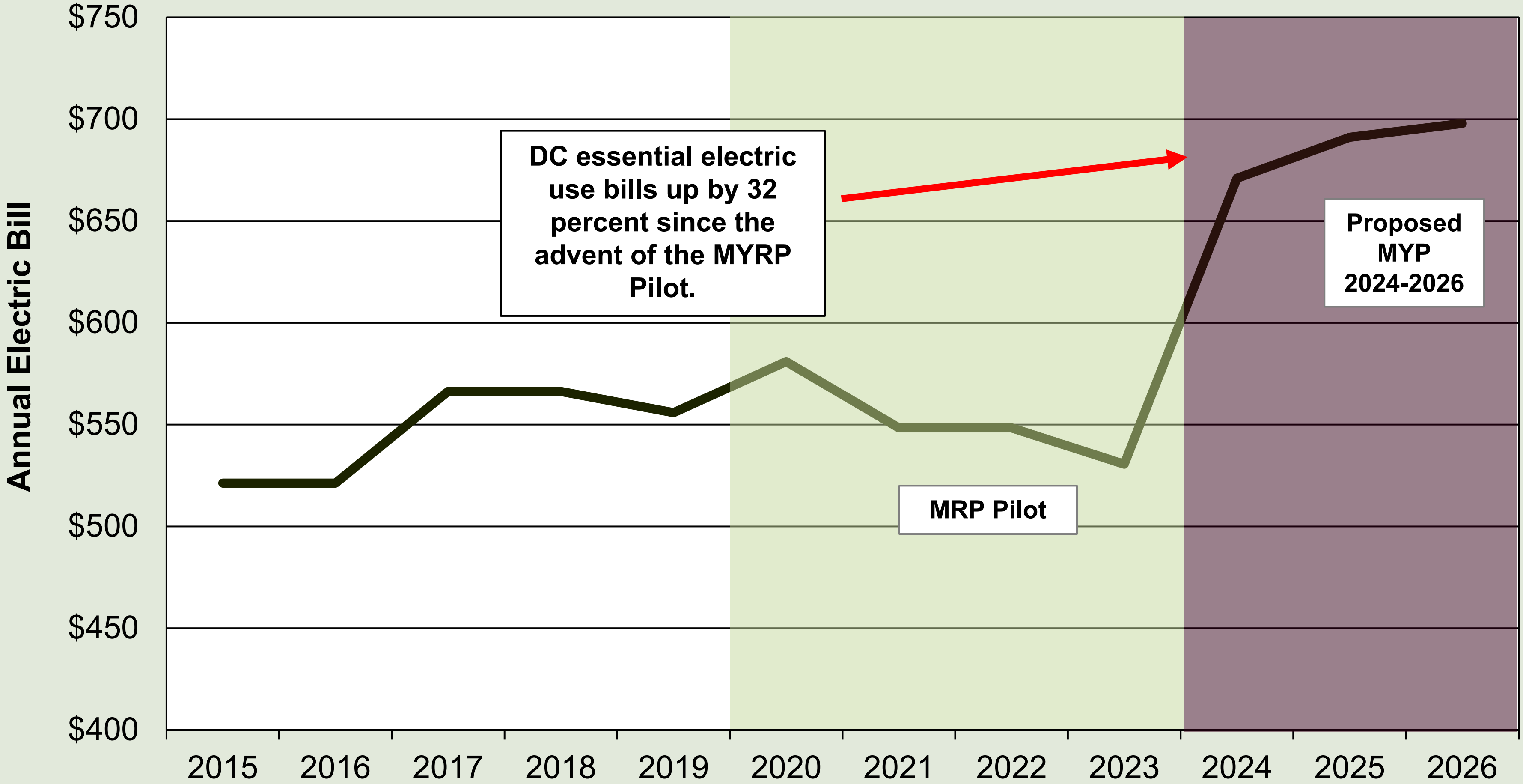
PEPCO residential essential electric bills

The **cost of essential electricity has skyrocketed** because of **Pepco's significant MYRP related rate increases**.



Source: FC 1176 OPC DR 3-19 and PEPCO (E)-5, baseline usage estimated by Brattle Study at 337 kWh per month.

Historic and proposed residential class revenue responsibilities

PEPCO proposes **full cost-of-service residential rates** that will increase by **80 percent** (three-year MYRP) or **2.30 times the overall proposed 34.84 percent increase**.

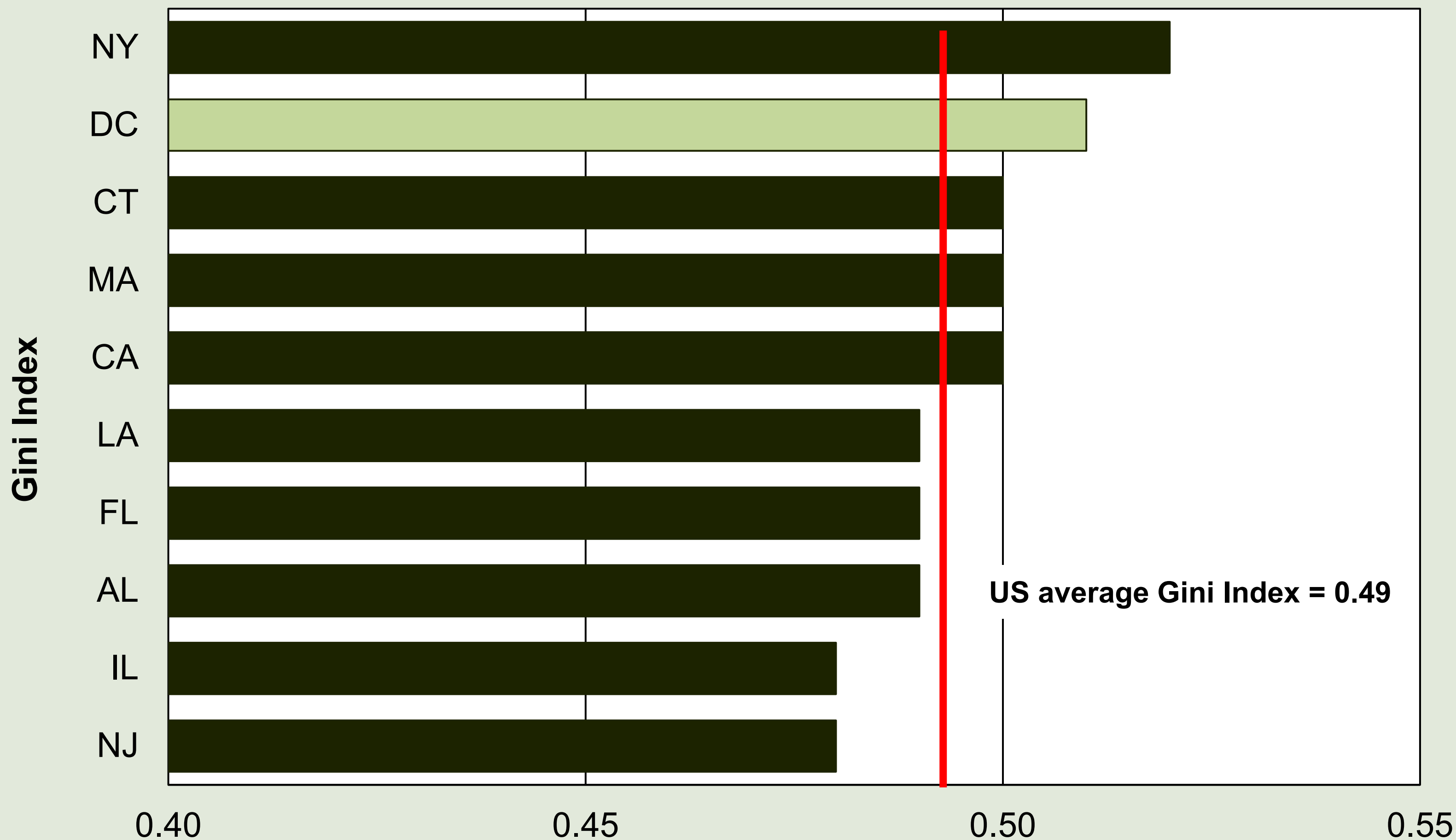
	Relative Rate of Return	Rate Increase		
Case No.	Total Residential	System Average	Total Residential	Relative Increase
FC 1053	-0.48	12.50%	13.33%	1.07
FC 1076	-0.47	7.94%	17.52%	2.21
FC 1087	-0.54	8.64%	21.40%	2.48
FC 1103	-0.41	7.48%	17.56%	2.35
FC 1139	-0.60	10.20%	9.25%	0.91
FC 1150/1151	-0.75	-6.05%	-3.02%	-0.50
FC 1156	-1.00	17.34%	14.00%	0.81
FC 1176	**-0.68**	**34.84%**	**80.14%**	**2.30**

Note - past residential rates increases **have not resulted in any improvement in the relative rate of return** associated with residential rates.

The District has an affordability challenge

DC income inequality is the worst in the U.S. (Gini Index = 2022)

The **District has one of the highest measures of income inequality** in the nation.

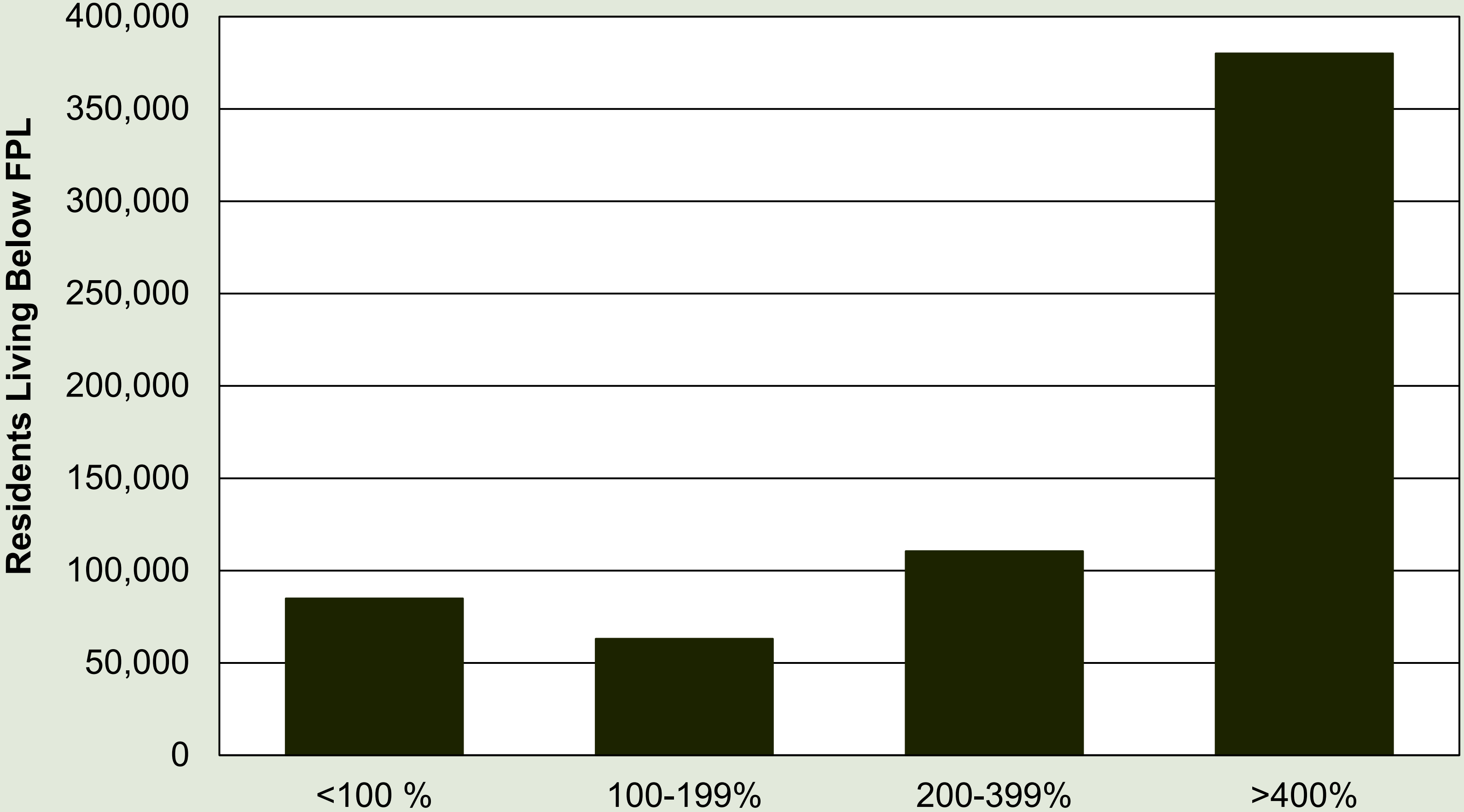


Note: A Gini Index is the difference between the Lorenz curve (the observed cumulative income distribution) and a perfectly equal income distribution. A score of 0 reflects perfect income equality and 1 indicates perfect "inequality" where one person holds all wealth.

Source: U.S. Census, Statista Gini Coefficient in the United States, 2022

D.C. population distribution by federal poverty level, 2022

The District has a considerable number of residents living below the federal poverty level ("FPL"): **23 percent live at our below 200 percent of the FPL.**



Source: KFF, 2022 American Community Survey, 1-Year Estimates.

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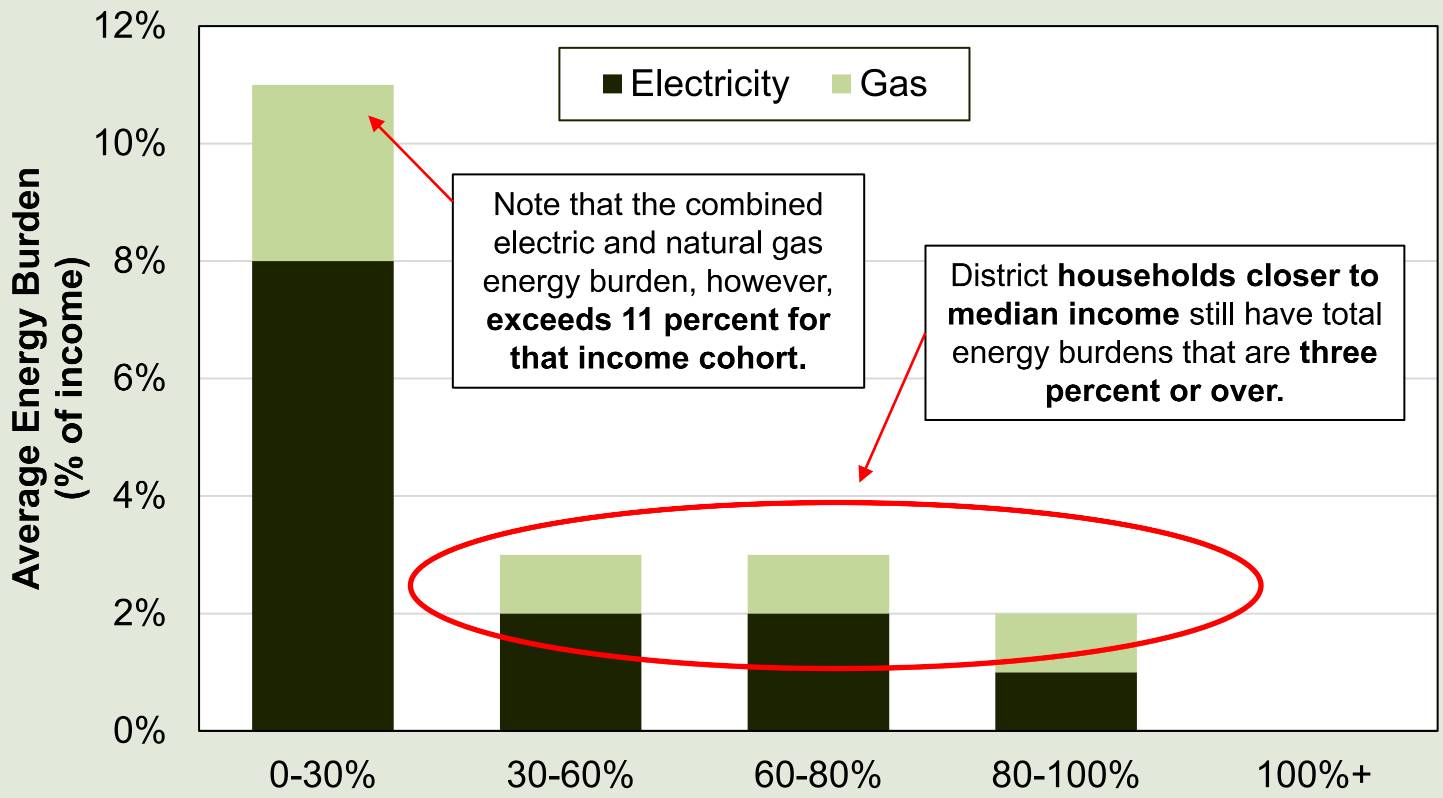
LEAD Tool analysis of DC energy affordability

A recent Low-Income Energy Affordability Tool (LEAD) analysis found that DC low-income households (less than 30 percent of overall median income) have an **average electric energy burden of eight percent – well above a six percent burdensome threshold.**



Source: Low-Income Energy Affordability Data Tool (LEAD).

Measuring Affordability: Analysis and Practice

Affordability indices in utility regulation

Energy affordability is increasingly becoming an important issue in regulatory policy making. Several states require affordability calculations, and some are regularly developing their own estimates. Several non-governmental organizations and research groups are also engaged in this effort.

- The **California Public Utilities Commission (CPUC)** developed the state's first energy affordability metric that tracks affordability for essential service level (electric, gas, water, and communications, see Order 18-07-006, 2018). California adopted the following three metrics: Affordability Ratio, Hours-at-Minimum-Wage, and Socioeconomic Vulnerability Index. The third phase of the order is focused on analyzing strategies to mitigate future rate increases based on the affordability metrics calculated.
- The **Connecticut Green Bank** mapped household energy and transportation affordability in Connecticut in 2020. The report and mapping utilizes a metric that measures the effect of energy and transportation costs on household income by census tract. The report calculated that households earning less than 50 percent of the State Median Income had an annual building energy affordability gap of $1,010. This gap represents the difference between affordable level of spending in a census tract and actual levels of spending.

Sources: California Public Utilities Commission, Rulemaking 18-07-006, Jule 12, 2018.
Connecticut Green Bank, Mapping Household Energy and Transportation in Connecticut, October 2020.

Affordability indices in utility regulation (continued)

- The **Pennsylvania Utility Commission (PUC)** examined home energy burdens for low-income Pennsylvanians in its Home Energy Affordability 2019 report. The study found a wide disparity in the average percent of household income spent on natural gas and electric services by Customer Assistance Programs (CAP) customers and non-CAP customers. CAP customers with gas heating and electric non-heating had a combined average energy burden of 12 to 14 percent or with electric heat 8 to 10 percent. In contrast, non-CAP customers had an average energy burden of 4 percent for gas heating and electric non-heating or 4 percent for electric heating.
- **Legal Action Chicago, Nicor Gas Company Rate Case** (Docket No. 23-0066, 2023) created a series of metrics and indexes that measure the impact of natural gas bills on low-income customers. Legal Action Chicago found that NICOR burdens fell between 8 to 17 percent of income for households with income less than 50 percent of the Federal Poverty Line (FPL). In comparison, at incomes between 100 to 150 percent of FPL, burdens are between 3 and 4 percent.
- **Synapse Energy Economics** analyzed low-income energy burden by county in its Maine Low-Income Home Energy Burden Study 2019. The report calculates affordability ratios for various income levels and found that the average home energy burden for low-income households is 19 percent while the mean energy burden for all households in the state is 6 percent.

Sources: Home Energy Affordability for Low-Income Customers in Pennsylvania, January 2019, Pennsylvania Public Utility Commission.
Direct Testimony of Roger D. Colton, Legal Action of Chicago, May 2, 2023. Maine Low-Income Home Energy Burden Study, Synapse Energy Economics, June 3, 2019.

Affordability indices in utility regulation (continued)

- The **New York Public Service Commission** (Case 14-M-0565, 2016) analyzed utility affordability for low-income households and adopted regulatory policy framework to address these customers' needs, including an energy burden target of 5 percent for all 2.3 million low-income households in New York.
- **West Virginia American Water** (Rate Case No. 23-0383-W-42T) submitted an "Affordability Index for Basic Water Service" (estimated at 40 gallons of water per household member per day). The index showed that customers who spend more than 2 percent of their income on Basic Water Service represent 45 percent of the total customer population and have an income that is generally less than $35,000 per year.
- **National Consumer Law Center** conducted a Utility Bill Affordability Study in 2020 for Colorado. The study analyzed affordability program designs, income, and cost of living for families at or below 200 percent of the Federal Poverty Level. The study showed that if an additional 70 cents per month per customer were added to increase funds for the Percentage of Income Payment Plan (PIPP), a 3 percent target energy burden would be reached for all customers. For example, the undiscounted electricity burden for a Black Hills Electric customer who is single and makes minimum wage is 7.8 percent compared to the discounted electricity burden of 3 percent.

Sources: Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability, May 20, 2016, Case 14-M-0565.
Direct Testimony of Charles B. Rea Case No. 23-0383-W-42T. National Consumer Law Center "Utility Bill Affordability in Colorado" October 2020.

Affordability indices in utility regulation (continued)

- The **Energy Information Administration (EIA)** analyzed household energy insecurity in 2020 across the United States. The EIA found that nearly 26 percent of all households in the Mid Atlantic suffer from some form of energy insecurity, including approximately 18 percent of households reporting reducing or forgoing food or medicine to pay energy costs, and approximately 11.2 percent of households reporting leaving home at an unhealthy temperature. EIA also found that energy insecurity was prevalent even up to households earning above $60k a year (approximately 20 percent).
- The **Department of Public Utilities (DPU)** in Massachusetts, in D.P.U. 22-22, required ENSTAR to provide a "detailed household economic burden index analysis evaluating residential energy electric utility customer bills as percentage of household income by county and to provide the summary results of detailed household burden index analysis". The Department required three income groups in the analysis: 50 percent of FPL, 100 percent of FPL, and 200 percent of FPL. The Department also issued directives to National Grid and Until to perform similar burden analysis in their 2022 Annual Returns Report to the Department.

Sources: Energy Information Administration (EIA) Household Energy Insecurity 2020 Report, March 2023.
Order D.P.U. 22-22, Petition of NSTAR Electric Company, doing business as Eversource Energy, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Plan, November 30, 2022.

D.C. Affordability Analysis

Energy affordability ratio

- The **energy affordability ratio** measures the percentage of a household income that is used to pay for electricity and natural gas**.** While academic literature has focused on total utility affordability, for purposes of this analysis only electric and natural gas rates in the District are examined.
- This ratio, or quotient, has “**average” energy expenditures** as the numerator **and income less rent (housing costs)** as the denominator.
- The data used includes:

  Income: Disposable household income based on two groups (15th and 20th income percentiles) using American Community Survey Economic Characteristics DC Census Tract data.

  Rent: Average rent in the District was calculate based on information for 15th and 20th income percentiles using American Community Survey Economic Characteristics DC Census Tract data.

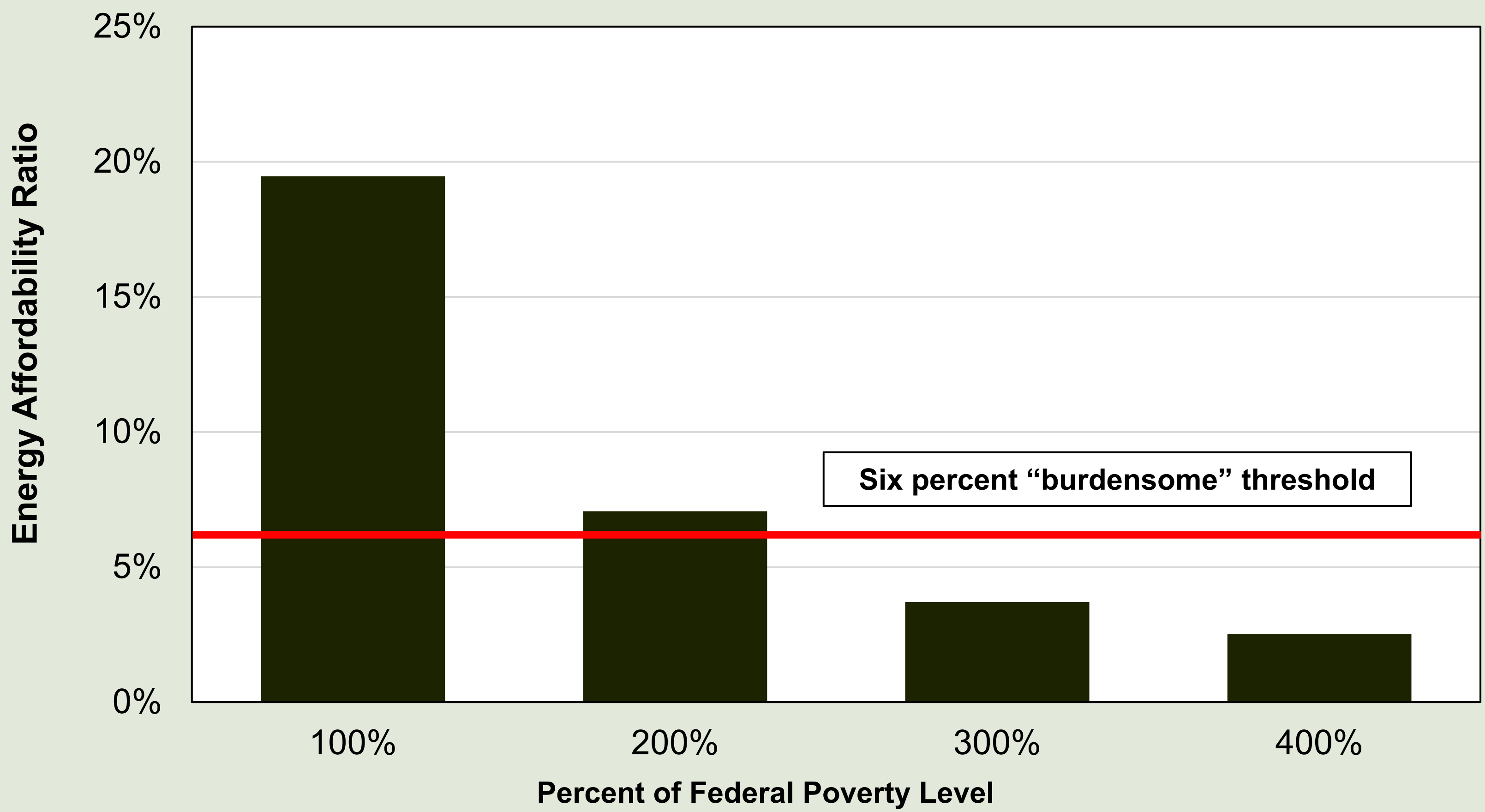
  Electric and Natural Gas Consumption: Average annual consumption by income level based on the EIA Residential Consumption Survey 2020.

  Electric and Natural Gas Rates: Based on PEPCO and Washington Gas and Light Tariffs.

Sources: American Community Survey 5-Year Estimates, 2015-2021. The Brattle Group, Pepco DC Conditional Demand Analysis, December 2017, EIA Residential Consumption Survey 2020.

D.C. energy affordability ratio by FPL, 2022

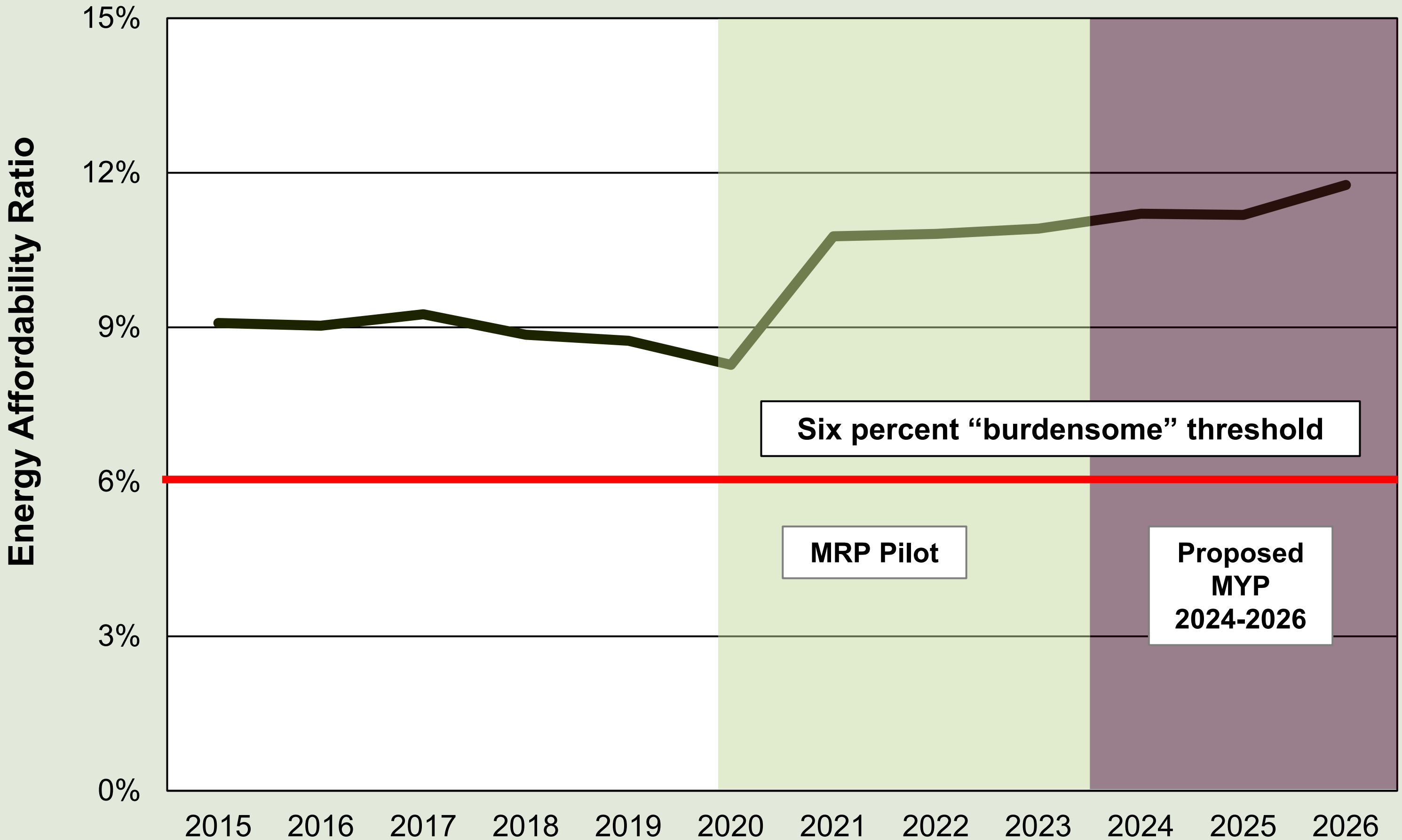
DC residents at 100 and 200 percent of the FPL exceed the burdensome threshold levels. Importantly, this analysis is limited to only electric and natural gas utility rates, and excludes utility rates associated with water, sewer, or telecommunications service. Therefore, this six percent threshold is likely conservative.



Source: ACS Community Survey 5-Year Estimates, Federal Poverty Level Guidelines 2022, DC Health Matters Average Household Size.

District energy affordability ratio: 15th percentile income

The lowest percentile is receiving the most harm from continued Pepco rate increases – **energy affordability ratios will rise to 11.8 percent by 2026.**



Source: Author's estimates from data provided in American Community Survey 5-Year Estimates 2015-2021, PEPCO Tariffs, FC 1176 OPC DR 3-19 and PEPCO (E)-5.

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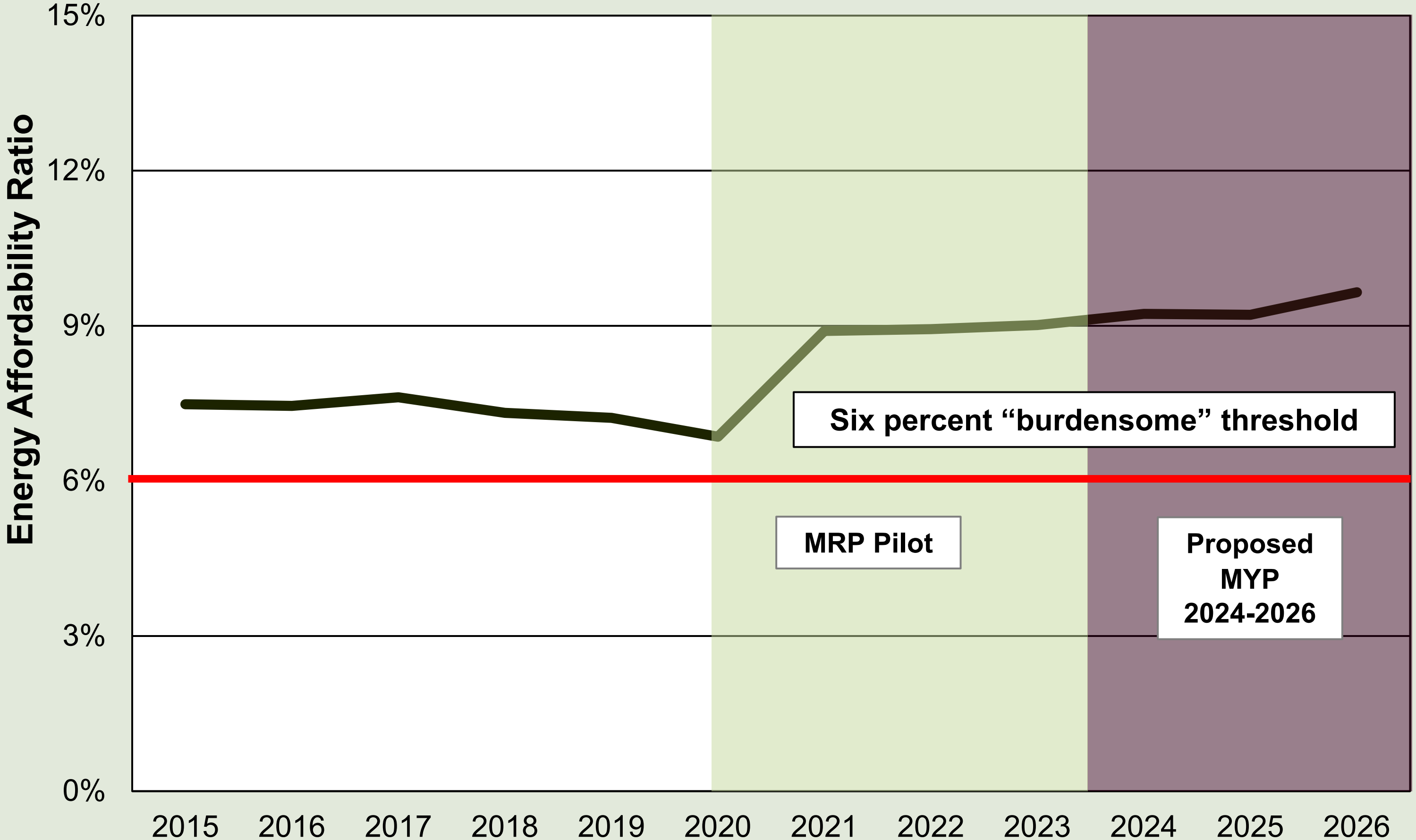
District energy affordability ratio: 15th percentile income with RAD discount

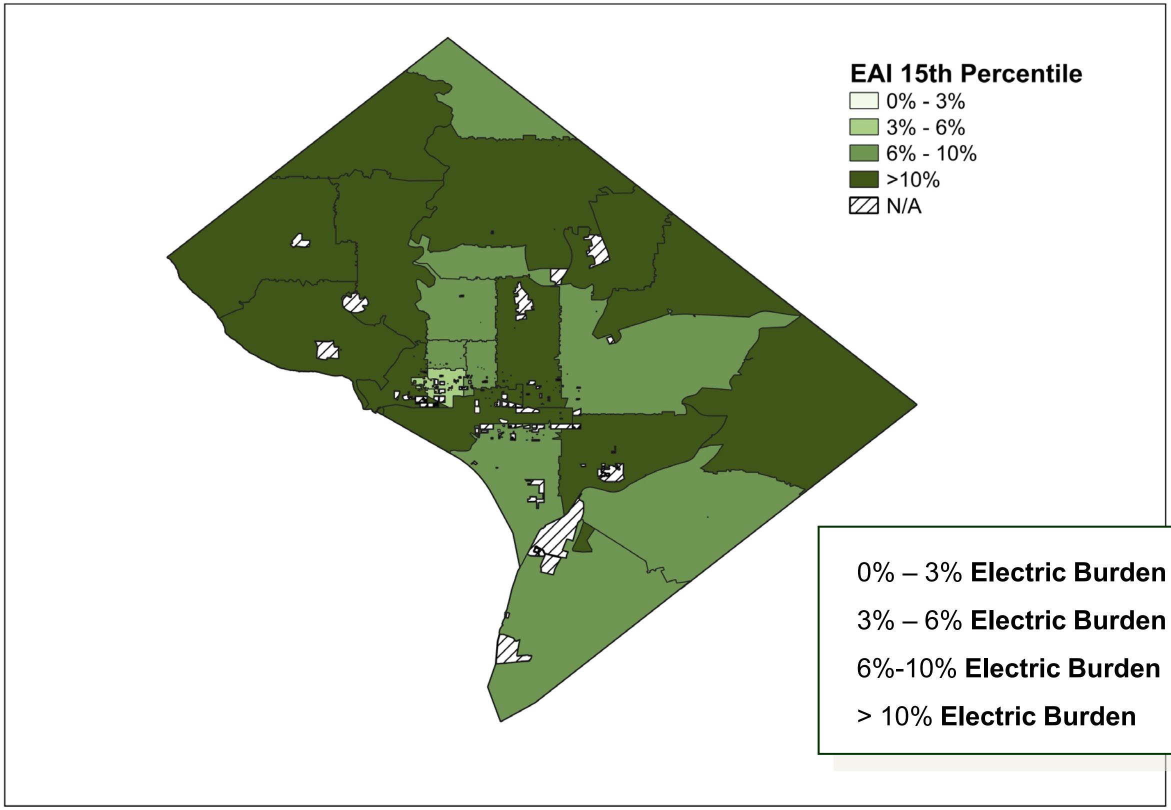
The RAD program offers eligible low-income customers a **25 percent discount** on their monthly electric bill. Even with RAD discounts, rates for the lowest 15th percentile of District ratepayers are **above burdensome levels** throughout the proposed MYP.



Source: Author's estimates from data provided in American Community Survey 5-Year Estimates 2015-2021, PEPCO Tariffs, FC 1176 OPC DR 3-19 and PEPCO (E)-5.

Affordability by location, lowest 15th household income percentile (2022)

The darker areas of the map shows that households in the lowest income quartile in the District **are all facing high or severe electric burdens**. Importantly, this analysis is limited to only electric utility rates in the District and excludes other utility rate burdens, including natural gas utility rates included in the previous analysis.



0% – 3% **Electric Burden**

3% – 6% **Electric Burden**

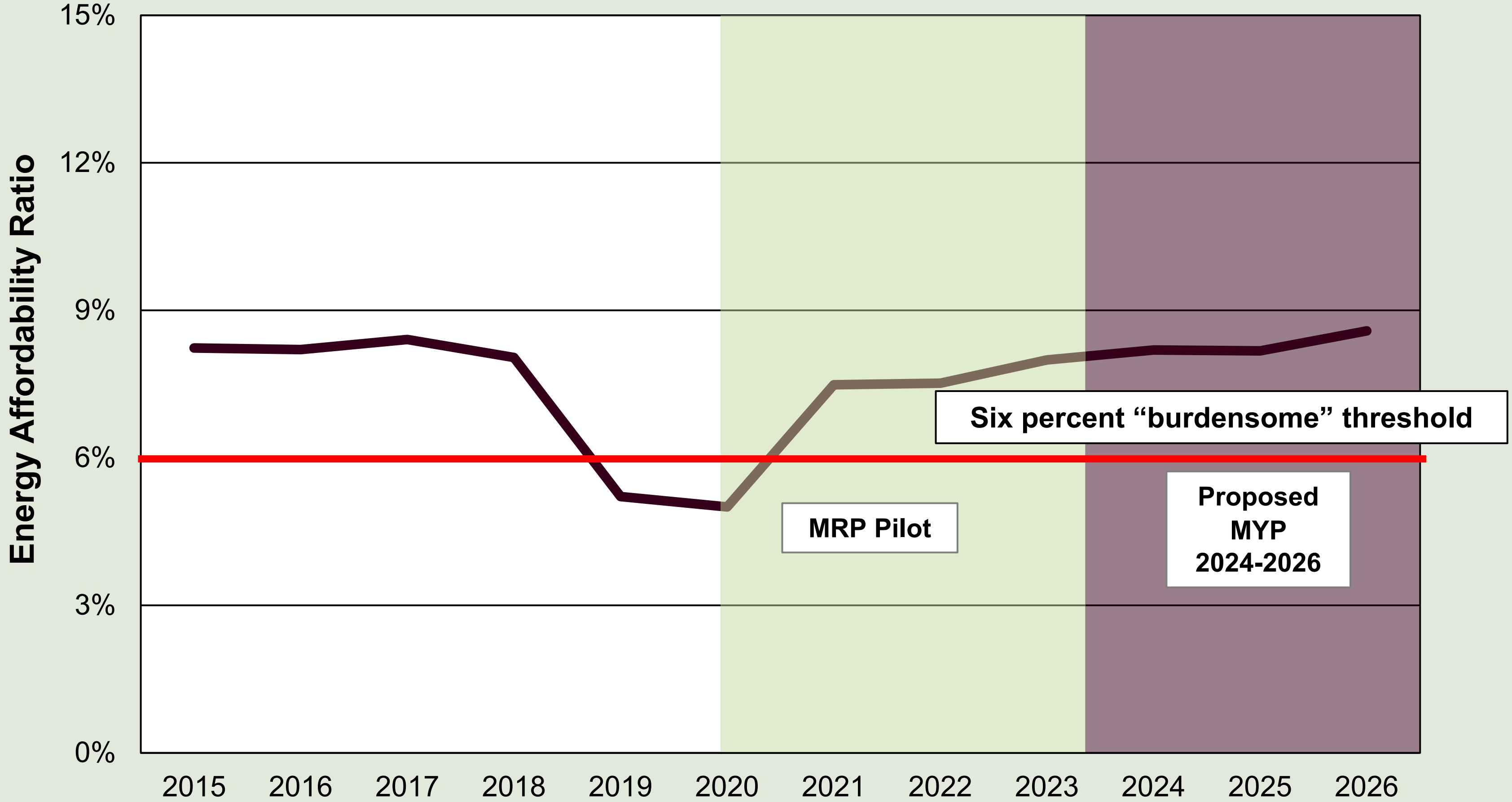
6%-10% **Electric Burden**

> 10% **Electric Burden**

Note: This affordability analysis utilizes average usage and expenditures provided by Pepco.
Source: FC 1176 OPC DR 3-47, ACS 2022 1-Year Estimates,

District energy affordability ratio: 20th percentile income

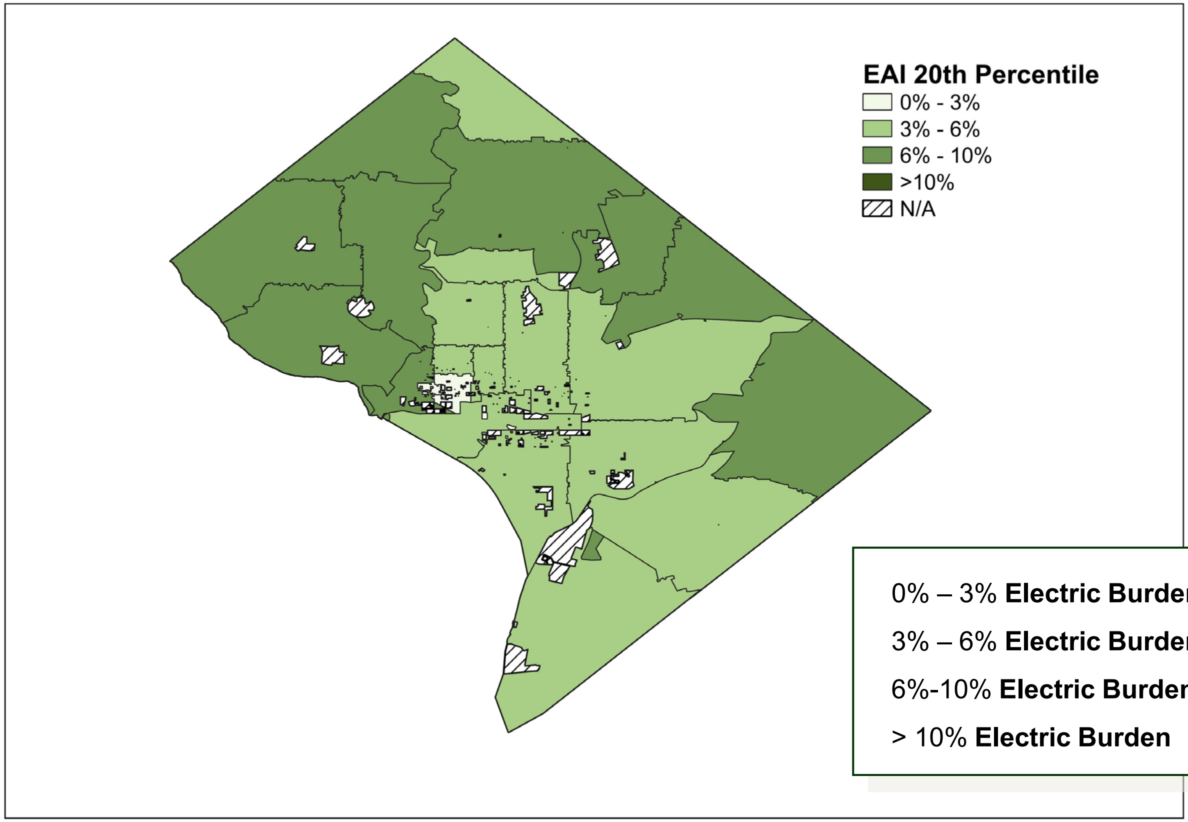
The energy affordability for District residents at the 20th percentile has seen high levels of energy burden since at least 2015. **This is estimated to grow during the proposed MYP.**



Source: Author's estimates from data provided in American Community Survey 5-Year Estimates 2015-2021, PEPCO Tariffs, FC 1176 OPC DR 3-19 and PEPCO (E)-5.

Affordability by location, lowest 20th household income percentile (2022)

Households in the 20th lowest household income quartile **are all facing high to moderate electric burdens.** Importantly, this analysis is limited to only electric utility rates in the District, and excludes other utility rate burdens, including natural gas utility rates included in the previous analysis.



0% – 3% **Electric Burden**

3% – 6% **Electric Burden**

6%-10% **Electric Burden**

> 10% **Electric Burden**

Note: This affordability analysis utilizes average usage and expenditures provided by Pepco.
Source: FC 1176 OPC DR 3-47, ACS 2022 1-Year Estimates,

Alternative energy affordability measures: Hours at Minimum Wage

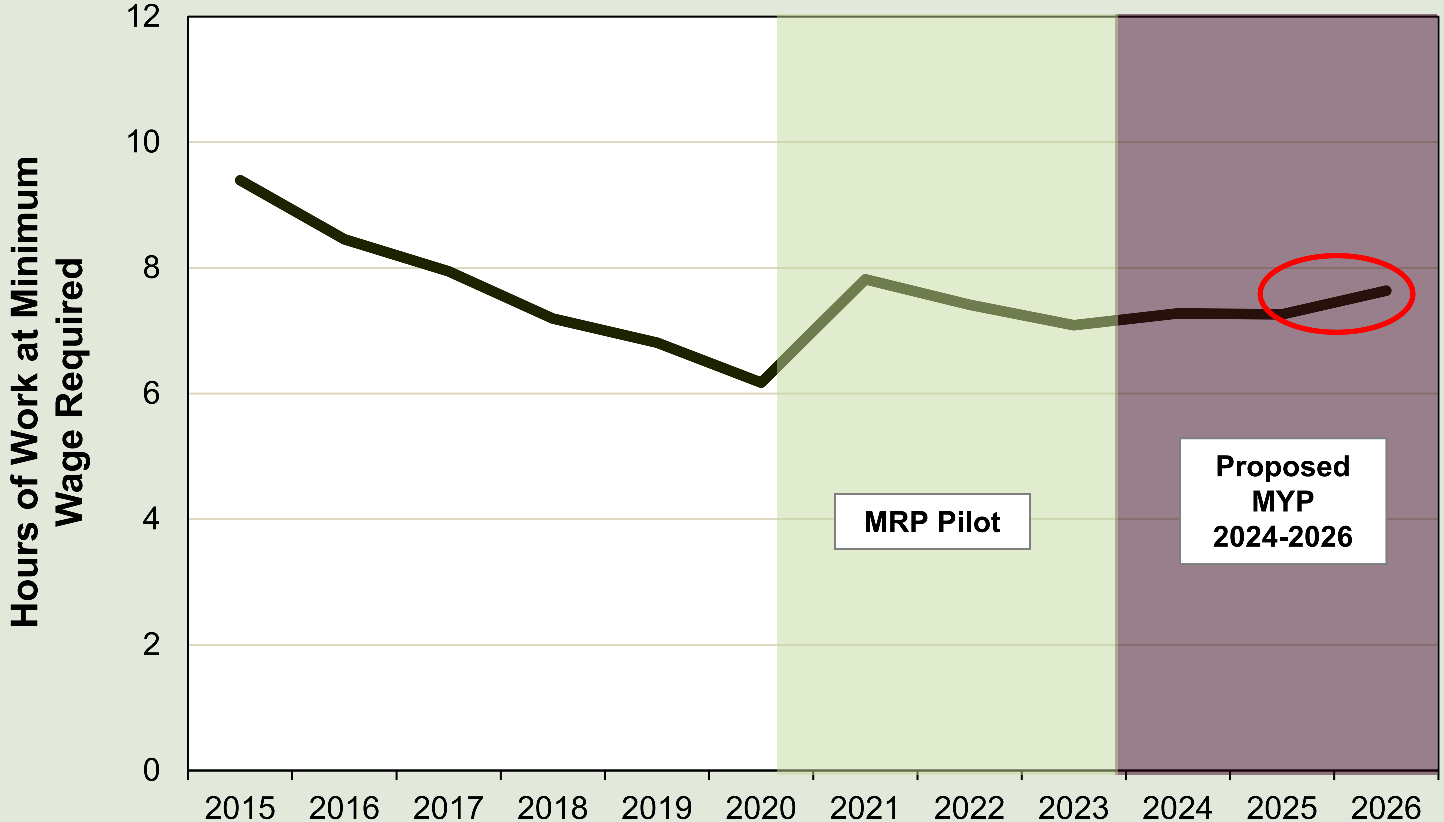
- The hours at minimum wage (HM) measures **the number of hours of earned employment at the minimum wage necessary for a household to pay for essential services: in this case, electricity and natural gas.**
- **Hours at minimum wage** = electric and natural gas bills / minimum wage.
- Electric and natural gas rates were based on 15th percentile income consumption.
- This metric quantifies the number of hours low-income residents must work to meet their basic electricity and natural gas expenses.

ACADIAN CONSULTING GROUP

Affordability Analysis

Hours at minimum wage (HM)

The number of hours needed to pay for electric and natural gas bills has increased and will **continue to increase with the proposed MYP despite minimum wages increasing by 62 percent since 2015.**



A DC resident will have to work close to 7.64 hours per week at minimum wage to pay their electric and natural gas bills if the MYP is approved.

Source: Author's estimates from data provided in American Community Survey 5-Year Estimates 2015-2021, PEPCO Tariffs, FC 1176 OPC DR 3-19 , PEPCO (E)-5, and DC Historic Minimum Wage https://fred.stlouisfed.org/series/STTMINWGDC.

Pepco Low-Income Affordability Programs

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Pepco Existing Programs

Affordability Assistance Programs in D.C.

Residential Aid Discount Program (RAD): provides eligible customers a discount of about 25 percent on their monthly electric bill.

Utility Discount Programs (UDP): provides eligible low-income customers up to $475 per year on electric bills, $276 during the winter season on gas bills, and over $962 per year on water and sewer bills.

Weatherization Assistance Program (WAP): provides income eligible households with energy audits and installation of audit-recommended energy efficiency measures and water conversation to promote energy efficiency.

Solar for All: offers incentives to low to moderate income households for solar panel installations. According to the program, eligible households can expect to see a 50 percent savings on their electric bill over 15 years.

Low Income Home Energy Assistance Program (LIHEAP): assists income-eligible households with cooling and energy costs through a $250-$1,800 one-time benefit.

Source: https://doee.dc.gov/energyassistance and https://doee.dc.gov/solarforall.

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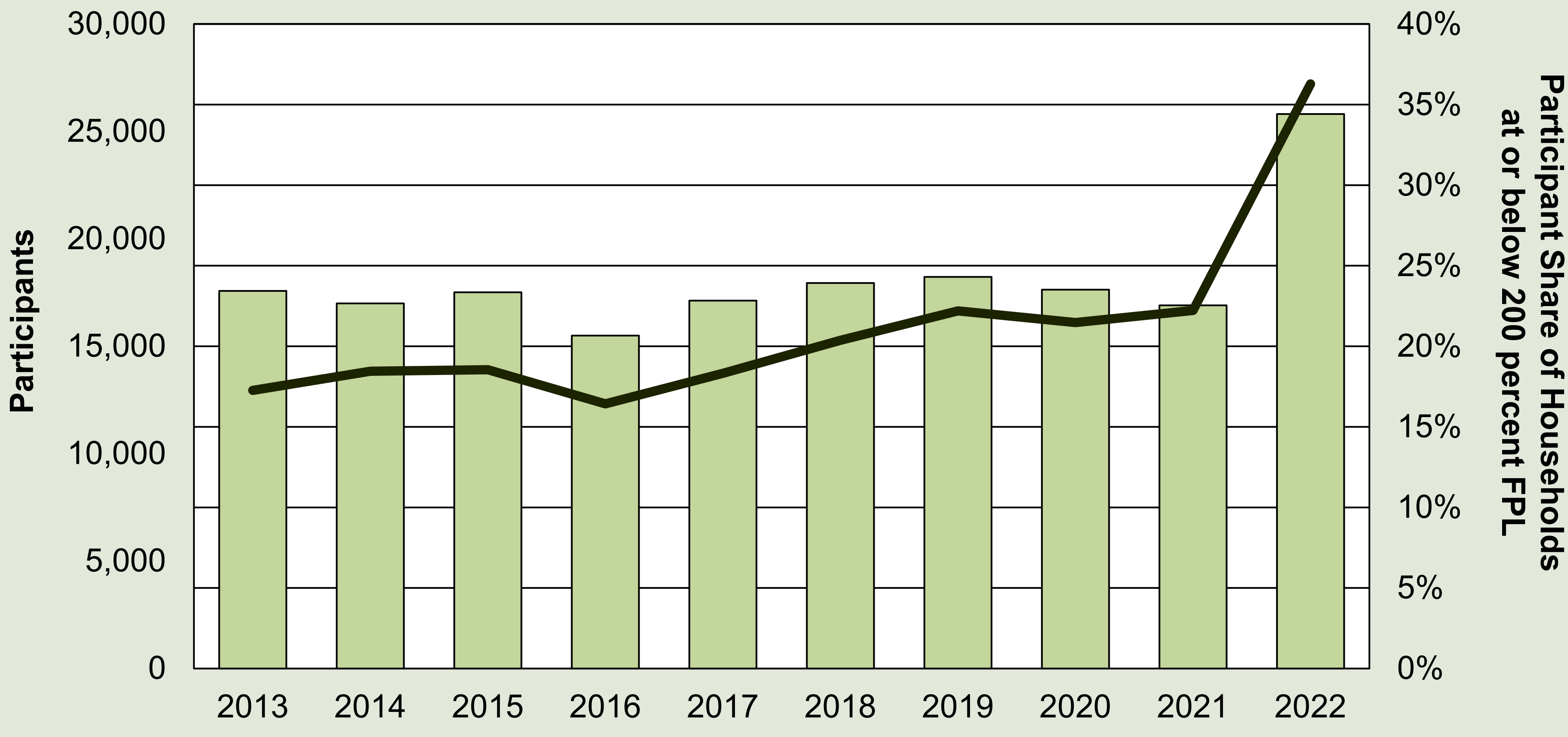
Pepco Existing Programs

Pepco's Residential Aid Discount Program (RAD): participants.

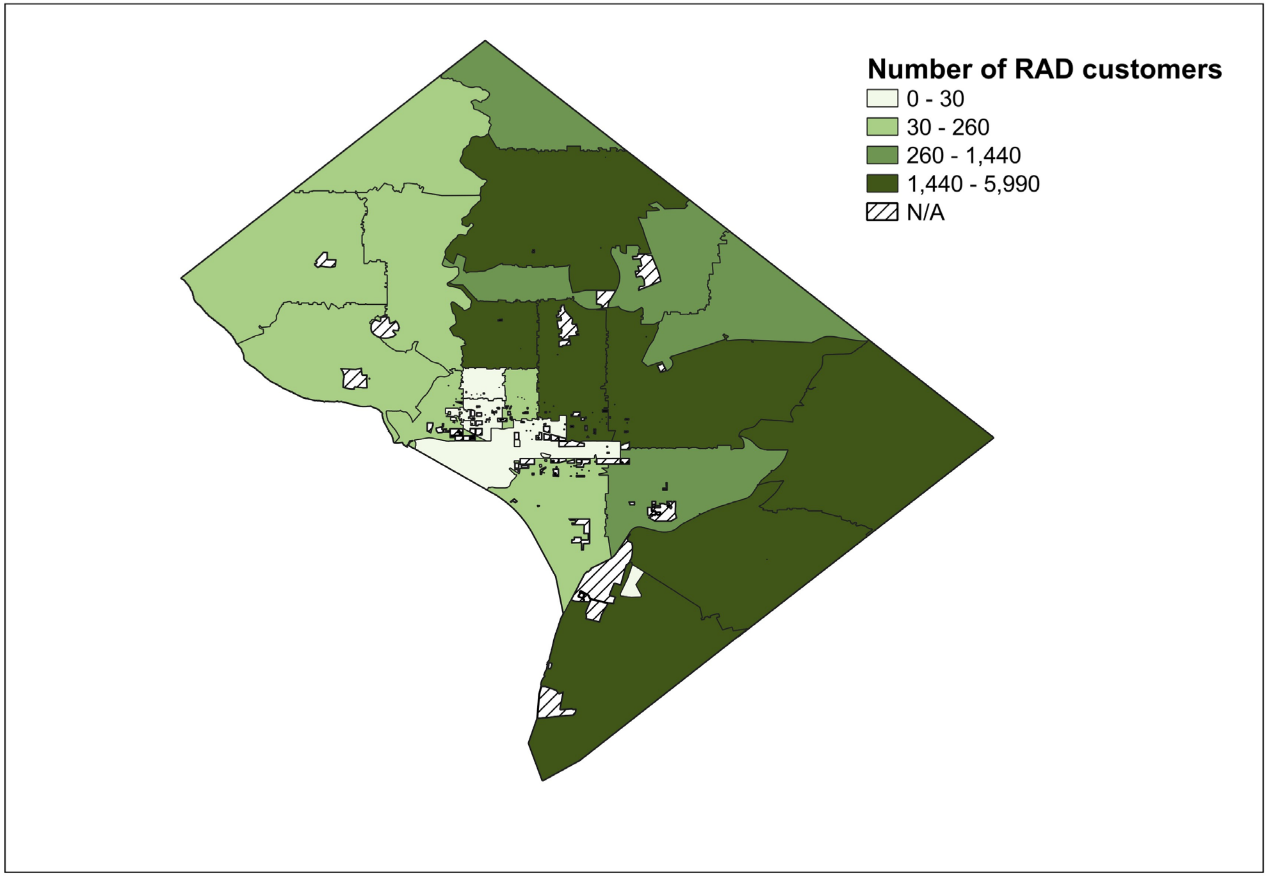
The number of customers participating in the RAD program has increased dramatically since the initiation of the MRP Pilot. **There has been a 32 percent increase since 2013 alone.**



Source: FC 1176 OPC DR 3-45.

Number of RAD Customers, 2022

The **majority of RAD customers receiving low-income bill payment assistance** are densely concentrated in the eastern part of the District.



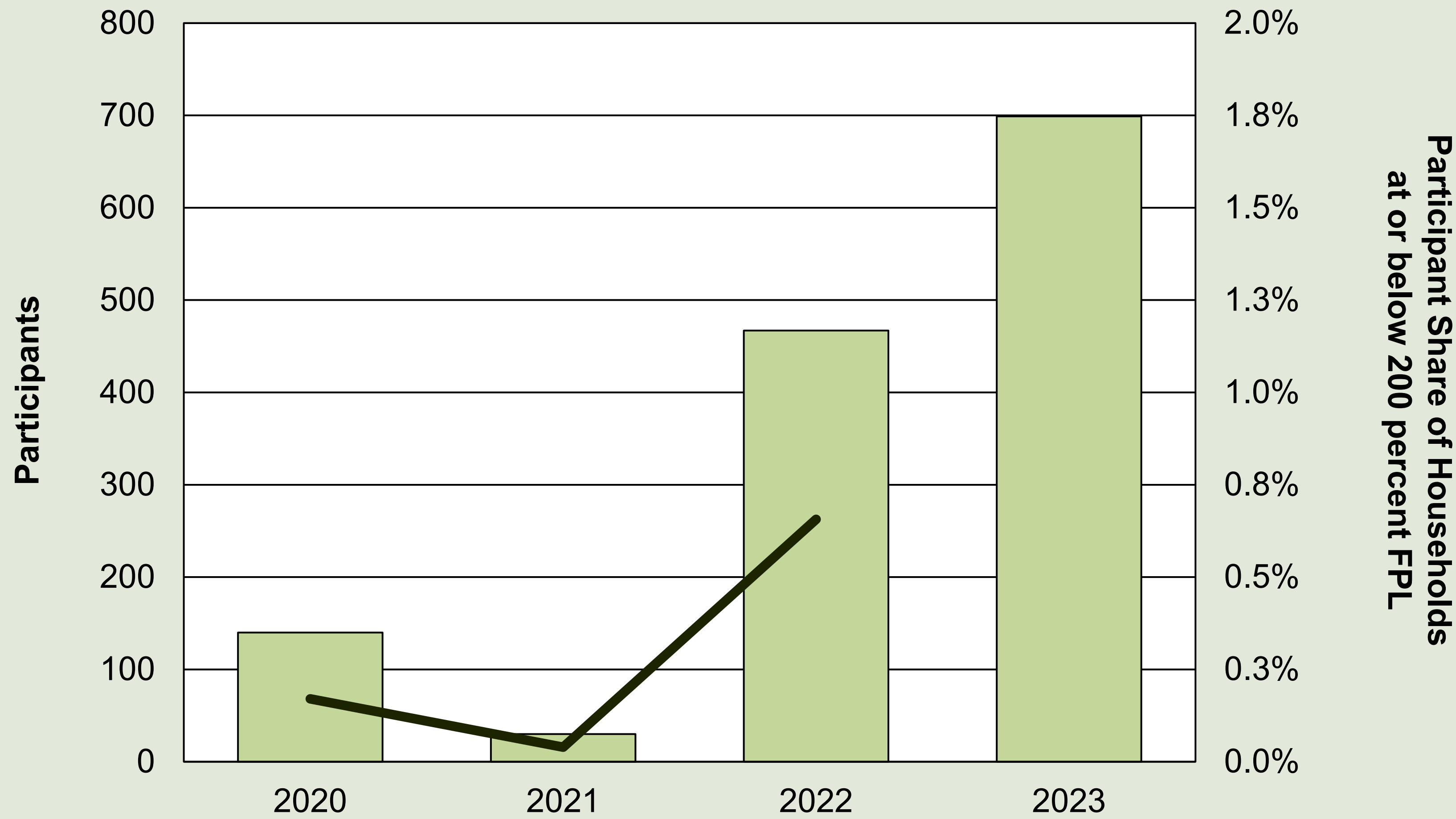
Source: FC 1176 OPC DR 3-47

ACADIAN CONSULTING GROUP

Pepco Existing Programs

Pepco's Arrearage Management Program (AMP): participants.

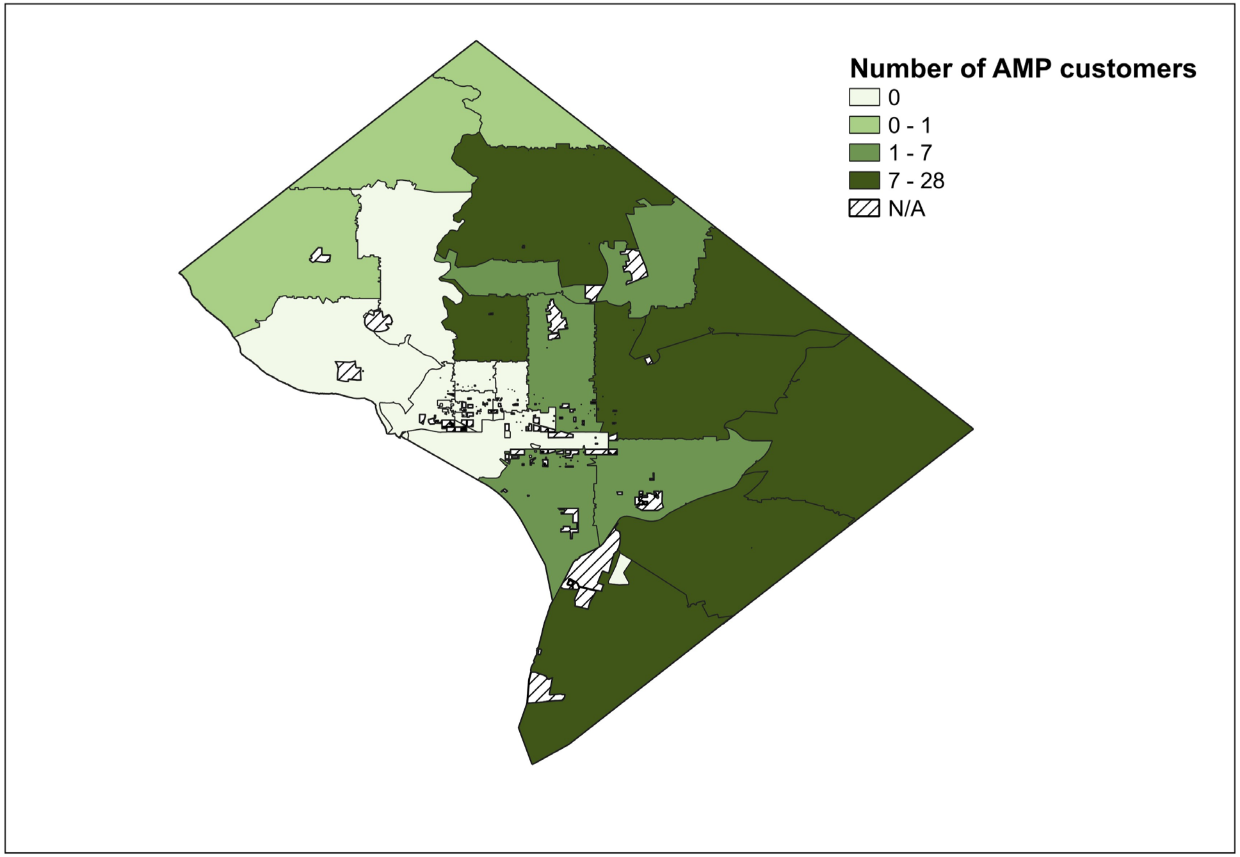
AMP enrollment increased dramatically since the inception of the MRP Pilot.



Note: Number of Households at or below 200 percent of FPL has not been reported for 2023.
Source: FC 1176 OPC DR 9-16.

Number of AMP Customers, 2022

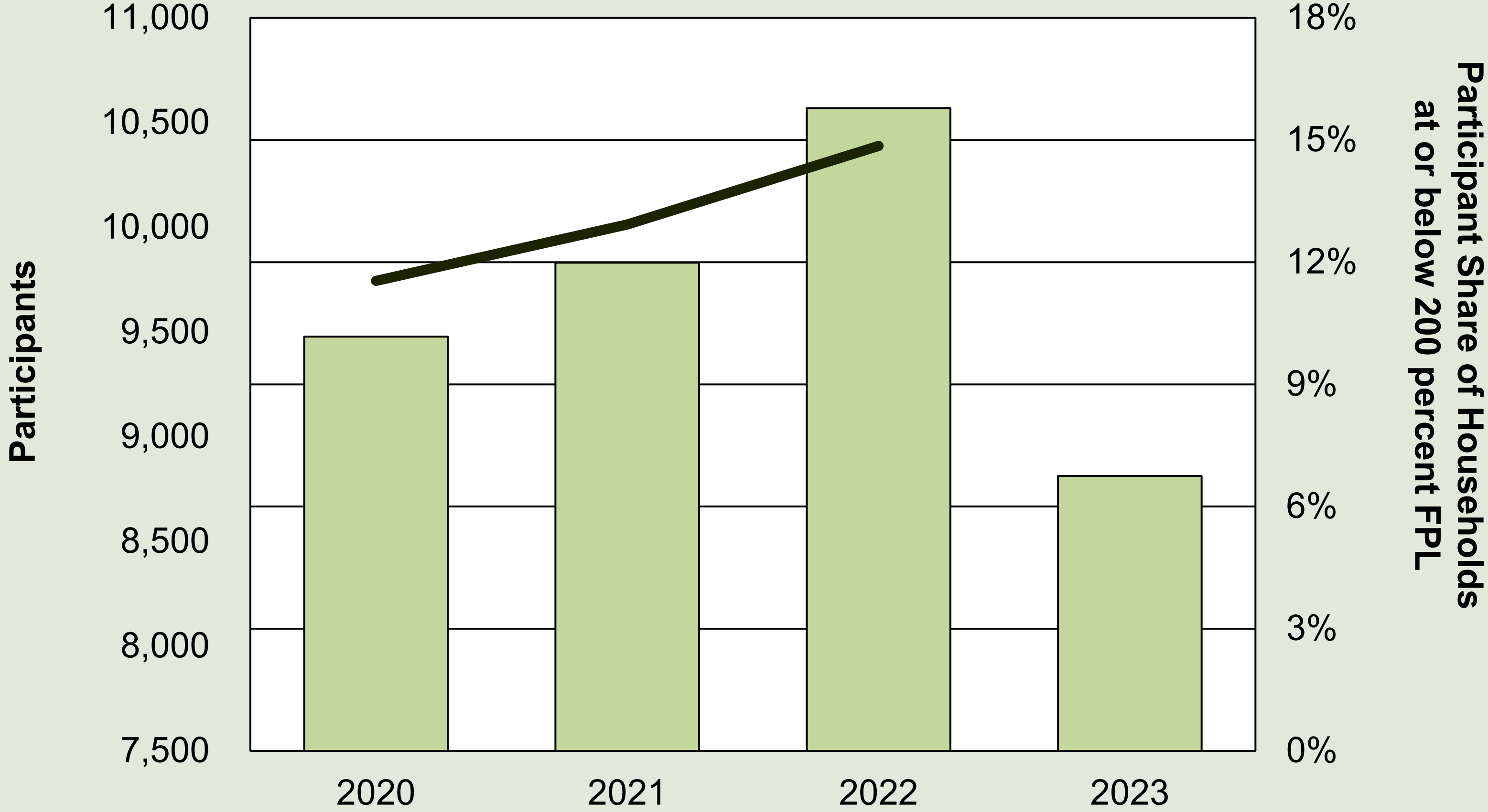
The **location and distribution of AMP customers** is comparable to that for RAD customers in the District.



Source: FC 1176 OPC DR 3-47

Low Income Home Energy Assistance Program (LIHEAP) participants

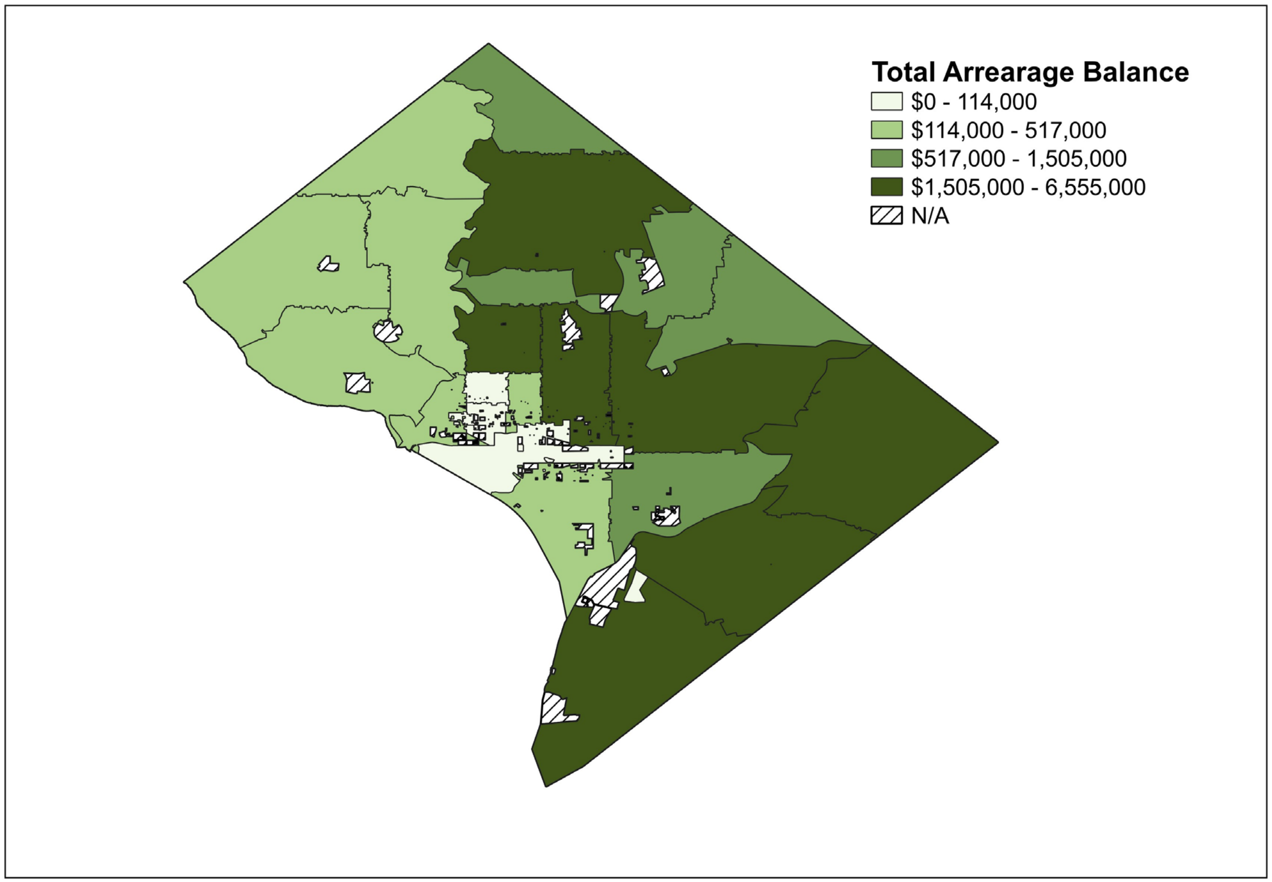
The LIHEAP program participation has increased dramatically since the inception of the MRP Pilot.



Note: LIHEAP participation has been reported up to July 2023. Number of Households at or below 200 percent of FPL has not been reported for 2023.
Source: FC 1176 OPC DR 9-16.

Location of total arrearage management customers, 2022

Total arrearage management program balances are also concentrated in lower-income areas.



Source: FC 1176 OPC DR 3-47

Conclusions & Recommendations

Conclusions and Recommendations

ACG makes the following recommendations:

- **Do not approve the proposed MYP**. The current MRP Pilot has done nothing but make electricity more expensive in the District.
- **Limit Pepco's proposed annual capital expenditures** to levels that are more sustainable and consistent with affordability concerns.
- Require Pepco to **regularly examine and file affordability analyses**.
- **Review the Pepco's low-income proposals** for:

  (a) potential modifications that **expand coverage** to a larger number of eligible households and

  (b) **means test and scale financial assistance levels** to assure adequacy, minimize adverse rate impacts on other supporting customers, and to get the "biggest bang for the buck" in low-income assistance.

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Exhibit OPC (A)-3
Formal Case No. 1176

Company’s Proposed Revenue Distribution

Line No.		Total D.C. Jurisdiction	Residential Service		General Service		Time Metered General Service				Rapid Transit Service ("RT")	Street Lighting Service		Traffic Signal Service ("TS")	Telecommunications Network Service ("TN")
			Residential ("R")	Master Metered Apartment ("MMA")	Secondary Service ("GS LV"); ("GS ND"); and ("T")	Primary Service ("GS 3A")	Medium Secondary Service ("MGT LV")	Secondary Service ("GT LV")	Primary Service ("GT 3A")	Sub-Transmission Service ("GT 3B")		Servicing ("SL-S")	Street Light ("SL-E")		
1	**Cost of Service Results**														
2	COS Operating Revenue	$ 577,708,236	$ 115,649,788	$ 14,475,701	$ 56,915,707	$ 78,227	$ 179,751,943	$ 113,615,870	$ 81,396,685	$ 3,161,355	$ 10,057,567	$ 662,228	$ 1,492,774	$ 339,855	$ 110,537
3	Operating Expenses	442,892,079	154,452,449	9,468,440	37,580,594	44,074	102,830,364	70,894,290	54,233,562	2,940,171	7,597,169	448,006	2,076,175	258,556	68,228
4	Operating Income	$ 134,816,157	$ (38,802,661)	$ 5,007,261	$ 19,335,113	$ 34,153	$ 76,921,579	$ 42,721,580	$ 27,163,123	$ 221,184	$ 2,460,398	$ 214,223	$ (583,402)	$ 81,299	$ 42,309
5	Rate Base	$ 2,362,347,333	$ 1,005,958,658	$ 55,112,950	$ 214,005,450	$ 122,942	$ 515,613,777	$ 317,454,591	$ 196,351,095	$ 2,876,974	$ 35,698,397	$ 5,090,622	$ 12,918,487	$ 923,257	$ 220,133
6	**Rate of Return**	**5.71%**	**-3.86%**	**9.09%**	**9.03%**	**27.78%**	**14.92%**	**13.46%**	**13.83%**	**7.69%**	**6.89%**	**4.21%**	**-4.52%**	**8.81%**	**19.22%**
7	**Relative Rate of Return**	**1.00**	**(0.68)**	**1.59**	**1.58**	**4.87**	**2.61**	**2.36**	**2.42**	**1.35**	**1.21**	**0.74**	**(0.79)**	**1.54**	**3.37**
8	**Revenue Increase**														
9	Revenue Requirement	$ 67,893,261													
10	Operating Income Deficiency	$ 49,210,700													
11	ROR	7.79%													
12	Revenue Conversion Factor	1.3796													
13	Annualized Bridge Year Distribution Revenues	$ 547,348,203	$ 101,697,378	$ 13,115,360	$ 55,052,143	$ 62,356	$ 179,480,961	$ 122,616,340	$ 64,613,234	$ 574,129	$ 8,504,334	$ 757,187	$ 533,298	$ 257,730	$ 83,753
14	Proposed System ROR	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%
15	Operating Income from COS	134,816,157	(38,802,661)	5,007,261	19,335,113	34,153	76,921,579	42,721,580	27,163,123	221,184	2,460,398	214,223	(583,402)	81,299	42,309
16	Operating Income at System ROR	184,026,857	78,364,179	4,293,299	16,671,025	9,577	40,166,313	24,729,713	15,295,750	224,116	2,780,905	396,559	1,006,350	71,922	17,148
17	Incremental Income at System ROR	$ 49,210,700	$ 117,166,840	$ (713,962)	$ (2,664,088)	$ (24,576)	$ (36,755,265)	$ (17,991,867)	$ (11,867,372)	$ 2,933	$ 320,507	$ 182,337	$ 1,589,752	$ (9,377)	$ (25,160)
18	Revenue Conversion Factor	1.3796	1.3796	1.3796	1.3796	1.3796	1.3796	1.3796	1.3796	1.3796	1.3796	1.3796	1.3796	1.3796	1.3796
19	Increment Revenue Requirement at System ROR	$ 67,893,261	$ 161,648,561	$ (985,014)	$ (3,675,494)	$ (33,906)	$ (50,709,192)	$ (24,822,377)	$ (16,372,752)	$ 4,046	$ 442,186	$ 251,560	$ 2,193,292	$ (12,937)	$ (34,712)
20	Percent Increase at System ROR	12.40%	158.95%	-7.51%	-6.68%	-54.37%	-28.25%	-20.24%	-25.34%	0.70%	5.20%	33.22%	411.27%	-5.02%	-41.45%
21	Relative Revenue Increases	1.00	12.81	(0.61)	(0.54)	(4.38)	(2.28)	(1.63)	(2.04)	0.06	0.42	2.68	33.16	(0.40)	(3.34)
22	**Step One Increase**														
23	Maximum Increase at 2.30 times System Average Increase	28.53%	28.53%	28.53%	28.53%	28.53%	28.53%	28.53%	28.53%	28.53%	28.53%	28.53%	28.53%	28.53%	28.53%
24	Step One Revenue Increase	$ 29,381,696	$ 29,013,530	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 216,020	$ 152,146	$ -	$ -
25	Remaining Revenue Deficiency	$ 38,511,565													
26	**Step Two Increase**														
27	Current Revenues for Step Two Classes	$ 444,214,231	$ -	$ 13,115,360	$ 55,052,143	$ -	$ 179,480,961	$ 122,616,340	$ 64,613,234	$ 574,129	$ 8,504,334	$ -	$ -	$ 257,730	$ -
28	Step Two Revenue Increase	$ 38,511,565	$ -	$ 1,137,048	$ 4,772,797	$ -	$ 15,560,269	$ 10,630,338	$ 5,601,704	$ 49,775	$ 737,291	$ -	$ -	$ 22,344	$ -
29	**Total Proposed Revenue Increase**	**$ 67,893,261**	**$ 29,013,530**	**$ 1,137,048**	**$ 4,772,797**	**$ -**	**$ 15,560,269**	**$ 10,630,338**	**$ 5,601,704**	**$ 49,775**	**$ 737,291**	**$ 216,020**	**$ 152,146**	**$ 22,344**	**$ -**
30	**Rate Schedule Revenue Increase Allocation**														
31	Current Annualized Distribution Revenues	$ 547,348,203	$ 101,697,378	$ 13,115,360	$ 55,052,143	$ 62,356	$ 179,480,961	$ 122,616,340	$ 64,613,234	$ 574,129	$ 8,504,334	$ 757,187	$ 533,298	$ 257,730	$ 83,753
32	Proposed Revenue Increase	$ 67,893,261	$ 29,013,530	$ 1,137,048	$ 4,772,797	$ -	$ 15,560,269	$ 10,630,338	$ 5,601,704	$ 49,775	$ 737,291	$ 216,020	$ 152,146	$ 22,344	$ -
33	Proposed Revenues	$ 615,241,464	$ 130,710,908	$ 14,252,408	$ 59,824,940	$ 62,356	$ 195,041,230	$ 133,246,678	$ 70,214,938	$ 623,904	$ 9,241,625	$ 973,207	$ 685,444	$ 280,074	$ 83,753
34	**Proposed Revenue Increase**	**12.40%**	**28.53%**	**8.67%**	**8.67%**	**0.00%**	**8.67%**	**8.67%**	**8.67%**	**8.67%**	**8.67%**	**28.53%**	**28.53%**	**8.67%**	**0.00%**
35	**Relative Revenue Increase**	**1.00**	**2.30**	**0.70**	**0.70**	**0.00**	**0.70**	**0.70**	**0.70**	**0.70**	**0.70**	**2.30**	**2.30**	**0.70**	**0.00**

Source: Exhibits PEPCO (D)-1 and PEPCO (E)-3.

Company's Proposed MYRP Rate Increases by Rate Class and Year

	Rate Schedule	Current Net Revenues	Rate Year 1 Allocated RR Increase	Rate Year 1 Impact of 5-Year EDIT	Rate Year 2 Allocated RR Increase	Rate Year 2 Impact of Year EDIT	Rate Year 3 Allocated RR Increase	Rate Year 3 Impact of 5-Year EDIT	End Revenue Requirement	Total Rate Increase
Residential Service	Residential ("R")	$101,697,378	$ 27,166,644	$ 139,708	$27,166,644	$ -	$27,166,644	$ -	$183,337,018	80.3%
	Master Metered Appartment ("MMA")	13,115,360	2,611,068	152,487	285,417	-	297,519	-	16,461,851	25.5%
Secondary General Service	Non-Demand ("GS ND")	18,542,282	3,691,649	156,499	403,536	-	420,647	-	23,214,613	25.2%
	Temporary ("T")	1,231,658	245,031	11,279	26,785	-	27,920	-	1,542,673	25.3%
	Low-Voltage ("GS LV")	35,278,203	7,023,363	288,408	767,728	-	800,280	-	44,157,982	25.2%
	Primary General Service ("GS 3A")	62,356	-	588	-	396	-	-	63,340	1.6%
Time Metered General Service	Medium Secondary ("MGT LV")	179,480,961	35,731,927	436,715	3,905,876	-	4,071,490	-	223,626,969	24.6%
	Secondary ("GT LV")	122,616,340	24,411,047	328,131	2,668,384	-	2,781,527	-	152,805,429	24.6%
	Primary ("GT 3A")	64,613,234	12,863,511	332,738	1,406,117	-	1,465,738	-	80,681,338	24.9%
	Sub-Transmission ("GT 3B")	574,129	114,300	16,459	12,494	-	13,024	-	730,406	27.2%
	Rapid Transit Service ("RT")	8,504,334	1,693,084	45,871	185,072	-	192,919	-	10,621,280	24.9%
Street Lighting	Servicing ("SL-S")	757,187	496,059	2,927	54,224	976	56,524	-	1,367,897	80.7%
	Street Light ("SL-E")	533,298	349,381	2,455	38,191	-	39,810	-	963,135	80.6%
	Traffic Signal Service ("TS")	257,730	51,310	3,450	5,609	-	5,847	-	323,946	25.7%
	Telecommunications Network Service ("TN")	83,753	-	5,584	-	-	-	-	89,337	6.7%
	Total Company	**$547,348,203**	**$116,448,374**	**$1,923,299**	**$36,926,077**	**$ 1,372**	**$37,339,889**	**$ -**	**$739,987,214**	**35.2%**

Source: Exhibit PEPCO (E)-3

Historic Authorized Revenue Allocations by Residential Rate Class

Exhibit OPC (A)-5
Formal Case No. 1176
David E. Dismukes

	Relative Rate of Return	Rate Increase		
Case No.	Total Residential	System Average	Total Residential	Relative Increase
FC 1053	-0.48	12.50%	13.33%	1.07
FC 1076	-0.47	7.94%	17.52%	2.21
FC 1087	-0.54	8.64%	21.40%	2.48
FC 1103	-0.41	7.48%	17.56%	2.35
FC 1139	-0.60	10.20%	9.25%	0.91
FC 1150/1151	-0.75	-6.05%	-3.02%	-0.50
FC 1156	-1.00	17.34%	14.00%	0.81
FC 1176	**-0.68**	**34.84%**	**80.14%**	**2.30**

Note: FC 1139 Relative Rates of Return are taken from Pepco's improved CCOSS filed on September 5, 2017.
FC 1156 and 1176 include all MYRP Rate Year rate increases.

Source: FC 1053, FC 1076, FC 1087, and FC 1103 Company Applications and Compliance Filings, Attachment B; Supplemental Direct Testimony of Joseph F. Janocha, Exhibit Pepco (2G)-1; FC 1139 Order 18846, page 148; FC 1150 Exhibits PEPCO E-1 and F-1; FC1156 Compliance Filing; and Exhibit PEPCO (E-3)

Historic Changes in Ratemaking Statistics per kWh

Exhibit OPC (A)-6
Formal Case No. 1176
David E. Dismukes

Test Year Ending:	March-06 FC 1053	February-08 FC 1076	March-11 FC 1087	December-12 FC 1103	March-16 FC 1139	September-17 FC 1150	December-18 FC 1156	Current Rates	Proposed Rates (RY1) FC 1176 (2023)	Proposed Rates (RY2) FC 1176 (2024)	Proposed Rates (RY3) FC 1176 (2025)	Growth: FC 1053 - Current Rates	Growth: FC 1053 - Proposed FC 1156 (2025)
Customer Counts													
Total Residential	267,428	273,956	286,392	289,176	310,430	320,864	329,122	372,131	372,132	378,757	385,374	39.2%	44.1%
General Service - Low Voltage ("GSD-LV")	5,503	5,509	5,395	5,491	5,397	5,100	5,106	4,305	4,305	4,210	4,115	-21.8%	-25.2%
Time Metered GS LV ("GT-LV")	2,317	2,514	2,692	2,795	3,039	3,322	3,521	3,823	3,823	3,842	3,860	65.0%	66.6%
Time Metered GS Primary Service ("GT-3A")	142	144	145	146	155	156	156	150	150	150	150	5.5%	5.5%
Selected Commercial Classes	**7,962**	**8,166**	**8,232**	**8,432**	**8,590**	**8,578**	**8,783**	**8,278**	**8,278**	**8,202**	**8,124**	**4.0%**	**2.0%**
Energy Sales (KWh)													
Total Residential	2,229,358,810	2,231,920,709	2,415,815,595	2,260,068,001	2,390,365,088	2,368,372,164	2,584,770,916	2,664,436,320	2,664,436,320	2,669,659,010	2,671,411,400	19.5%	19.8%
General Service - Low Voltage ("GSD-LV")	818,674,870	716,496,219	687,298,839	627,608,424	635,741,579	632,329,266	628,714,108	493,165,070	493,165,070	480,443,370	467,158,890	-39.8%	-42.9%
Time Metered GS LV ("GT-LV")	4,724,320,075	4,848,441,524	4,945,900,937	4,788,768,728	4,766,416,593	4,645,684,402	4,875,658,033	4,278,365,690	4,278,365,690	4,230,647,110	4,174,098,530	-9.4%	-11.6%
Time Metered GS Primary Service ("GT-3A")	2,856,545,199	2,747,423,484	2,852,293,292	2,644,739,228	2,556,599,062	2,415,312,503	2,346,640,497	1,889,231,330	1,889,231,330	1,829,366,300	1,765,725,180	-33.9%	-38.2%
Selected Commercial Classes	**8,399,540,144**	**8,312,361,227**	**8,485,493,068**	**8,061,116,380**	**7,958,757,234**	**7,693,326,171**	**7,851,012,638**	**6,660,762,090**	**6,660,762,090**	**6,540,456,780**	**6,406,982,600**	**-20.7%**	**-23.7%**
Revenues ($)													
Total Residential	$39,781,812	$42,271,249	$53,755,689	$63,922,788	$80,327,789	$77,089,773	$89,557,013	$115,104,905	$144,884,635	$172,327,485	$199,792,008	189.3%	402.2%
General Service - Low Voltage ("GSD-LV")	$28,858,856	$28,345,915	$28,890,801	$29,008,353	$36,505,853	$32,531,729	$31,504,018	$35,566,611	$42,589,508	$43,358,589	$44,158,166	23.2%	53.0%
Time Metered GS LV ("GT-LV")	$101,520,135	$118,049,879	$132,781,051	$143,613,433	$162,854,015	$176,773,674	$198,577,012	$302,862,147	$363,007,238	$369,594,651	$376,442,747	198.3%	270.8%
Time Metered GS Primary Service ("GT-3A")	$39,452,474	$42,684,283	$205,696,526	$41,496,072	$45,298,520	$47,543,727	$51,349,707	$64,945,971	$77,803,309	$79,217,819	$80,682,123	64.6%	104.5%
Selected Commercial Classes	**$169,831,465**	**$189,080,077**	**$367,368,378**	**$214,117,858**	**$244,658,388**	**$256,849,130**	**$281,430,737**	**$403,374,729**	**$483,400,055**	**$492,171,059**	**$501,283,036**	**137.5%**	**195.2%**
Revenues per kWh ($ per kWh)													
Total Residential	$0.0178	$0.0189	$0.0223	$0.0283	$0.0336	$0.0325	$0.0346	$0.0432	$0.0544	$0.0646	$0.0748	142.1%	319.1%
General Service - Low Voltage ("GSD-LV")	$0.0353	$0.0396	$0.0420	$0.0462	$0.0574	$0.0514	$0.0501	$0.0721	$0.0864	$0.0902	$0.0945	104.6%	168.2%
Time Metered GS LV ("GT-LV")	$0.0215	$0.0243	$0.0268	$0.0300	$0.0342	$0.0381	$0.0407	$0.0708	$0.0848	$0.0874	$0.0902	229.4%	319.7%
Time Metered GS Primary Service ("GT-3A")	$0.0138	$0.0155	$0.0721	$0.0157	$0.0177	$0.0197	$0.0219	$0.0344	$0.0412	$0.0433	$0.0457	148.9%	230.8%
Selected Commercial Classes	**$0.0202**	**$0.0227**	**$0.0433**	**$0.0266**	**$0.0307**	**$0.0334**	**$0.0358**	**$0.0606**	**$0.0726**	**$0.0753**	**$0.0782**	**199.5%**	**287.0%**

Note: Residential and R-All Electric rates include associated revenues from Mastered-Metered Apartments ("MMA");
September 2017 Revenues are adjusted to account for the effect of the Tax Cut and Jobs Act of 2017.

Source: FC 1053, FC 1076, FC 1087, FC 1103, and FC 1156 Compliance Filing, Attachment B; FC 1139 Supplemental Direct Testimony of Joseph F. Janocha, Exhibit Pepco (2G)-1; FC 1150 Supplemental Testimony of Joseph F. Janocha, Exhibit PEPCO(E)-8.

OPC's Alternative Proposed Revenue Allocation

Exhibit OPC (A)-7
Formal Case No. 1176
David E. Dismukes

Line No.		Total D.C. Jurisdiction	Residential Service: Residential ("R")	Residential Service: Master Metered Apartment ("MMA")	General Service: Secondary Service ("GS LV"); ("GS ND"); and ("T")	General Service: Primary Service ("GS 3A")	Time Metered General Service: Medium Secondary Service ("MGT LV")	Time Metered General Service: Secondary Service ("GT LV")	Time Metered General Service: Primary Service ("GT 3A")	Time Metered General Service: Sub-Transmission Service ("GT 3B")	Rapid Transit Service ("RT")	Street Lighting Service: Servicing ("SL-S")	Street Lighting Service: Street Light ("SL-E")	Traffic Signal Service ("TS")	Telecommunications Network Service ("TN")
1	<u>Cost of Service Results</u>														
2	COS Operating Revenue	$ 577,708,236	$ 115,649,788	$ 14,475,701	$ 56,915,707	$ 78,227	$ 179,751,943	$ 113,615,870	$ 81,396,685	$ 3,161,355	$ 10,057,567	$ 662,228	$ 1,492,774	$ 339,855	$ 110,537
3	Operating Expenses	442,892,079	154,452,449	9,468,440	37,580,594	44,074	102,830,364	70,894,290	54,233,562	2,940,171	7,597,169	448,006	2,076,175	258,556	68,228
4	Operating Income	$ 134,816,157	$ (38,802,661)	$ 5,007,261	$ 19,335,113	$ 34,153	$ 76,921,579	$ 42,721,580	$ 27,163,123	$ 221,184	$ 2,460,398	$ 214,223	$ (583,402)	$ 81,299	$ 42,309
5	Rate Base	$ 2,362,347,333	$ 1,005,958,658	$ 55,112,950	$ 214,005,450	$ 122,942	$ 515,613,777	$ 317,454,591	$ 196,351,095	$ 2,876,974	$ 35,698,397	$ 5,090,622	$ 12,918,487	$ 923,257	$ 220,133
6	**Rate of Return**	**5.71%**	**-3.86%**	**9.09%**	**9.03%**	**27.78%**	**14.92%**	**13.46%**	**13.83%**	**7.69%**	**6.89%**	**4.21%**	**-4.52%**	**8.81%**	**19.22%**
7	**Relative Rate of Return**	**1.00**	**(0.68)**	**1.59**	**1.58**	**4.87**	**2.61**	**2.36**	**2.42**	**1.35**	**1.21**	**0.74**	**(0.79)**	**1.54**	**3.37**
8	<u>Revenue Increase</u>														
9	Revenue Requirement	$ 67,893,261													
10	Operating Income Deficiency	$ 49,210,700													
11	ROR	7.79%													
12	Revenue Conversion Factor	1.3796													
13	Annualized Bridge Year Distribution Revenues	$ 547,348,203	$ 101,697,378	$ 13,115,360	$ 55,052,143	$ 62,356	$ 179,480,961	$ 122,616,340	$ 64,613,234	$ 574,129	$ 8,504,334	$ 757,187	$ 533,298	$ 257,730	$ 83,753
14	Proposed System ROR	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%
15	Operating Income from COS	134,816,157	(38,802,661)	5,007,261	19,335,113	34,153	76,921,579	42,721,580	27,163,123	221,184	2,460,398	214,223	(583,402)	81,299	42,309
16	Operating Income at System ROR	184,026,857	78,364,179	4,293,299	16,671,025	9,577	40,166,313	24,729,713	15,295,750	224,116	2,780,905	396,559	1,006,350	71,922	17,148
17	Incremental Income at System ROR	$ 49,210,700	$ 117,166,840	$ (713,962)	$ (2,664,088)	$ (24,576)	$ (36,755,265)	$ (17,991,867)	$ (11,867,372)	$ 2,933	$ 320,507	$ 182,337	$ 1,589,752	$ (9,377)	$ (25,160)
18	Revenue Conversion Factor	1.3796	1.3796	1.3796	1.3796	1.3796	1.3796	1.3796	1.3796	1.3796	1.3796	1.3796	1.3796	1.3796	1.3796
19	Increment Revenue Requirement at System ROR	$ 67,893,261	$ 161,648,561	$ (985,014)	$ (3,675,494)	$ (33,906)	$ (50,709,192)	$ (24,822,377)	$ (16,372,752)	$ 4,046	$ 442,186	$ 251,560	$ 2,193,292	$ (12,937)	$ (34,712)
20	Percent Increase at System ROR	12.40%	158.95%	-7.51%	-6.68%	-54.37%	-28.25%	-20.24%	-25.34%	0.70%	5.20%	33.22%	411.27%	-5.02%	-41.45%
21	Relative Revenue Increases	1.00	12.81	(0.61)	(0.54)	(4.38)	(2.28)	(1.63)	(2.04)	0.06	0.42	2.68	33.16	(0.40)	(3.34)
22	<u>Step One Increase</u>														
23	Maximum Increase at 1.25 times System Average Increase	15.51%	15.51%	15.51%	15.51%	15.51%	15.51%	15.51%	15.51%	15.51%	15.51%	15.51%	15.51%	15.51%	15.51%
24	Step One Revenue Increase	$ 15,968,313	$ 15,768,223	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 117,402	$ 82,688	$ -	$ -
25	Remaining Revenue Deficiency	$ 51,924,948													
26	<u>Step Two Increase</u>														
27	Current Revenues for Step Two Classes	$ 444,214,231	$ -	$ 13,115,360	$ 55,052,143	$ -	$ 179,480,961	$ 122,616,340	$ 64,613,234	$ 574,129	$ 8,504,334	$ -	$ -	$ 257,730	$ -
28	Step Two Revenue Increase	$ 51,924,948	$ -	$ 1,533,076	$ 6,435,138	$ -	$ 20,979,831	$ 14,332,830	$ 7,552,750	$ 67,111	$ 994,086	$ -	$ -	$ 30,126	$ -
29	**Total Proposed Revenue Increase**	**$ 67,893,261**	**$ 15,768,223**	**$ 1,533,076**	**$ 6,435,138**	**$ -**	**$ 20,979,831**	**$ 14,332,830**	**$ 7,552,750**	**$ 67,111**	**$ 994,086**	**$ 117,402**	**$ 82,688**	**$ 30,126**	**$ -**
30	<u>Rate Schedule Revenue Increase Allocation</u>														
31	Current Annualized Distribution Revenues	$ 547,348,203	$ 101,697,378	$ 13,115,360	$ 55,052,143	$ 62,356	$ 179,480,961	$ 122,616,340	$ 64,613,234	$ 574,129	$ 8,504,334	$ 757,187	$ 533,298	$ 257,730	$ 83,753
32	Proposed Revenue Increase	$ 67,893,261	$ 15,768,223	$ 1,533,076	$ 6,435,138	$ -	$ 20,979,831	$ 14,332,830	$ 7,552,750	$ 67,111	$ 994,086	$ 117,402	$ 82,688	$ 30,126	$ -
33	Proposed Revenues	$ 615,241,464	$ 117,465,601	$ 14,648,436	$ 61,487,281	$ 62,356	$ 200,460,792	$ 136,949,170	$ 72,165,984	$ 641,240	$ 9,498,420	$ 874,589	$ 615,986	$ 287,856	$ 83,753
34	**Proposed Revenue Increase**	**12.40%**	**15.51%**	**11.69%**	**11.69%**	**0.00%**	**11.69%**	**11.69%**	**11.69%**	**11.69%**	**11.69%**	**15.51%**	**15.51%**	**11.69%**	**0.00%**
35	**Relative Revenue Increase**	**1.00**	**1.25**	**0.94**	**0.94**	**0.00**	**0.94**	**0.94**	**0.94**	**0.94**	**0.94**	**1.25**	**1.25**	**0.94**	**0.00**

Comparison of Current and Proposed Customer Charges

Description	Current Charge	Proposed Charges RY1	RY2	RY3	Cumulative Increase (%)
Residential ("R", "RPIV")	$ 16.09	$ 17.09	$ 18.09	$ 19.09	18.6%
Residential - Master Metered Apartments ("MMA")	$ 5.44	$ 2.24	$ 2.01	$ 1.78	-67.3%
General Service - Secondary ("GS ND")	$ 32.88	$ 34.68	$ 36.48	$ 38.28	16.4%
General Service - Low Voltage ("GS LV")	$ 38.75	$ 38.29	$ 38.29	$ 38.29	-1.2%
General Service - Primary ("GS 3A")	$ 89.41	$ 89.41	$ 89.41	$ 89.41	0.0%
General Service - Temporary ("T")	$ 32.88	$ 34.68	$ 36.48	$ 38.28	16.4%
Time Metered General Service - Medium Secondary ("MGT LV")	$ 237.00	$ 228.19	$ 219.38	$ 210.57	-11.2%
Time Metered General Service - Low Voltage ("GT LV")	$ 1,908.28	$ 2,295.44	$ 2,682.60	$ 3,069.76	60.9%
Time Metered General Service - Primary ("GT 3A")	$ 197.49	$ 211.31	$ 225.13	$ 238.95	21.0%
Time Metered General Service - Sub-Transmission ("GT 3B")	$ 311.66	$ 273.59	$ 235.52	$ 197.45	-36.6%
Rapid Transit Service ("RT")	$ 7,830.01	$ 9,315.37	$ 9,477.51	$ 9,646.74	23.2%
Telecommunications Network Service ("TN")	$ 15.43	$ 15.43	$ 15.43	$ 15.43	0.0%

Source: Exhibit PEPCO (E)-5.

Survey of Regional Customer Charges

Exhibit OPC (A)-9
Formal Case No. 1176
David E. Dismukes

Company	State	Residential Customer Charge ($/month)	Commercial Customer Charge ($/month)
The Potomac Edison Company (current)	**DC**	**$ 16.09**	**$ 32.88**
Appalachian Power Co	VA	7.96	9.77
Atlantic City Electric Co	NJ	6.25	11.90
Baltimore Gas & Electric Co	MD	9.00	14.00
Consolidated Edison Co-NY Inc	NY	18.00	30.00
Delmarva Power	DE	15.04	18.77
Duquesne Light Co	PA	12.50	15.00
Jersey Central Power & Lt Co	NJ	3.25	4.09
New York State Elec & Gas Corp	NY	17.00	33.00
Niagara Mohawk Power Corp.	NY	17.33	21.02
PECO Energy Co	PA	10.52	18.99
Potomac Electric Power Co	MD	8.22	12.31
PPL Electric Utilities Corp	PA	16.10	16.10
Public Service Elec & Gas Co	NJ	4.64	4.73
Rochester Gas & Electric Corp	NY	22.00	22.00
Virginia Electric & Power Co	VA	6.58	10.78
West Penn Power Company	PA	7.44	9.52
Peer Group Average		**$ 11.36**	**$ 15.75**

Source: Utility Companies' Tariffs.

Exhibit OPC (A)-10
Formal Case No. 1176

Analysis of Company Customer-Related Costs

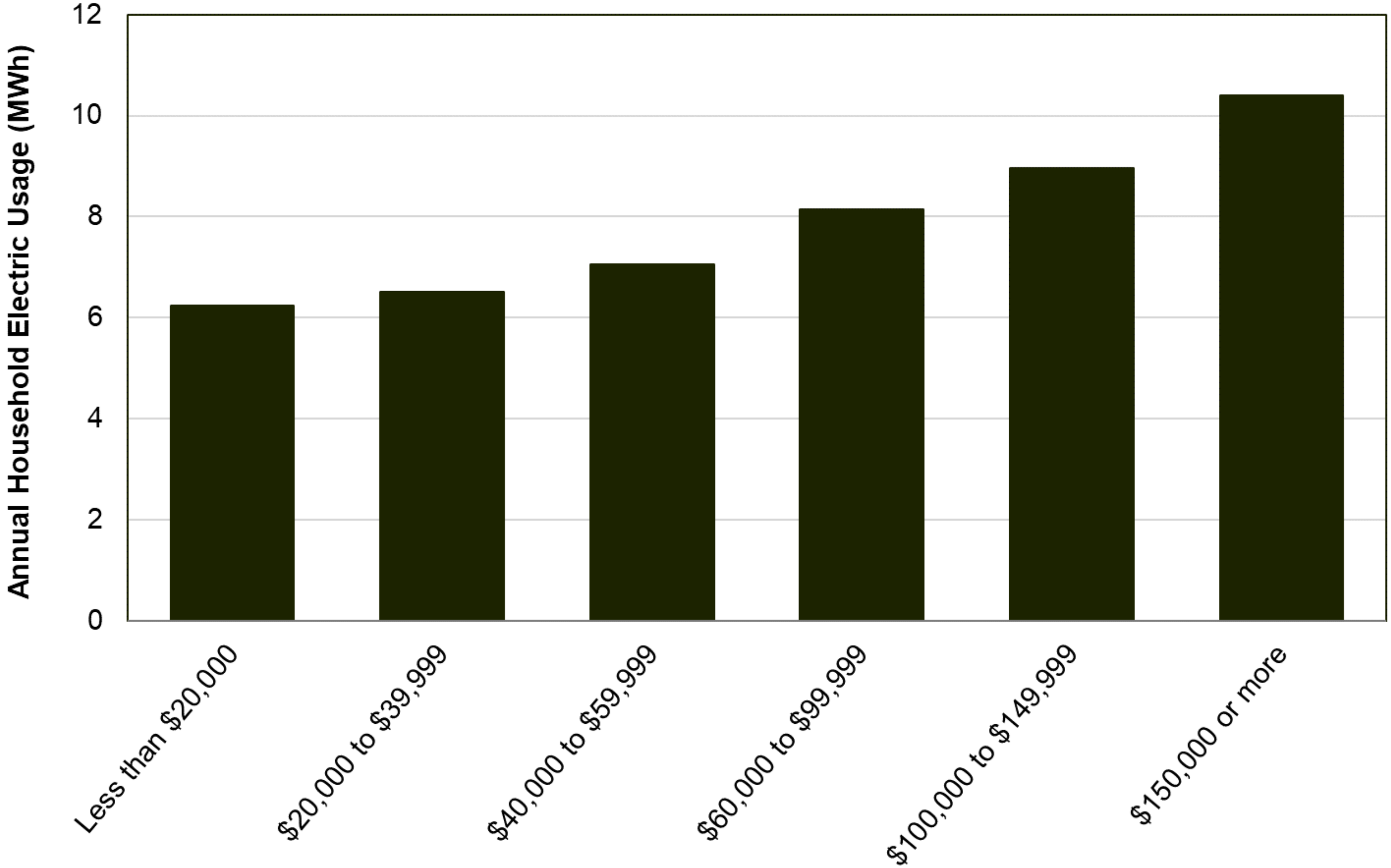
Exhibit OPC (A)-10
Formal Case No. 1176
David E. Dismukes

	Residential Service		General Service		Time Metered General Service			
	Residential ("R")	Master Metered Apartment ("MMA")	Low Voltage ("GS LV")	High Voltage ("GS HV")	Medium Secondary Service ("MGT LV")	Low Voltage ("GT LV")	Gen. Service High Voltage 69KV ("GT HV 69KV")	Gen. Service High Voltage Other ("GT HV OTHER")
Customer Related Costs per Company's CCOSS:								
Total Customer-Related Costs	$ 77,112,129	$ 824,521	$ 10,520,843	$ 8,298	$ 8,534,310	$ 16,184,426	$ 2,370	$ 434,174
Average Number of Customers	297,377	52,791	22,895	6	3,377	319	1	151
Monthly Customer-Related Costs/Customer	$ 21.61	$ 1.30	$ 38.29	$ 115.26	$ 210.58	$ 4,231.22	$ 197.46	$ 238.95
Customer Charge Revenue at Current Rates	$ 48,326,521	$ 891,890	$ 11,032,013	$ 12,189	$ 12,227,303	$ 18,304,560	$ 2,362	$ 498,909
Monthly Customer Charge Revenue/Customer	$ 13.54	$ 1.41	$ 40.16	$ 169.29	$ 301.71	$ 4,785.51	$ 196.84	$ 274.58
Relationship of Customer Charge Revenues to Customer-Related Costs	**62.7%**	**108.2%**	**104.9%**	**146.9%**	**143.3%**	**113.1%**	**99.7%**	**114.9%**

Source: Exhibit PEPCO (D)-1.

Analysis of Electricity Usage and Household Income

Exhibit OPC (A)-11
Formal Case No. 1176
David E. Dismukes



Source: Energy Information Administration, 2020 Residential Energy Consumption Survey.

PUBLIC VERSION
Exhibit OPC (A)-12
Formal Case No. 1176

Confidential Materials Omitted

Exhibit OPC (A)-13
Formal Case No. 1176

ACADIAN
CONSULTING GROUP

The implications of alternative regulation for retail ratepayers in the District of Columbia.

Prepared on the behalf of the District of Columbia, Office of Peoples Counsel

David E. Dismukes, Ph.D.
Acadian Consulting Group

January 12, 2024

Table of Contents

Executive Summary – Overall Findings

There are **three major forms of alternative regulation**: Formula Rate Plans ("FRPs"); Performance-Based Ratemaking ("PBR") plans; and Multi-Year Rate Plans ("MYRPs"). To date, **none have led to any meaningful nor measurable ratepayer benefits.** Alternative regulation **has not resulted in any sustainable nor distinctly measurable improvement in reliability or quality of service.**

Alternative regulation mechanisms have resulted in large rate increases with very few rate decreases nor earning sharing opportunities.

In addition, **no measurable operating costs efficiencies have arisen in any state due to alternative regulation**. In fact, most states **have seen a deterioration in capital investment discipline and huge gains in rate base due to alternative regulation**.

There is <u>not one single state adopting alternative regulation that has shown outcomes that can be held out as an unequivocal "success" for ratepayers.</u>

Study purpose

The Acadian Consulting Group, LLC ("ACG") has been asked by the District of Columbia ("District"), Office of the Peoples Counsel ("OPC") to **examine alternative regulation**.

The purpose of this analysis is to assess and evaluate the potential of alternative forms of regulations. This analysis reviews the potential benefits, or lack thereof, of alternative regulation as it has been implemented throughout the United States and is intended to complement OPC's case-in-chief which will directly address Pepco's proposed extension of the MYRP.

The analysis finds that few to no ratepayer benefits will arise from the adoption of alternative regulation and will likely lead to excessive capital investment and higher electricity rates. Alternative regulation **has not led to any meaningful nor measurable operating cost efficiencies nor has it resulted in any improvements in reliability or quality of service.**

Section 2: The fallacies of alternative regulation

Why alternative regulation?

Moral hazard notes that often, the **informational asymmetry** between regulators and regulated companies, **prevents traditional regulation from forcing the most optimal outcome**.

The **basis for alternative regulation is that while optimal costs are difficult to observe, profits are not**. Thus, alternative regulation seeks to **eliminate the traditional base rate case regulatory process** to one where rates are automatically increased by a formula or some fixed allowed levels. **This pricing "flexibility," supposedly, gives utilities greater incentives, through higher profits, to seek capital and operating cost efficiencies.**

The entire basis for alternative regulation is that **unobservable efficiency opportunities** actually **exist** and the **benefits** of changing the current form of regulation are **greater than the costs**.

<u>**However, actual experience has not proven either premise is true, nor has alternative regulation been successful at: (a) lowering rates; (b) generating cost/operating efficiencies; (c) improving service quality or reliability; and (d) creating ratepayer benefits**</u>**.**

How does traditional regulation differ from alternative regulation?

Alternative regulation starts with a large policy leap of faith: regulators have to be willing to allow **prices (or revenues)** become **"decoupled"** with **traditional (utility-specific) measures of costs**.

Such approaches **challenge the traditional policy and legal foundations of utility regulation** that set rates on **"known and measurable"** information to assure those rates are **fair, just, and reasonable**.

Alternative regulation **presumes that if utilities are given pricing and investment flexibility, they will lead to considerable efficiencies** that can be **shared with ratepayers** in the form of (a) l**ower retail rates and (b) earnings or profit sharing.**

However, **alternative regulation shifts all utility performance risk onto ratepayers**: utilities are allowed, up front, to increase rates to increase or preserve profitability. Benefits only arise if utilities create operating and capital efficiencies – **if these efficiencies do not arise, ratepayers receive no benefits from alternative regulation and thus bear the risk of the poor utility performance**.

Does alternative regulation lead to ratepayer benefits?

To date, there is **no systematic evidence that clearly shows that alternative regulation, for electric utilities, has resulted in any (a) reduced/improved retail rates; (b) improved cost efficiencies; or (c) improved quality of service or reliability.**

In fact, the **evidence to date shows that various different forms of alternative regulation have resulted in the opposite**: (a) increased rates; (b) increased inefficiencies, particularly capital investment inefficiencies; (c) little to no improvement in reliability or quality of service.

Very little, **to zero, ratepayer financial benefits have arisen from "sharing" or "earnings sharing mechanisms"** as applied to most major forms of alternative regulation (i.e., FRPs, PBRs, MYRPs).

In fact, **many states** that have utilized alternative regulation mechanisms in the past, **have abandoned their use**. For instance, **Maine and Vermont do not use PBR mechanisms** anymore, and **North Dakota, Indiana, Colorado, and Oklahoma no longer use MYRPs.**

Reduced administrative/regulatory costs?

To date, there is **no systematic evidence that clearly shows that alternative regulation results in lower regulatory or administrative costs.**

Most utilities that are under some form of alternative regulation continue to make repeated and regular regulatory filings. **It is a myth that alternative regulation significantly reduces administrative and regulatory costs**.

Further, rate proceedings such as FRPs and MYRPs **have compliance and or reconciliation proceedings** that continue to require regulatory and administrative costs. It has not been shown that **the sum of these smaller and repeated annual filings offset base rate expenses** incurred prior to the alternative regulatory regime.

Lastly, future rate case filings can also be more contentious and require additional resources since the prudence of many cumulative capital investments are evaluated at that time.

Alternative Regulation Fallacies

The theoretic basis for alternative regulation is flawed.

The **theoretic literature supporting alternative regulation** was written and developed with the **experience of the 1980s-1990s in mind**. This period followed a **large era of major capital/capacity expansion**, particularly in the development of nuclear and coal fired electric generation.

Capital and capacity utilization during the 1980s-1990s was abysmal. Consider that throughout the 1980s, **nuclear generators operated at an average utilization of between 40 to 60 percent**. **Coal plant utilization**, particularly for super-critical units, were equally low.

In addition, **energy utilities (electric and natural gas) were also saddled with out-of-market longer-term generation contracts**, executed during a period in which price/cost inflation was expected to increase at a double digit percents and when fossil fuels, particularly natural gas, were expected to be in short supply.

This **high degree of industry inefficiency upon which alternative regulation is based simply does not exist today nor do the technical potentials for achieving better overall cost and pricing efficiencies**.

Why is alternative regulation no longer appropriate/relevant?

Today's utility investments **are intended to address a wide range of market failures and social policy goals**, not generate cost efficiencies including:

- Renewables (GHG externalities)
- Safety/reliability (GHG externalities, public goods)
- Environmental (GHG externalities)
- Energy efficiency (GHG, externalities, imperfect info, risk/uncertainty)

The regulatory challenge is that these policies' benefits, by definition, **do not have an easily-measured market value**. Just about **any benefit estimate can be used to justify any level of the investment**. This runs counter to the goals of alternative regulation to create efficiencies.

Further, <u>**few of these social/environmental investments will lead to improved system efficiency**</u> since many are non-revenue generating or have no/little capacity value, resulting in lower system utilization, <u>**thus, making alternative regulation irrelevant and useless.**</u>

Regulation and the capital investment bias

Since the 1960s, the **theory and practice of utility regulation has recognized that utilities have a capital investment bias**. This bias is technically referred to as the **"Averch-Johnson effect"** after the two economists publishing the theory in the *American Economic Review* – but is more **commonly referred to as "gold plating"** in utility practice.

This **capital investment bias notes that the larger a utility's investment base, the larger the potential earnings**. The larger and faster this investment base (or "rate base") grows, the faster the potential earnings growth.

Historically, **utilities have justified very large capital/capacity investments on energy usage growth** that, while slowing, has still been considerable over the past three decades.

Over the past decade, however, utilities have faced slowing to potentially contracting energy usage. **No usage growth means no need for capacity, no capacity needs mean no capital investment, and no capital investment means lower earnings opportunities**.

How do utilities grow earnings in a low to non-growth environment?

Utilities are finding new alternatives to **grow their rate base** through **social investments** that include those **dedicated to reliability/resiliency, safety/security, renewables, energy storage, and other emerging new technologies and resources.**

The **basis for these investments contradicts the purposes of alternative regulation**. First, social investments are often uneconomic. This means that **alternative regulation can not incent utilities into making cost-effective decisions since the resources themselves are not cost effective**.

Second, **social investments do not lead to improved system efficiencies** and can lead to lower, not higher system utilization **running counter to the purpose of using alternative regulation**.

Third, **alternative regulation delegates social investment prioritization to for-profit utilities and their shareholders**. This outcome contradicts traditional regulation that allows utilities, under the direct supervision of regulators, to make these investments if the gains are shared with ratepayers.

Media recognition of the new utility capital bias.

Even the **media recognizes this capital bias** in the face of flat electricity demand growth – **a trend that is proven to be exacerbated with alternative regulation**.

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BUSINESS

Utilities' Profit Recipe: Spend More

To expand regulator-imposed earnings caps, electricity producers splurge on new equipment, boosting customers' bills

Every time Southern California Edison replaces a 50-year-old pole with a new one, it has a fresh investment on which it is eligible to earn an annual profit. *PHOTO: FRED PROUSER/REUTERS*

By REBECCA SMITH

April 20, 2015 6:04 p.m. ET

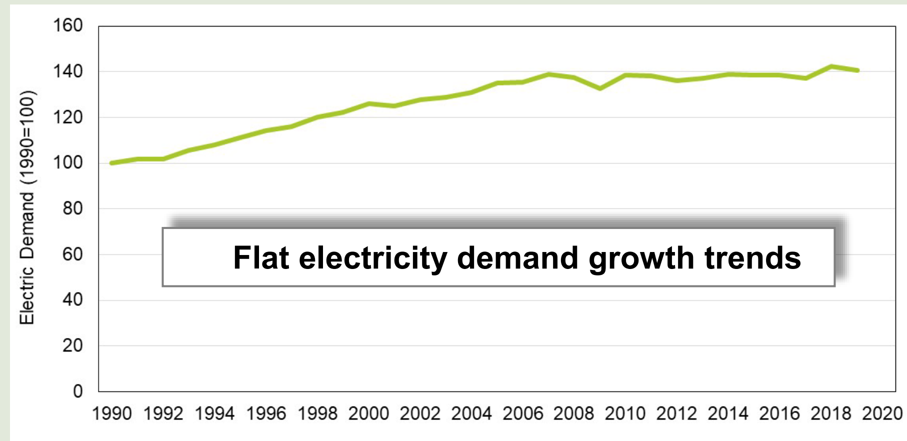
101 COMMENTS

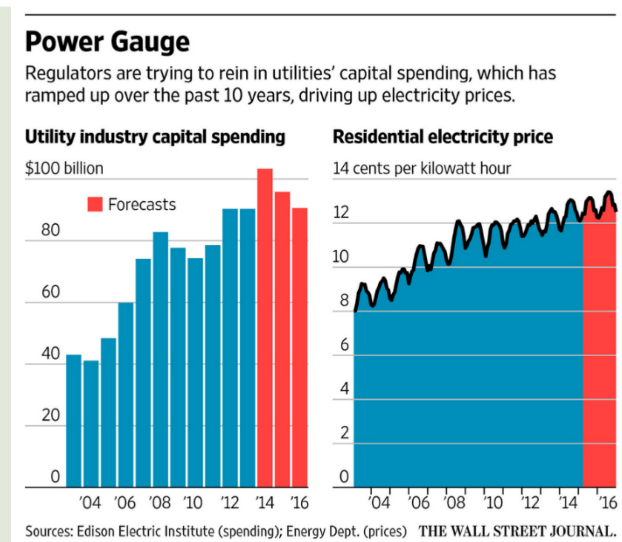
Families in New York are paying 40% more for electricity than they were a decade ago. Meanwhile, the cost of the main fuel used to generate electricity in the state—natural gas—has plunged 39%.

Why haven't consumers felt the benefit of falling natural-gas prices, especially since fuel accounts for at least a quarter of a typical electric bill?

One big reason: utilities' heavy capital spending. New York power companies poured $17 billion into new equipment—from power plants to pollution-control devices—in the past decade, a spending surge that customers have paid for.

New York utilities' spending plans could push electricity prices up an additional 63% in the next decade, said Richard Kauffman, the former chairman of Levi Strauss & Co. who became New York's energy czar in 2013. It's "not a sustainable path for New York," he said.





Major forms of alternative regulation: multiyear rate plans ("MYRPs").

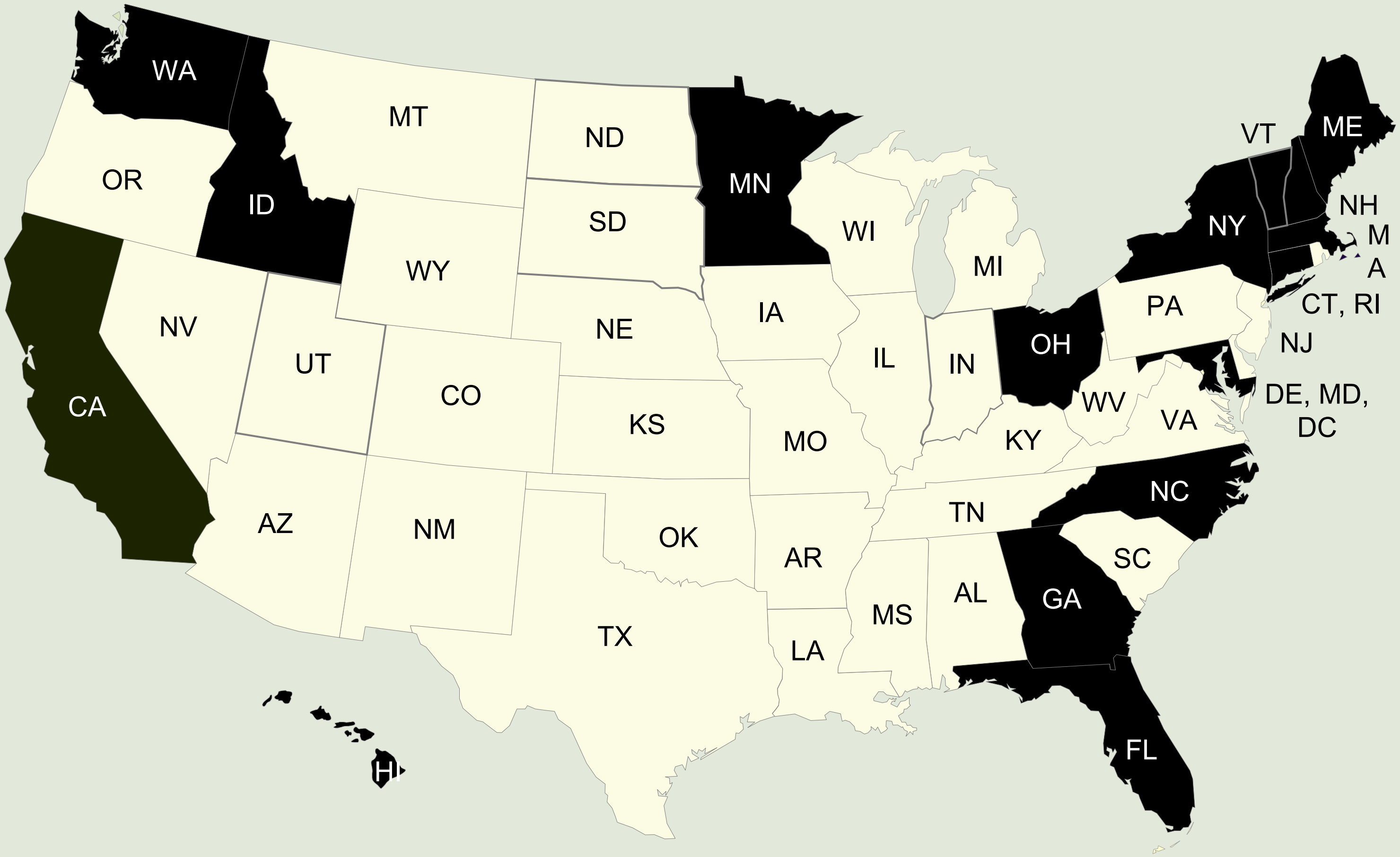
Multi-Year Rate Plans ("MYRPs") are rate plans **designed to span multiple years similar to PBR.**

However, unlike PBR, **MYRPs do not rely on a formula to determine future rate increases and instead are approved with defined rate increases each year of the proposed plan**. Due to this, MYRPs tend to be shorter in duration, typically only two or three years in total.

The **biggest concern with MYRPs is the approval of large upfront rate increases that are based on projected, not actual information.** Additionally, depending on the extent of these allowed future rate increases, **MYRPs may include little to no incentive for the utility to control costs during the term of the plan. Once rates have been allowed to increase, it is difficult to "claw back" those increases in the form of expense/investment disallowances.**

Prevalence of MYRPs.

MYRPs are used in several states in the east, **primarily in states New England states.**



Sources: Electricity Regulation for a Customer-Centric Future – Survey of Alternative Regulatory Mechanisms, Guidehouse (for EEI), 2Q 2020; Idaho PUC Case No. AVU-E-23-01, AVU-G-23-01; DC PSC FC 1156; MD PSC Case No. 9655; VT PUC Case No. 18-1633-PET; NC PUC Docket No. E-2, SUB 1300, S&P Global RRA Regulatory Focus.

Major forms of alternative regulation: formula rate plans ("FRPs").

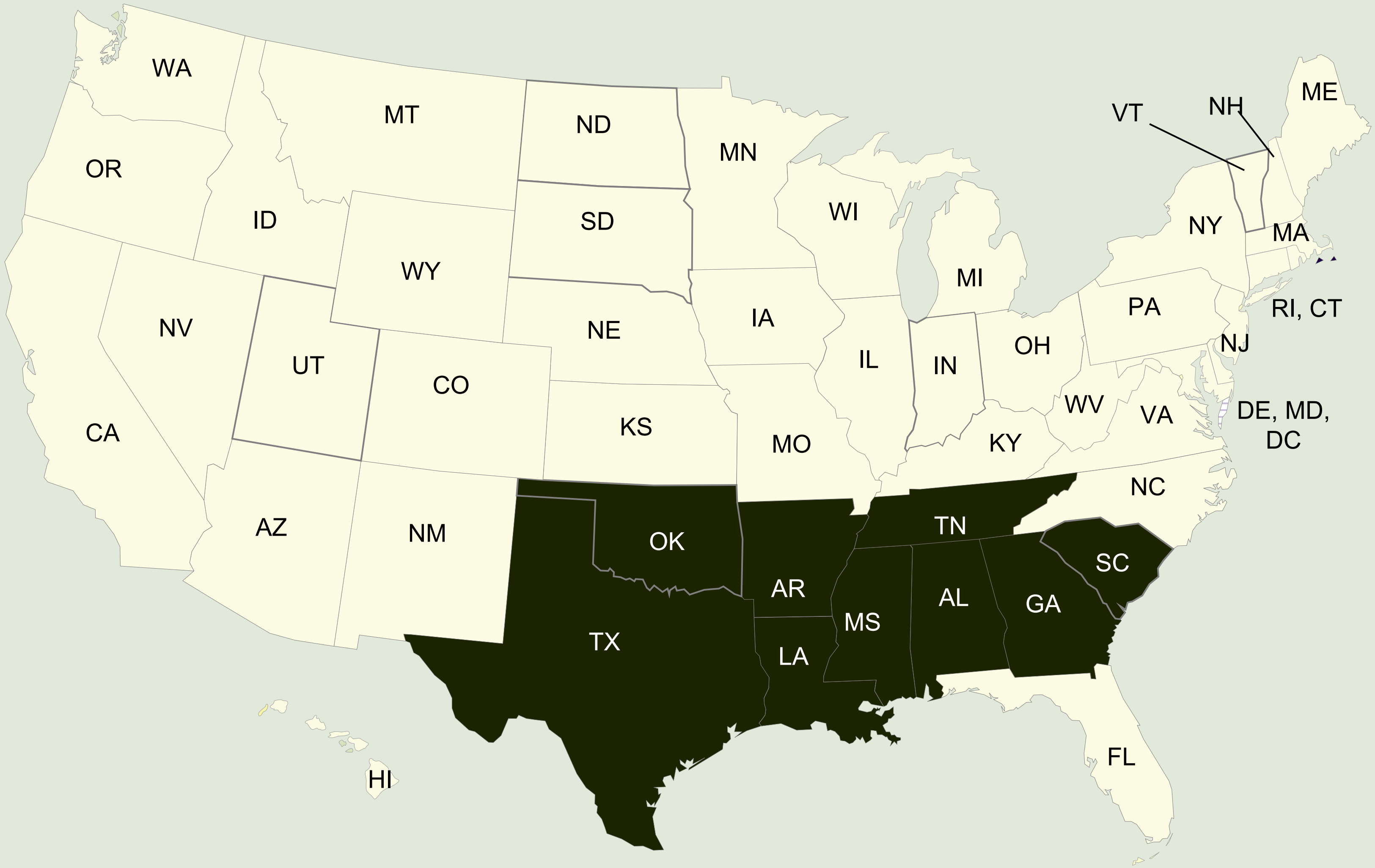
Formula rate plans ("FRPs") are a form of alternative regulation **that allows for annual rate adjustments between rate cases based on the difference between a utility's achieved return on equity to an established target return on equity set during the prior rate case**. Essentially FRPs **allow for annual "mini rate cases"** that involve a review of utility expenditures, capital investments, and revenue variances (**challenging the claim of "lower regulatory and administrative costs"**).

FRPs in practice, however, **have been plagued by constant rate increases to fund growing utility investments, inefficient utility capital investments, and in some cases utility windfall profits due to outdated capital market assumptions.**

FRPs also **have been criticized for reducing the ability of independent oversight of utility expenses and capital investments** since annual FRP reviews are typically conducted on a significantly expedited compared to traditional rate cases.

FRP use throughout the southeast.

FRPs are almost **exclusively used in the southeast**.



Source: "Innovative Rates, Non-Volumetric Rates, and Tracking Mechanisms: Current List" American Gas Association, 2016.

Major forms of alternative regulation: performance-based regulation ("PBRs").

Performance-Based Regulation ("PBR") allows either utility revenues or prices (i.e. rates) to increase each year using a set formula that **importantly includes an inflation term ("I") and a productivity offset ("X").** This "I-X" component is the core of such regulation paradigms and **represents a guaranteed rate increase**.

Revenue Cap

$$\overline{R}_t = (\overline{R}_{t-1} + CGA * \Delta Cust) * (1 + I - X) \pm Z$$

Price Cap

$$\overline{P}_{m,t} = \overline{P}_{m,t-1} * (1 + I - X) \pm Z$$

Where:

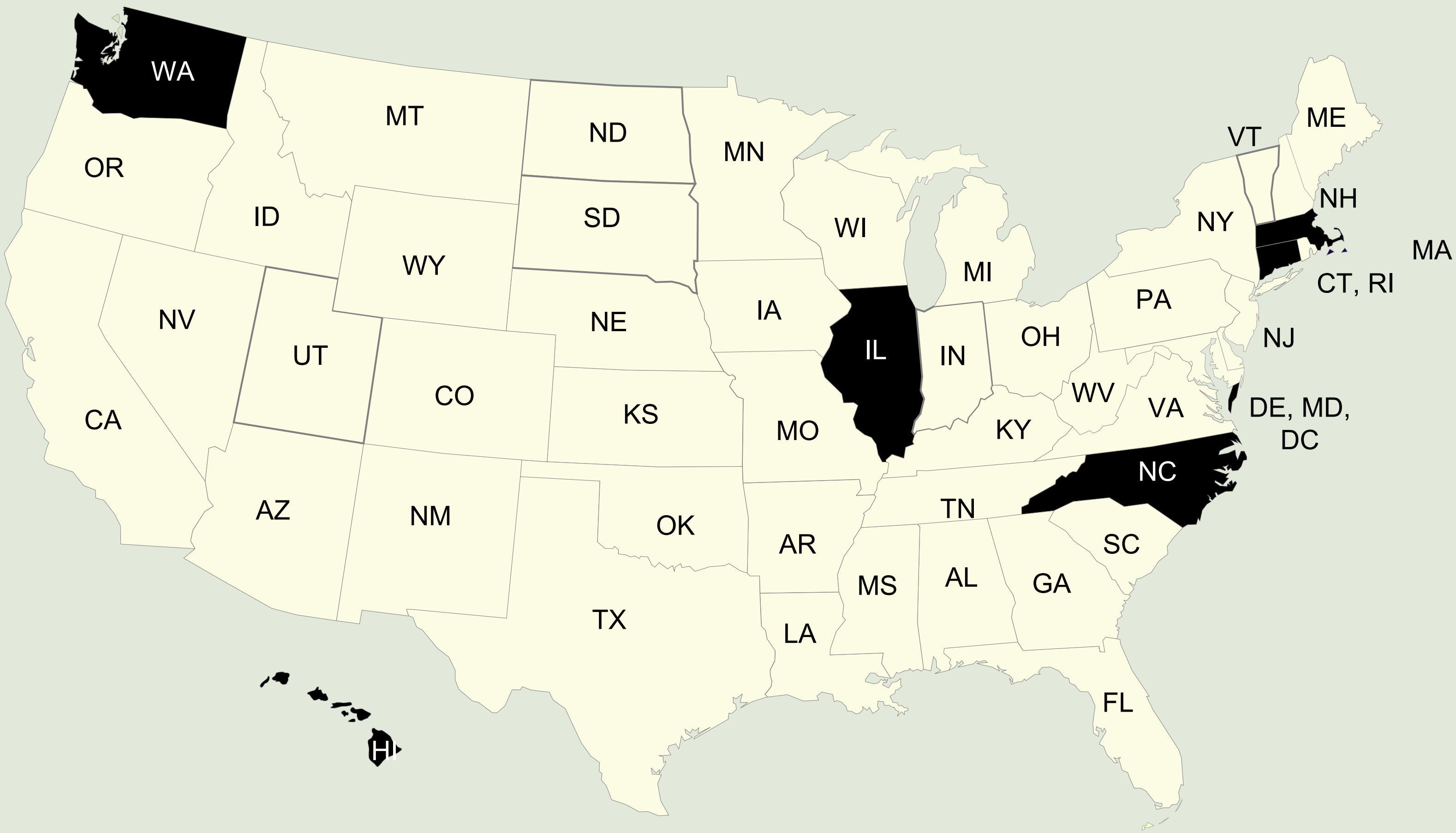
I = Annual percent change in prices (Inflation index)

X = An index of expected efficiency gains (Productivity offset)

Z = Adjustments for unforeseen events beyond management's control

Prevalence of electric utility PBR plans.

PBRs are rarely and sporadically used in a handful of states.



Note: CT and WA are in in the process of finalizing PBR rules, but most utilities use FRPs at the current time in WA.

Section 3: Alternative regulation increases rates

Alternative regulation increases rates.

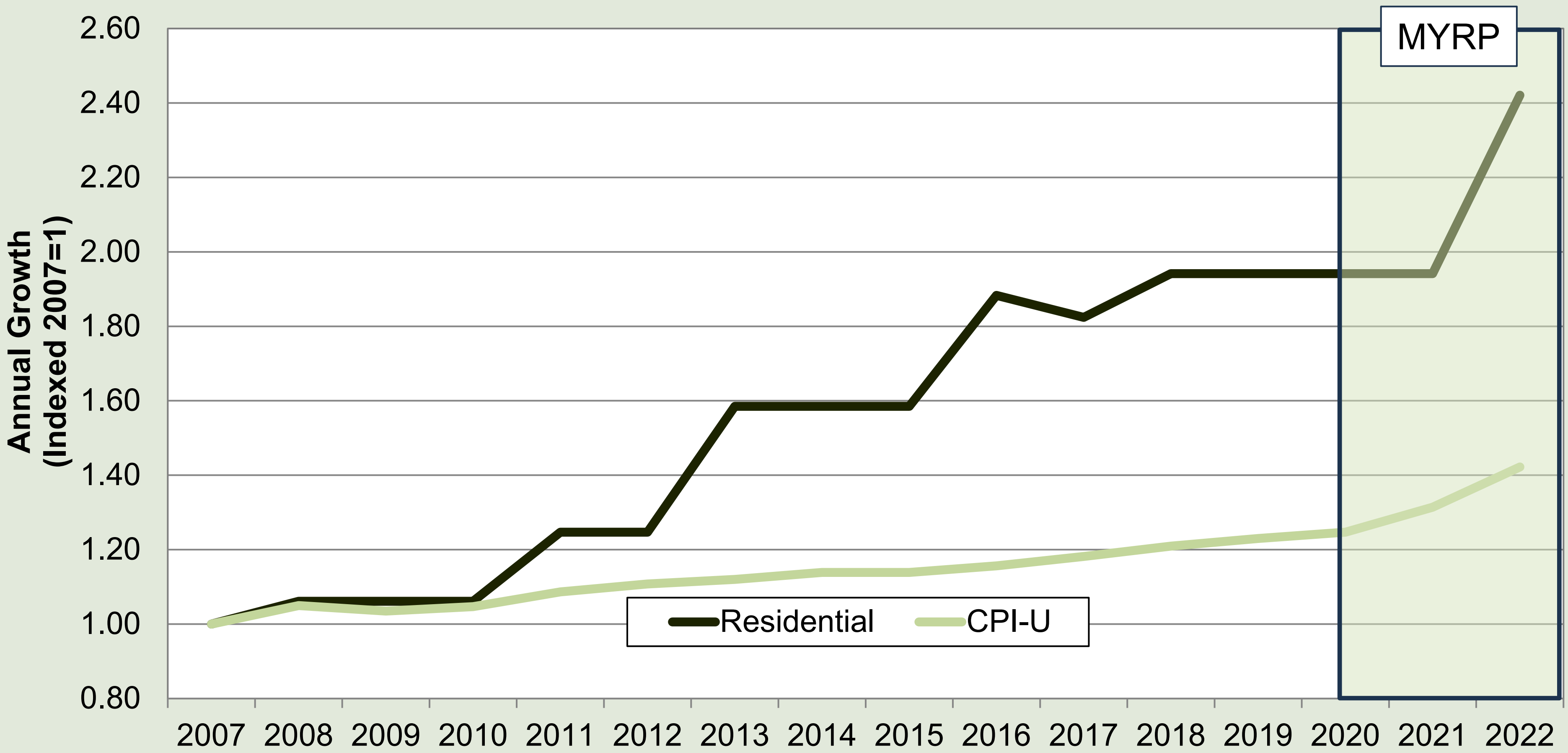
Alternative regulation does not lead to any meaningful nor measurable ratepayer benefits. Utilities that have been allowed to adopt various forms of alternative regulation (MYRPs, PBRs, FRPs) have **requested very large and generous rate increases, in most instances, orders of magnitude larger than what was historically requested under traditional regulation**.

There are simply **no "real-world" examples nor evidence that shows that ratepayers have received any meaningful benefits, particularly in the form of rate decreases, from alternative regulation.**

The following analysis provides several **real-world examples of post-alternative regulation rate increase requests**.

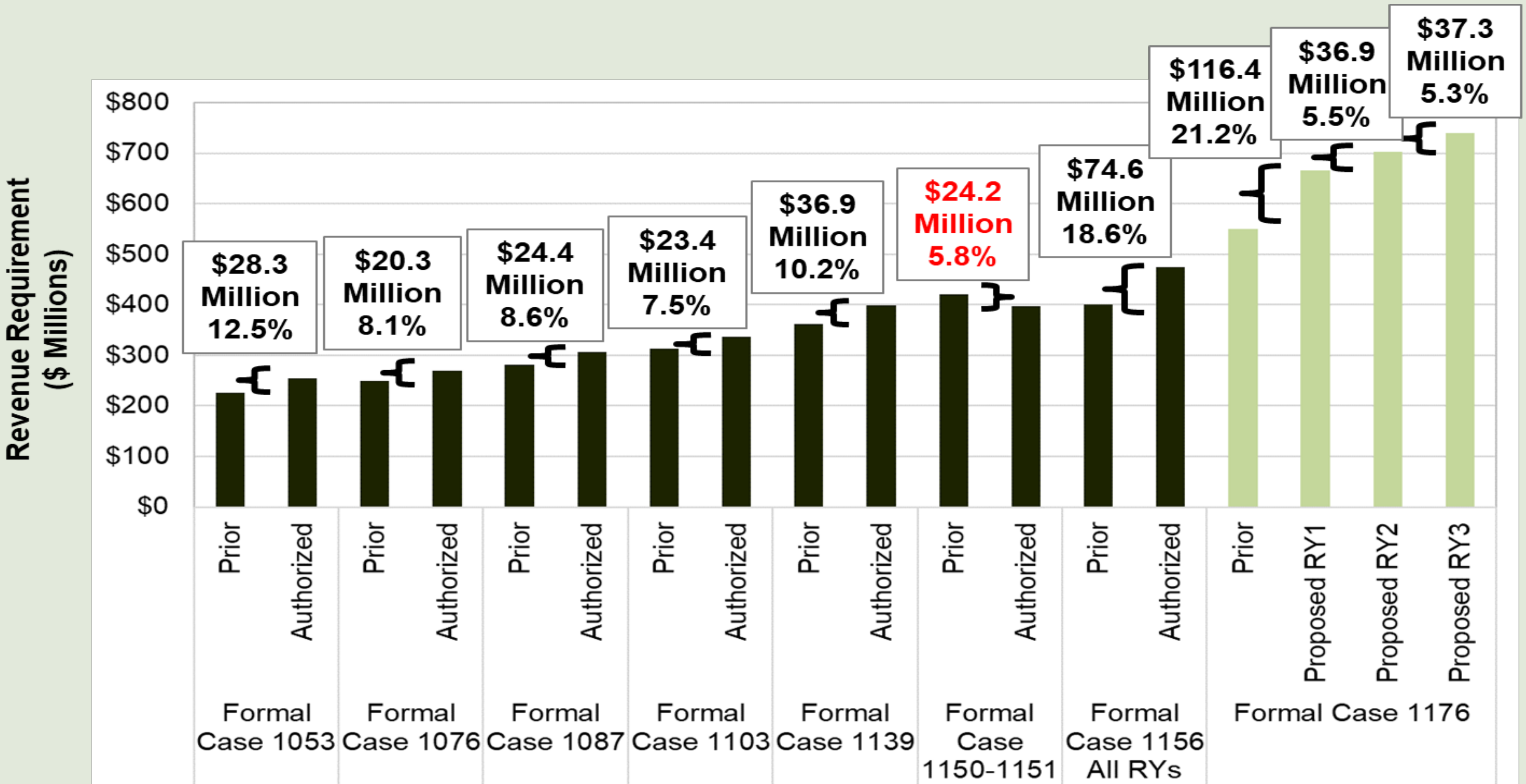
MYRP deficiency example: Pepco DC.

Even under traditional regulation, Pepco's rates were increasing faster than inflation. **Rate increases for all customers accelerated in a dramatic fashion after MYRP implementation**. Current pending MYRP is even greater than prior two years.



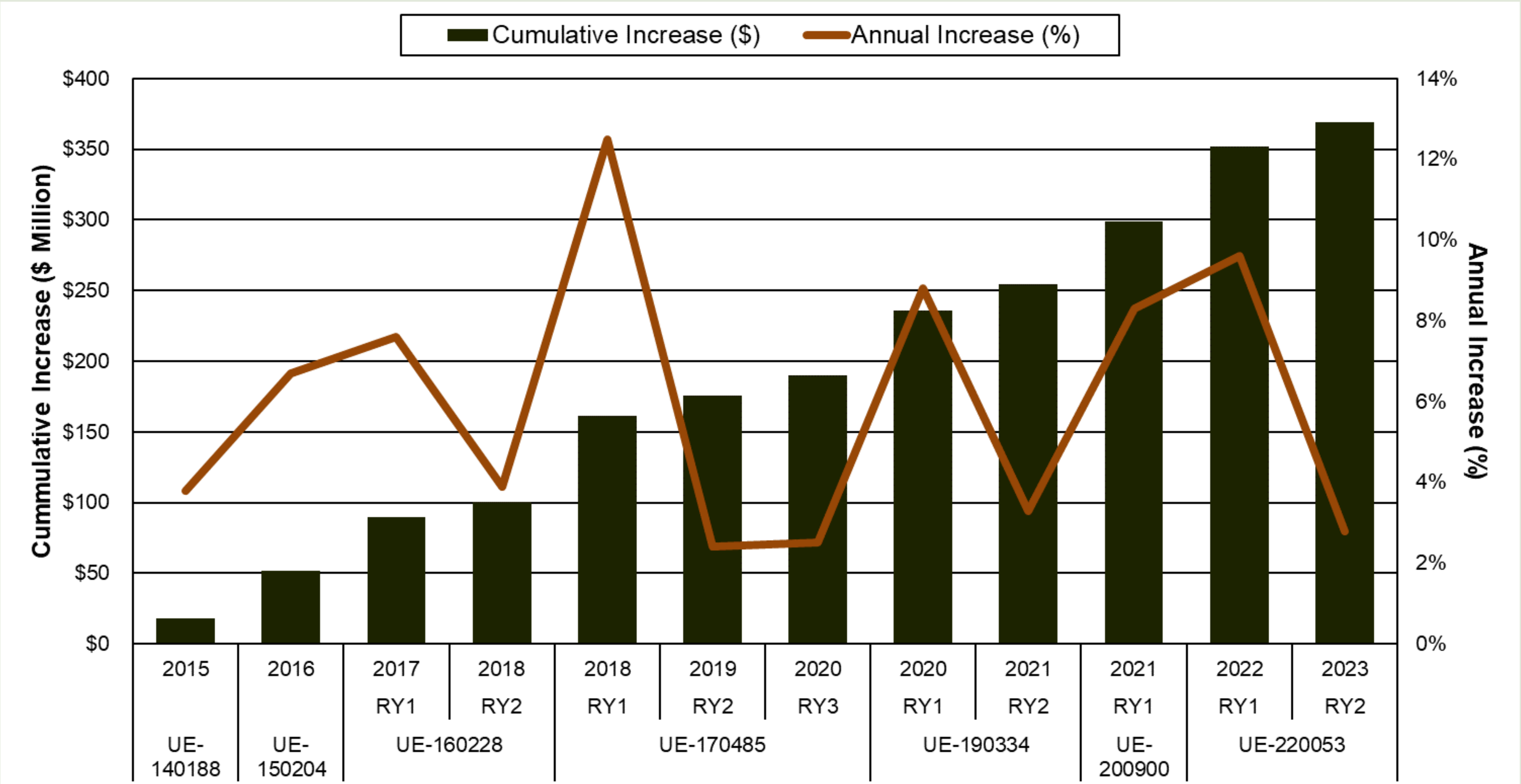
MYRP deficiency example: PEPCO DC.

Pepco's most recent MYRP filing requests an increase of $190.6 million over three years. This is equal to a **32 percent increase** in distribution rates, or nearly **10 percent per year of the proposal**.



MYRP deficiency example: Avista (Washington)

Under alternative regulation, Avista has imposed **annual rate increases that have exceeded 6 percent (almost $350 million since 2015).**



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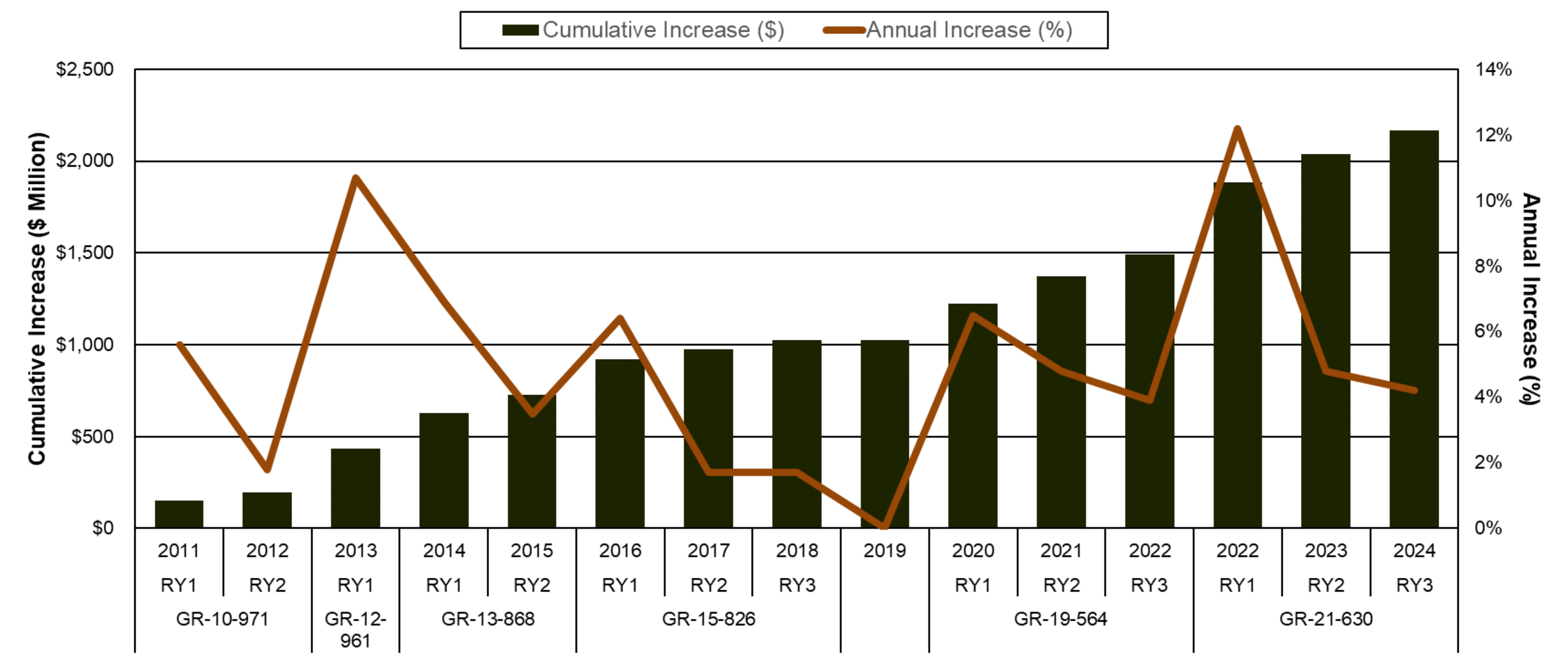
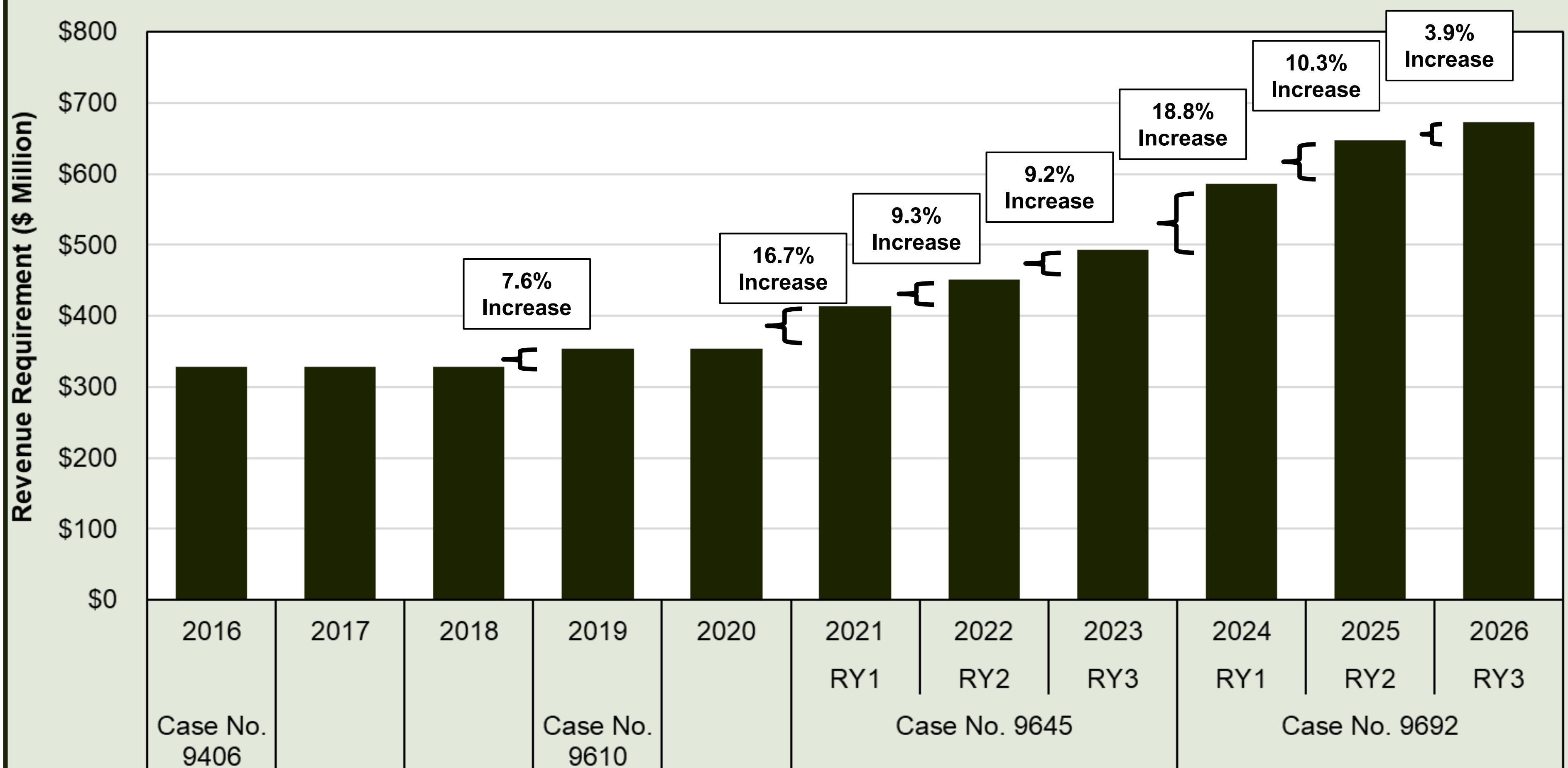
MYRP deficiency example: Xcel (Minnesota)

Xcel, under alternative regulation, has seen **cumulative rate increases of more than $2.2 billion since 2011 (5 percent per year)**.



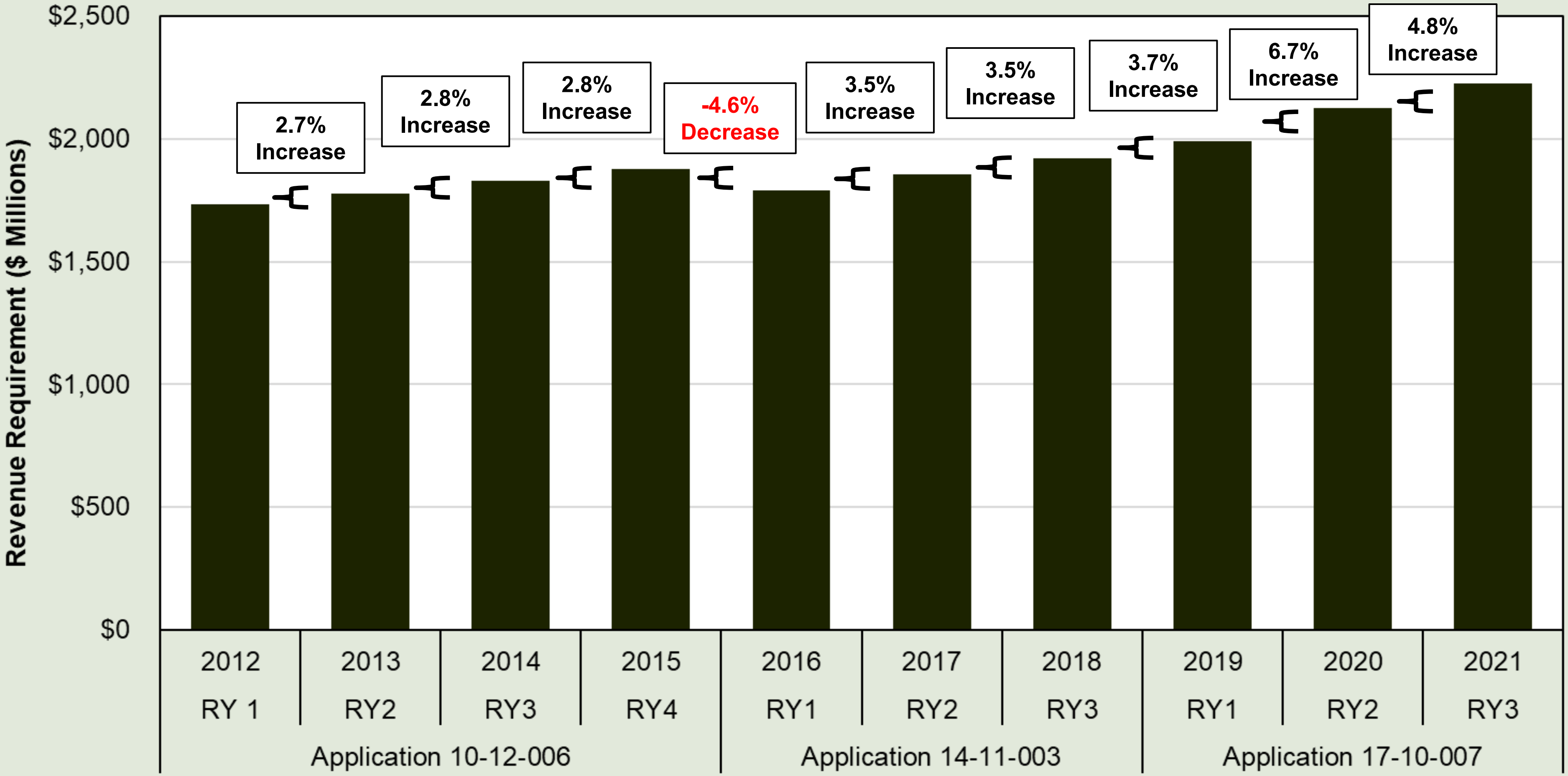
MYRP deficiency example: Baltimore Gas & Electric (Maryland)

From 2016 to 2020, BG&E saw one rate increase of 7.6%. **Since adopting alternative regulation, it has seen an average annual increase of 15%.**



MYRP deficiency example: San Diego Gas & Electric (California)

Under alternative regulation, SDG&E saw only one rate decrease in the past 10 years. **Rates grew at an average of 3.2% each year.**



MYRP proposals are stimulating community opposition.

Criticism of MYRP use is not unique to utility regulatory experts, as community organizations have also expressed concerns. For instance, the executive director of Economic Action Maryland strongly criticized Baltimore Gas and Electric's ("BGE's") performance during its MYRP pilot program and its requested extension, observing:

> [B]efore the evaluation of the first [MYRP] pilot program is completed, BGE is back asking for a second multiyear rate increase. Essentially, BGE is asking for our trust and for us to pay rate increases based on what they expect to spend. BGE seeks to shift the costs of their infrastructure investments to customers while reaping the profits from these investments. A multiyear proposal incentivizes BGE's desired spending spree when what is needed is prudent oversight and review by the PSC.
>
> Rate increases in 2022 and 2023 are creating undue hardship for households across Central Maryland, particularly in Baltimore. Again, I can speak from experience. Since 2021, my BGE bills have increased by $200 per month, or $2,400 per year, while my consumption remains unchanged. … While this cost increase is a hardship for some middle-class families like mine, it is catastrophic for many families my nonprofit organization supports. … An increase in utility costs will hurt working families living paycheck-to-paycheck, forcing them to make impossible choices between keeping the lights on or keeping food on the table.

Source: "Commentary: BGE rate increase unaffordable for many in Maryland," The Baltimore Banner, Dec. 3, 2023.

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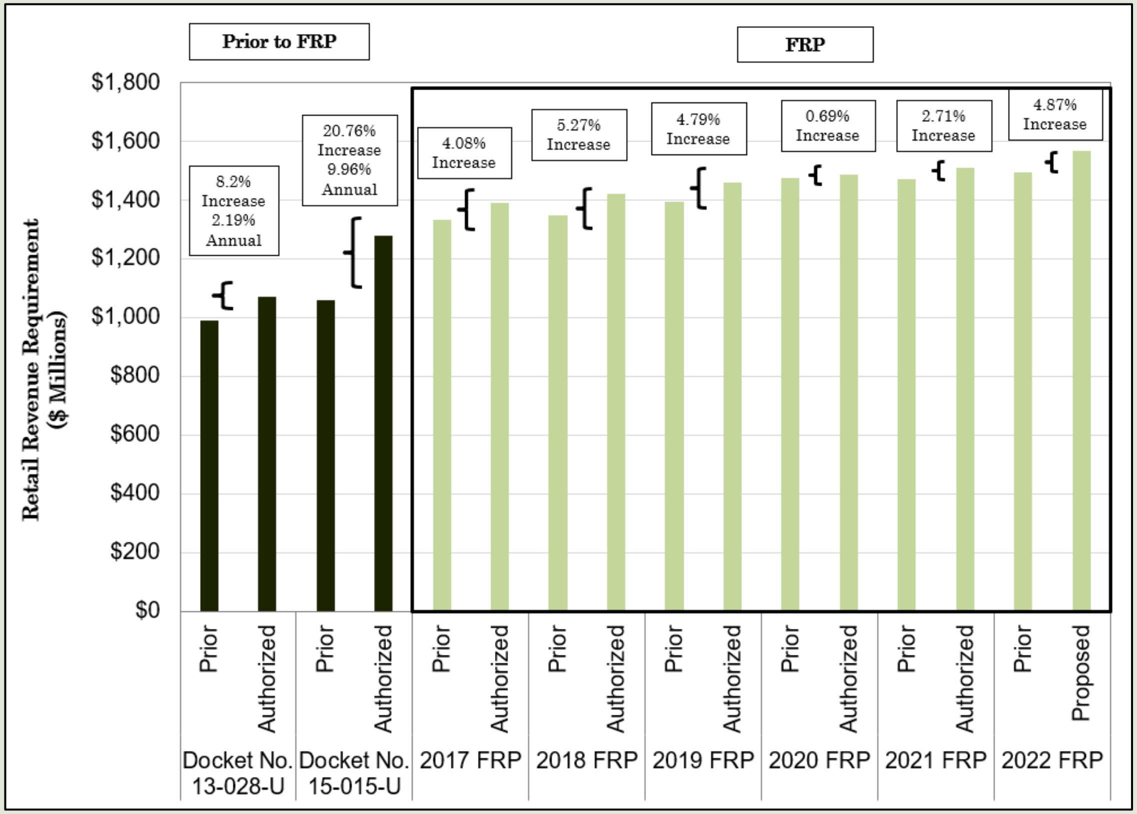
FRP deficiency example: Entergy Arkansas ("EAI") rate increases.



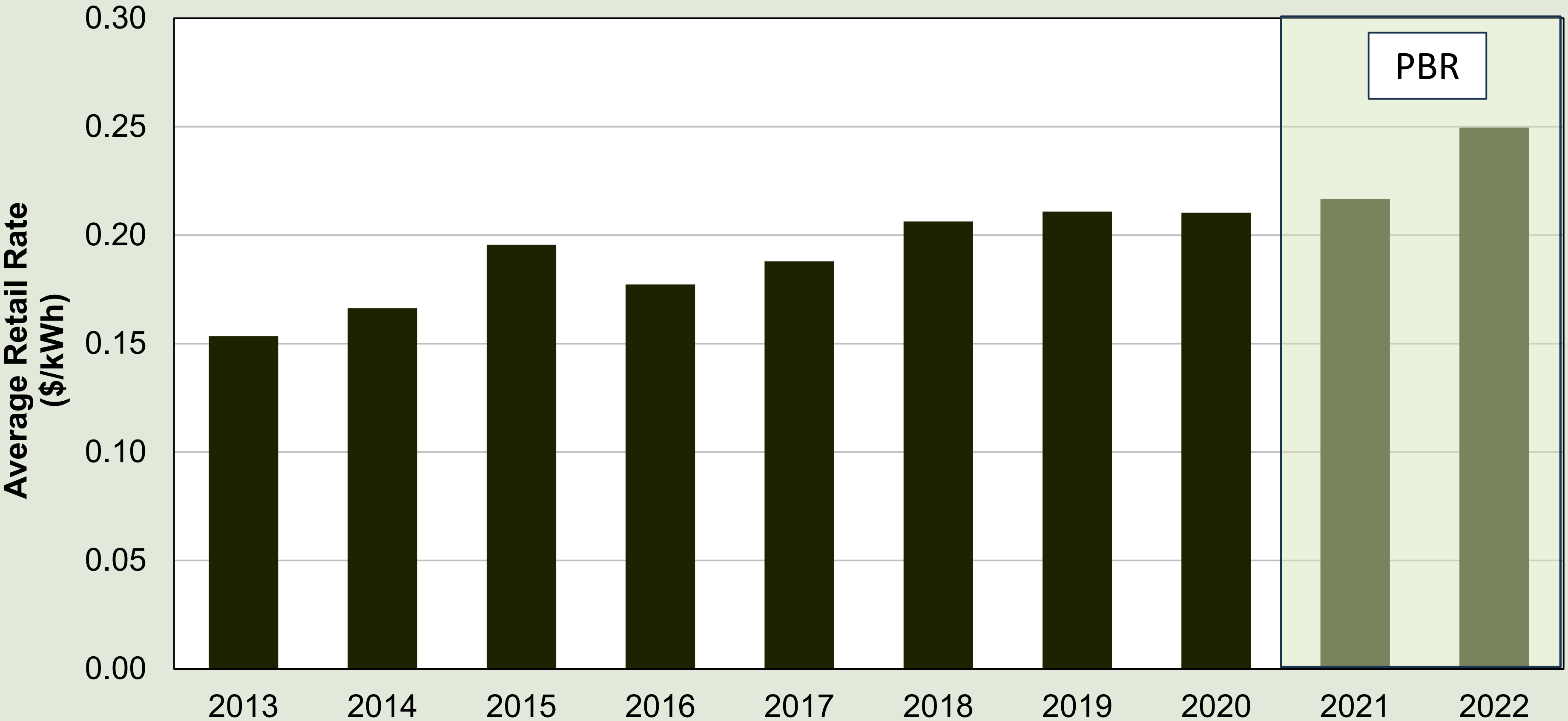
Unsurprisingly, most of EAI's FRP filings has been at a statutory cap. This is after the Company received a rather large pre-FRP "cast off" rate case.

Prior to alternative regulation, EAI's average rate increases were low, averaging 2.73 percent per year. Post alternative regulation, this increased to 3.74 percent annually or 6.83 percent including the FRP "cast off" rate case.

Source: Rate Case Compliance Filings, FRP Compliance Filings Attachment A and 2021 Evaluation Report, Attachment A.2-Extension

PBR deficiency examples: National Grid rate increases.

National Grid (Massachusetts Electric Company) saw rates **increase from $0.2103 per kWh in 2020 to $0.2496 per kWh in 2022, an increase of 18.7 percent over the course of its approved PBR plan.** When evaluating historic rates, **it is clear that PBR did not slow the pace of rate increases.**

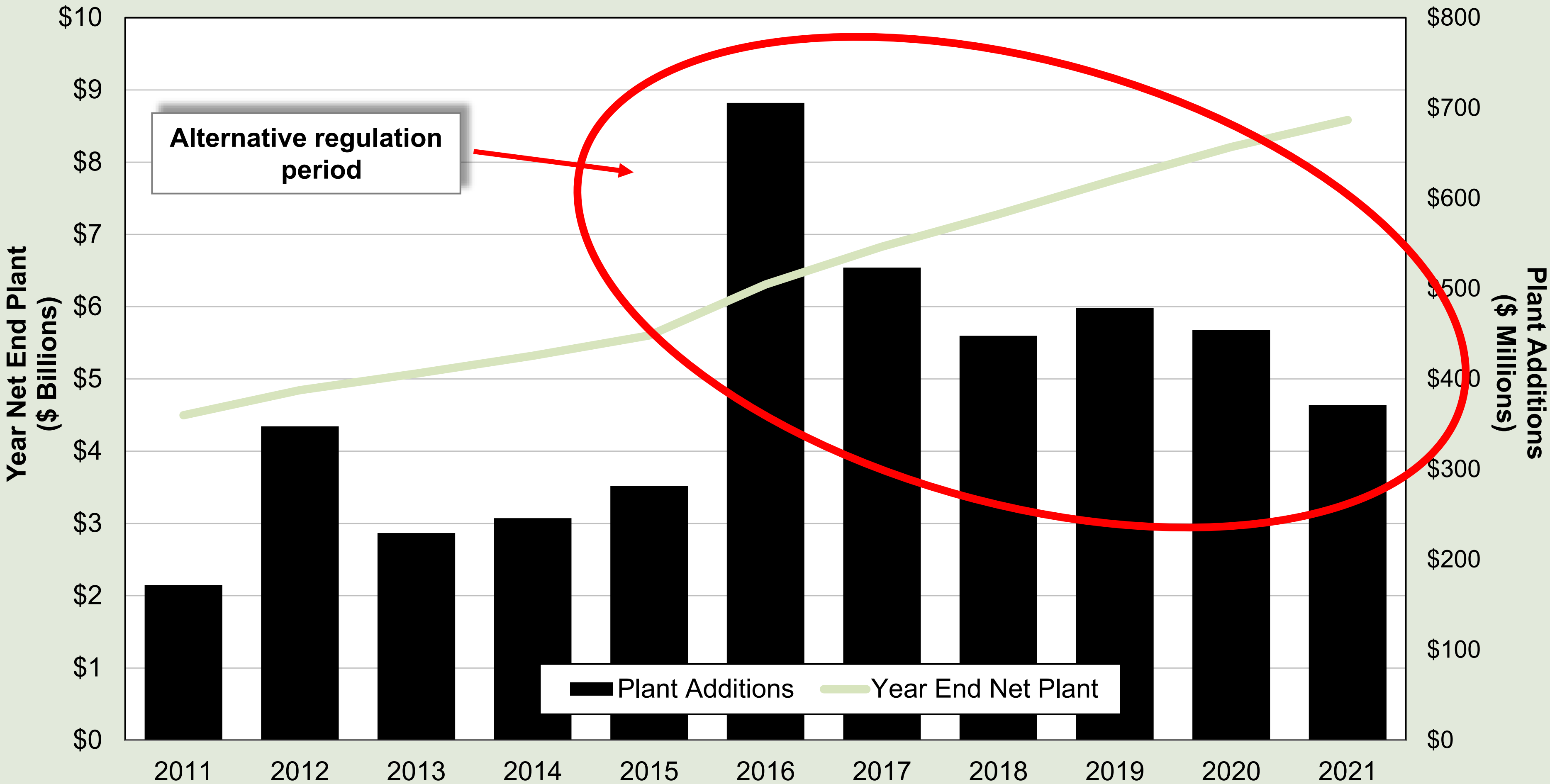


Source: EIA Form 826.

Section 4: Alternative regulation leads to operating inefficiencies

FRP deficiency example: EAI net plant growth

Net plant for EAI has almost doubled since 2011. In 2018, net plant additions amounted over to $700 million.



Source: FERC Form 1 as provided by S&P Global.

FRP deficiency example: concerns with Entergy Arkansas cost containment.

The **Arkansas Public Service Commission has repeatedly expressed concern about whether the FRRA is achieving the intended public policy objectives** (such as greater cost containment) envisioned by the Arkansas General Assembly, noting:

> The Commission expects all utilities to control their costs in a prudent and reasonable manner **and not utilize the FRP as an automatic yearly four percent rate increase.**[1]
>
> Many of the FRP processes, including a reduction in the time afforded for review, the use of projections, and the annual rate adjustments **do little to incentivize a utility to control its costs as compared to traditional ratemaking** …[2]

Source 1: Docket No. 255, Order No. 14, issued 12/13/2017, at 31. (Emphasis added.)
Source 2: Docket No. 420, Order No. 21, issued 7/5/2019, at 40. (Emphasis added.)

PBR deficiency examples: Eversource (NSTAR) operating cost efficiencies.

There is **no significant post-PBR cost efficiency (Massachusetts) – Eversource is still above regional peer average in operating costs per MWh.**

Company	State	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
		($/MWh)									
NSTAR Electric	**MA**	**$ 35.47**	**$ 37.10**	**$ 37.91**	**$ 37.76**	**$ 38.27**	**$ 40.32**	**$ 39.83**	**$ 35.02**	**$ 38.14**	**$ 38.67**
Central Hudson	NY	35.43	36.45	37.29	37.97	35.98	36.46	39.95	40.68	44.91	46.18
Connecticut Light and Power	CT	30.03	31.35	30.72	31.63	31.85	33.57	36.03	36.88	40.76	40.32
Consolidated Edison	NY	48.24	51.68	50.15	52.65	52.42	53.05	52.59	54.29	57.19	57.58
Duquesne Light Co	PA	19.65	20.31	21.83	23.14	24.77	26.20	26.91	27.83	30.55	30.75
Green Mountain Power Corp	VT	39.46	36.10	27.71	27.52	27.80	28.38	29.57	31.02	32.79	32.62
Jersey Central Power	NJ	25.09	30.15	23.18	28.07	26.92	27.48	28.20	34.35	35.26	40.11
Massachusetts Electric	MA	27.09	29.29	31.91	33.05	33.99	37.03	37.33	37.99	40.24	40.77
Monongahela Power Co	NY	17.08	20.15	15.22	20.09	19.45	19.26	20.75	20.45	20.38	20.36
Narragansett Electric	RI	27.37	28.76	31.18	31.70	31.28	34.80	37.48	37.25	41.44	40.09
New York State Elec & Gas Corp	NY	29.33	29.37	28.80	29.91	28.48	31.34	34.28	35.39	37.10	39.61
Niagara Mohawk Power Corp	NY	36.38	36.09	33.06	30.66	29.20	30.51	32.22	31.97	33.57	35.43
Orange & Rockland Utils Inc	NY	41.42	44.39	46.07	48.53	48.63	45.18	47.84	48.31	49.94	50.78
PECO Energy Company	PA	21.23	23.39	22.20	25.40	23.51	24.44	25.07	27.10	27.81	31.25
Pennsylvania Electric Company	PA	19.85	20.81	20.55	21.01	22.39	22.86	23.83	25.47	27.14	26.11
Public Service Co of NH	NH	28.11	28.97	30.11	30.60	32.05	32.84	34.35	34.65	38.98	38.09
Public Service Electric & Gas	NJ	19.28	21.49	22.74	23.77	23.54	23.04	24.19	25.08	25.16	24.64
Peer Group Average		**$ 29.44**	**$ 30.93**	**$ 30.04**	**$ 31.38**	**$ 31.21**	**$ 32.16**	**$ 33.55**	**$ 34.34**	**$ 36.55**	**$ 37.26**

Source: EIA 876, D.P.U. 22-22 Exhibit ES-PBR-TFP-4

Section 5: Alternative regulation does not improve reliability

Concerns regarding MYRP reliance on projections.

MYRPs **establish rates based upon projected revenue, costs, and expenses**. Utilities can **over-estimate projected costs and expenses to insulate it** from having to bear unforeseen costs or expenses and perhaps.

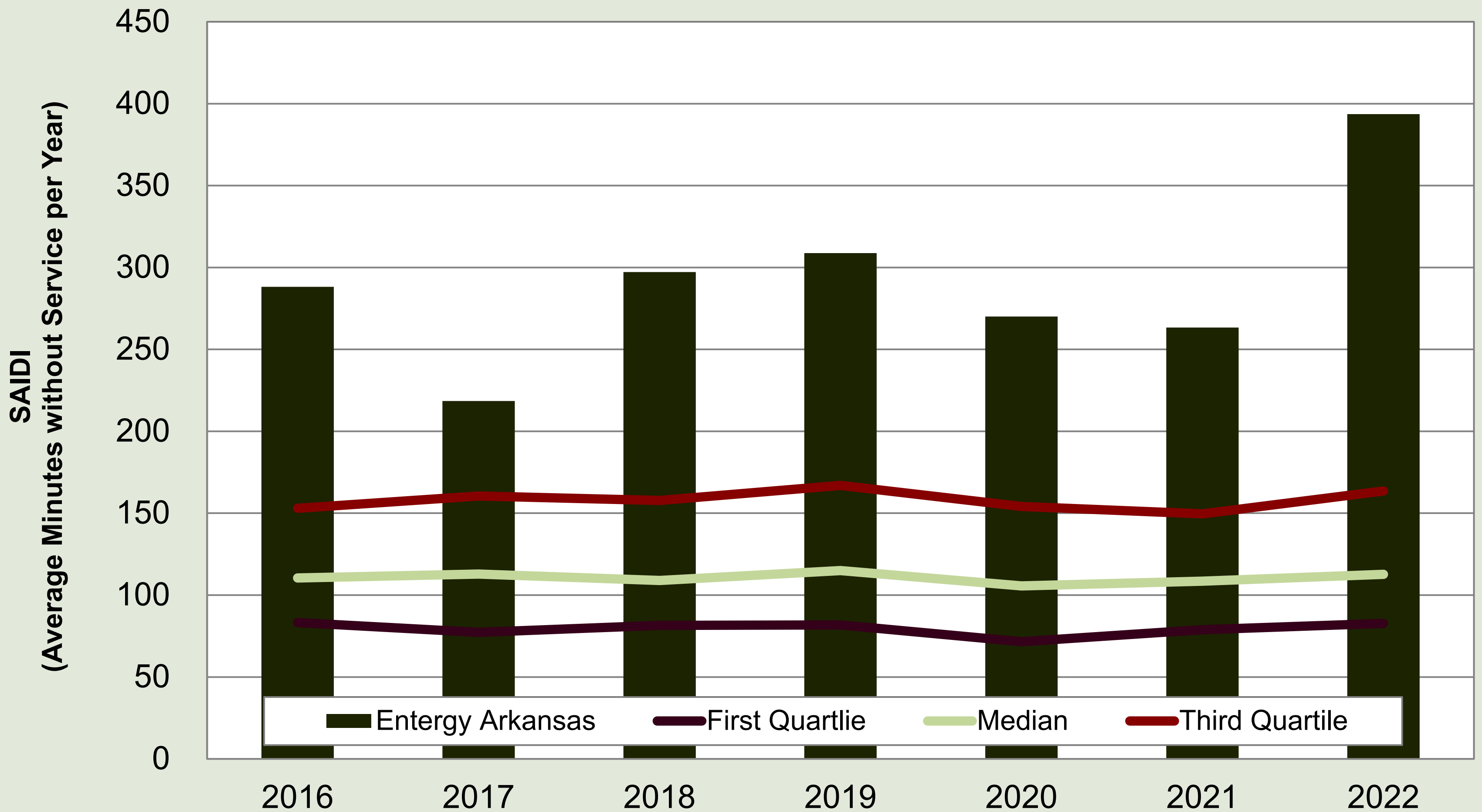
The **Connecticut Public Utility Regulatory Authority ("Authority")**[1] criticized United Illuminating Company ("UI") and its MYRP for its **incorrectly estimated seven-year period capital spend** including anticipated **investments in reliability,** such as storm resilience, substation flood mitigation, step down bank removal projects, substation getaway projects, and perimeter feeder ties projects.

The Authority calculated that UI had underspent its allowed capital budget for the years 2013 through 2019 **by more than $80 million** noting **"For multi-year rate plans, this level of underspending introduces risk that customers pay for plant additions that are not actually in service."**

Source: Proposed Final Decision, CT Public Utility Regulatory Authority Docket No. 22-08-08, July 21, 2023, pp. 44-48.

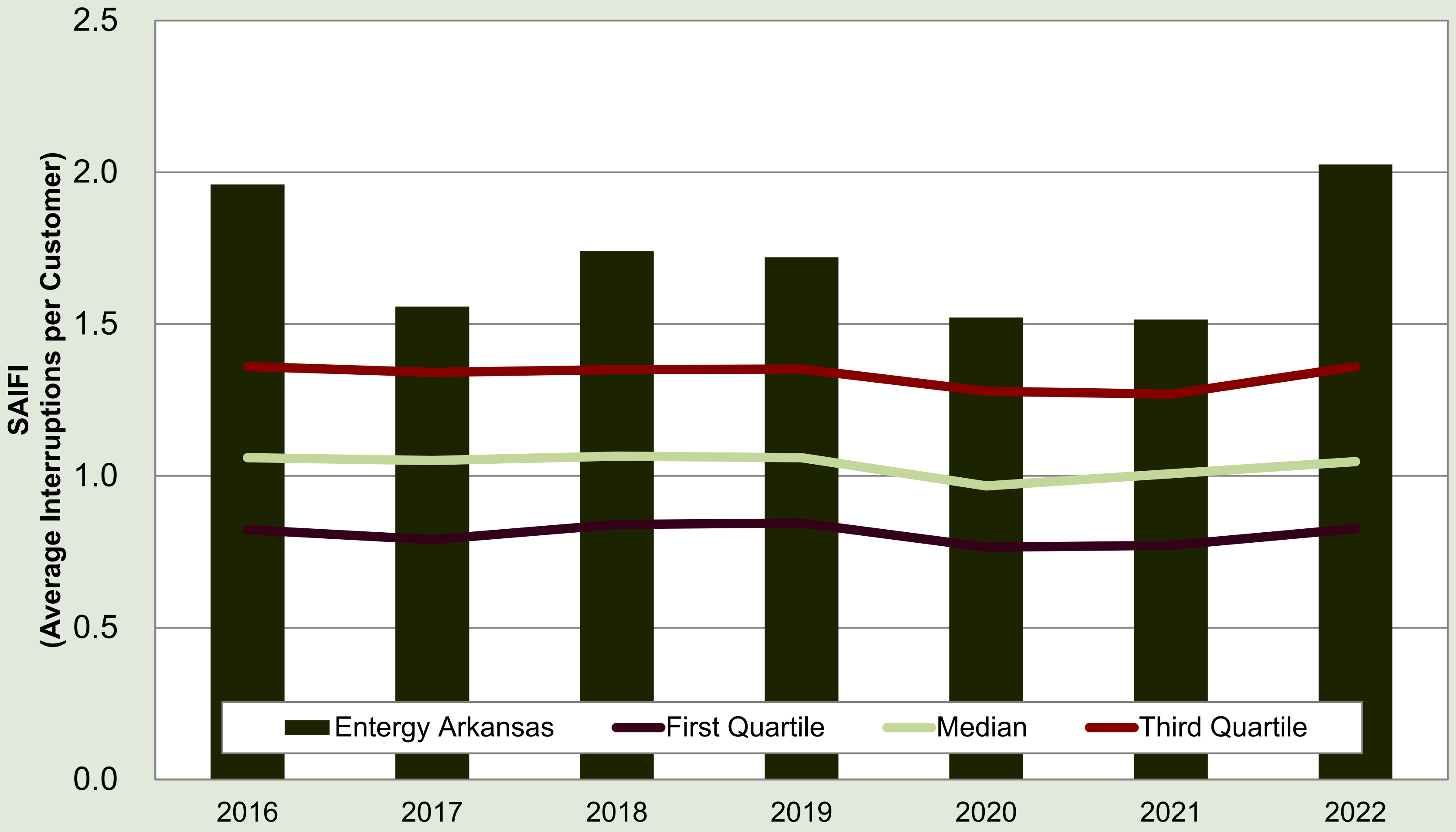
FRP deficiency example: Entergy Arkansas reliability performance ("SAIDI").

FRP has not resulted in any meaningful reliability improvement for EAI falling well into the **bottom fourth quartile** of utility SAIDI performance.



FRP deficiency example: Entergy Arkansas reliability performance (“SAIFI”).

EAI’s SAIFI performance is in the **bottom fourth quartile of peer utilities**.



FRP deficiency example: Entergy Mississippi reliability performance.

EAI's sister utility in Entergy Mississippi ("EMI") **also under an FRP, acknowledged its reliability performance has not met customers' expectations** despite being afforded a special alternative regulation framework.

For Immediate Release

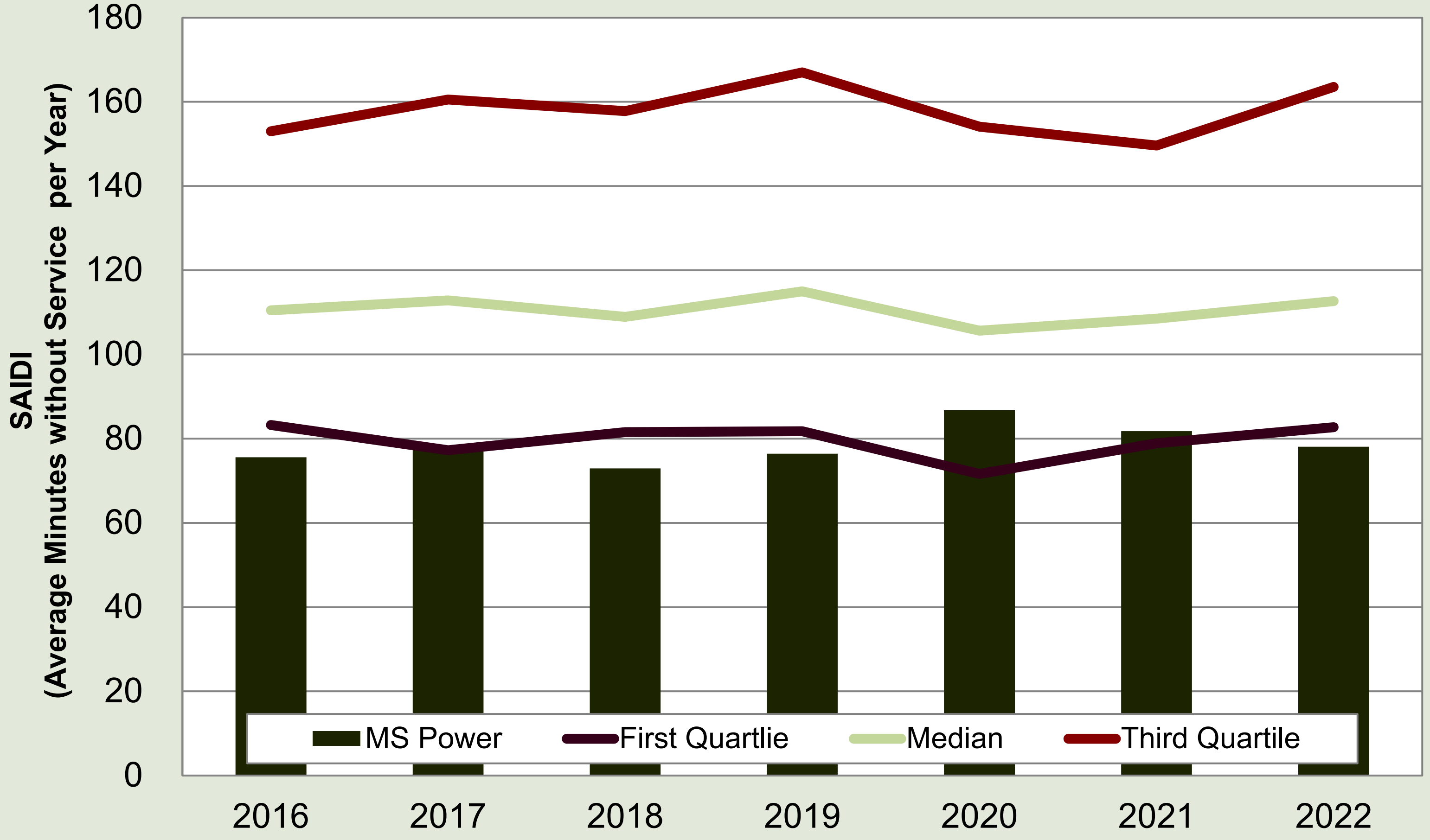
Entergy Mississippi acknowledges challenges in June storm response

09/12/2023

Company files Commission report and welcomes comments

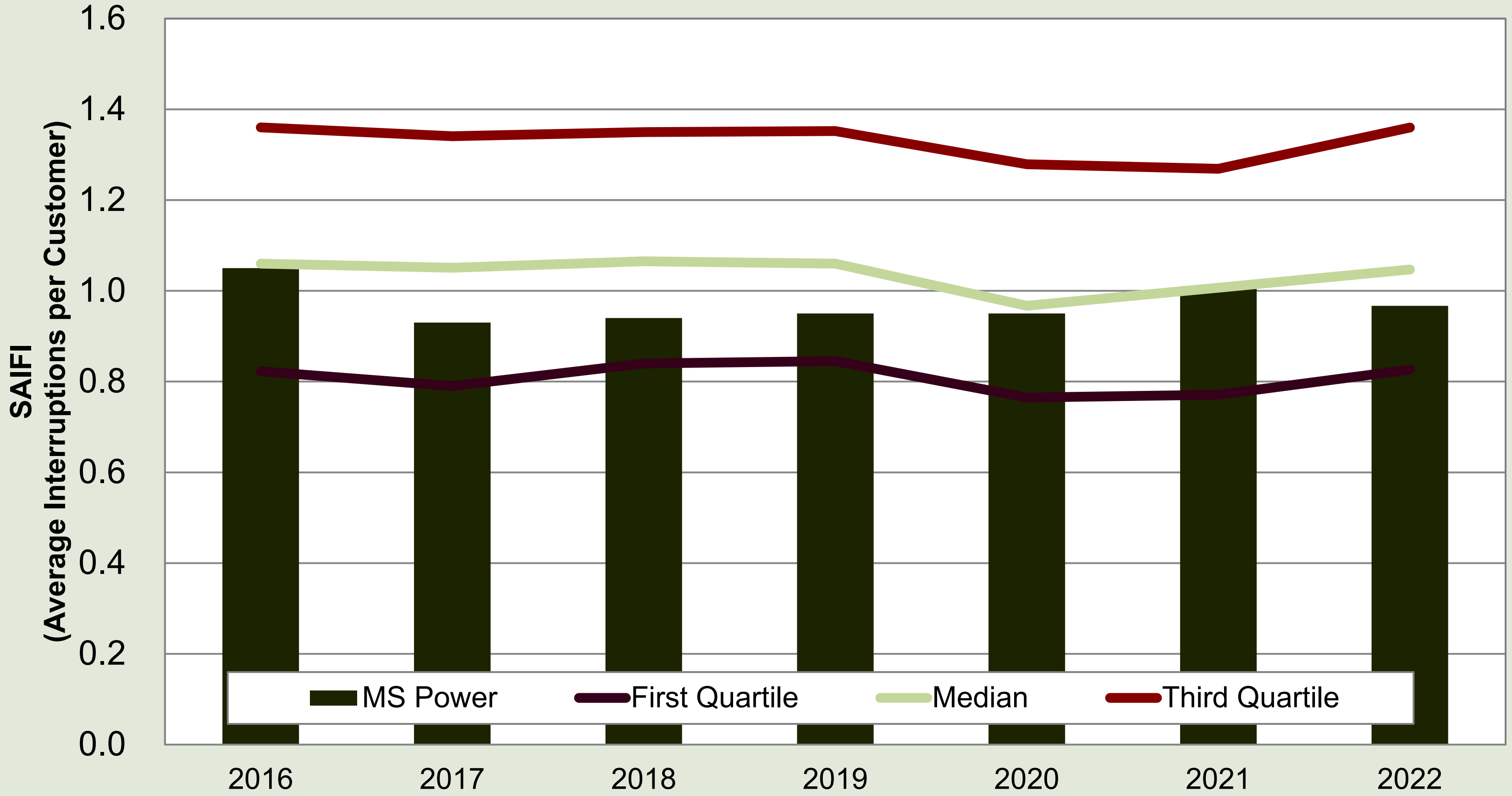
Example: Mississippi Power reliability comparison (SAIDI)

Mississippi Power has not seen any reliability improvement over the last several years.



Example: Mississippi Power reliability comparison (SAIFI)

Mississippi Power has not seen any improvement in SAIFI over the years.



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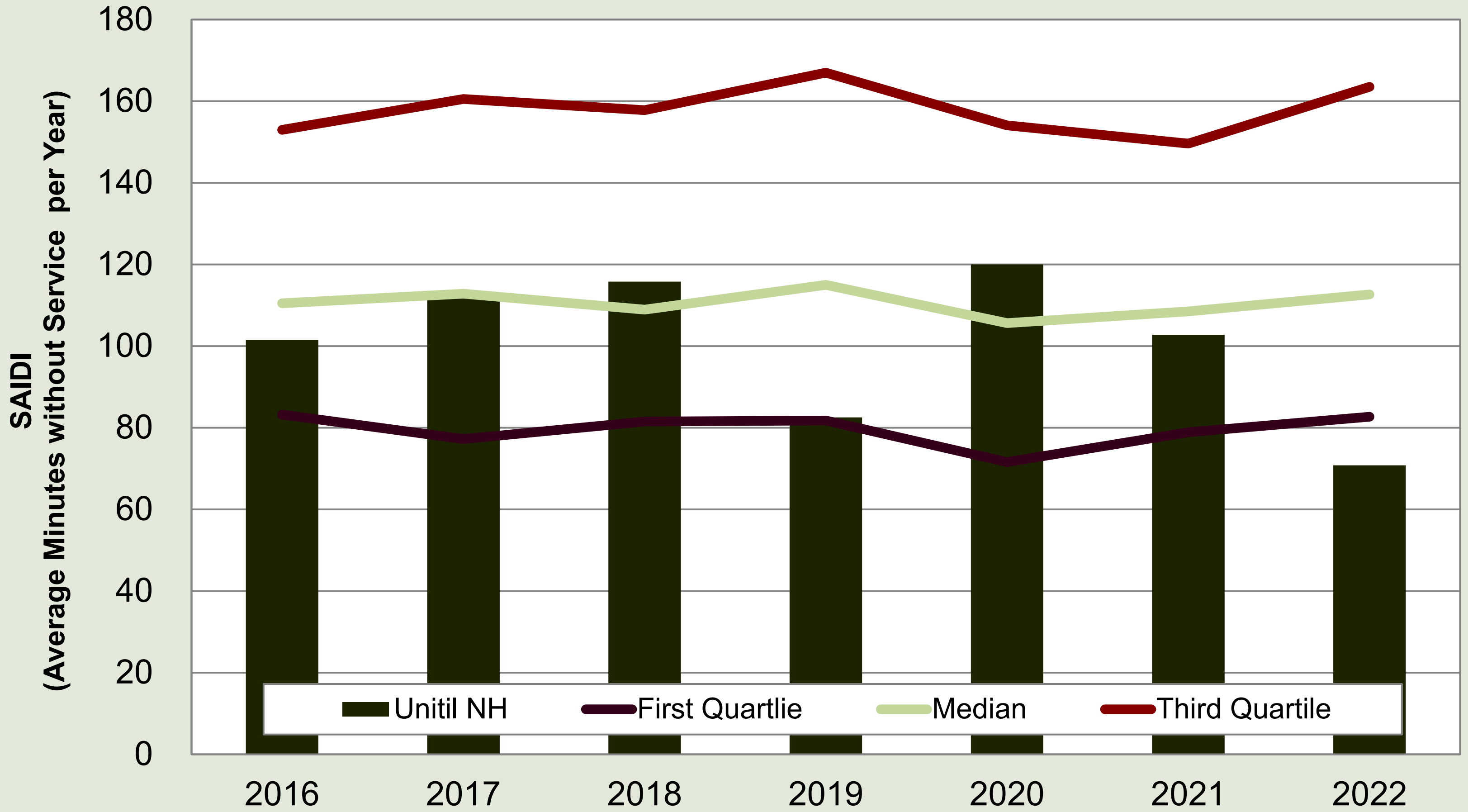
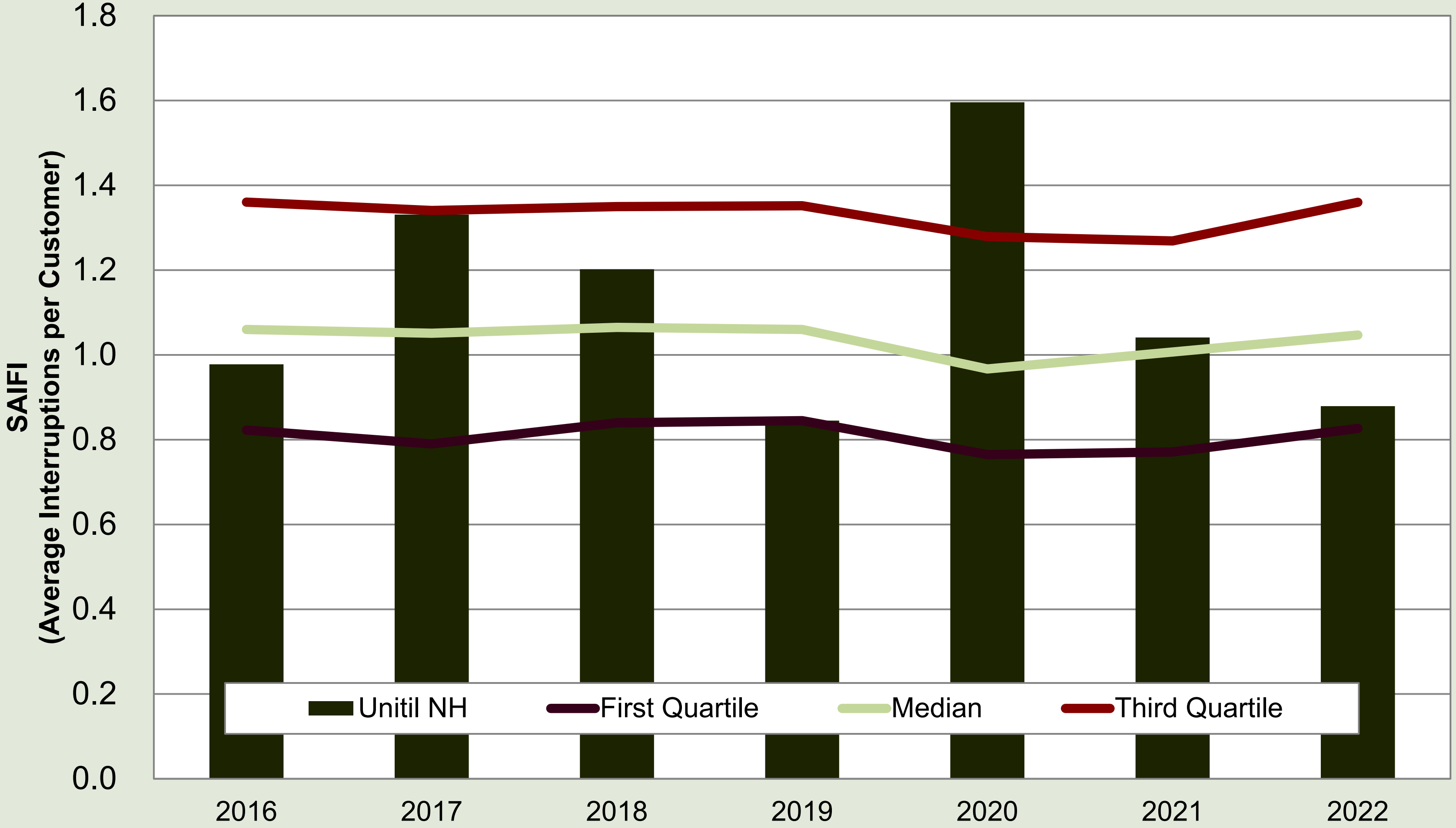
Example: Unitil New Hampshire reliability comparison (SAIDI)

Unitil has seen inconsistent SAIDI scores over the years, half the time reaching above the median average.



Example: Unitil New Hampshire reliability comparison (SAIFI)

Unitil has seen above average SAIFI scores over the last 7 years.



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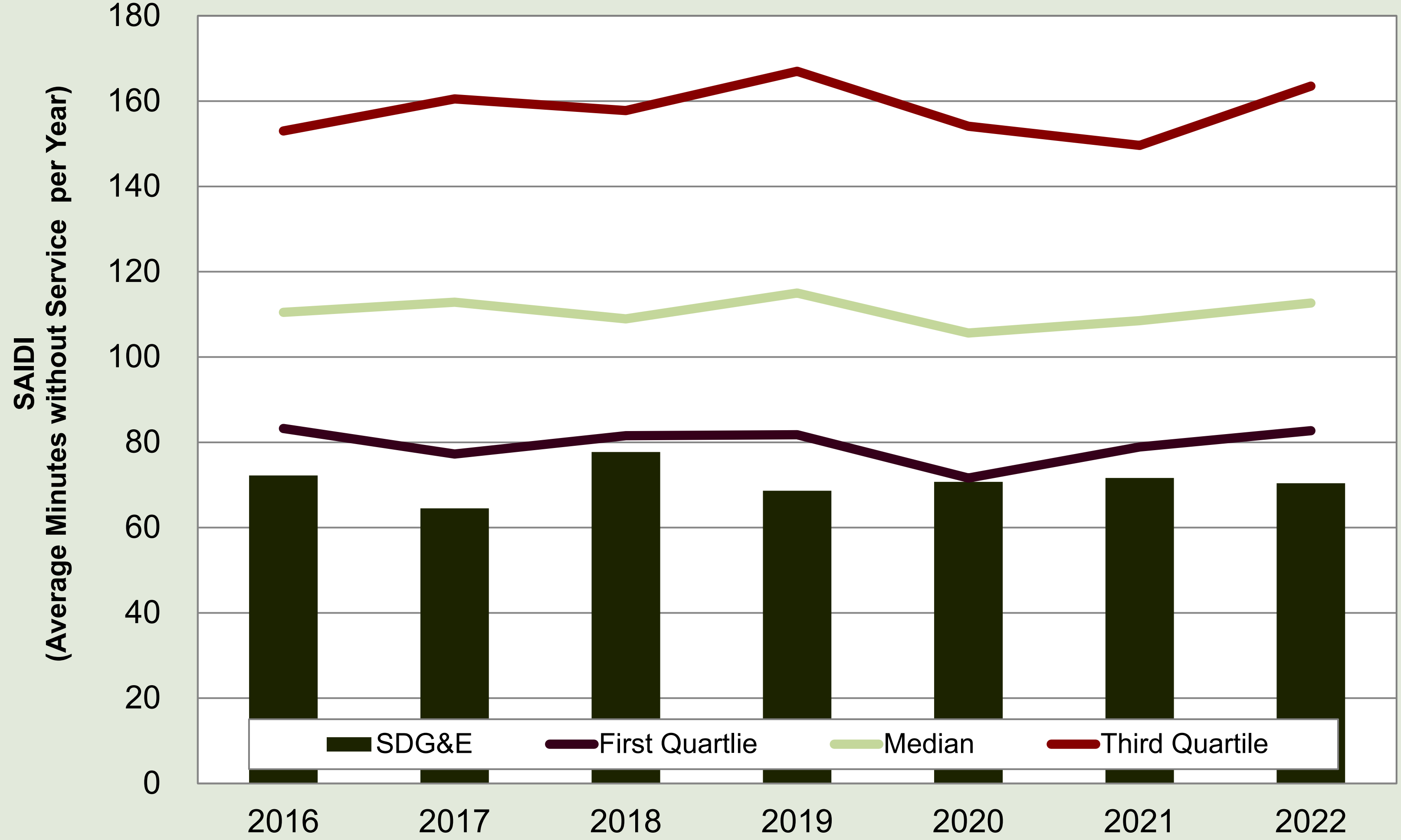
Example: San Diego Gas & Electric reliability comparison (SAIDI)

Although below average, SDG&E has seen very flat SAIDI scores and low improvement over the years.



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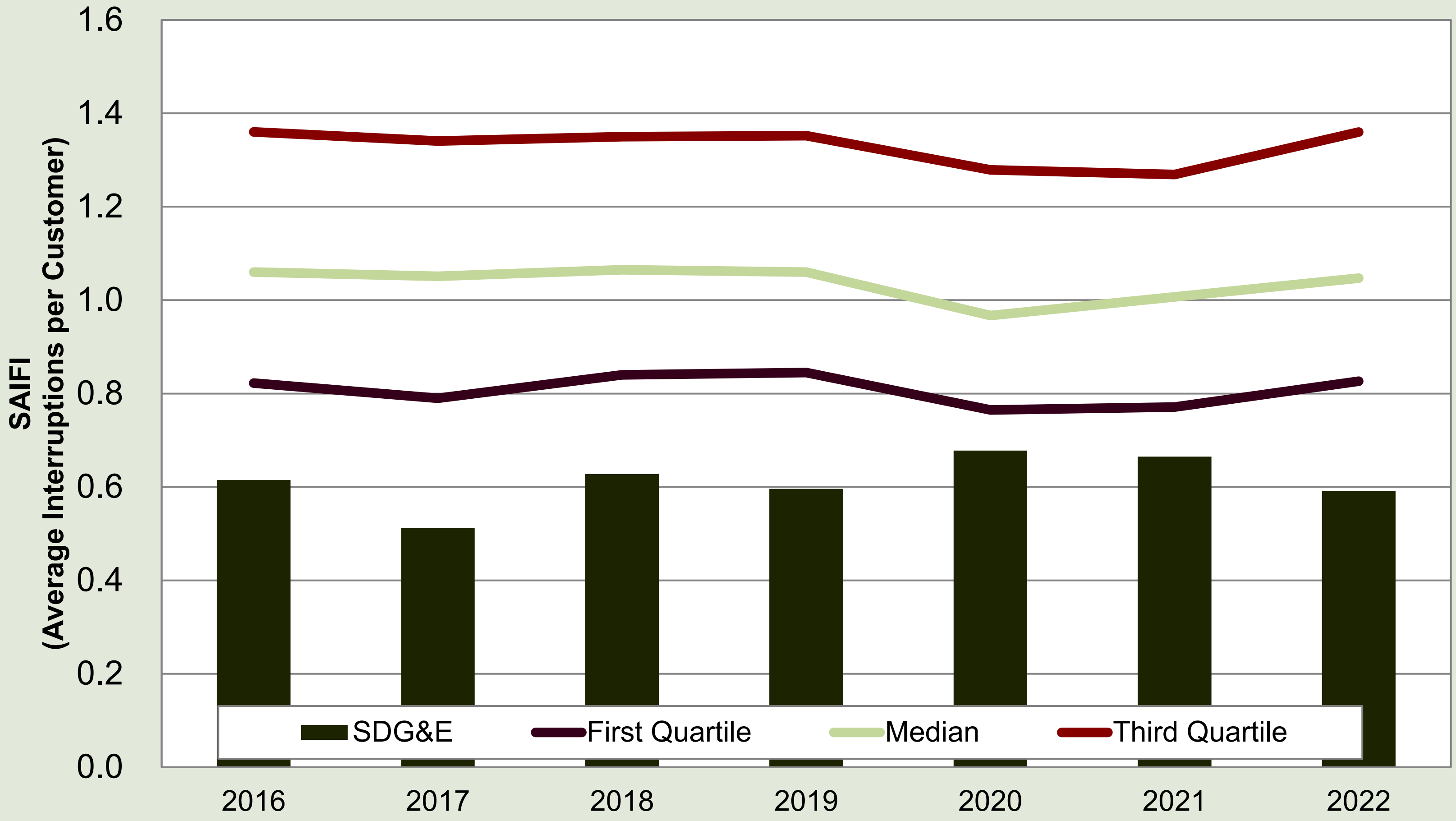
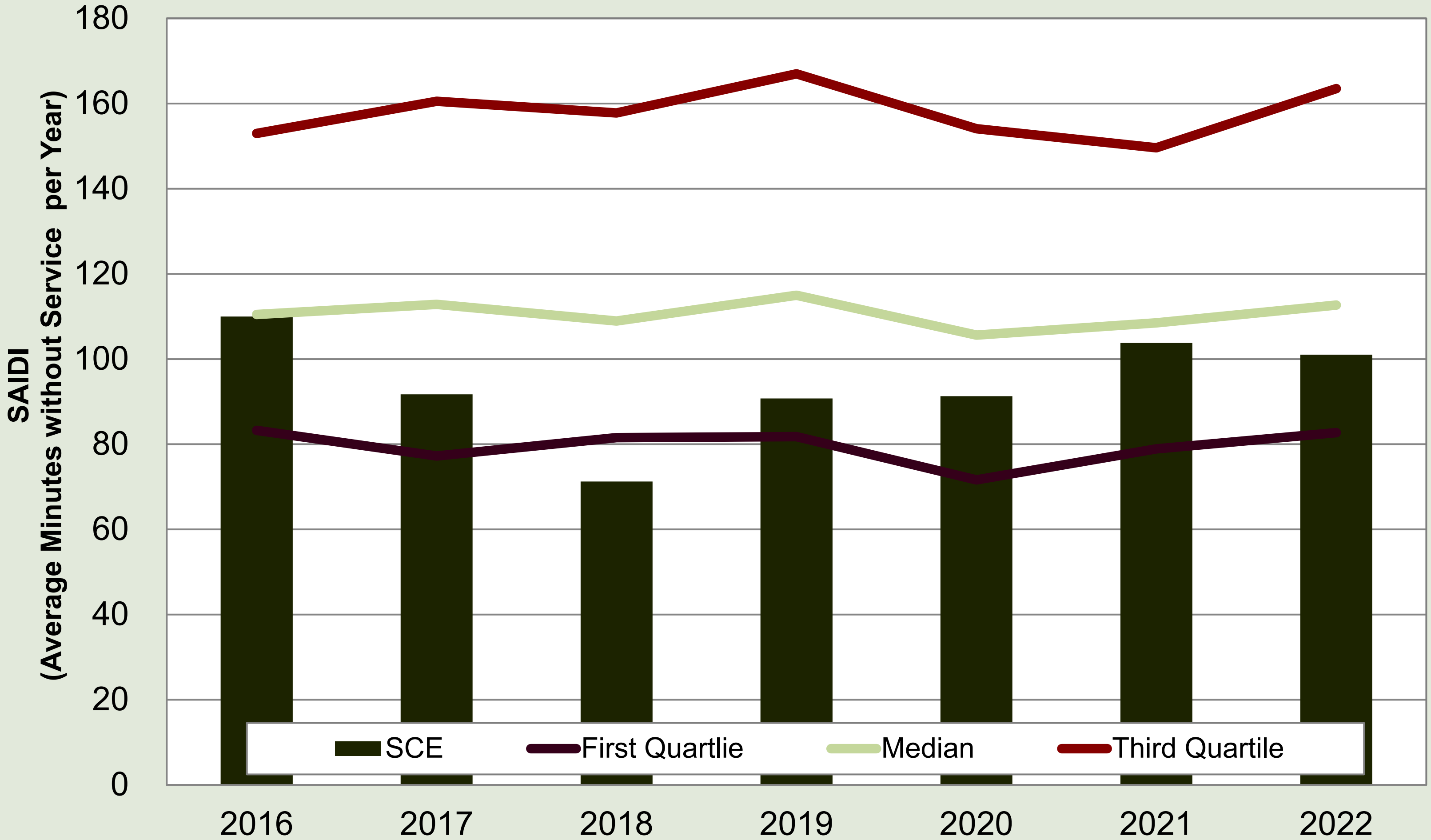
Example: San Diego Gas & Electric reliability comparison (SAIFI)

SDG&E has seen SAIFI scores increase in recent years as compared to previous.



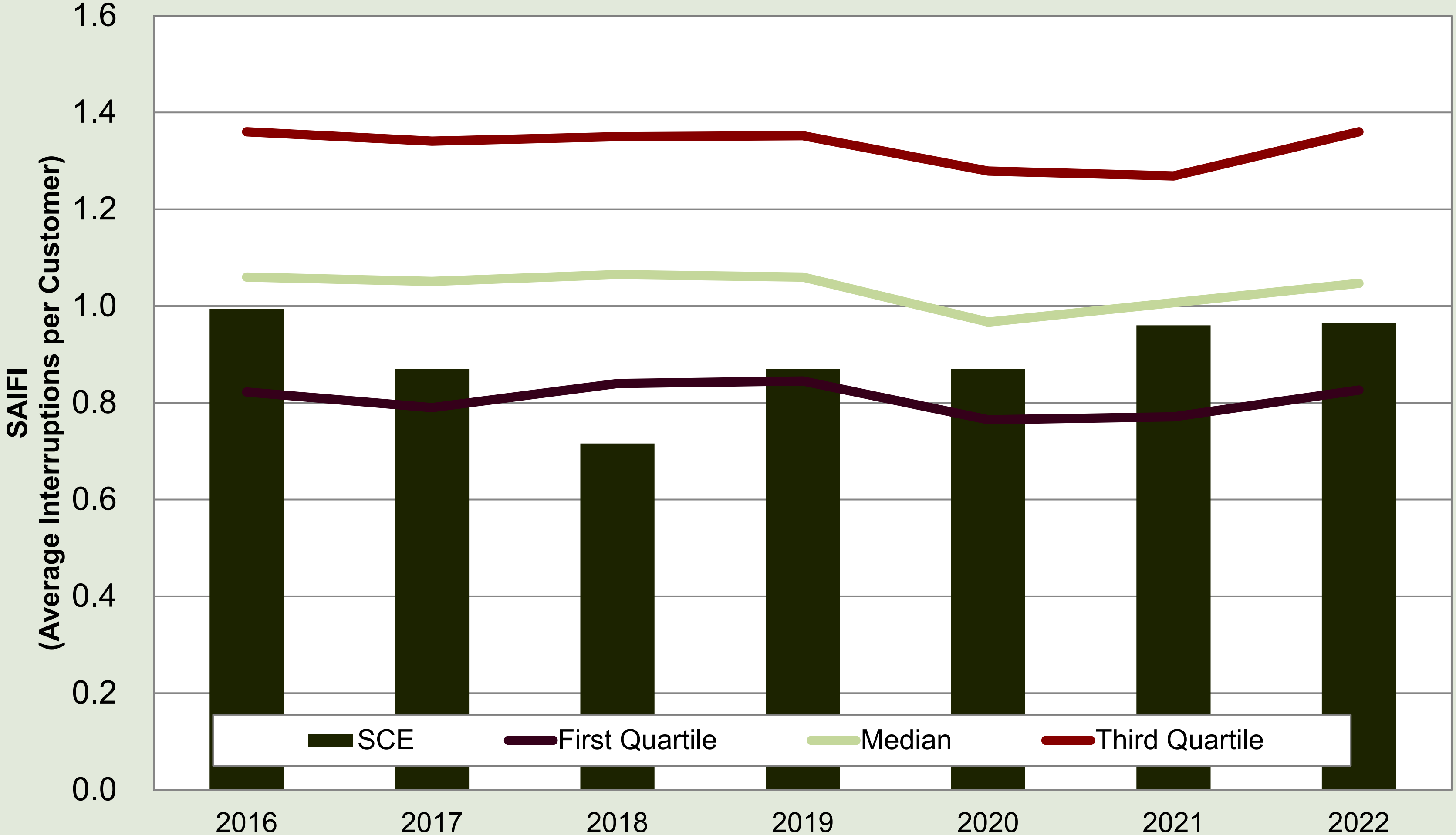
Example: Southern California Edison reliability comparison (SAIDI)

SCE has seen increasing SAIDI scores the last four years as compared to their downward trend between 2016-2018.



Example: Southern California Edison reliability comparison (SAIFI)

SCE has seen increasing SAIFI scores over the last four years.



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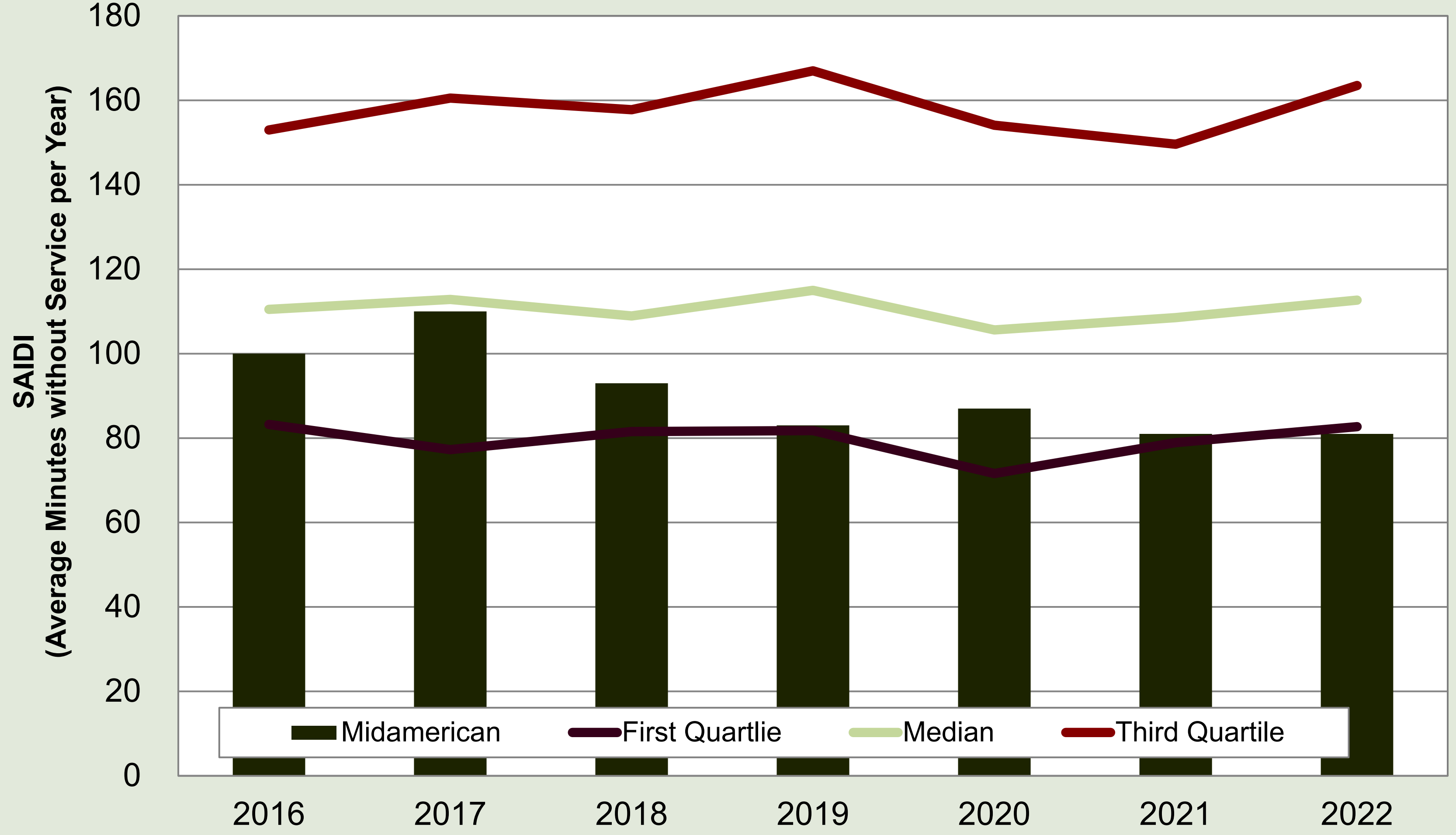
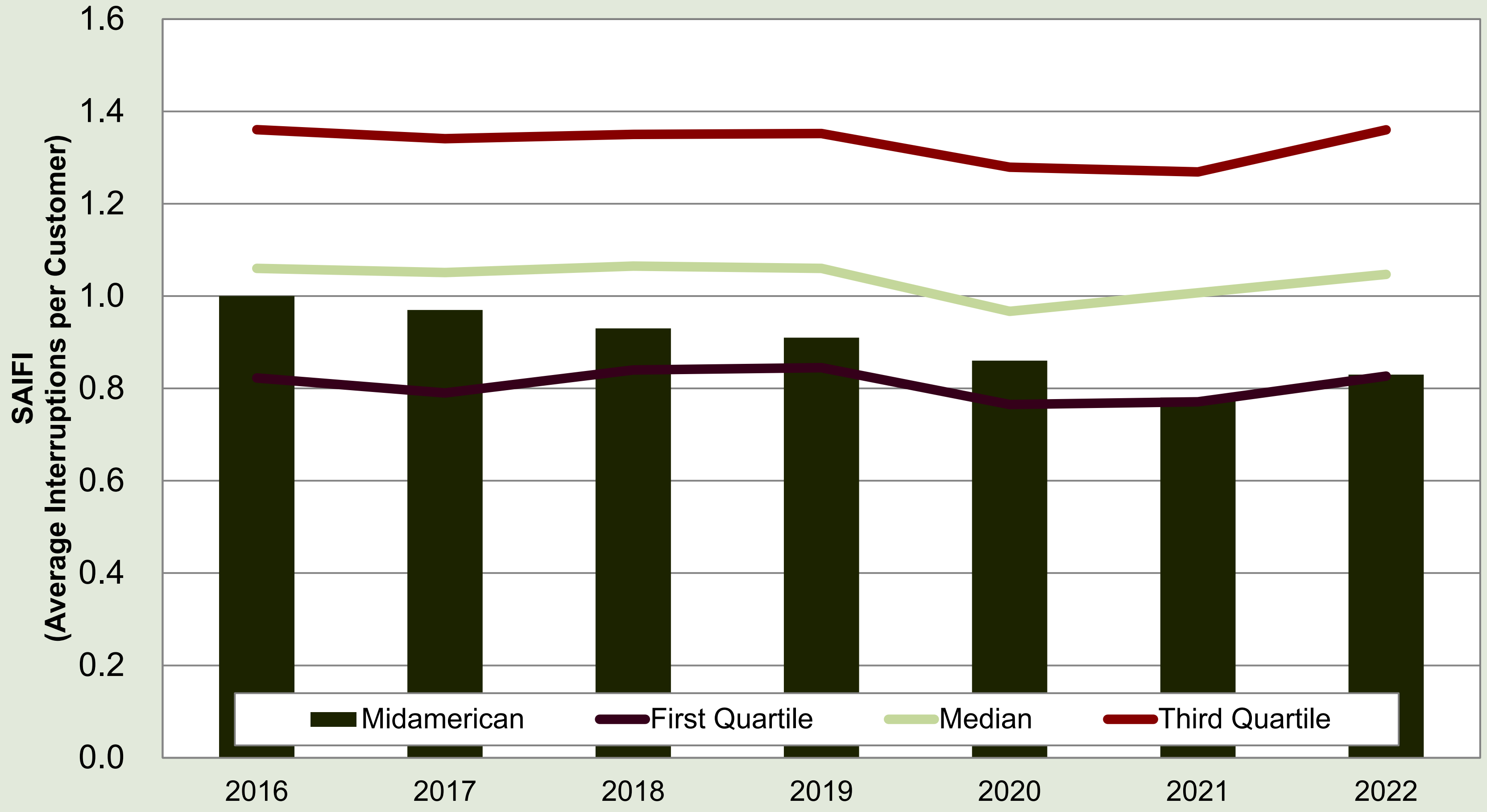
Example: MidAmerican reliability comparison (SAIDI)

MidAmerican has seen mild improvements.



Example: MidAmerican reliability comparison (SAIFI)

MidAmerican has seen relatively flat SAIFI reliability.



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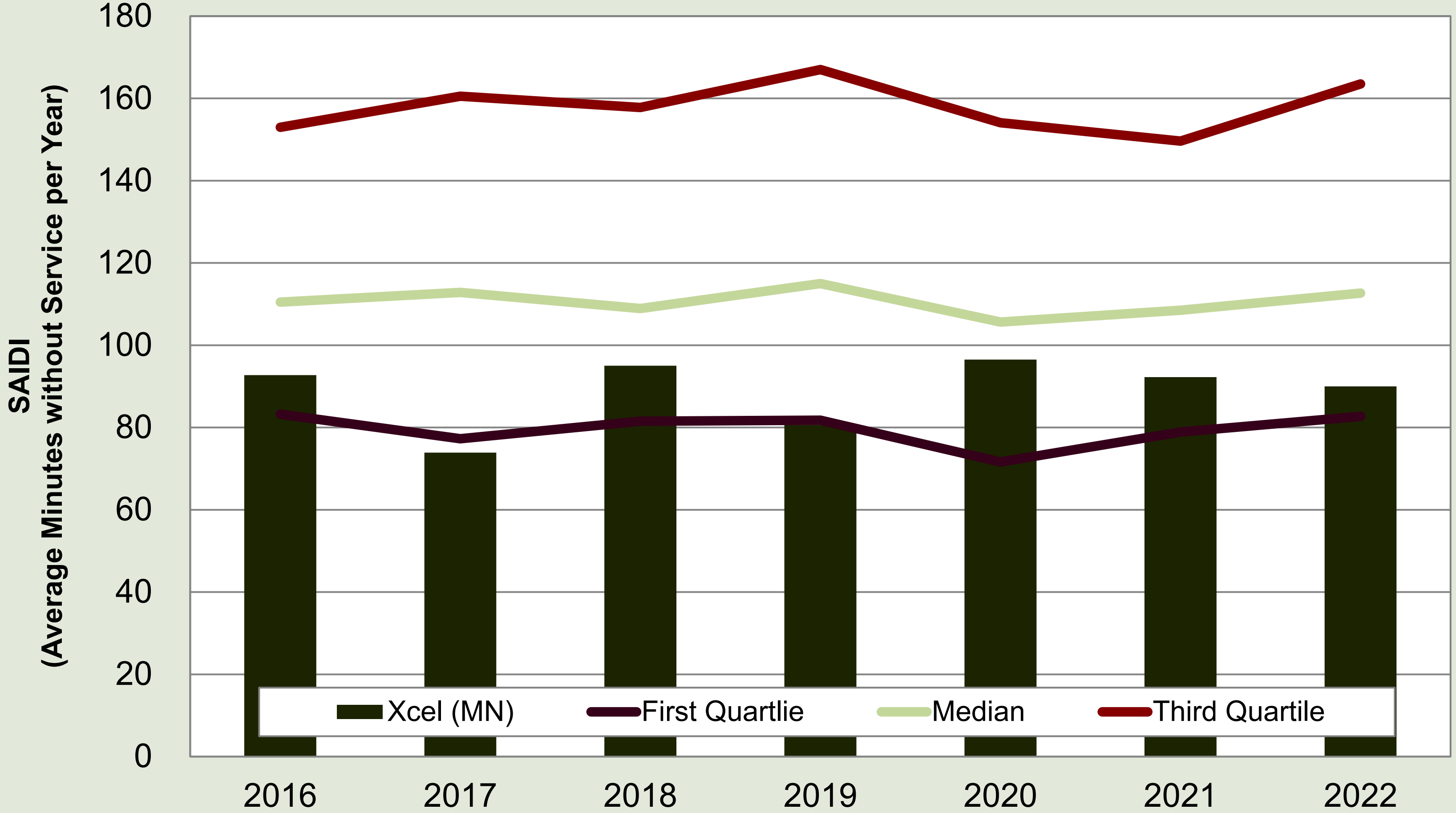
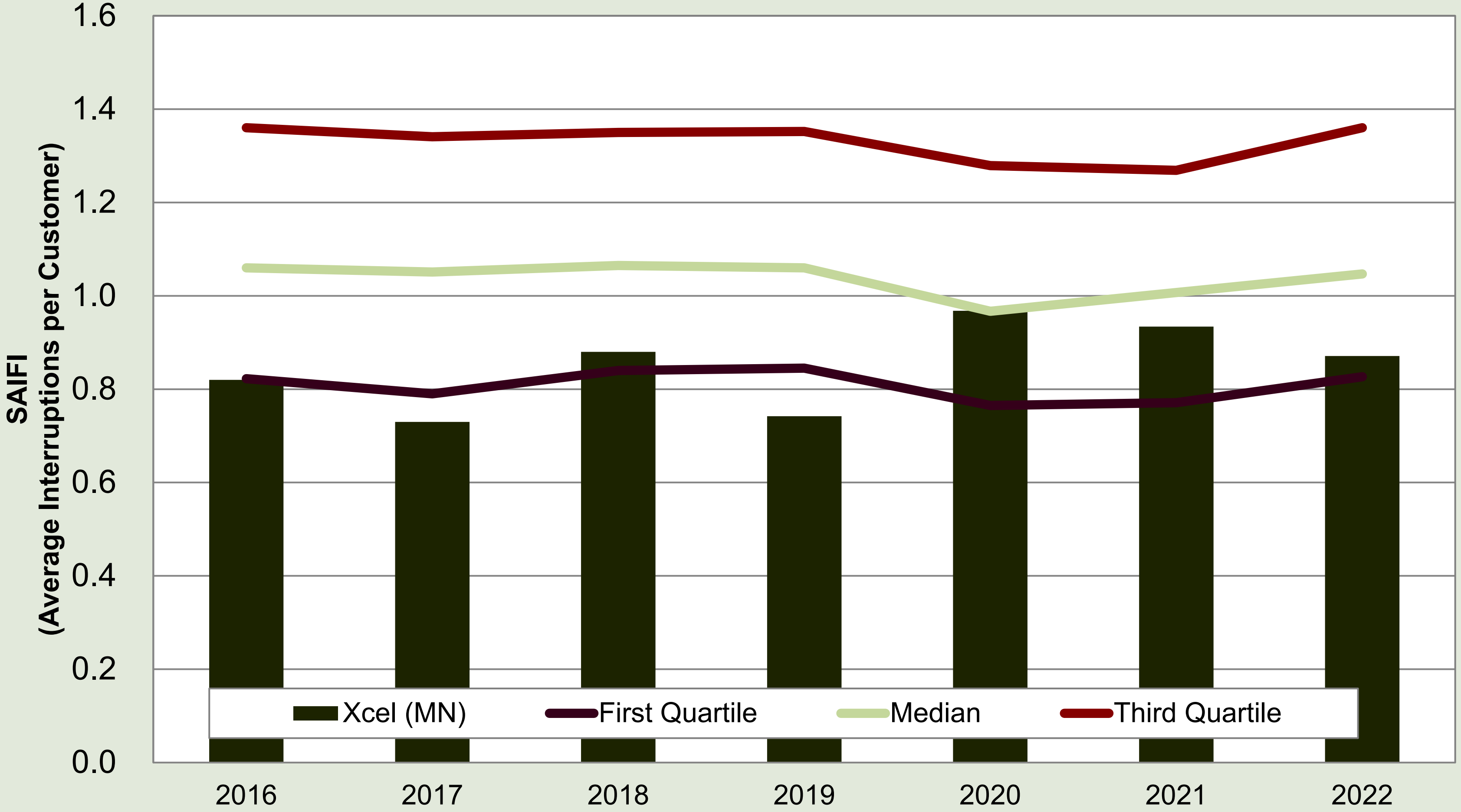
Example: Xcel Minnesota reliability comparison (SAIDI)

Xcel has seen flat level of SAIDI reliability.



Example: Xcel Minnesota reliability comparison (SAIFI)

Xcel has seen the highest level SAIFI scores the past three years.



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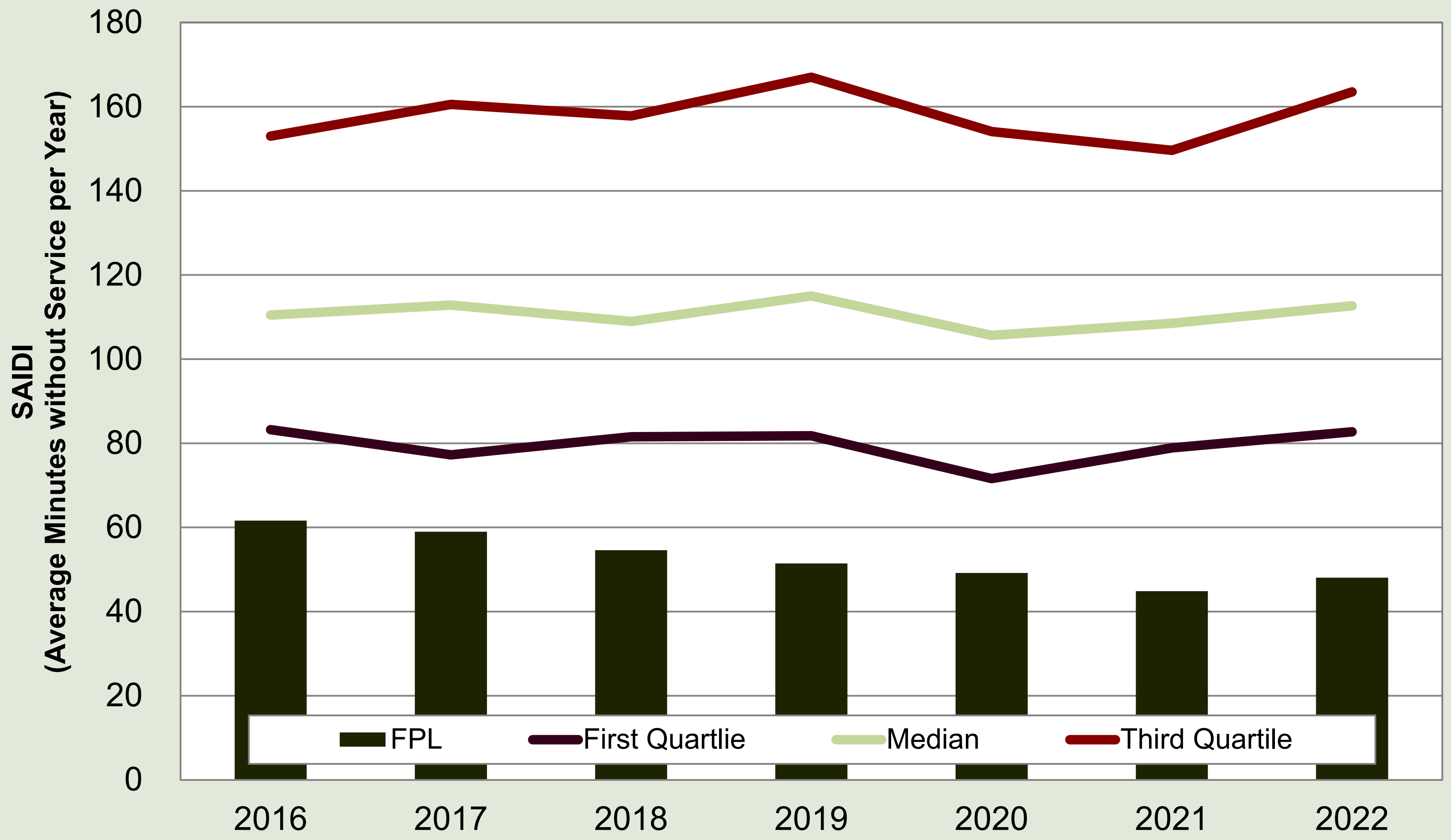
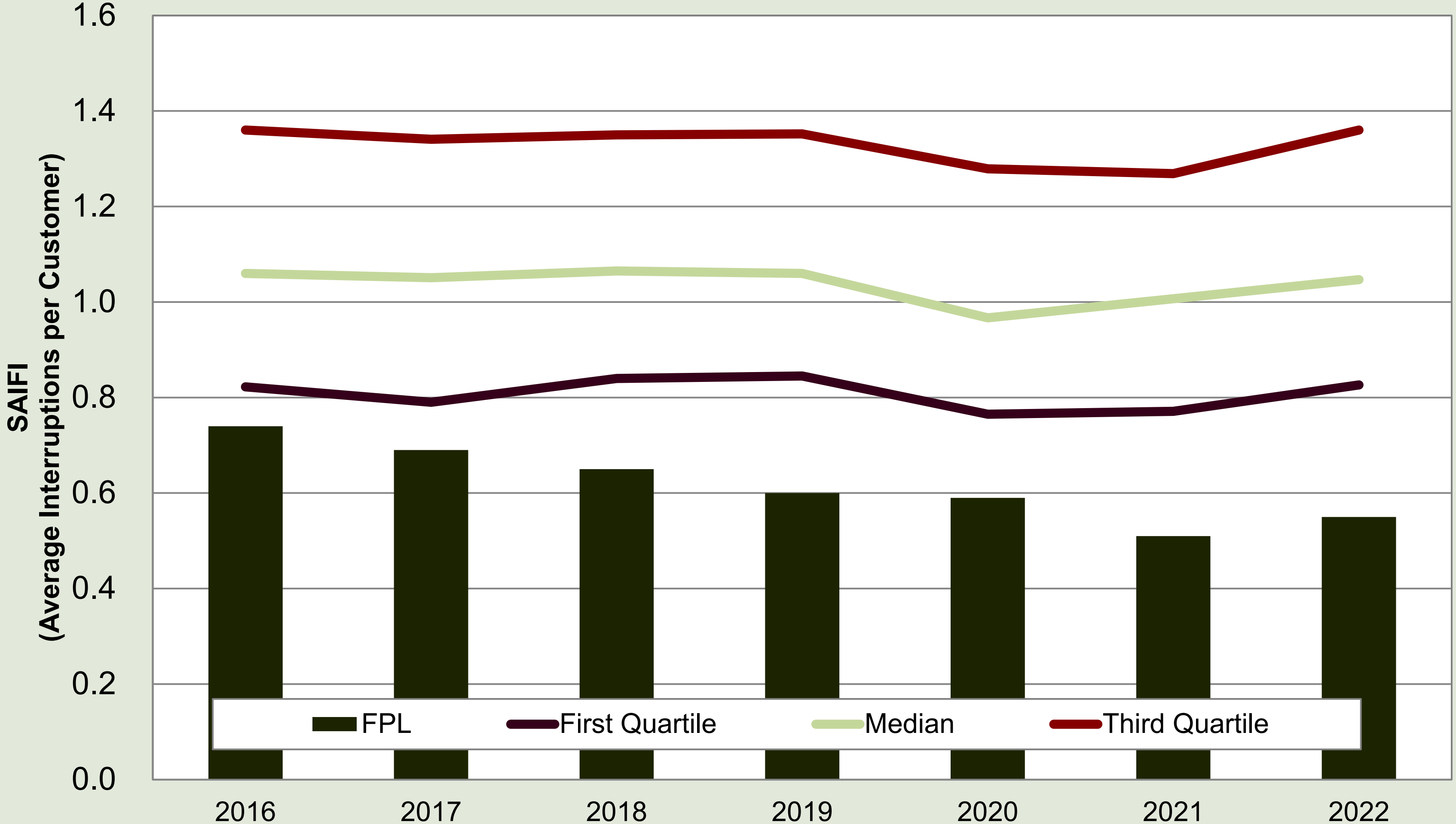
Example: Florida Power & Light reliability comparison (SAIDI)

FP&L has seen improved SAIDI reliability.



Example: Florida Power & Light reliability comparison (SAIFI)

FP&L has seen relatively flat and decreasing SAIFI scores.



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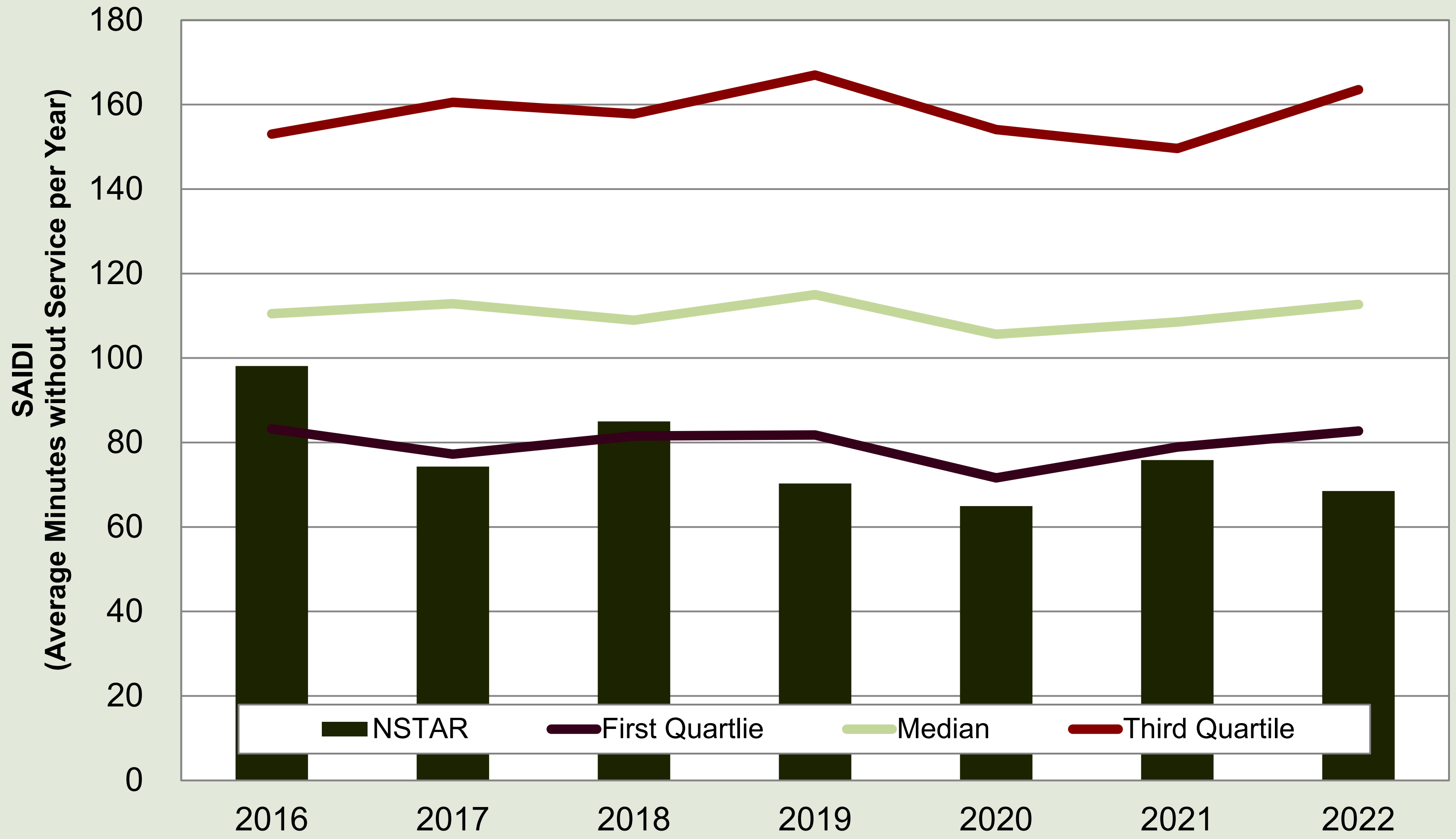
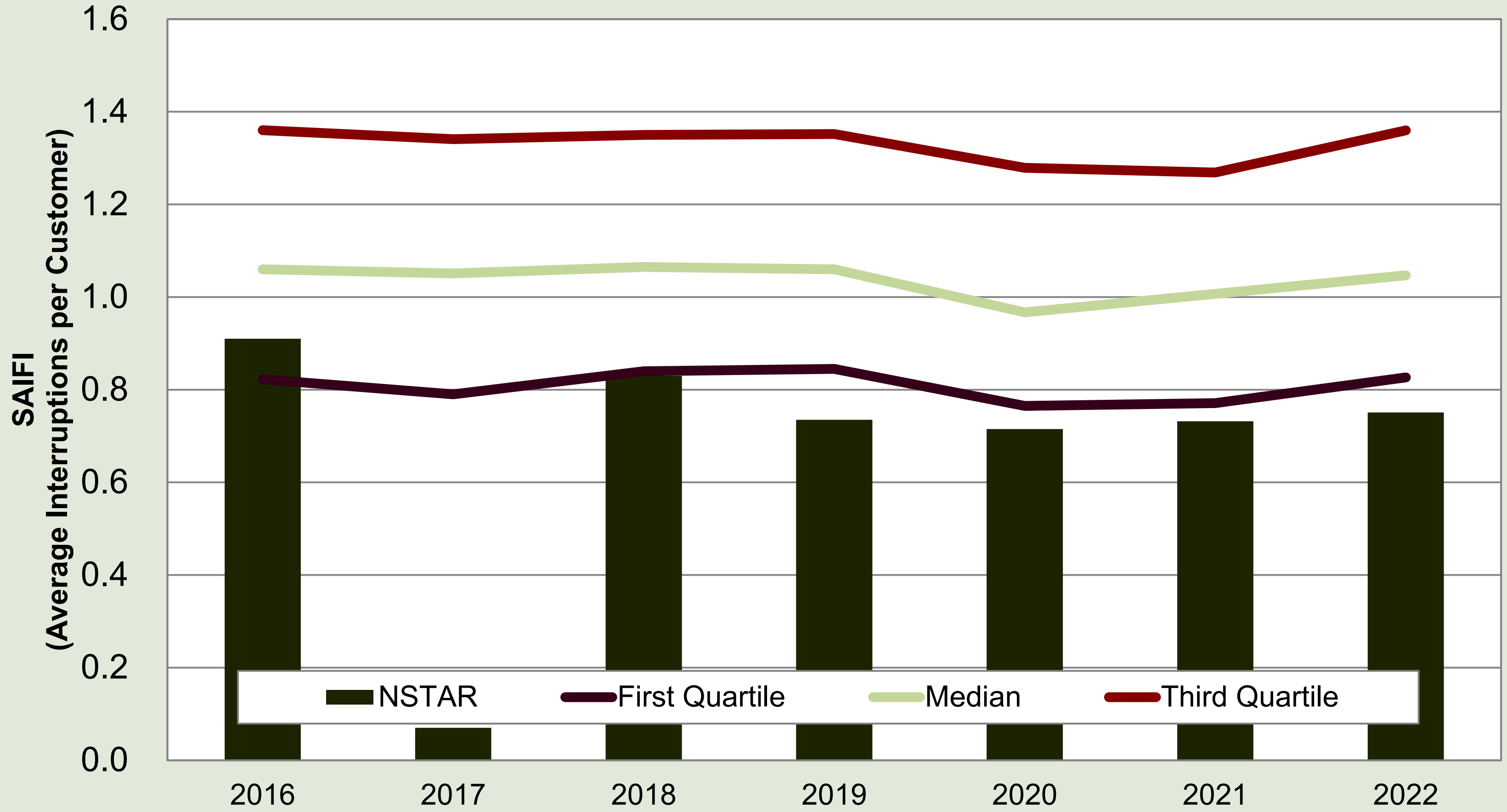
Example: NSTAR reliability comparison (SAIDI)

NSTAR has seen inconsistent SAIDI scores over the years.



Example: NSTAR reliability comparison (SAIFI)

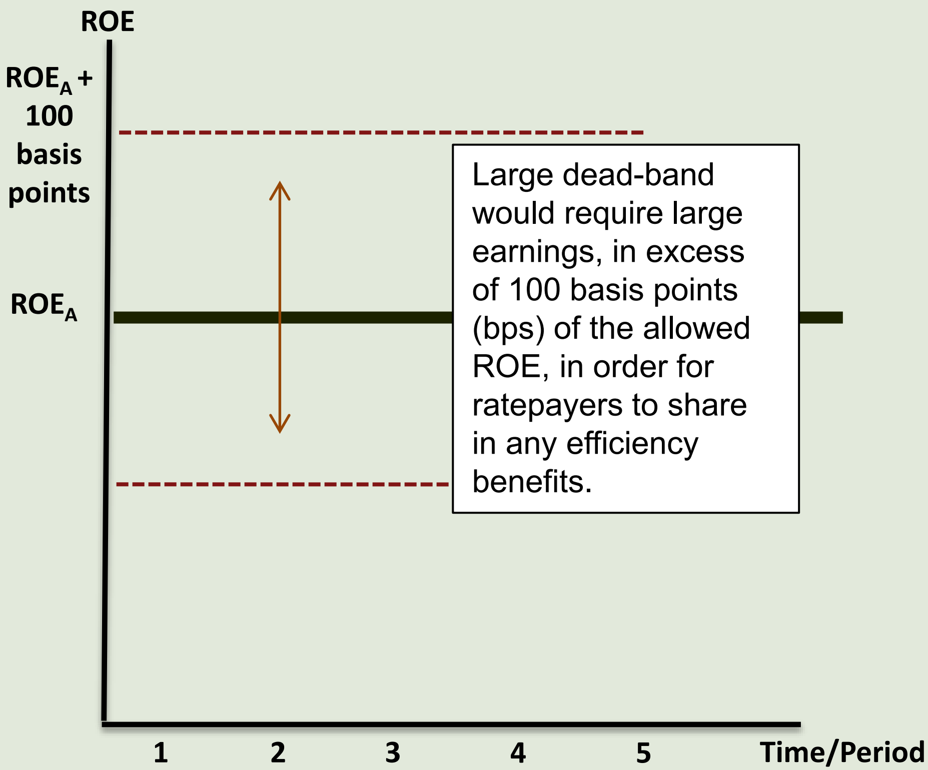
NSTAR has seen relatively flat SAIFI scores over the last few years.

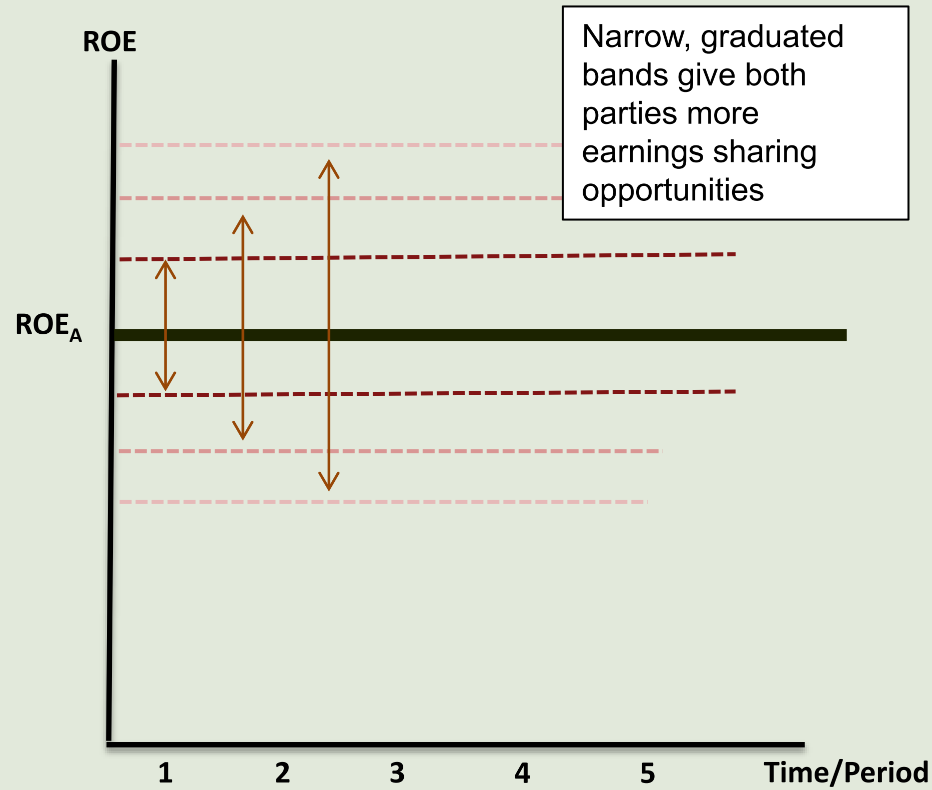


Section 6: Alternative regulation leads to utility gamesmanship

Earnings sharing in alternative regulation.

Most **alternative regulation is paired with earnings sharing mechanisms** that share purported efficiency gains, **as measured through excess earnings**, with ratepayers.





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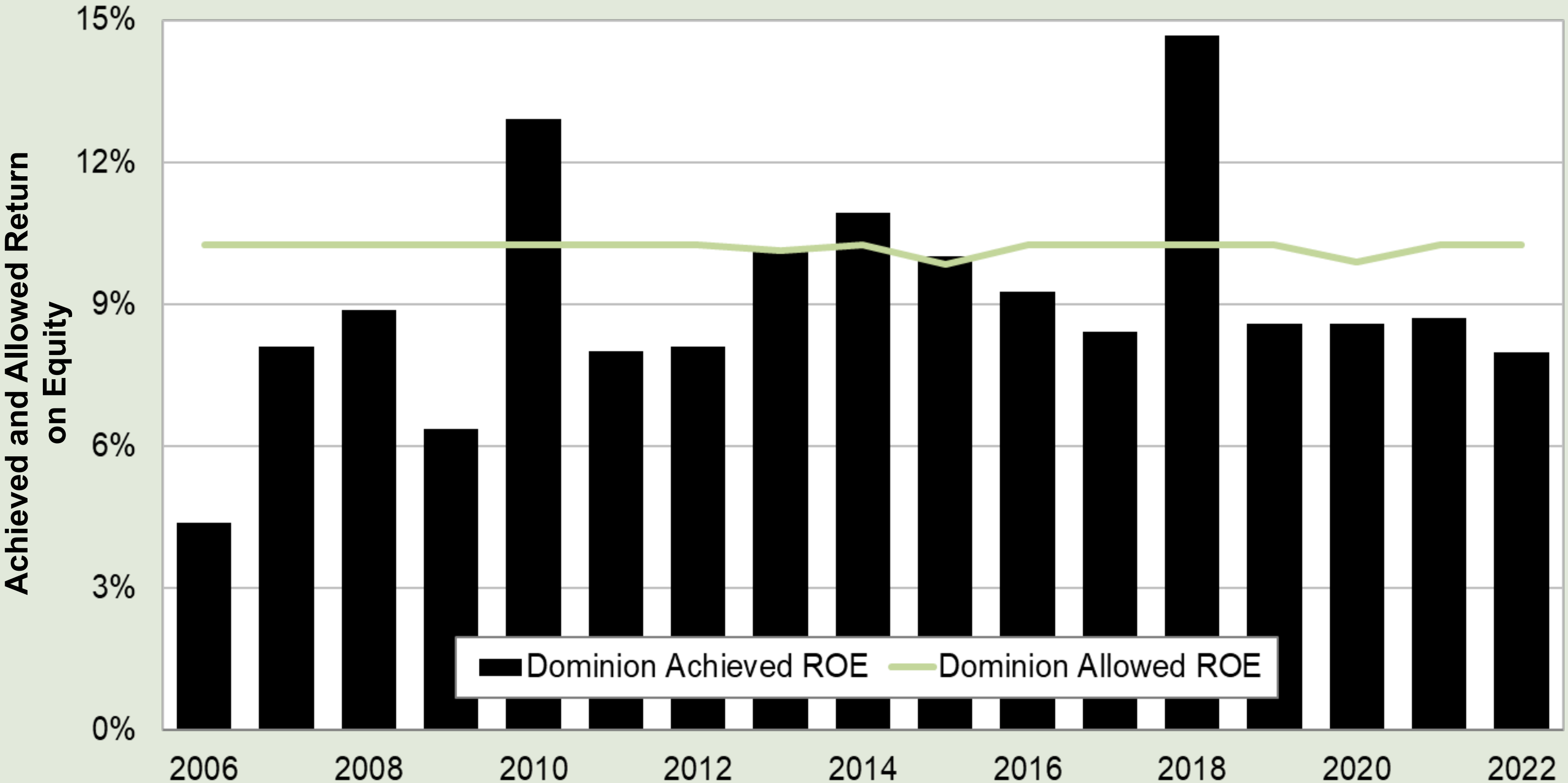
FRP deficiency example: Dominion SC earnings sharing mechanism.

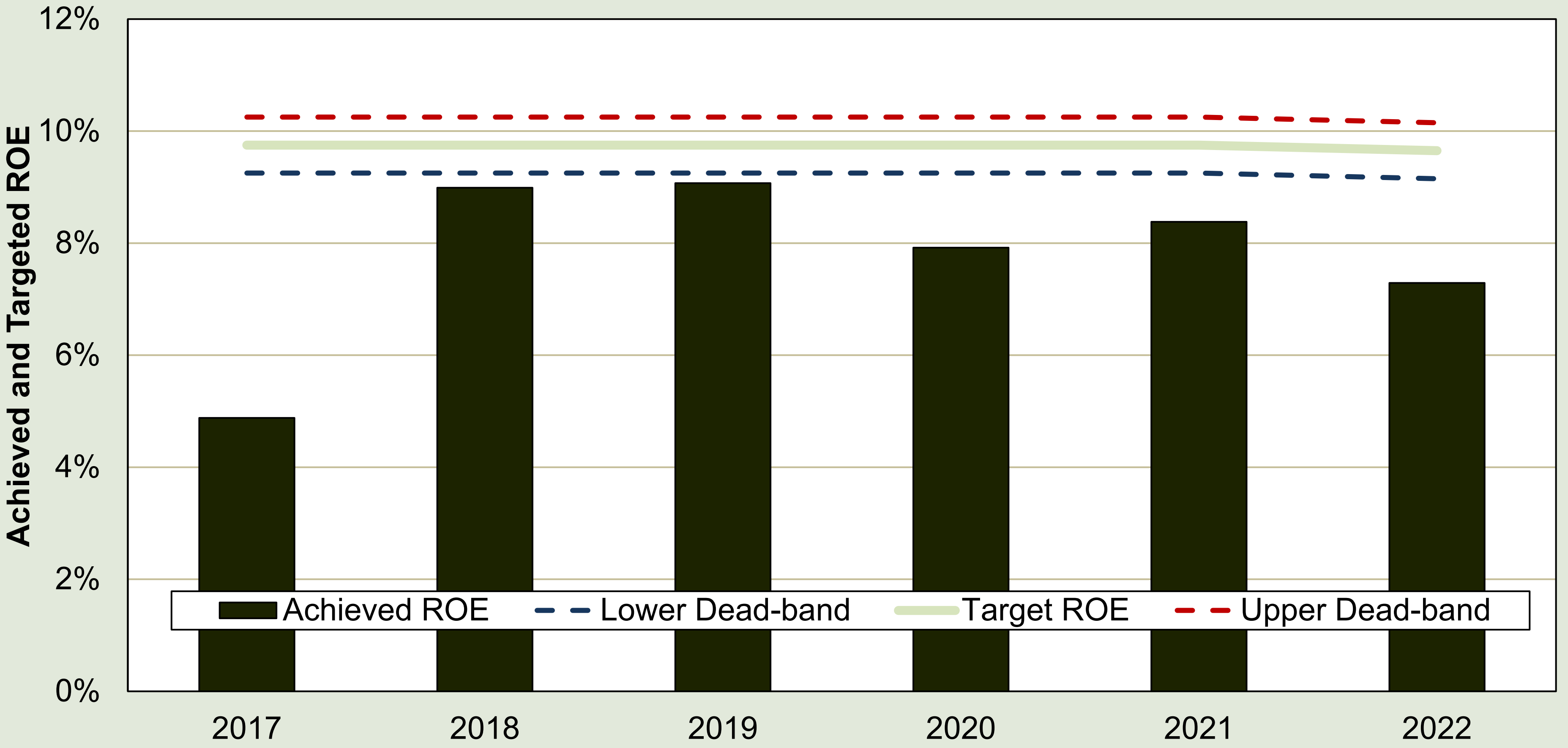
DESC's **achieved ROE has fallen below its allowed ROE deadband in 13 of 17** different FRP reporting periods since FRP was implemented in 2006.



Source: RSA filings and Annual Reports

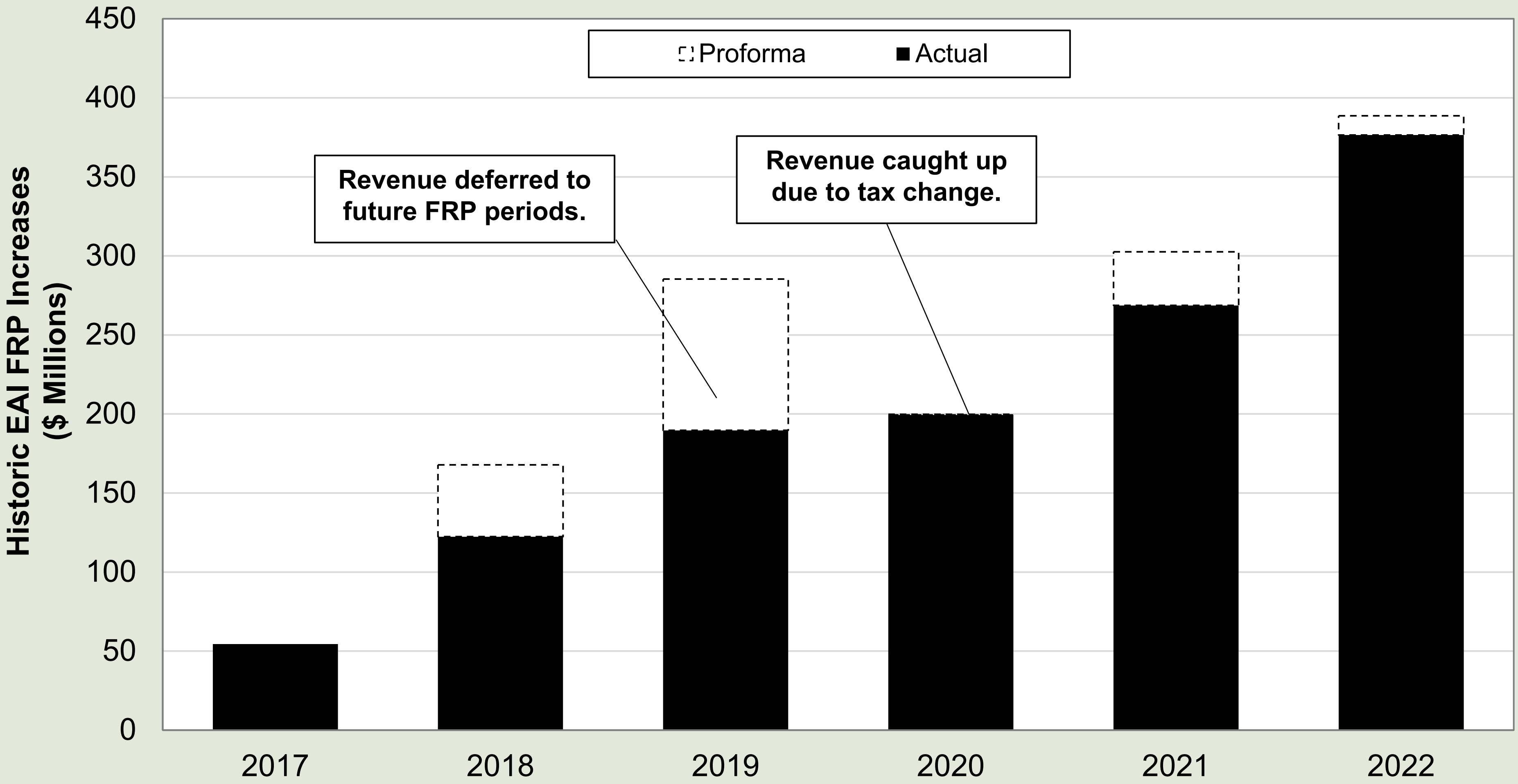
FRP deficiency example: Entergy Arkansas strategic earnings.

EAI has never shared any benefits with ratepayers through its earnings sharing mechanism. Instead, it has **been guaranteed a *de facto* statutorily-allowed four percent rate increase every year**.



FRP deficiency example: EAI revenue alternative regulation increases

EAI has **booked expenses/investments in excess of rate cap** to **assure those investments are "used and useful" for future ratemaking purposes.**



Source: Commission Filings.

Section 7: Pepco Performance

Section 7.1: Retail rates and revenues

Regional non-fuel residential rates ($ per kWh).

Pepco's non-fuel residential rates have been consistently at or above the regional average on a dollar per kWh basis. In 2022 Pepco's residential rates fell below the regional average due to significant rate increase in Duquesne Light Company and PECO Energy Company.

Company	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	($/kWh)									
Potomac Electric Power Company (Pepco)	**$ 0.083**	**$ 0.086**	**$ 0.087**	**$ 0.090**	**$ 0.093**	**$ 0.092**	**$ 0.097**	**$ 0.097**	**$ 0.093**	**$ 0.095**
Atlantic City Electric Company	0.085	0.083	0.095	0.099	0.100	0.097	0.104	0.109	0.106	0.117
Baltimore Gas and Electric Company	0.071	0.072	0.079	0.084	0.085	0.076	0.075	0.076	0.075	0.079
Delmarva Power & Light Company	0.081	0.084	0.085	0.086	0.091	0.086	0.084	0.087	0.089	0.090
Duquesne Light Company	0.088	0.092	0.107	0.109	0.117	0.112	0.122	0.124	0.128	0.143
Jersey Central Power & Light Company	0.074	0.069	0.073	0.073	0.076	0.074	0.074	0.069	0.071	0.078
Metropolitan Edison Company	0.076	0.071	0.079	0.082	0.092	0.087	0.088	0.086	0.088	0.091
PECO Energy Company	0.095	0.095	0.095	0.100	0.098	0.093	0.098	0.099	0.099	0.113
Pennsylvania Electric Company	0.081	0.076	0.091	0.102	0.116	0.111	0.114	0.113	0.113	0.116
Public Service Electric and Gas Company	0.105	0.106	0.107	0.108	0.108	0.106	0.112	0.117	0.122	0.120
Rockland Electric Company	0.089	0.089	0.096	0.096	0.087	0.086	0.078	0.083	0.087	0.091
The Potomac Edison Company	0.061	0.060	0.066	0.073	0.073	0.071	0.072	0.072	0.074	0.073
UGI Utilities, Inc.	0.066	0.066	0.064	0.062	0.061	0.063	0.067	0.067	0.068	0.089
West Penn Power Company	0.050	0.049	0.061	0.070	0.078	0.075	0.078	0.076	0.073	0.082
Peer Group Average	**$ 0.079**	**$ 0.078**	**$ 0.085**	**$ 0.088**	**$ 0.091**	**$ 0.087**	**$ 0.090**	**$ 0.090**	**$ 0.092**	**$ 0.099**

Source: FERC Form 1 as provided by S&P Global.

Rank Order: residential rates.

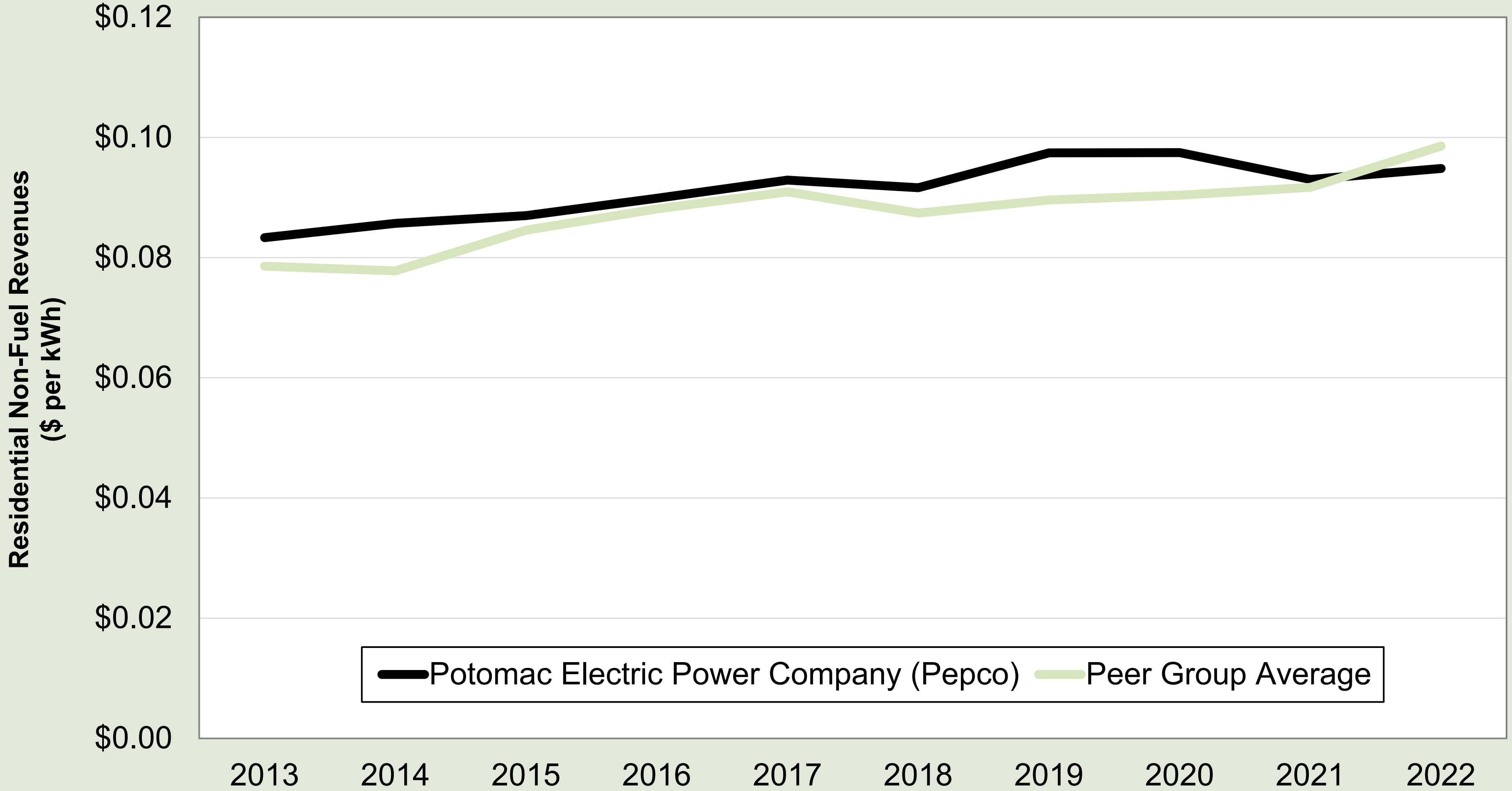
Pepco's residential rates have been consistently ranked 8-10 out of 14 regional peer utilities (meaning Pepco's rates fall in the top half of regional peers) over the period 2013-2022. Importantly, this position has not improved in recent years with the MYP Pilot.

Company	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	(Ranking)									
Potomac Electric Power Company (Pepco)	**9**	**10**	**8**	**8**	**9**	**9**	**9**	**9**	**9**	**9**
Atlantic City Electric Company	10	8	10	10	11	11	11	11	11	12
Baltimore Gas and Electric Company	4	6	6	6	5	5	4	5	5	3
Delmarva Power & Light Company	8	9	7	7	7	7	7	8	8	6
Duquesne Light Company	11	12	13	14	14	14	14	14	14	14
Jersey Central Power & Light Company	5	4	4	4	3	3	3	2	2	2
Metropolitan Edison Company	6	5	5	5	8	8	8	7	7	8
PECO Energy Company	13	13	11	11	10	10	10	10	10	10
Pennsylvania Electric Company	7	7	9	12	13	13	13	12	12	11
Public Service Electric and Gas Company	14	14	14	13	12	12	12	13	13	13
Rockland Electric Company	12	11	12	9	6	6	6	6	6	7
The Potomac Edison Company	2	2	3	3	2	2	2	3	4	1
UGI Utilities, Inc.	3	3	2	1	1	1	1	1	1	5
West Penn Power Company	1	1	1	2	4	4	5	4	3	4

Source: FERC Form 1 as provided by S&P Global.

Trends in residential rates.

Regional residential rates have been increasing slowly since 2013. **Pepco rate increases have been consistent with this regional trend.**



Source: FERC Form 1 as provided by S&P Global.

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Regional commercial rates ($ per kWh).

Pepco's non-fuel commercial rates have consistently been higher than the regional average since 2014. Pepco's relative rate position has dropped to one of the worst in the peer group in recent years.

Company	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	($/kWh)									
Potomac Electric Power Company (Pepco)	**$ 0.021**	**$ 0.024**	**$ 0.025**	**$ 0.026**	**$ 0.030**	**$ 0.031**	**$ 0.037**	**$ 0.037**	**$ 0.041**	**$ 0.048**
Atlantic City Electric Company	0.015	0.015	0.020	0.023	0.020	0.014	0.064	0.069	0.067	0.077
Baltimore Gas and Electric Company	0.048	0.051	0.051	0.053	0.058	0.049	0.051	0.055	0.058	0.070
Delmarva Power & Light Company	0.003	0.004	0.008	0.007	0.013	0.014	0.012	0.012	0.014	0.018
Duquesne Light Company	0.022	0.024	0.022	0.021	0.024	0.023	0.026	0.026	0.027	0.032
Jersey Central Power & Light Company	0.013	0.013	0.013	0.015	0.021	0.015	0.017	0.013	0.012	0.020
Metropolitan Edison Company	0.021	0.018	0.022	0.023	0.026	0.023	0.023	0.030	0.029	0.034
PECO Energy Company	0.029	0.030	0.031	0.033	0.033	0.031	0.032	0.034	0.035	0.040
Pennsylvania Electric Company	0.025	0.023	0.030	0.030	0.035	0.032	0.044	0.041	0.040	0.043
Public Service Electric and Gas Company	0.027	0.027	0.024	0.021	0.025	0.024	0.026	0.030	0.030	0.033
Rockland Electric Company	0.023	0.024	0.022	0.021	0.018	0.012	0.005	0.010	0.007	0.019
The Potomac Edison Company	0.028	0.029	0.030	0.033	0.032	0.031	0.034	0.034	0.039	0.042
UGI Utilities, Inc.	0.014	0.018	0.017	0.019	0.020	0.020	0.021	0.022	0.026	0.019
West Penn Power Company	0.013	0.012	0.014	0.015	0.014	0.018	0.038	0.033	0.031	0.035
Peer Group Average	**$ 0.022**	**$ 0.022**	**$ 0.023**	**$ 0.024**	**$ 0.026**	**$ 0.024**	**$ 0.030**	**$ 0.031**	**$ 0.032**	**$ 0.037**

Source: FERC Form 1 as provided by S&P Global.

Rank Order: commercial rates.

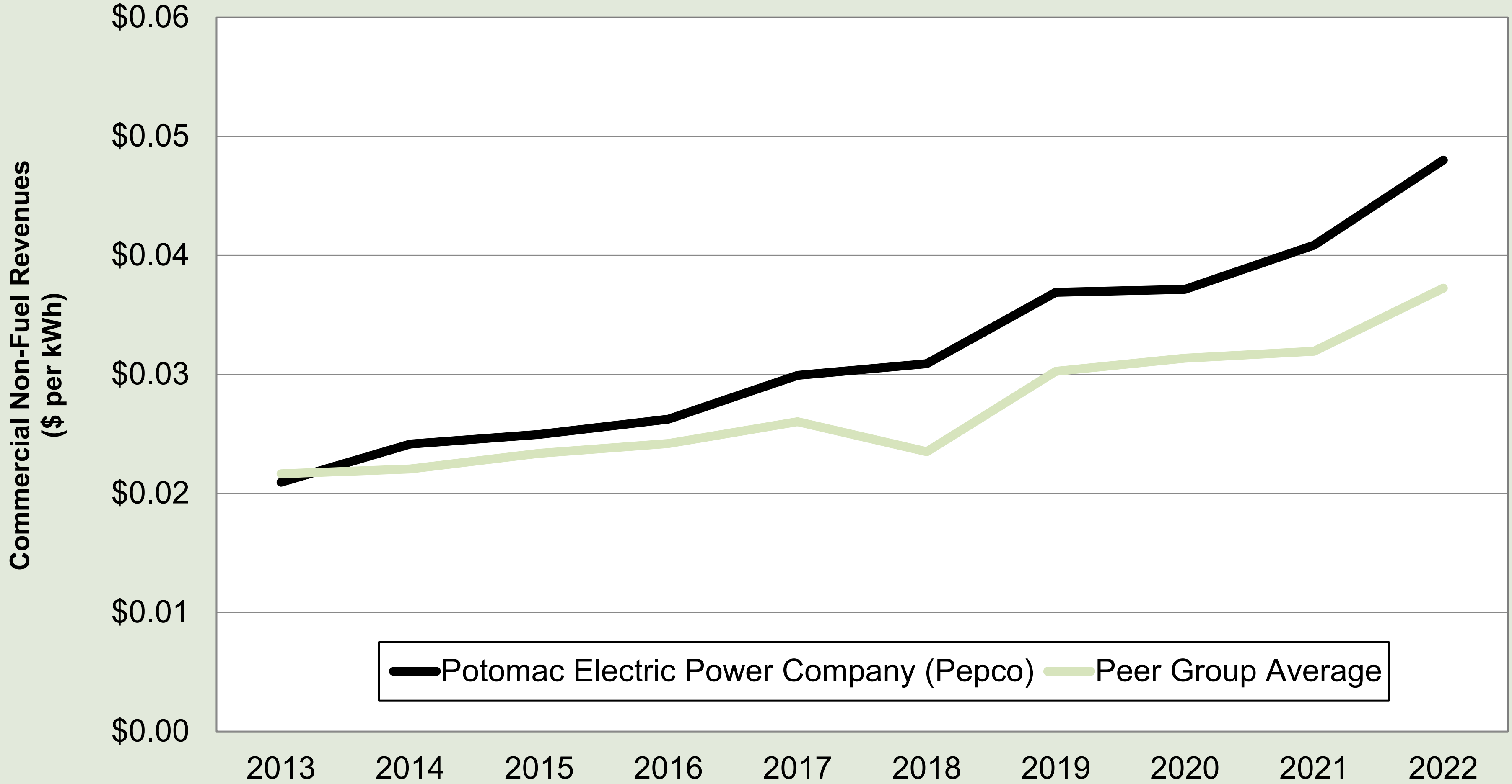
Pepco's commercial rates rank towards to bottom of regional peers, falling to 12th out of 14 peer utilities (meaning Pepco's commercial rates are in the top quartile of regional peers) in 2022.

Company	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	(Ranking)									
Potomac Electric Power Company (Pepco)	**7**	**10**	**10**	**10**	**10**	**11**	**10**	**11**	**12**	**12**
Atlantic City Electric Company	5	4	5	9	4	3	14	14	14	14
Baltimore Gas and Electric Company	14	14	14	14	14	14	13	13	13	13
Delmarva Power & Light Company	1	1	1	1	1	2	2	2	3	1
Duquesne Light Company	8	9	6	7	7	7	7	5	5	5
Jersey Central Power & Light Company	3	3	2	3	6	4	3	3	2	4
Metropolitan Edison Company	6	5	7	8	9	8	5	6	6	7
PECO Energy Company	13	13	13	13	12	10	8	10	9	9
Pennsylvania Electric Company	10	7	11	11	13	13	12	12	11	11
Public Service Electric and Gas Company	11	11	9	5	8	9	6	7	7	6
Rockland Electric Company	9	8	8	6	3	1	1	1	1	3
The Potomac Edison Company	12	12	12	12	11	12	9	9	10	10
UGI Utilities, Inc.	4	6	4	4	5	6	4	4	4	2
West Penn Power Company	2	2	3	2	2	5	11	8	8	8

Source: FERC Form 1 as provided by S&P Global.

Trends in commercial rates.

Pepco's commercial rates continue to grow relative to the regional peer average, and has not improved in recent years due to the MYP Pilot.



Source: FERC Form 1 as provided by S&P Global.

Section 7.2: Operating efficiencies

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Operating Expense Efficiencies

Distribution O&M expense ($ per MWh) comparisons.

Since 2021, Pepco has had distribution O&M expenses greater than those of regional peers.

Company	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	($/MWh)									
Potomac Electric Power Company (Pepco)	**$ 4.81**	**$ 4.72**	**$ 5.19**	**$ 6.06**	**$ 6.26**	**$ 6.84**	**$ 7.91**	**$ 7.71**	**$ 7.91**	**$ 8.36**
Atlantic City Electric Company	6.44	7.38	7.89	9.65	10.63	10.82	12.11	13.00	11.60	12.13
Baltimore Gas and Electric Company	5.65	6.82	6.18	7.85	6.89	7.79	7.14	7.41	8.01	8.25
Delmarva Power & Light Company	4.55	5.85	6.04	6.90	7.14	6.46	7.18	9.12	7.94	7.69
Duquesne Light Company	2.81	3.06	3.20	3.64	3.28	3.38	3.87	4.63	4.42	4.71
Jersey Central Power & Light Company	4.90	4.19	5.04	4.55	4.61	11.91	8.51	14.77	8.13	7.83
Metropolitan Edison Company	2.65	3.72	2.86	3.27	3.73	7.84	5.12	5.79	5.49	6.32
PECO Energy Company	5.31	8.41	6.54	6.90	7.05	8.70	8.46	11.59	9.84	9.51
Pennsylvania Electric Company	3.04	3.07	3.19	3.27	4.82	6.13	5.00	5.52	5.11	7.78
Public Service Electric and Gas Company	3.92	4.15	4.05	4.24	4.16	4.72	4.25	4.78	4.44	4.36
Rockland Electric Company	6.98	7.44	9.99	11.72	12.26	10.93	10.07	12.37	14.17	15.63
The Potomac Edison Company	2.50	4.03	3.15	3.10	3.09	3.41	4.45	4.22	4.39	5.66
UGI Utilities, Inc.	5.95	7.97	6.73	7.18	7.31	8.09	9.45	8.63	11.40	11.48
West Penn Power Company	1.89	1.90	2.74	2.44	3.45	4.08	4.24	3.99	4.06	5.77
Peer Group Average	**$ 4.35**	**$ 5.23**	**$ 5.20**	**$ 5.75**	**$ 6.03**	**$ 7.25**	**$ 6.91**	**$ 8.14**	**$ 7.62**	**$ 8.24**

Source: FERC Form 1 as provided by S&P Global.

Rankings: distribution O&M expenses ($ per MWh).

Pepco ranks in the middle of peers in terms of distribution O&M performance. In 2022, they ranked 10 out of 14.

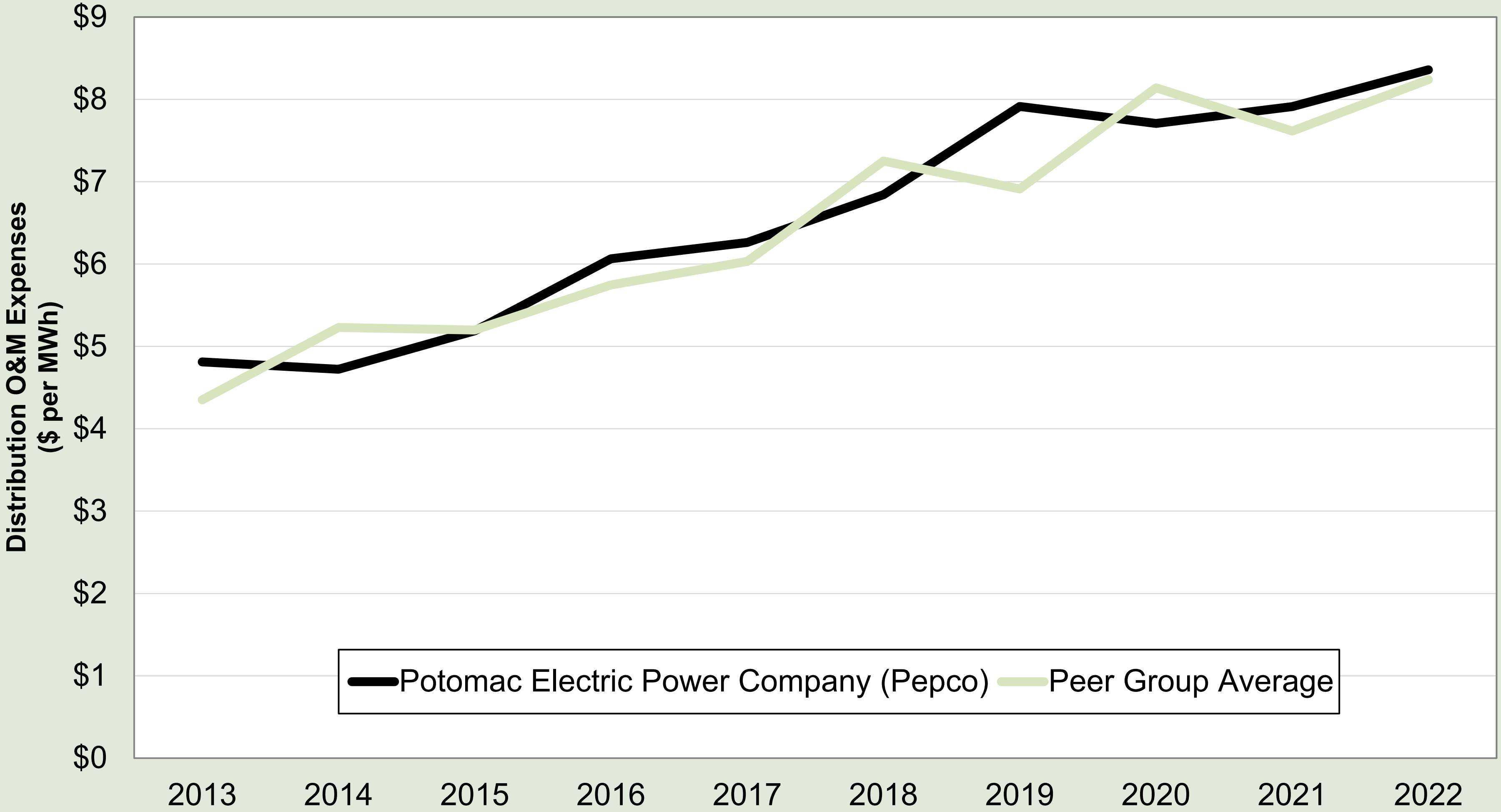
Company	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	(Ranking)									
Potomac Electric Power Company (Pepco)	**8**	**8**	**8**	**8**	**8**	**7**	**9**	**8**	**7**	**10**
Atlantic City Electric Company	13	11	13	13	13	12	14	13	13	13
Baltimore Gas and Electric Company	11	10	10	12	9	8	7	7	9	9
Delmarva Power & Light Company	7	9	9	9	11	6	8	10	8	6
Duquesne Light Company	4	2	5	5	2	1	1	3	3	2
Jersey Central Power & Light Company	9	7	7	7	6	14	11	14	10	8
Metropolitan Edison Company	3	4	2	3	4	9	6	6	6	5
PECO Energy Company	10	14	11	10	10	11	10	11	11	11
Pennsylvania Electric Company	5	3	4	4	7	5	5	5	5	7
Public Service Electric and Gas Company	6	6	6	6	5	4	3	4	4	1
Rockland Electric Company	14	12	14	14	14	13	13	12	14	14
The Potomac Edison Company	2	5	3	2	1	2	4	2	2	3
UGI Utilities, Inc.	12	13	12	11	12	10	12	9	12	12
West Penn Power Company	1	1	1	1	3	3	2	1	1	4

Source: FERC Form 1 as provided by S&P Global.

Operating Expense Efficiencies

Trends: Distribution O&M expenses ($ per MWh).

Since 2013, Pepco has exceeded the peer group average six times.



Source: FERC Form 1 as provided by S&P Global.

A&G expense ($ per MWh) comparisons.

Pepco has seen improvement in their A&G expense performance. In 2013, their A&G expense was $6.40 per MWh compared to $4.07 per MWh in 2022.

Company	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	($/MWh)									
Potomac Electric Power Company (Pepco)	**$ 6.40**	**$ 6.14**	**$ 6.81**	**$ 6.26**	**$ 6.48**	**$ 5.20**	**$ 5.77**	**$ 3.97**	**$ 4.04**	**$ 4.07**
Atlantic City Electric Company	5.58	5.93	5.67	8.86	7.66	10.32	9.71	9.95	9.26	9.46
Baltimore Gas and Electric Company	3.79	4.30	4.64	4.62	5.07	5.10	5.09	5.89	5.22	5.41
Delmarva Power & Light Company	4.52	4.49	4.56	6.99	6.24	7.92	7.13	7.48	7.47	7.72
Duquesne Light Company	4.59	5.29	6.38	6.93	6.65	6.89	9.06	9.03	9.15	9.43
Jersey Central Power & Light Company	2.27	2.68	1.79	3.29	3.81	3.97	3.48	3.60	4.26	6.64
Metropolitan Edison Company	2.70	2.97	2.75	3.24	3.08	4.36	2.88	3.23	2.59	2.96
PECO Energy Company	3.53	3.49	3.49	3.93	4.20	4.29	3.80	4.53	4.02	4.19
Pennsylvania Electric Company	2.58	2.71	2.61	3.22	3.19	3.77	3.11	3.48	2.94	3.50
Public Service Electric and Gas Company	2.76	2.65	3.14	3.24	3.63	3.27	3.49	3.56	3.57	4.12
Rockland Electric Company	6.64	6.58	7.05	7.88	7.89	7.57	8.41	9.64	8.52	9.85
The Potomac Edison Company	2.00	2.12	1.90	2.47	2.60	3.12	2.97	3.26	2.62	3.07
UGI Utilities, Inc.	4.11	5.54	6.72	4.64	6.36	6.48	6.66	8.48	7.34	7.88
West Penn Power Company	2.08	2.33	2.17	2.63	2.86	2.99	2.86	3.43	2.54	2.93
Peer Group Average	**$ 3.63**	**$ 3.93**	**$ 4.07**	**$ 4.77**	**$ 4.86**	**$ 5.39**	**$ 5.28**	**$ 5.81**	**$ 5.34**	**$ 5.94**

Source: FERC Form 1 as provided by S&P Global.

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Operating Expense Efficiencies

Rankings: A&G expenses ($ per MWh).

Compared to regional peers, Pepco ranks in the top five in terms of A&G expense per MWh. This is an improvement from 2013 where they were ranked 13 out of 14.

Company	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	(Ranking)									
Potomac Electric Power Company (Pepco)	**13**	**13**	**13**	**10**	**11**	**9**	**9**	**7**	**7**	**5**
Atlantic City Electric Company	12	12	10	14	13	14	14	14	14	13
Baltimore Gas and Electric Company	8	8	9	8	8	8	8	9	9	8
Delmarva Power & Light Company	10	9	8	12	9	13	11	10	11	10
Duquesne Light Company	11	10	11	11	12	11	13	12	13	12
Jersey Central Power & Light Company	3	4	1	6	6	5	5	6	8	9
Metropolitan Edison Company	5	6	5	5	3	7	2	1	2	2
PECO Energy Company	7	7	7	7	7	6	7	8	6	7
Pennsylvania Electric Company	4	5	4	3	4	4	4	4	4	4
Public Service Electric and Gas Company	6	3	6	4	5	3	6	5	5	6
Rockland Electric Company	14	14	14	13	14	12	12	13	12	14
The Potomac Edison Company	1	1	2	1	1	2	3	2	3	3
UGI Utilities, Inc.	9	11	12	9	10	10	10	11	10	11
West Penn Power Company	2	2	3	2	2	1	1	3	1	1

Source: FERC Form 1 as provided by S&P Global.

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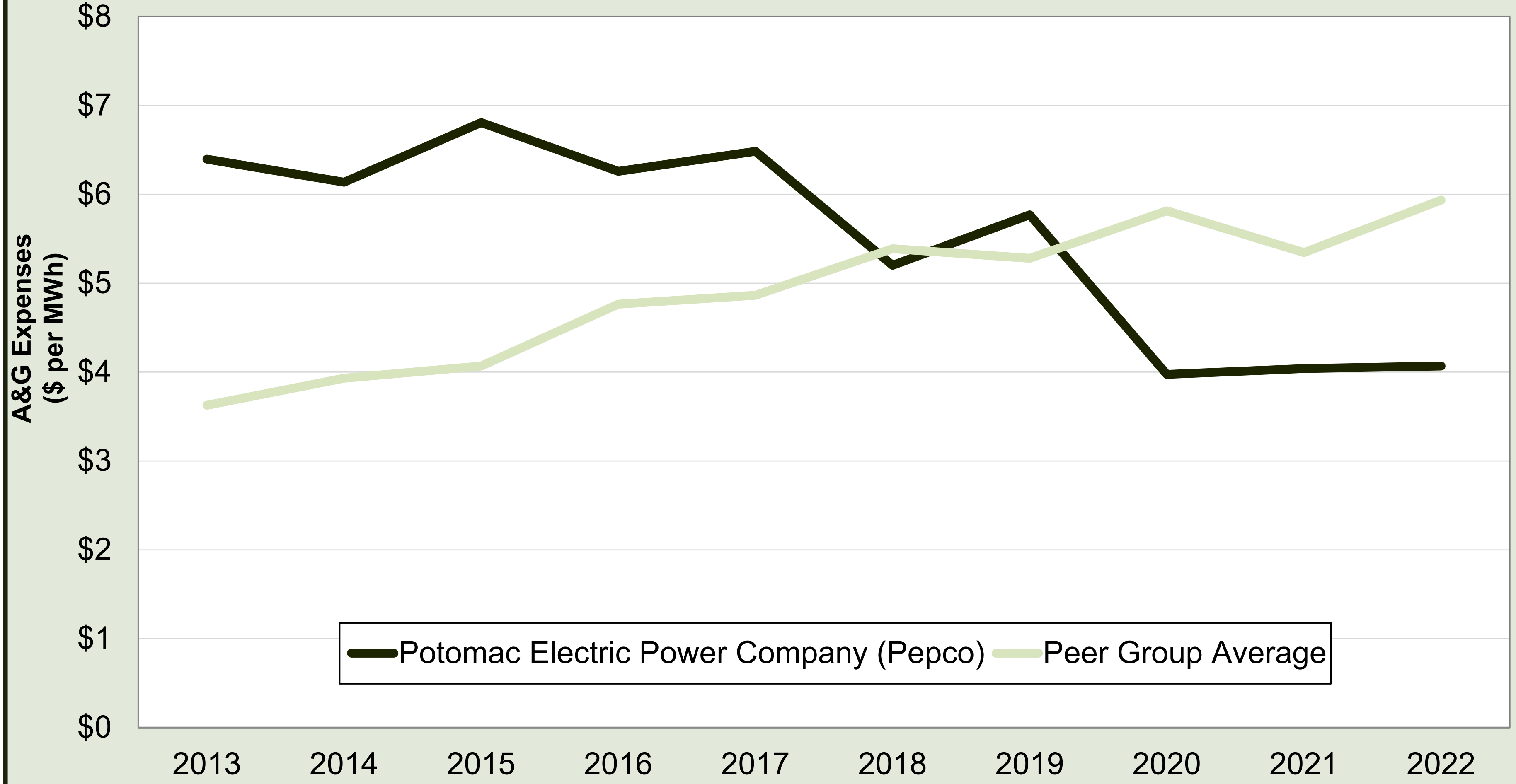
Operating Expense Efficiencies

Trends: A&G expenses ($ per MWh).

Starting in 2018, Pepco has seen improvement compared to regional peers. A&G expense has been level since 2020.

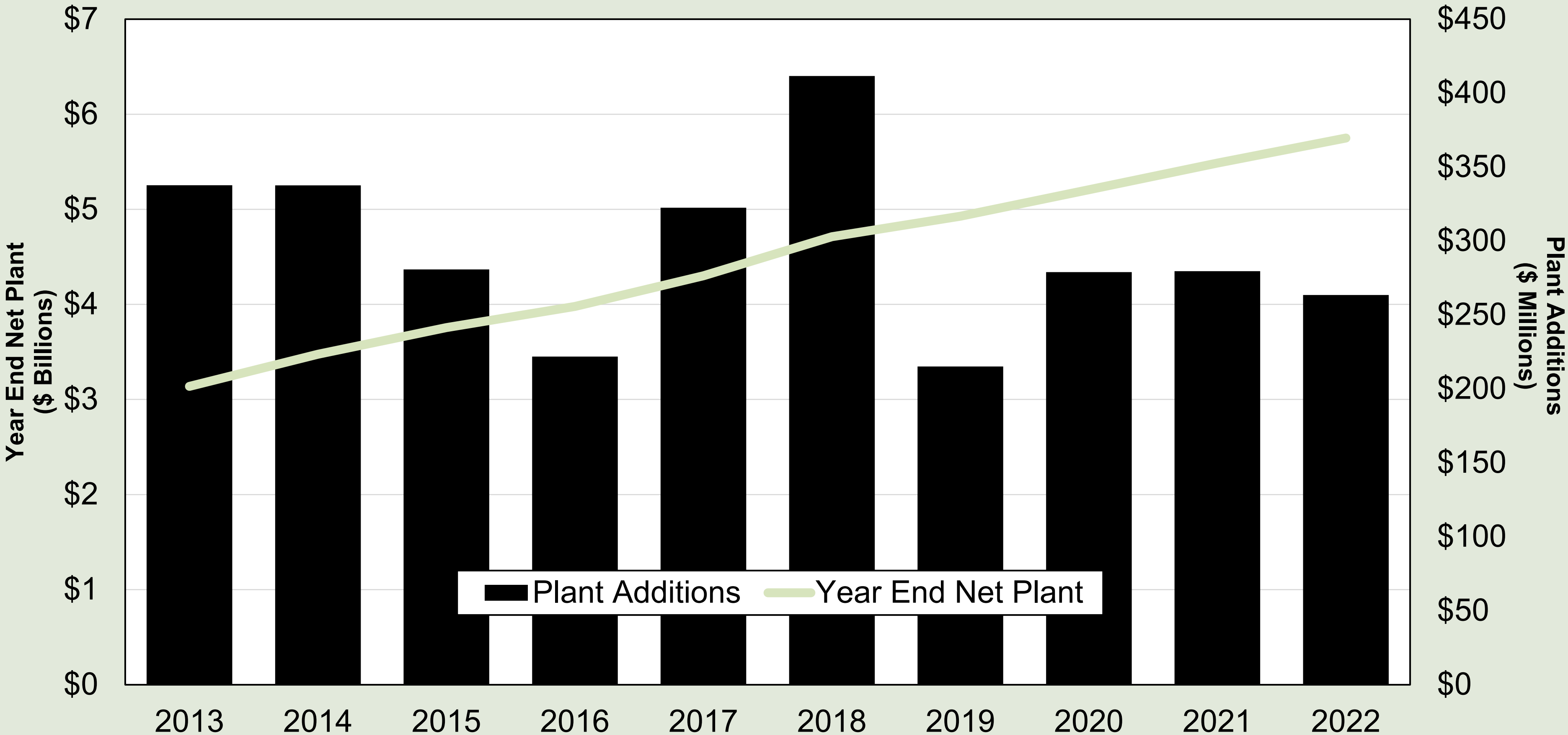


Source: FERC Form 1 as provided by S&P Global.

Section 7.3: Capital investment efficiencies

Pepco net distribution plant growth.

Pepco has seen considerable growth in net distribution plant. It increased from $3.1 billion in 2013 to $5.7 billion in 2022. The largest increase was in 2018 with $411 million added.



Source: FERC Form 1 as provided by S&P Global.

Regional net distribution plant ($/MWh) investment.

Net distribution plant in service in Pepco's service territory has constantly outpaced regional peer utilities since 2013. This disparity has grown in recent years with the growth in distribution plant investments.

Company	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	($/MWh)									
Potomac Electric Power Company (Pepco)	**$ 121**	**$ 135**	**$ 145**	**$ 152**	**$ 173**	**$ 182**	**$ 197**	**$ 227**	**$ 234**	**$ 243**
Atlantic City Electric Company	119	127	137	151	176	175	193	219	212	241
Baltimore Gas and Electric Company	99	103	164	113	120	121	129	143	146	154
Delmarva Power & Light Company	97	109	118	130	140	140	150	163	166	174
Duquesne Light Company	108	114	120	127	140	147	162	178	184	194
Jersey Central Power & Light Company	126	129	142	147	155	156	168	182	188	184
Metropolitan Edison Company	99	103	102	107	115	118	128	138	140	140
PECO Energy Company	95	102	105	110	117	119	134	152	162	175
Pennsylvania Electric Company	105	114	114	122	128	132	141	159	166	169
Public Service Electric and Gas Company	116	122	123	135	150	159	168	178	188	195
Rockland Electric Company	123	129	129		164	176	188	201	212	211
The Potomac Edison Company	71	74	76	82	87	86	93	104	103	105
UGI Utilities, Inc.	70	74	76	79	88	89	106	116	125	137
West Penn Power Company	57	60	61	64	70	74	84	93	96	95
Peer Group Average	**$ 99**	**$ 105**	**$ 113**	**$ 114**	**$ 127**	**$ 130**	**$ 142**	**$ 156**	**$ 161**	**$ 167**

Source: FERC Form 1 as provided by S&P Global.

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Rankings: Regional net distribution plant ($/MWh) investment.

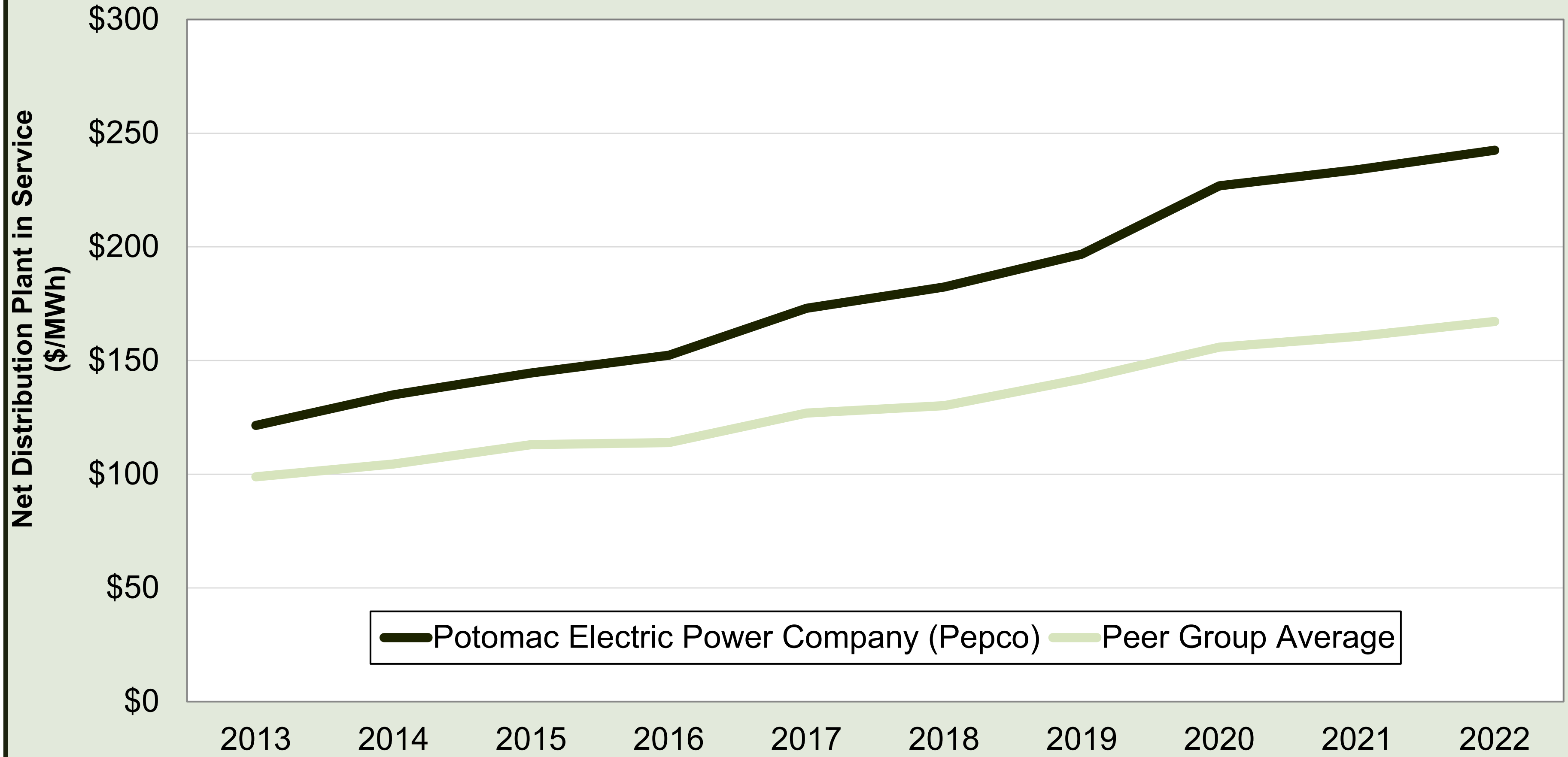
Pepco's net distribution plant (in terms of $/MWh of load) has grown to the highest of all regional peer utilities.

Company	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	(Ranking)									
Potomac Electric Power Company (Pepco)	**12**	**14**	**13**	**13**	**13**	**14**	**14**	**14**	**14**	**14**
Atlantic City Electric Company	11	11	11	12	14	12	13	13	13	13
Baltimore Gas and Electric Company	7	6	14	6	6	6	5	5	5	5
Delmarva Power & Light Company	5	7	7	9	8	8	8	8	8	7
Duquesne Light Company	9	9	8	8	9	9	9	10	9	10
Jersey Central Power & Light Company	14	13	12	11	11	10	11	11	10	9
Metropolitan Edison Company	6	5	4	4	4	4	4	4	4	4
PECO Energy Company	4	4	5	5	5	5	6	6	6	8
Pennsylvania Electric Company	8	8	6	7	7	7	7	7	7	6
Public Service Electric and Gas Company	10	10	9	10	10	11	10	9	11	11
Rockland Electric Company	13	12	10		12	13	12	12	12	12
The Potomac Edison Company	3	2	3	3	2	2	2	2	2	2
UGI Utilities, Inc.	2	3	2	2	3	3	3	3	3	3
West Penn Power Company	1	1	1	1	1	1	1	1	1	1

Source: FERC Form 1 as provided by S&P Global.

Trends: Regional net distribution plant ($/MWh) investment.

Not only does Pepco perform poorly compared to peers in terms of net plant investment, it is growing at a faster rate as well. Pepco saw an average growth of 11.1% per year while the peer average has grown at 7.7%.



Source: FERC Form 1 as provided by S&P Global.

Section 7.4: Greenhouse Gas Trends

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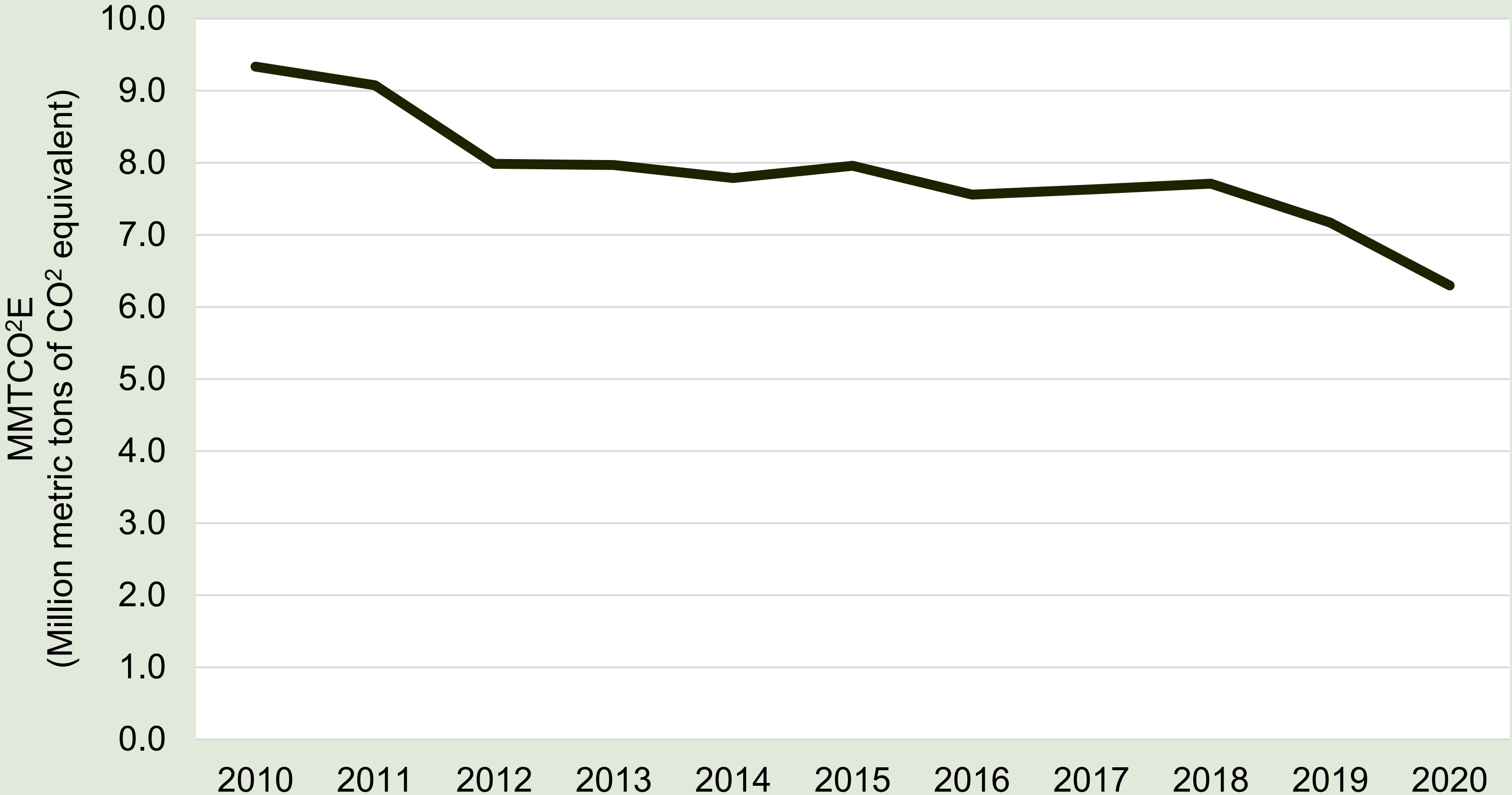
Greenhouse Gas Emissions

Trends: Greenhouse gas total

The District of Columbia overall has seen decreases in GHG emissions, this is mostly due to switching over from coal to natural gas generation from regional power plants. Further drops in 2020 are attributed to the Covid-19 pandemic.



Source: DC Department of Energy & Environment

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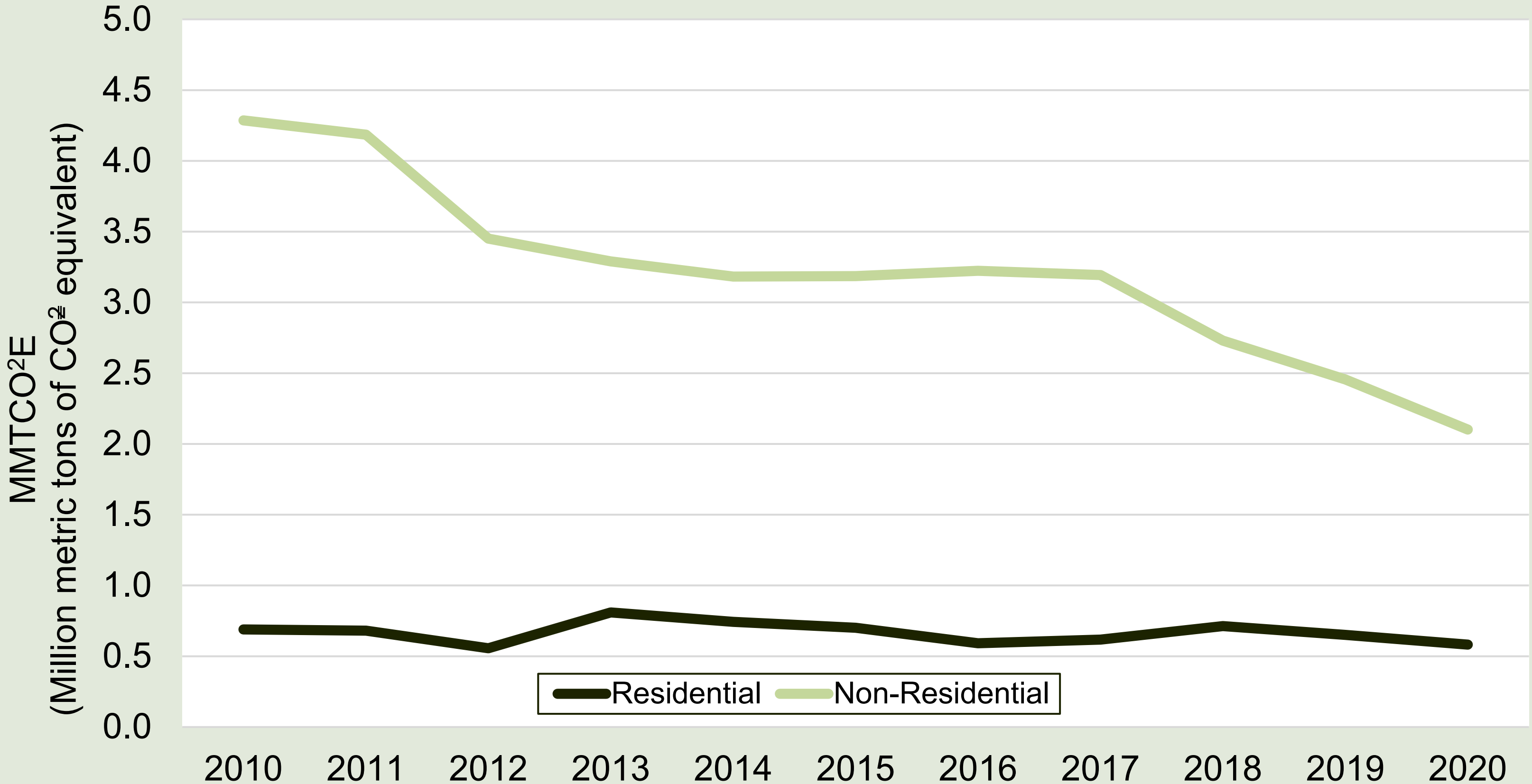
Trends: Building and energy electricity estimated GHG emissions.

The District of Columbia has seen very flat rates for residential electricity emissions, while non-residential emissions follow a similar trend of total GHG emissions.



Source: DC Department of Energy & Environment

Section 8: Conclusions and Recommendations

Conclusions.

There are **three major, comprehensive forms of alternative regulation**: FRPs; PBR plans; and MYRPs. To date, **no major form of alternative regulation has led to any meaningful nor measurable ratepayer benefits.** Alternative regulation **has not resulted in any sustainable nor distinctly measurable improvement in reliability or quality of service.**

Alternative regulation mechanisms have resulted in large rate increases with very few rate decreases or earning sharing opportunities.

In addition, **no measurable nor sustainable improvement in operating costs or efficiencies have arisen in any state due to alternative regulation**. In fact, most states **have seen a deterioration in capital investment discipline and huge gains in rate base due to alternative regulation**.

There is <u>not one single state adopting alternative regulation that has shown outcomes that can be held out as an unequivocal "success" for ratepayers.</u>

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Historic Total BSA Revenues by Month

Exhibit OPC (A)-14
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Report Month	Pepco BSA Revenue $(Credit)/Debit														
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
January		$ 1,292,936	$ 731,147	$ 1,650,526	$ 1,962,013	$ 1,568,760	$ 792,394	$ 1,791,218	$ 1,559,601	$ 2,312,826	$ 2,163,729	$ 2,289,173	$ 2,292,701	$ 2,922,384	$ 2,609,331
February		952,244	(239,132)	1,107,816	2,071,119	1,828,793	1,349,382	1,361,271	1,250,523	1,455,289	2,515,531	2,850,545	2,534,376	3,468,639	3,875,186
March		423,109	476,863	1,320,489	1,516,666	889,229	1,359,729	1,157,309	996,720	2,042,540	1,860,891	2,676,898	1,813,781	2,492,739	3,521,175
April		1,101,443	886,890	1,566,713	950,784	271,126	1,210,303	(181,589)	1,500,249	2,027,948	2,039,600	2,409,688	1,568,121	2,010,425	3,514,961
May		999,329	1,271,108	1,835,646	693,270	1,829,901	768,718	1,303,347	987,344	2,759,869	2,045,374	2,332,753	2,203,448	3,042,626	4,084,350
June		359,622	699,445	1,701,975	1,949,731	2,219,507	740,230	1,200,755	1,509,335	1,699,006	2,357,967	2,723,761	2,720,298	2,786,347	3,626,207
July		(145,360)	(432,058)	1,163,708	2,180,279	2,183,102	1,633,901	1,498,987	2,173,495	3,006,847	3,160,235	3,237,751	2,962,213	2,802,926	4,456,053
August		(659,178)	503,508	776,559	2,547,389	2,230,654	1,347,932	1,586,736	1,665,969	2,602,017	1,651,110	1,977,196	3,262,767	3,918,366	4,138,059
September		(701,309)	(292,624)	622,900	2,212,414	2,545,259	2,219,756	1,723,697	2,653,194	2,148,054	1,595,639	2,187,565	2,894,961	3,242,475	3,581,975
October		(348,225)	714,578	662,892	1,780,684	2,233,416	1,736,951	809,135	2,627,219	2,018,223	2,045,008	2,257,221	2,530,282	3,089,463	3,244,743
November		60,536	530,036	1,773,658	1,845,467	2,225,383	1,802,399	1,380,165	2,221,265	1,647,489	986,533	2,350,376	2,374,644	3,187,381	3,478,000
December	406,410	(185,079)	849,341	1,864,479	1,535,756	1,948,914	1,224,533	1,138,125	1,880,869	2,500,313	2,793,221	2,719,829	3,148,521	3,133,607	
Total	**$ 406,410**	**$ 3,150,069**	**$ 5,699,103**	**$ 16,047,360**	**$ 21,245,572**	**$ 21,974,043**	**$ 16,186,231**	**$ 14,769,155**	**$ 21,025,783**	**$ 26,220,422**	**$ 25,214,837**	**$ 30,012,755**	**$ 30,306,114**	**$ 36,097,379**	**$ 40,130,041**

Total All Years (2009 - November 2023): $ 308,485,273

Source: Pepco Monthly BSA Reports.

Exhibit OPC (A)-15
Formal Case No. 1176

Historic BSA Revenues by Rate Class

Exhibit OPC (A)-15
Formal Case No. 1176
David E. Dismukes

Year	Residential Service					General Service				Timed General Service					
	Residential R	MMA	All Electric AE	Timed Metered R-TM	Total Residential	Non Demand GS-ND	Low Voltage GS-LV	Primary GS-3A	Total General Service	Low Voltage GT-LV	High Voltage (Other) GT-3A	High Voltage (69kV) GT-3B	General Service MGT-LV	Total Timed General Service	Metro RT
	$(Credit)/Debit														
2009	$ (26,909)		$ (4,692)	$ 296	$ (31,306)	$ 26,738	$ 75,644	$ (164)	$ 102,217	$ 285,889	$ 41,505	$ 1,148		$ 328,541.85	$ 6,957
2010	(2,656,691)		(116,524)	1,947	(2,771,268)	(766,818)	2,120,430	6,238	1,359,849	4,884,396	(538,685)	38,823		4,384,534	176,954
2011	(2,706,850)		(192,793)	(30,697)	(2,930,340)	(1,431,057)	3,316,776	2,684	1,888,402	5,739,320	1,047,076	34,412		6,820,809	(79,768)
2012	(813,825)		726,955	43,940	(42,930)	(1,233,366)	3,347,202	(4,713)	2,109,124	11,363,199	2,704,619	38,090		14,105,908	(124,742)
2013	1,802,883		419,663	71,946	2,294,491	(1,210,589)	3,106,750	(6,676)	1,889,485	13,341,655	3,677,200	42,748		17,061,603	(7)
2014	2,485,028		152,627	49,401	2,687,056	(1,239,874)	3,219,750	(3,628)	1,976,247	13,313,309	4,008,136	(10,706)		17,310,740	
2015	1,864,600		(136,549)	734	1,728,784	(1,421,280)	(871,795)	2,820	(2,290,255)	12,485,928	4,299,204	(37,430)		16,747,701	
2016	978,788		385,487	46,922	1,411,197	(1,522,713)	(3,320,998)	2,280	(4,841,431)	14,093,265	4,126,781	(20,657)		18,199,389	
2017	2,619,308	401,440	340,557	31,892	3,393,197	(108,460)	(3,505,105)	3,997	(3,609,569)	16,555,828	4,660,924	25,402		21,242,154	
2018	575,602	308,482			884,084	1,253,408	(842,168)	6,759	418,000	15,641,568	5,315,988	47,057	3,913,726	24,918,338	
2019	(177,722)	69,284			(108,438)	1,277,105	1,559,036	4,801	2,840,942	6,654,024	3,571,191	(14,902)	12,272,019	22,482,333	
2020	1,809,618	283,744			2,093,362	1,222,054	3,023,611	5,192	4,250,856	6,658,540	4,759,617	(30,655)	12,281,035	23,668,536	
2021	2,133,893	(49,714)			2,084,179	1,234,690	2,938,897	4,959	4,178,546	6,771,569	4,750,725	(42,651)	12,563,746	24,043,389	
2022	3,942,791	(94,648)			3,848,144	457,839	3,154,145	5,110	3,617,094	8,058,046	5,574,313	(54,817)	15,054,600	28,632,141	
2023	7,758,513	248,260			8,006,773	(101,526)	3,206,367	4,570	3,109,411	8,122,648	5,356,982	9,856	15,524,370	29,013,857	
Total	**$ 19,589,026**	**$ 1,166,849**	**$ 1,574,731**	**$ 216,381**	**$ 22,546,987**	**$ (3,563,849)**	**$ 20,528,542**	**$ 34,226**	**$ 16,998,919**	**$ 143,969,184**	**$ 53,355,575**	**$ 25,718**	**$ 71,609,496**	**$ 268,959,974**	**$ (20,607)**

Source: Pepco Monthly BSA Reports.

Exhibit OPC (A)-16
Formal Case No. 1176

Company Use Per Customer Statistics: Residential ("R")

				Change in Use		Percent Change	
	MWh Sold	Number of Customers	MWh per Customer	Use from Existing Customers	Use from New Customers	Number of Customers	MWh per Customer
2010	1,772,674	2,790,601	0.64				
2011	1,794,524	2,789,562	0.64	22,518	(668)	-0.04%	1.27%
2012	1,842,572	2,791,269	0.66	46,922	1,127	0.06%	2.61%
2013	1,825,724	2,802,926	0.65	(24,441)	7,593	0.42%	-1.33%
2014	1,895,411	2,808,629	0.67	65,838	3,849	0.20%	3.61%
2015	1,854,373	2,890,141	0.64	(93,337)	52,300	2.90%	-4.92%
2016	1,730,751	2,947,226	0.59	(157,146)	33,523	1.98%	-8.47%
2017	1,849,153	2,783,404	0.66	227,237	(108,835)	-5.56%	13.13%
2018	2,119,678	3,274,523	0.65	(47,388)	317,913	17.64%	-2.56%
2019	2,163,290	3,369,069	0.64	(17,096)	60,708	2.89%	-0.81%
2020	2,183,908	3,456,156	0.63	(34,412)	55,029	2.58%	-1.59%
2021	2,218,818	3,546,072	0.63	(21,351)	56,261	2.60%	-0.98%
2022	2,267,981	3,648,300	0.62	(14,388)	63,550	2.88%	-0.65%

Note: Data represents weather-normalized customer counts and sales.

Source: Pepco Monthly BSA Reports.

Company Use Per Customer Statistics: Time-Metered General Service – Low Voltage (“GT-LV”)

				Change in Use		Percent Change	
	MWh Sold	Number of Customers	MWh per Customer	Use from Existing Customers	Use from New Customers	Number of Customers	MWh per Customer
2010	4,804,700	32,128	149.55				
2011	4,711,248	32,719	143.99	(178,551)	85,099	1.84%	-3.72%
2012	4,900,669	33,504	146.27	74,598	114,823	2.40%	1.58%
2013	5,029,354	34,159	147.23	32,247	96,438	1.95%	0.66%
2014	4,789,409	35,281	135.75	(392,257)	152,312	3.28%	-7.80%
2015	4,691,413	35,821	130.97	(168,719)	70,723	1.53%	-3.52%
2016	4,685,903	37,826	123.88	(253,890)	248,380	5.60%	-5.41%
2017	4,234,456	36,720	115.32	(323,906)	(127,541)	-2.92%	-6.91%
2018	4,794,550	41,664	115.08	(8,844)	568,939	13.46%	-0.21%
2019	4,641,607	42,554	109.08	(250,021)	97,077	2.14%	-5.21%
2020	4,671,513	43,298	107.89	(50,366)	80,272	1.75%	-1.09%
2021	4,235,492	44,212	95.80	(523,582)	87,561	2.11%	-11.21%
2022	4,235,829	44,793	94.56	(54,605)	54,942	1.31%	-1.29%

Note: Data represents weather-normalized customer counts and sales.
Data after 2018 represent both GT-LV and MGT-LV customer counts and sales.

Source: Pepco Monthly BSA Reports.

Company Use Per Customer Statistics:
Time-Metered General Service – Primary Voltage ("GT-3A")

				Change in Use		Percent Change	
	MWh Sold	Number of Customers	MWh per Customer	Use from Existing Customers	Use from New Customers	Number of Customers	MWh per Customer
2010	2,803,199	1,735	1615.68				
2011	2,736,836	1,745	1568.39	(82,047)	15,684	0.58%	-2.93%
2012	2,839,029	1,751	1621.38	92,465	9,728	0.34%	3.38%
2013	2,825,250	1,704	1658.01	64,147	(77,926)	-2.68%	2.26%
2014	2,648,227	1,767	1498.71	(271,441)	94,419	3.70%	-9.61%
2015	2,541,989	1,726	1472.76	(45,855)	(60,383)	-2.32%	-1.73%
2016	2,492,675	1,884	1323.08	(258,359)	209,046	9.15%	-10.16%
2017	2,227,939	1,697	1312.87	(19,230)	(245,507)	-9.93%	-0.77%
2018	2,434,558	1,866	1304.69	(13,875)	220,493	9.96%	-0.62%
2019	2,418,442	1,873	1291.21	(25,154)	9,038	0.38%	-1.03%
2020	2,215,365	1,856	1193.62	(182,785)	(20,292)	-0.91%	-7.56%
2021	2,023,911	1,825	1108.99	(157,075)	(34,379)	-1.67%	-7.09%
2022	2,143,781	1,802	1189.67	147,233	(27,362)	-1.26%	7.27%

Note: Data represents weather-normalized customer counts and sales.

Source: Pepco Monthly BSA Reports.

PUBLIC VERSION
Exhibit OPC (A)-17
Formal Case No. 1176

Confidential Materials Omitted

Company's Estimate of BSA Deferral Balance Drivers

Exhibit OPC (A)-18
Formal Case No. 1176
David E. Dismukes

Driver	2016	2017	2018	2019	2020	2021	Total
		($ Millions)					
Customer Growth	$ 2.9	$ 3.7	$ 1.8	$ 1.2	$ 4.2	$ 3.4	**$ 17.2**
Declining Usage/Demand (non-COVID)	14.1	20.7	11.7	9.2	16.8	16.0	**88.5**
Declining Usage/Demand (SEU Programs)	5.2	4.6	4.5	4.7	6.2	7.0	**32.2**
Declining Usage/Demand (COVID)	-	-	-	-	27.1	21.1	**48.2**
Weather per BSA Report	1.4	(0.6)	3.5	2.3	(1.3)	-	**5.3**
FC1150 GTLV Normalization Adjustment	**-**	**-**	**3.0**	**7.3**	**6.3**	**3.7**	**20.3**
FC1150 Billing Determinant Error	**-**	**(1.7)**	**5.8**	**5.5**	**4.8**	**0.9**	**15.3**
Other	(2.4)	4.1	(4.9)	(2.8)	3.1	(3.8)	**(6.7)**
Total Under-Collection	**$ 21.2**	**$ 30.8**	**$ 25.4**	**$ 27.4**	**$ 67.2**	**$ 48.3**	**$ 220.3**

Source: *Formal Case No. 1156;* December 9, 2021 Technical Conference; BSA Deferral Balances at 21.

Exhibit OPC (A)-19
Formal Case No. 1176

Analysis of BSA Deferral Balance Drivers from Atrium Report

Driver	2016	2017	2018	2019	2020	2021	2022	Total
	($ Millions)							
Customer Growth	$ 2.6	$ 3.4	$ 1.9	$ (0.5)	$ 4.3	$ 3.6	$ 3.7	**$ 19.0**
Declining Usage/Demand (non-COVID)	11.7	18.0	13.3	7.1	13.2	12.4	18.3	**94.0**
Declining Usage/Demand (SEU Programs)	6.1	5.5	5.2	6.2	7.0	7.3	-	**37.3**
Declining Usage/Demand (COVID)	-	-	-	-	31.6	23.3	14.6	**69.5**
Weather per BSA Report	2.7	(0.9)	5.4	3.2	(1.5)	0.4	(0.2)	**9.1**
FC1150 GTLV Normalization Adjustment	**-**	**-**	**3.9**	**9.7**	**8.4**	**5.1**	**-**	**27.1**
FC1150 Billing Determinant Error	**-**	**-**	**3.7**	**5.6**	**4.9**	**0.9**	**-**	**15.1**
Other	(1.8)	9.1	(6.0)	(3.6)	3.1	2.3	3.4	**6.5**
Total Under-Collection	**$ 21.3**	**$ 35.1**	**$ 27.4**	**$ 27.7**	**$ 71.0**	**$ 55.3**	**$ 39.8**	**$ 277.6**

Source: *Formal Case No. 1156,* Atrium Report at 50.

Commission approves Pepco's rate increase, a typical residential customer, who uses 648 kWh per month, will see a monthly bill increase of $7.56 (or 9.24% on a total bill basis).[2] In addition, Pepco requests a return on equity of 10.10%, which will allow the Company to earn a reasonable return on funds invested in the business.

Authorization of the requested rate increase will allow the Company to recover the investments it has already made in its electric distribution infrastructure and other costs necessary to operate the system. The Company has made, and continues to make, significant investments in the electric distribution system to improve reliability and customer satisfaction.[3] However, as Company Witness McGowan explains, the Company's existing electric distribution rates do not allow Pepco to fully recover the cost of providing electric distribution to its District of Columbia customers. In addition, the rate increase is also needed to finance replacement and maintenance of the Company's aging infrastructure. Furthermore, as customers use the grid differently by adding distributed resources, feeding excess generation back to the grid, or changing load patterns by charging electric vehicles at night, Pepco must make the necessary modifications to keep up with these changes.

To deliver safe and reliable service to customers, Pepco understands that it has the responsibility of improving system reliability, replacing aging infrastructure, and maintaining its electric distribution system. In doing so, Pepco requires a rate increase that will provide the Company a reasonable opportunity to earn a fair return for its District of Columbia operations.

[2] Company Witness McGowan discusses the impact of the requested rate increase on the Customer Base Rate Credit approved in Order No. 18846.

[3] Company Witness Clark testifies that the Company spent $234.8 million on capital programs in 2016 and is projected to spend $234.9 million on capital programs in 2017.

For purposes of deriving the settled-upon decrease of $24.1 million, the Settling Parties agreed, for settlement purposes only,[5] to a number of rate assumptions. For example, the NSA is based upon an overall rate of return of 7.45 percent, which includes a 9.525 percent return on equity.[6] The Settling Parties also agreed that Pepco will recalculate the negative net salvage component of its depreciation expenses for FERC Accounts 367 and 368 using a 4.60 and 6.6 percent discount rate, respectively.[7] The Settling Parties also agreed that Pepco will only include the actual cost of reliability projects that are closed to plant in service by March 31, 2018.[8] In addition, the Settling Parties agreed that Pepco will remove all Supplemental Executive Retirement Plans ("SERP") expenses previously included by the Company in its application in Formal Case No. 1150.[9]

Q. HOW DOES THE NSA PROPOSE TO INCORPORATE THE IMPACTS OF THE TCJA INTO RATES?

A. The Settling Parties made a series of agreements to define how the impacts of the TCJA will be incorporated into rates. The Settling Parties agreed to credit the Excess Deferred Income Taxes ("EDIT") created by the TCJA to rates using differing sets of fixed amortization periods to reflect (1) protected property-related EDIT, (2) non-protected property-related EDIT, and (3) non-protected, non-property-related EDIT.[10] As required by the TCJA, Pepco will use the Average Rate Assumption Method to flow back to

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5 NSA, ¶ 18.
6 NSA, ¶ 3.
7 NSA, ¶ 4.
8 NSA, ¶ 6.
9 NSA, ¶ 7.
10 NSA, ¶ 5.

Exhibit OPC (A)-22
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III. Explanation of the Need for a Rate Increase

As detailed in the testimonies of Company Witnesses Velazquez, McGowan and Verner, this case is driven by on-going investments on behalf of Pepco's customers. Specifically, Pepco has continued to invest in its system to maintain and improve reliability and to serve load growth in the District of Columbia. Pepco's revenue growth has not kept pace with the resulting growth in operating costs and rate base, and the current rates do not allow Pepco a reasonable opportunity to recover its costs and earn a fair return.[3] In spite of earning less than its Commission-authorized return on equity, Pepco has continued to initiate and implement major system improvements that have required significant amounts of capital.

Pepco's investments in its infrastructure have resulted in measurable benefits to Pepco's customers. During 2015, Pepco's customers experienced a 42% reduction in the frequency of outages, and a 33% reduction in the duration of outages (as measured by SAIFI and SAIDI, respectively) when compared to the Company's performance in 2011. Moreover, customer satisfaction with reliability has improved 14% during the same period. These investments resulting in enhanced reliability and customer satisfaction are being funded by the Company's debt and equity investors with an expectation that they will receive a reasonable return of and on their investment.

[3] At current rates, Pepco's adjusted earned return on equity ("ROE") is just 4.74%.

The Company has made, and has plans to continue to make, significant investments in the electric distribution system to maintain and improve reliability gains, continue to improve customer satisfaction, interconnect DER, and align to the District's environmental policy goals.[10] However, as Company Witness McGowan explains, the Company's existing electric distribution rates do not allow Pepco to fully recover the cost of providing electric distribution to its District of Columbia customers.

Furthermore, as customers use the grid differently by interconnecting DER, feeding excess generation back to the grid, and changing load patterns by charging electric vehicles at night, Pepco must make the modifications to the grid necessary to facilitate these changes. Pepco is excited to support the District in meeting its forward-looking policy goals and keeping pace with the fast-changing energy environment in the District of Columbia. The proposed MRP marries the traditional principles of cost of service rate design with the District's forward-looking policies, incentivizes the Company to meet the customer's needs in the face of the changing energy landscape through the proposed PIMs, and decreases the frequency, administrative burden, and costs associated with traditional rate cases. Pepco requires the proposed rate increases that will provide the Company a reasonable opportunity to earn a fair return for its District of Columbia operations.

Moreover, as Company Witness McGowan explains, the Company's proposal will allow Pepco to Maintain its investment-grade credit ratings which is vital to the financial health of Pepco and is critical to its ability to access capital markets for financing essential capital projects on

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10 As Company Witness Clark testifies, the Company is projected to spend in excess of $600 million over the 2018-2019 time period and more than $950 million during the term of the MRP (2020-2022) on upgrades and improvements to Pepco's distribution system.

Exhibit OPC (A)-24
Formal Case No. 1176

HOME ENERGY AFFORDABILITY FOR LOW-INCOME CUSTOMERS IN PENNSYLVANIA

January 2019

Pennsylvania Public Utility Commission

Home Energy Affordability for Low-Income Customers in Pennsylvania

Docket No. M-2017-2587711

January 2019

Published by:
Pennsylvania Public Utility Commission
PO Box 3265
Harrisburg, PA 17105-3265
www.puc.pa.gov

Bureau of Consumer Services
Alexis Bechtel, Director

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Executive Summary

On May 5, 2017, the Pennsylvania Public Utility Commission (Commission) initiated a study to examine home energy burdens for low-income Pennsylvanians as "a necessary first step in evaluating the affordability, cost-effectiveness, and prudence of Universal Service Programs." *Energy Affordability for Low Income Customers Order*, Docket No. M-2017-2587711 (order entered on May 5, 2017), at 1.

This staff report[1] by the Commission's Bureau of Consumer Services (BCS) and the Law Bureau tabulates 2012 to 2016 customer data related to energy burdens[2] gathered from Pennsylvania's larger natural gas distribution companies (NGDCs) and electric distribution companies (EDCs). The report also incorporates information from other states and several independent studies.[3]

This is the first comprehensive energy burden and affordability study of Pennsylvania households using customer income, billing, and payment information. While the information collected from utilities has allowed the Commission to fill in perception and presumption gaps and review trends and details that have never before been analyzed for Pennsylvania, staff has identified limitations of and inconsistencies in the reported data that impacted the scope and the extent of the analysis. In particular, the utilities that were queried for this study were unable to identify or provide income information on low-income households that did not participate in customer assistance programs (CAPs) or other universal service programs. Additionally, many of the responding utilities interpreted, tracked, and reported information differently from utility to utility and sometimes within a utility from year to year. For some years, data were not available.

It was anticipated that work at this docket would allow Commission staff to make "recommendations concerning affordable energy burdens." *Energy Affordability for Low Income Customers Order* at 5 (Ordering Paragraph #1). However, making these recommendations has proved somewhat elusive for several reasons. First, inconsistencies in utility reporting and limitations in the utility data constrain the development of a specific statement of what constitutes energy "affordability" for low-income Pennsylvanians. Further, the utilities and Commission staff were not generally privy to corresponding data for low-income customers who did not participate in a utility CAP. Second, energy efficiency and conservation can play major roles in making energy bills

[1] This report is solely the work product of staff and does not reflect the opinions of the Commission or actions that it may take in the future. The legal, policy, and procedural issues raised in this matter remain under Commission review and may be factored into a subsequent order at this or other dockets. The report will be published, and comment and reply comments periods will be established.

[2] For the purposes of this staff report, a household's energy burden is the percentage of household income dedicated to paying jurisdictional energy costs.

[3] The Commission's Consumer Services Information System (CSIS) Project at Pennsylvania State University assisted with the collation and processing of raw data and information and the review of the published studies.

more affordable. The impact of these programs on energy burden levels is not measured as part of this study. Third, the Pennsylvania Department of Human Services (DHS) administers the Commonwealth's Low-Income Home Energy Assistance Program (LIHEAP), which provides federally-funded energy assistance grants to low-income customers independent of Commonwealth- and Commission-mandated low-income benefits. As described in this report, whether low-income customers receive LIHEAP grants can have a sizable impact on customer energy burden levels.

Nevertheless, this study attempts to establish a starting point or process for identifying an affordable energy burden level for Pennsylvania's low-income population by evaluating the effectiveness of current utility CAPs. A CAP, as part of a jurisdictional energy utility's universal service and energy conservation program (universal service program), assists payment-troubled, low-income households by making their jurisdictional energy service more affordable through reduced bills and/or arrearage forgiveness. The Commission's CAP Policy Statement at 52 Pa. Code §§ 69.261-69.267 provides guidelines relative to the maximum energy burdens that low-income residential customers in customer assistance programs should be charged.[4] Currently, many low-income customers, both in CAPs and not in CAPS, have energy burdens in excess of the Commission's CAP Policy Statement guidelines.

Based on the available data, this study measures whether the various CAP payment designs are meeting universal service goals such as reducing customer debt, improving customer payment habits, reducing defaults and terminations, and reducing the number of customers in debt who are not on payment agreements. The study also examined the impact of LIHEAP grants on CAP customer energy burden levels, outlined the maximum energy burdens used by neighboring state programs, and reviewed previous third-party studies dealing with related topics. Finally, the study considers CAP cost trends and estimates the financial impact to CAP customers and non-CAP residential ratepayers if Pennsylvania were to adopt a maximum 10% energy burden.

Summarized below are staff observations related to each topic in the report. Citations have been omitted from these summaries but are included in the expanded discussion of each segment.

Energy Burden Levels for Gas and Electric Service

The study first examined the percent of household income spent on electric and gas service (*i.e.*, energy burdens) by low-income customers enrolled in CAPs and by non-CAP residential customers to determine the energy burden differences between these two groups.

[4] There is no similar guideline relative to low-income customers not enrolled in a CAP.

Even with discounted payments, CAP customers had a higher energy burden than non-CAP residential customers.[5] From 2012 to 2016, the average energy burden was 7% to 8% for NGDC CAP heating customers, 5 to 6% for EDC non-heating CAP customers, and 8 to10% for EDC CAP heating customers.[6] Residential non-CAP customers had an average annual energy burden of 4% for NGDC and EDC service during this time period, regardless of heating or non-heating status and energy type.

Customers in the 0 to 50% Federal Poverty Income Guidelines (FPIG) level, regardless of heating or non-heating status and energy type, often had energy burdens exceeding the CAP Policy Statement guidelines.

Impact of LIHEAP Grants on Energy Burden Levels

Unlike other states, Pennsylvania does not use LIHEAP grants to fund its CAPs. In Pennsylvania, LIHEAP grants issued to CAP accounts are applied as customer payments to reduce energy bills for the specific grantee-customer. Since LIHEAP is often the sole or primary source of funding for state energy assistance programs in other states, this study examined CAP accounts pre- and post-application of LIHEAP grants to determine LIHEAP's effect on energy burden levels in the Commonwealth.

The study found that LIHEAP had a measurable impact on energy burdens for CAP customers. CAP customers with incomes at or below 50% of the FPIG experienced an average energy burden decrease of approximately 5 to 6 percentage points for gas heating, 6 to 8 percentage points for electric non-heating, and approximately 7 to 9 percentage points for electric heating. CAP customers with incomes between 51 and 100% of the FPIG experienced an average energy burden decrease of approximately 2 to 3 percentage points for gas heating and 3 percentage points for electric non-heating and heating. CAP customers with incomes between 101 and 150% of the FPIG experienced an average energy burden decrease of approximately 1 to 2 percentage points for gas heating, electric non-heating, and electric heating.

Even with these decreases, however, the average energy burden for some CAP households at the 0 to 50% and 51 to 100% FPIG levels exceeded the maximum energy burden guidelines in the CAP Policy Statement.

Pre-Program Arrearages (PPAs) and In-Program Arrears

CAPs are intended to eliminate customer debt by deferring collection and payment of a CAP customer's pre-program arrearage (PPA) balance and reducing this debt with each monthly CAP payment. Full PPA forgiveness can be achieved within one to three years, depending on the utility's CAP provisions. Presumably, if CAP bills are

[5] Staff obtained data from the U.S. Census to determine average incomes for Pennsylvania non-CAP residential customers.
[6] The combined NGDC heating and EDC non-heating energy burden for CAP customers ranged between 12% and 14%.

affordable, low-income participants should gradually reduce their PPAs and accrue minimal or no new debt within the program. Staff considered the levels of PPA and in-program arrearage potential indicators of affordability within CAPs.

The data indicated that average PPAs and in-program arrears for most NGDCs showed decreasing arrearage trends, possibly due to lower natural gas costs, warmer winters, and declining CAP enrollments during this study period.

Most EDC CAP customers with in-program arrears carried an average balance of less than $200.

Since many utilities were unable to provide data for the PPA and in-program arrears balances by FPIG levels and/or by heating type, it is unclear whether customers at specific incomes (*e.g.*, at or below 50% of the FPIG) or with specific heating types carried a disproportionate share of CAP PPA or in-program arrears.

CAP enrollment eligibility varied among the utilities. Utilities that required low-income customers to be "payment troubled" (*e.g.*, had a payment arrangement in the past 12 months) to qualify for CAPs had higher average PPA balances than CAPs that did not have this restriction.

Percentage of CAP Bills Paid In-Full

If a CAP provides affordable monthly bills, the expectation was that a large percentage of participating customers would be paying their CAP bills in-full (i.e., 100% of the bill) by the due date. Staff considered payment history another possible indicator of affordability for utility CAPs.

At the 0 to 50% FPIG level, a higher percentage of NGDC CAP bills were paid in comparison to the percentage of EDC CAP bills paid in-full at the same FPIG level. Given the low cost of natural gas compared to electricity, this observation may be indicative that the bills of NGDC CAP customers were more affordable in comparison to the bills of EDC CAP customers during this five-year study period.

Payment behavior of CAP customers did not appear to have been strongly or definitively correlated to household income. EDCs reported *fewer* CAP heating customers at the 101 to 150% FPIG level paid their bills in comparison to the percentage of bills paid by customers at the 51 to 100% FPIG level. This pattern may indicate that other factors – beyond income – had an impact on whether CAP utility bills were regularly paid in full.

NGDC and EDC billing system changes and upgrades appeared to affect CAP monthly billing amounts and thus influenced whether utility bills were paid in-full.

CAP Default Exit and Termination Rates

Other indicators of affordability for CAP customers may include the rate of customers defaulting (*i.e.*, default exiting) on program requirements (*e.g.*, making full and timely payments) and termination rate for CAP customers. Presumably, CAPs with affordable monthly payments should have lower instances of customers defaulting on the programs and lower termination rates.

Given the apparent inconsistencies between how utilities defined and tracked "default exits" and CAP terminations, staff was unable to compare these data points among utilities or to confidently establish a correlation. However, differences in the CAP heating termination rates for Met-Ed and the other FirstEnergy companies suggested that other factors – besides CAP design – contributed to higher termination rates for CAP customers in Met-Ed's service territory.

Non-CAP Residential and Confirmed Low-Income Customer Debt

The final indicator of affordability reviewed was the amount of debt owed by customers on utility- or Commission-issued payment agreements and those not on agreements. When customers have difficulty paying their bills on time and accrue debt, accounts may be terminated and the debt written-off to be recovered through base rates. Debt that is on agreement is considered active and less at risk for write-off. Debt that is not on agreement is considered a higher risk for write-off.

The number of NGDC and EDC confirmed low-income customers in debt to their utility who were not on payment agreements had declined from 2012 to 2016. This may indicate that utilities were having greater success in either enrolling/maintaining low-income customers into CAPs or in establishing payment agreements.[7]

Review of Other State Programs and Relevant Studies

Pennsylvania's maximum energy burdens as articulated in the CAP Policy Statement are higher than maximum energy burdens used by neighboring states. Ohio's utility payment assistance program has a maximum energy burden of 10%. The New York and New Jersey utility payment assistance programs both have a maximum energy burden level of 6%.

Staff reviewed multiple independent studies that dealt with topics similar to those addressed in this study. Insights from these studies include:

- If the cost of all sources of household energy are counted – not just natural gas and electric – Pennsylvania households with incomes at or below 150% of the FPIG experience some of the highest energy burdens in the country. Pennsylvania residents with incomes at or below 50% of the FPIG had energy burden levels at

[7] However, these assumptions cannot be confirmed from available data.

30% or higher for four of the five years of this study. This suggests that households that use non-electric heating (*e.g.*, propane, oil) may have higher energy burden levels than those reflected in this study.

- Although nearly eight-in-ten Pennsylvanians live in urban areas,[8] households in rural areas may experience the highest energy burden levels due to poor housing stock. Focusing energy-efficient education and weatherization services can help to reduce the energy burden disparity in these areas and help make CAPs more effective.
- Payment behavior may not reflect affordability. Customers may neglect other household expenses to pay their utility bill each month;
- Not every household in poverty is payment-troubled;
- Factors other than income play a role in determining the effectiveness of an assistance program; and
- Customers that enter a payment assistance program with lower PPAs are more likely to improve their payment behavior than customers with higher PPAs.

CAP Costs and Forecasts

Based on information submitted by NGDCs and EDCs in support of USECPs covering the period after 2016, NDGC and EDC CAP costs are projected to increase annually through 2021 despite an industry drop in CAP expenditures from 2012-2016. The overall average costs per non-CAP residential customer are also projected to increase through 2021, varying among the utilities and with CAP enrollments levels. EDC customers could experience the largest increase, with average annual CAP costs recovered from non-CAP residential customers projected to increase by approximately $20 from 2017 to 2021.

Based on an energy burden model developed by Commission staff for this Report, staff estimated the cost of establishing a 10% maximum energy burden level for CAPs, which parallels Ohio's maximum energy burden level. Based on 2012 to 2016 average CAP bills and income levels, the total amount of additional discounts (*i.e.*, CAP credits) that would have been needed to establish maximum energy burdens of 6% for gas heating, 4% for electric non-heating, and 10% for electric heating would be approximately $102 million per year, not accounting for inflation. This amount breaks down to approximately $32 million for gas heating, $62 million for electric non-heating, and $9 million for electric heating. Such a change would have resulted in an average annual increase of $14.52 to non-CAP residential ratepayers' gas and electric bills. Average increases would vary among the utilities.

The energy burden model developed by staff for this Report does not factor in all variables and specifically does not take into consideration (1) any possible reductions in CAP costs if some CAP customers are required to pay more under a new energy burden

[8] Pennsylvania State Data Center, Penn State Harrisburg. (October 2012). Pennsylvania's Urban and Rural Population. Retrieved from http://pasdc.hbg.psu.edu/sdc/pasdc_files/researchbriefs/Urban_Rural_SF1_RB.pdf.

level; (2) whether rate discount pricing (rather than, *e.g.*, percent of income pricing) might be better for some CAP customers or reduce overall CAP costs; (3) CAP costs borne by PGW's non-residential ratepayers; (4) individual utility CAP credit limits; (5) system/administrative costs associated with adopting new energy burdens; and (6) factors specific to each utility.

Study Limitations

There have been changes in utility CAPs and other universal service programs since the data reviewed in this study were collected. Such program changes are on-going. More current data reflecting these changes may have an impact on the observations drawn in this study. Further inspection of future data may substantiate trends as well as identify the aspects of CAPs that appear to work well or that produce better customer outcomes. Collection of valid data that can be consistently compared across income levels, among utilities, and over time would increase the reliability of projections and allow better evaluations of the success of CAPs.

I. Introduction

According to the 2012-2016 American Community Survey (ACS) data, Pennsylvania had a population of approximately 12.8 million and approximately 5 million housing units.[9] Almost 38% of Pennsylvania residents were either elderly (age 65 or over) or minors (under 18). Over 70% of Pennsylvania households heat with either natural gas or electricity (51% of heat with natural gas and 22% heat with electricity).[10] Over one-third of Pennsylvania households experience some level of poverty.[11] Approximately 8% of Pennsylvania's households reported incomes below 50% of the FPIG; 17% reported incomes below 100%; 27% reported incomes below 150%, and 37% had incomes below 200%, cumulatively.[12]

Universal Service Programs in Pennsylvania

The Commission's leadership in addressing the home energy needs of low-income households in Pennsylvania began as early as 1984 when it commenced *Recommendations for Dealing with Payment Troubled Customers* at Docket No. M-840403. As a result of that proceeding, energy utilities in Pennsylvania began implementing low-income usage reduction programs (LIURPs) and contemplating how to address the arrearages of low-income customers.

In 1992, with the continued accumulation of arrearages and uncollectable debt by low-income utility customers, the Commission adopted a policy statement at 52 Pa. Code §§ 69.261-69.267 that established guidelines for major electric and natural gas utilities to voluntarily implement pilot CAPs. The purpose of a CAP is two-fold: to help make utility services more affordable for low-income, payment-troubled individuals and to reduce the costs of a utility's uncollectible amounts. *Investigation of Uncollectible Balances*, Docket No. I-900002, at 115 to 118. Low-income, payment-troubled customers are defined as residential utility customers whose annual household gross income is at or below 150% of the FPIG and who have failed to maintain one or more payment arrangements.[13] 52 Pa. Code §§ 54.72 and 62.2.

The CAP Policy Statement, which was subsequently amended, in part, in 1999, provides guidelines on the design and operation of CAPs, including establishing guidance on maximum energy burden ranges that low-income customers could be expected to pay in exchange for continued utility services. The 1992 CAP Policy Statement

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[9] Table B11001. Household Type (Including Living Alone) (Universe - Households) - 5 Year Estimates. Table B11002. Household Type by Relatives and Nonrelatives for Population in Households (Universe - Population) - 5 Year Estimates.
[10] 2012-2016 ACS 5-Year Estimates.
[11] Approximately 15% of Pennsylvania residents were age 65 and over and 23% were under the age of 18. 2012-2016 ACS 5-Year Estimates.
[12] *See* Appendix 1 for demographic profiles for each NGDC and EDC service territory.
[13] The requirement of a missed payment arrangement has been somewhat eased over the years by Commission orders regarding individual utility universal service programs.

recommended that a CAP customer's combined jurisdictional natural gas and electric energy burden should not exceed 15%. The 1999 CAP Policy Statement amendment increased the maximum household energy burden to 17%. Table 1-1 below indicates the energy burden levels based on the FPIG and the nature of the energy usage in the household from Section 69.625 in the CAP Policy Statement.

Table 1-1
CAP Policy Statement Maximum Energy Burden Levels[14]

Utility Service	0-50% FPIG	51-100% FPIG	101-150% FPIG
Non-Heat Electric	2-5%	4-6%	6-7%
Gas Heat	5-8%	7-10%	9-10%
Electric Heat	7-13%	11-16%	15-17%

The Competition Acts

In 1997 and 1999, respectively, the Electricity Generation Customer Choice and Competition Act (Electric Competition Act), 66 Pa. C.S. §§ 2801-2812 and the Natural Gas Choice and Competition Act (Gas Competition Act), 66 Pa. C.S. §§ 2201-2212, were adopted. (Collectively, Competition Acts.) The primary purpose of the Competition Acts was to introduce competition into the retail electric and natural gas markets by establishing standards and procedures for the restructuring of the electric and natural gas utility industries. The Competition Acts also included several provisions relating to universal service programs for low-income customers in the Commonwealth. The Competition Acts require the Commission to continue, at a minimum, the policies, practices, and services that were in existence as of the effective date of the laws. 66 Pa. C.S. §§ 2203(7) and 2802(10).

The Competition Acts define "universal service and energy conservation" as the policies, practices, and services that help low-income customers maintain utility service. Although the universal service provisions of the Competition Acts tie the affordability of electric and natural gas service to a customer's ability to maintain utility service, the Competition Acts do not specifically define the term "affordable" as it relates to the provision of retail electric and natural gas services to customers.[15]

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[14] 52 Pa. Code § 69.265(2)(i)(A-C).
[15] Section 2202 defines "universal service and energy conservation" as the "[p]olicies, practices and services that help residential low-income retail gas customers and other residential retail gas customers experiencing temporary emergencies, as defined by the [C]ommission, to maintain natural gas supply and distribution services. The term includes retail gas [CAPs], termination of service protections and consumer protection policies and services that help residential low-income customers and other residential customers experiencing temporary emergencies to reduce or manage energy consumption in a cost-effective manner, such as [LIURPs] and consumer education." Section 2803 defines universal service and energy conservation as the "[p]olicies, protections and services that help low-income customers to maintain electric service. The term includes [CAPs], termination of service protection and policies and services that help low-

The Commission is tasked with ensuring that utilities administer universal programs in a cost-effective manner and that services are appropriately funded and available in each utility distribution territory. 66 Pa. C.S. §§ 2203(8) and 2804(9). In the exercise of this authority, the Commission balances the interests of customers who benefit from the programs with the interests of the residential customers who pay for the programs. *See Final Investigatory Order on CAPs: Funding Levels and Cost Recovery Mechanisms*, Docket No. M-00051923 (Dec. 18, 2006), (*Final CAP Investigatory Order*), at 6-7.[16]

Universal Service Programs

Utility universal service programs include CAP, LIURP, Customer Assistance Referral and Evaluation Program (CARES), and Hardship Funds. Of particular relevance to this study and report are the CAPs which are administered individually by the major EDCs and NGDCs. CAPs, which vary in design by utility, provide an alternative to traditional collection methods for low-income, payment-troubled customers. Customers who enroll in a CAP agree to make monthly payments in exchange for continued utility services and debt forgiveness. Those monthly payments, which may be set at an amount less than the customer's current bill based on usage at tariff rates, are generally based on factors such as household size and gross income of the household and may include an add-on amount to help offset the customer's pre-program arrearages (PPAs), if relevant. EDCs and NGDCs may call their respective CAPs by different names (*e.g.*, PPL refers to its CAP as OnTrack, PGW refers to its CAP as the Customer Responsibility Program or CRP). For the purposes of this report, staff will collectively refer to all utility customer assistance programs as CAPs.

Energy Affordability for Low-Income Customers Study

On May 5, 2017, at Docket No. M-2017-2587711, the Commission initiated a study to evaluate residential energy burdens for electric and gas service in Pennsylvania

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income customers to reduce or manage energy consumption in a cost-effective manner, such as [LIURPs], application of renewable resources and consumer education."

[16] The proceeding at Docket No. M-00051923 was closed December 18, 2006, and staff was directed to revise the CAP Policy Statement (OP 1) and to initiate a rulemaking regarding funding and design of CAPs (OP 2). Two proceedings were opened: *Proposed Revision to CAP Policy Statement*, Docket No, M-00072036 (order entered September 5, 2007), and *Proposed Rulemaking relating to Universal Service and Energy Conservation Reporting Requirements*, Docket No, L-00070186 (order entered September 4, 2007). These dockets were closed by Commission order entered May 10, 2012, due, in part, to "changes to the LIHEAP policy and the initiation of a stakeholder process studying the treatment of universal service customers in an enhanced competitive retail electricity market. . . . [*See Investigation of Pennsylvania's Retail Electricity Market*, Docket No. I-2011-2237952.] . . . A new rulemaking and amended policy statement will be initiated in the future after these issues have been resolved and the stakeholder process completed." May 10, 2012 Order at-12-14,

and to determine what may constitute an affordable energy burden for Pennsylvania's low-income households. May 5, 2017 Order. Despite the programs and services designed to bridge the energy affordability gap[17] in Pennsylvania, the Commission routinely receives complaints from customers enrolled in CAPs who are failing to or are unable to keep up with payments, accumulating in-program arrears, facing loss of program eligibility, and risking service termination. *See, e.g., Knapp v. Penelec*, Docket No. C-2015-2511723 (Order entered October 27, 2016). This payment, assistance, and arrearage cycle is a recurring issue for many low-income customers in the state.

According to some sources, households falling below 50% of the FPIG are billed an average of 30% of their income for home energy costs.[18] However, only approximately 30% of eligible Pennsylvania households are enrolled in a CAP.[19] Given these realities, the Commission concluded that the necessary first step to evaluate the affordability, cost-effectiveness, and prudence of universal service programs would be to undertake an energy affordability study. The Commission also recognized its obligation to balance the costs[20] and benefits of universal service programs as potential changes to affordability standards will inevitably require an examination of overall program funding. May 5, 2017 Order at 3-4.

While other fuel sources[21] are available and used by households in Pennsylvania, for purposes of this study the Commission is exclusively examining the affordability of jurisdictional natural gas and electric services to low-income customers in Pennsylvania. The original intent of this study was to examine energy affordability for low-income customers both inside and outside of CAPs. However, NGDCs and EDCs could not provide income information and other data for customers who were not participating in CAPs or other universal service programs. Further, absent enrollment in a CAP, even a confirmed low-income residential customer is required to pay the full tariff rate for

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[17] Fisher, Sheehan, & Colton, cited and discussed in greater detail below, use "affordability gap" to refer to the difference between *actual home energy bills* and *affordable home energy bills*.

[18] Fisher, Sheehan, & Colton. *The Home Energy Affordability Gap 2015: Pennsylvania* (Public Finance and General Economics, 2nd Ser. 2016), at 1. These studies are based on jurisdictional and deliverable energy sources.

[19] 2012-2016 Reports on Universal Service Programs & Collections Performance.
http://www.puc.state.pa.us/filing_resources/universal_service_reports.aspx
http://www.puc.state.pa.us/filing_resources/universal_service_reports.aspx

[20] The May 5, 2017 Order noted that, based on a review of the Commission's Reports on Universal Service Programs & Collections Performance for the years 2001 through 2015, total gross CAP costs for EDCs have increased by approximately 177% between 2001 and 2015 (inflation adjusted), from $68.25 million to $189 million (expressed in 2001 dollars). Total gross CAP costs for NGDCs distribution companies have increased by approximately 270% between 2002 and 2015 (inflation adjusted), from $22.6 million to $83.6 million (expressed in 2002 dollars). Additionally, during the 2001/2002 to 2015 timeframe, the numbers of estimated low-income EDC and NGDC customers have increased by 80% and 104%, respectively.

[21] Also, not included in this study are customers of such energy providers as small jurisdictional NGDCs and EDCs, rural electric cooperatives, municipal authorities, and municipalities providing energy services to customers outside the municipal boundaries.

jurisdictional energy service. As a result, the staff analysis focuses primarily on low-income customers enrolled in large-utility CAPs.

Specifically, the overarching objectives of this study are to:

1. Identify the average energy burden of low-income customers enrolled in CAPs compared to the average energy burden of all other residential customers in Pennsylvania and the impact of LIHEAP grants on CAP energy burden levels;

2. Ascertain and analyze trends and indicators of energy affordability in Pennsylvania CAPs, including PPAs (*i.e.*, pre-CAP arrearages) and in-program CAP arrears, the percentage of CAP bills paid in-full, and CAP default/termination rates;

3. Determine trends in residential/low-income debt and CAP costs for EDCs and NGDCs and identify the projected impacts of adjusting the household energy burden in the Commonwealth; and

4. Compare and contrast the average energy burden of low-income residents in Pennsylvania with the energy burden of customers of neighboring states.

Staff used the Commission's CSIS Project at Penn State University to collect and collate the results of the utility responses and the state surveys and to review independent studies that may provide further insight into energy affordability issues. The analyses and observations in this report are solely the work product of staff[22] and do not reflect the opinions of the Commission. Nor is this report an indication of any action the Commission may take in the future.

[22] This document is the collective work product of BCS and the Law Bureau.

II. Methodology

By Secretarial Letter dated October 16, 2017, the Commission notified the major jurisdictional energy distribution companies of its intent to conduct an energy affordability study and requested specific information from the eight major NGDCs and seven major EDCs for the years 2012-2016. The NGDCs and EDCs that reported data to the Commission include the following:

> **Natural Gas**: Columbia Gas of Pennsylvania (Columbia), PECO Energy Co. (PECO Gas), National Fuel Gas Distribution Corp. (NFG), Peoples Natural Gas Co. (Peoples), Peoples-Equitable Division (Peoples Equitable), Philadelphia Gas Works (PGW), UGI Utilities Inc.– Gas (UGI Gas) and UGI Penn Natural Gas (UGI PNG).[23]
>
> **Electric**: Duquesne Light Co. (Duquesne), Metropolitan Edison Co. (Met-Ed), PECO Energy Co. (PECO Electric), Pennsylvania Electric Co. (Penelec), Pennsylvania Power Co. (Penn Power), PPL Electric Utilities Corp. (PPL), and West Penn Power Co. (West Penn).

The Commission's data request asked for the following information, broken down by customer type (residential, confirmed low-income [CLI], CAP), by heating type, and by poverty level from each NGDC and EDC, consistent with universal service and collections reporting (USR) requirements[24]:

- Number of monthly bills issued
- Amount (in dollars) of monthly bills issued
- Number of monthly bills paid in full
- Amount (in dollars) of monthly bills paid in full
- Number of account terminations
- Number of account reconnections
- Energy Burden Levels for LIHEAP recipients
- Energy Burden Levels for non-LIHEAP recipients
- Number of CAP Accounts with Pre-Program Arrears

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[23] By Order entered September 20, 2018, the Commission approved a Joint Petition for Approval of Settlement in *Joint Application of UGI Utilities, Inc., UGI Penn Natural Gas, Inc., and UGI Central Penn Gas, Inc. for Approval of Merger*, Docket Nos. A-2018-3000381, A-2018-3000382, & A-2018-3000383. By Secretarial Letter at those dockets, the Commission approved tariff supplements, effective October 1, 2018, that reflect post-merger name changes due to the adoption by UGI Utilities, Inc. of UGI Penn Natural Gas, Inc.'s and UGI Central Penn Gas, Inc.'s existing tariffs and their application within new service and rate districts of UGI Utilities, Inc. corresponding to their existing service territories as UGI North and UGI Central, respectively, and the adoption by UGI Utilities, Inc. of its existing tariff to be applied to a new UGI South service and rate district. For the purposes of this study, which references data for a time period prior to the merger, the UGI companies were treated as separate NGDCs.

[24] Pursuant to 52 Pa. Code §§ 54.71-54.78 (electric) and §§ 62.1-62.8 (natural gas).

- Amount (in dollars) of Pre-Program Arrears
- Number of CAP Accounts with In-Program Arrears
- Amount (in dollars) of In-Program Arrears
- Number of CAP and Confirmed Low-Income Accounts
- Annual average income of CAP and Confirmed Low-Income accounts
- Number of accounts in arrears on an agreement
- Number of accounts in arrears not on an agreement
- Amount of arrears (in dollars) for accounts on an agreement
- Amount of arrears (in dollars) for accounts not on an agreement

When an analysis in this report refers to an "average" for multiple utilities, the average is a weighted average to compensate for the differences in size among the utilities.

Data Limitations

Staff identified inconsistencies and limitations in the reported data that impacted the analysis. Reasons for data variations included policy and procedure changes implemented by the utilities during the five-year time frame, specific enhancements to their systems, changes to their low-income programs, and/or mergers/acquisitions. Upon review of the data submitted, staff also found many utilities interpreted, tracked, and reported information differently.

At the onset of the study, the Commission initially requested the above data be categorized by CAP, CLI, and non-CAP residential accounts. Although the utilities responded to this request, staff questioned the validity and consistency of some of the reported numbers of CLI accounts; thus, the data used in this report do not always differentiate between CLI and non-CAP residential.

Furthermore, there is marked variability among the utilities in how they determine and verify the income status of their customers. For example, some utilities allow customers to "self-certify" their income designation while others require documentation from the customer to verify income status. As a result, staff used current U.S. Census data, when appropriate, to describe any relevant demographics of a utility's service area as opposed to the low-income account information submitted by the utilities.

III. Energy Burden Levels for Gas and Electric Service

Objective

Examining the percent of household income spent on electric and gas service (*i.e.*, energy burdens) by low-income customers enrolled in CAPs and by non-CAP residential customers to determine the energy burden differences between these two groups.

Background[25]

For the purposes of this segment, staff intended to compare three groups of residential customers: CAP households, residential non-CAP households, and CLI households. While all three groups of residential customers comprise the Residential Class of customers, CAP households are tracked separately as a group. CLI households are a subset of the non-CAP residential household group. The utilities reported that they do not possess income information for most CLI customers.[26] Thus, this segment will only compare CAP energy burdens to non-CAP residential energy burdens.

Staff considered the following components:

- The average energy burden for households for electric and gas service;
- Individual utility service type (electric heating, electric non-heating, and natural gas heating);
- FPIG level; and
- Status as residential non-CAP or CAP customer for the past five years.

Additionally, utilities use a variety of payment approaches to structure their CAP programs, consistent with the CAP Policy Statement guidelines. Utilities charge different amounts, offer various percentage discounts or billing options, and can have differing minimum payment requirements. Table 3-1 below shows each utility's CAP payment method and any applicable minimum payments for both heating and non-heating accounts during the study.

[25] *See also* VIII. Residential and Confirmed Low-Income Customer Debt for a discussion of CLI customers.
[26] CLI customers are often identified when they assign a LIHEAP grant to the utility. Receipt of LIHEAP confirms the customer has income at or below 150% of the FPIG, but it does not disclose the household's gross income, so energy burdens at the three FPIG levels cannot be calculated for comparison.

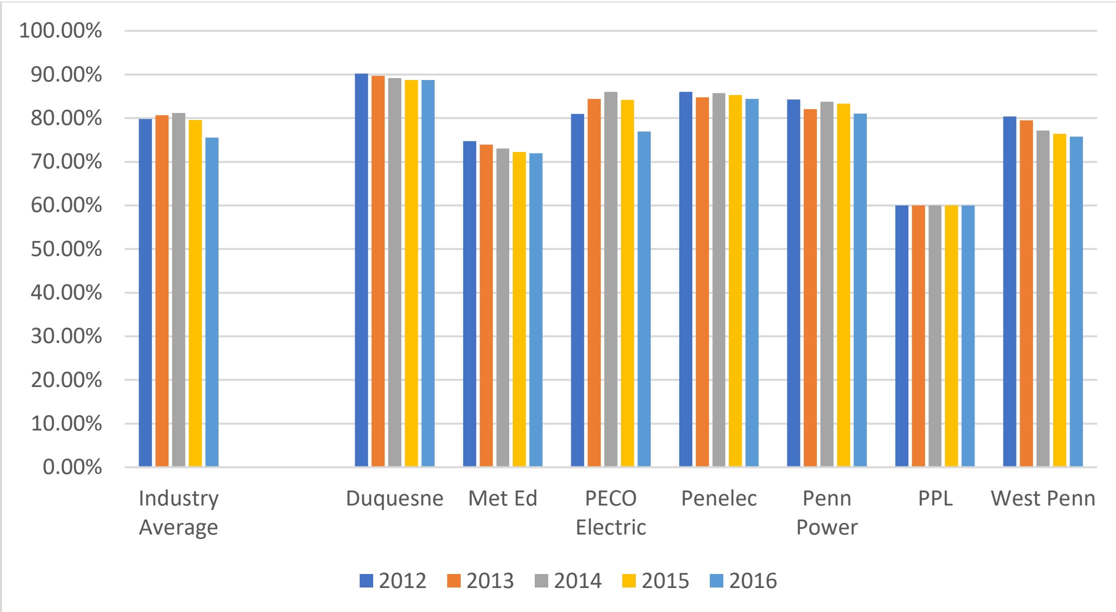
Table 3-1
CAP Billing Methods by Utility

Utility	CAP Billing Method	Minimum Payments
Duquesne	*Percentage of Budget Billing* 30% to 85% of Budget Billing	**Heat:** \$40 **Non-Heat:** \$15
FE Companies: Met-Ed, Penelec, and Penn Power West Penn (2016)	*Percent of Income and Fixed Annual Credits* Annual credits are calculated based on customer paying 3% of income for non-heat electric and 9% for electric heat. FE Companies provide 1/12th of annual credits each month.	**Heat:** \$45 **Non-Heat:** \$12
West Penn (formerly Allegheny Power) West Penn (2012-2015)	*Percentage of Income Payment Plan* Subsidy credits are calculated based on total gross household income, primary heat source, and energy burden. 1. Either 13%, 16%, or 17% of income for Electric Heat 2. Either 8%, 12%, or 14% of income for Water Heat 3. Either 5%, 6%, or 7% for Baseload Heat *(i.e.*, electric non-heating)	**Electric Heat:** \$50 **Water Heat:** \$30 **Baseload Heat:** \$25
PECO Electric*	*Rate Discount* Between 3-93% discount (dependent upon the household's FPIG level)	**Heat:** \$30 **Non-Heat:** \$12
PPL	*Percentage of Budget Billing* 3 options based on customer ability to pay: 1. Minimum Payment (budget bill - maximum monthly CAP credit) 2. 50% to 80% of Budget Billing 3. Agency Selected (% of budget bill plus discounts)	**Heat:** \$30 **Non-Heat:** \$12
Columbia	*Percent of Income, Budget Billing, or Average Payment* 3 options based on customer ability to pay: 1. 7% or 9% of income 2. Average payment 3. 50% of budget billing	**Heat:** \$25
PECO Gas*	*Rate Discount* Between 14-79% (dependent upon the Household's FPIG level)	**Heat:** \$25
Peoples	*Percentage of Income* 8% to 10% of income OR budget billing, whichever is lower	**Heat:** \$21
Peoples-Equitable	*Percentage of Income* 8% to 10% of income	**Heat:** \$39
NFG	*Rate Discount* 10-40% discount off budget billing	**Heat:** \$12
PGW	*Percentage of Income* 8% to 10% of income	**Heat:** \$25
UGI Gas and UGI PNG	*Percentage of Income* 7% to 9% of income OR average bill, whichever is lower	**Heat:** \$25

*PECO implemented a fixed credit methodology as part of its gas and electric CAP on October 1, 2016.

Table 3-1 above does not delineate the utilities that that add CAP Plus[27] and/or monthly PPA co-payment amounts[28] to the CAP customer bills.

Table 3-2
Percent of EDC CAP Bills Rendered to Non-Heating Customers



Another consideration to note is that Pennsylvania EDCs have a higher percentage of non-heating accounts in CAP than heating accounts. As seen in Table 3-2, based on the PA industry average, over 75% of EDC CAP bills issued were for non-heating accounts. *See* Appendix 5.D *for EDCs Number of CAP Bills Paid*. Thus, affordability issues involving electric non-heating accounts impact the majority of EDC CAP customers.

Methodology

To calculate the energy burden levels for non-CAP residential and CAP customers for the years 2012 to 2016, staff obtained data from the utilities and information from the U.S. Census to determine average bills and average incomes for both sets of customers. The average annual tariff rate, usage, and median income was used to determine the

[27] A CAP Plus payment is intended to help offset program expenses for all residential customers who pay for CAPs. Utilities that use CAP Plus typically calculate the monthly charge on an annual basis contingent on the amount of LIHEAP Cash grants they were assigned by their CAP customers in the prior year. At the time of this study, PPL, Columbia Gas, and Peoples added CAP Plus amounts to CAP bills.

[28] Some NGDCs and EDCs charge a monthly PPA co-payment amount to their CAP customers. During the time of this study, Columbia Gas, Peoples, Peoples-Equitable, and PGW each added a $5 co-payment to the monthly CAP bill for customers that had PPAs. Until 2018, PPL charged its $5 monthly PPA co-payment even if a customer had received full PPA forgiveness.

average energy burden levels for non-CAP residential customers. The average annual CAP bill amount and the average annual CAP income were used to determine the average energy burden levels for CAP customers.

Data Limitations

Customers who enroll in utility CAPs with zero income (zero-income customers) may inflate the average energy burdens levels, particularly for the analysis of customers with incomes at or below 50% of the FPIG. Utilities require customers that report zero income to pay the utility's CAP minimum payment amount. Thus, it is not mathematically possible for zero-income customers to receive bills below the maximum energy burden guidelines in the CAP Policy Statement because any billed amount will exceed 100% of their household income. There is some question regarding whether or not the utilities treated the zero-income customers consistently when reporting data for this study.

PPL reported system issues that required it to reconstruct all data prior to 2016 for several of the requested data points. Thus, all PPL data for the energy burden calculations in 2012 to 2015 should be considered estimates.

PECO originally reported combined data for all three customer types, electric heating, electric non-heating and gas heating. PECO was instructed to separate electric from gas but had to apply an allocation percentage to separate the dual-enrolled customers. PECO used actual 2016 data, but the 2012 to 2015 data had to be estimated.

NFG could not provide its data broken down by FPIG level, so staff did not include NFG in the analysis of NGDC average energy burdens at different FPIG levels, and only included NFG in the aggregate analysis.

As noted above, the utilities do not have income levels for the CLI customers so the CLI aspect of this study has been eliminated.

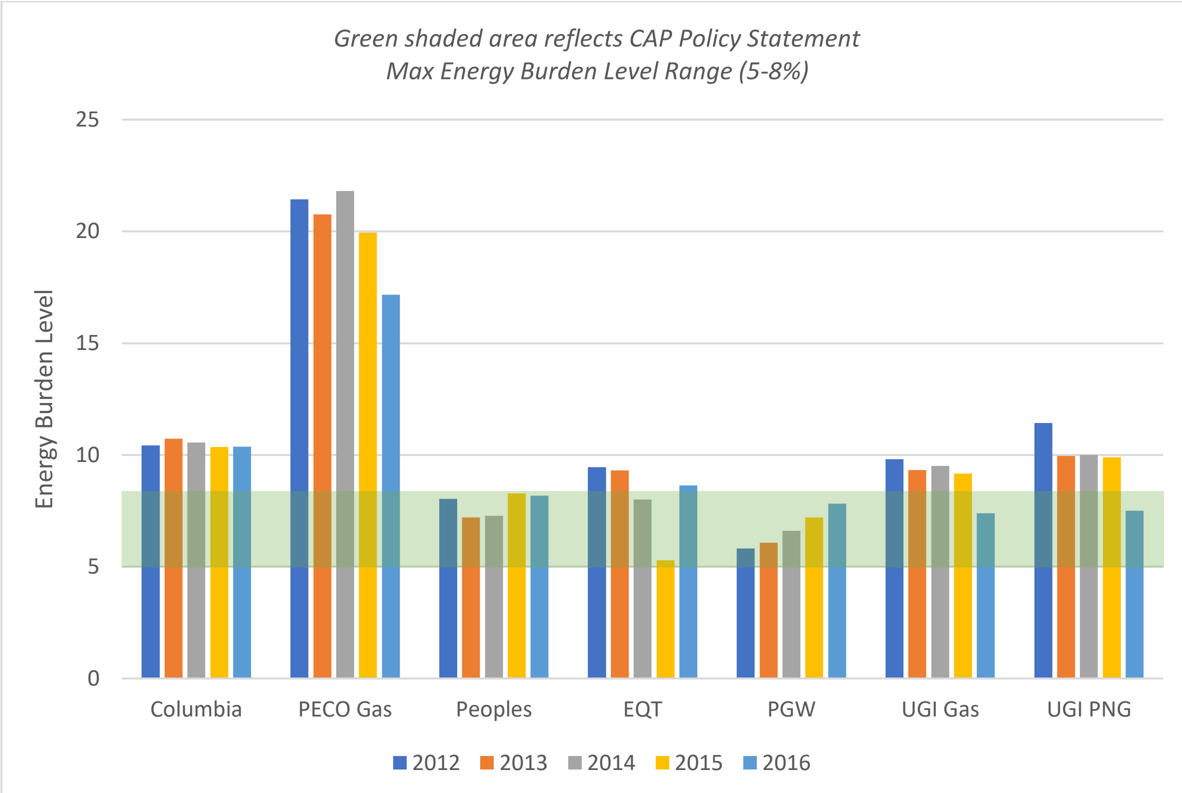
Analysis

Non-CAP Residential NGDC and EDC Customers

The non-CAP residential data show that the average energy burden for residential customers was approximately 4% for combined gas heating and electric non-heating (*i.e.*, 2% for each) and 4% for electric heating. These data can be found in Appendix 1.A: *Non-CAP Residential NGDC and EDC Average Energy Burdens*. For the residential categories, the averages did not vary widely throughout the years of the study or among the utilities and remained relatively consistent for the non-CAP residential customers.

NGDC CAP Customers[29]

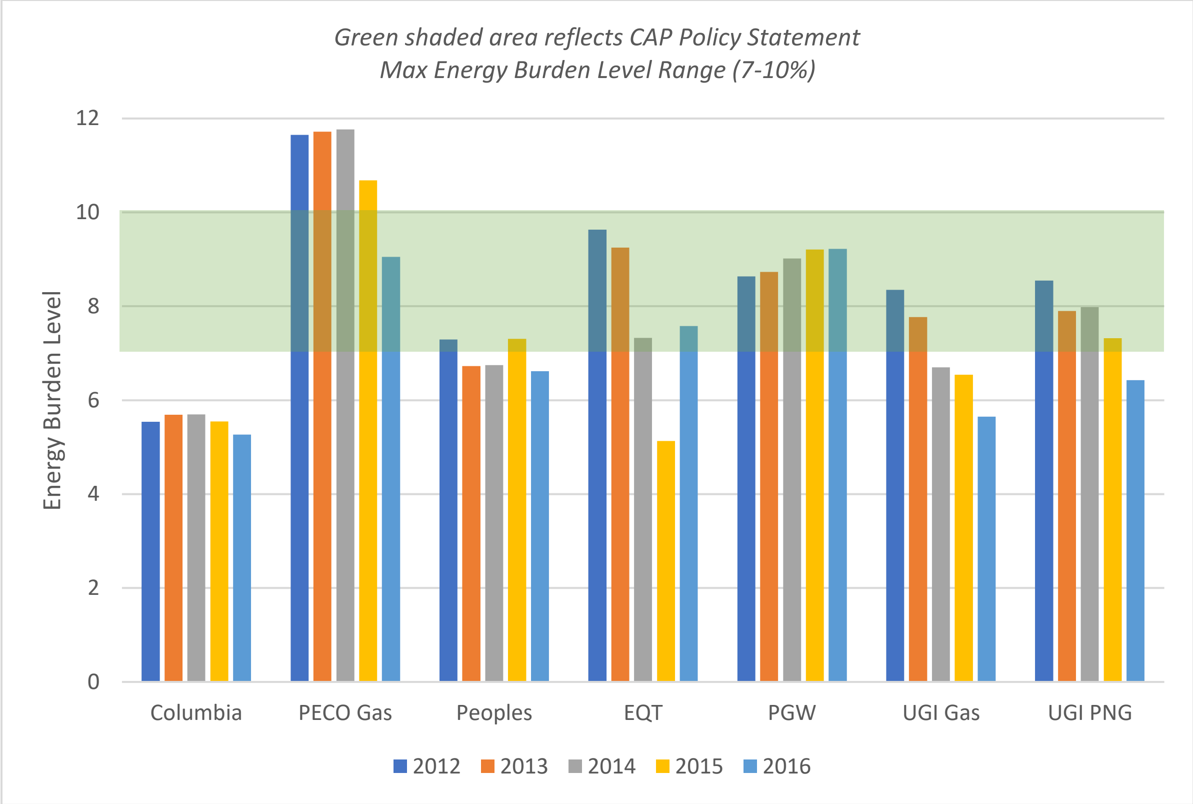
Table 3-3
NGDC CAP Energy Burden Levels for Heating Customers at 0-50% of FPIG, 2012-2016



NGDC CAP customers in the 0-50% FPIG level had the highest reported energy burdens. CAP customers at this income level from Columbia, Peoples Equitable, PECO Gas, UGI Gas, and UGI PNG had energy burdens that exceeded the guidelines in the CAP Policy Statement. PECO Gas' energy burdens for customers at this income level ranged from 17% to 22% over the five years of this study. Columbia's percentages remained in the 10% range throughout this study. Peoples Natural Gas' energy burdens were also relatively consistent, but lower at the 7 to 8% range. The remaining NGDCs had energy burdens that varied from year to year but generally stayed within a few percentage points: Peoples Equitable ranged from 5-9%, UGI PNG from 7 to 11%, UGI Gas from 7 to 10%, and PGW from 6 to 8%. This pattern is illustrated in Table 3-3 above.

29 *See* Appendix 2.B: *CAP Industry Average NGDC and EDC Energy Burdens.*

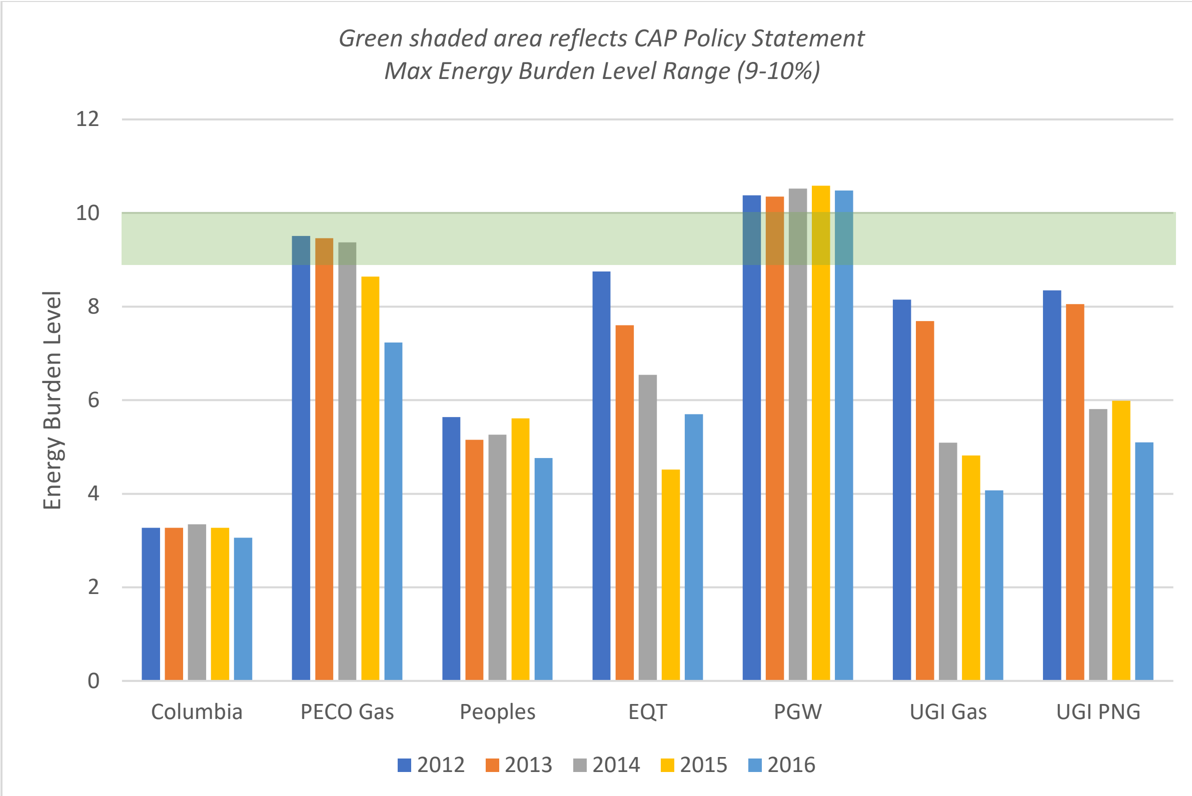
Table 3-4
NGDC CAP Energy Burden Levels for Heating Customers at 51-100% of FPIG, 2012-2016



As seen in Table 3-4, on average, NGDC CAP customers with incomes in the 51 to 100% FPIG level had energy burdens that fell within or below the CAP Policy Statement range of 7 to 10%. PECO Gas, however, had the highest energy burdens in the category with three out of five years above the CAP Policy Statement guidelines. Overall, the PECO Gas energy burdens were between 9 and 12% which is above the range in the CAP Policy Statement guidelines and replicates the trend from the 0 to 50% FPIG level. PECO's lowest energy burden in 2016, was within the range in the CAP Policy Statement guidelines.[30] Columbia's energy burdens fell well below the range and were consistently less than 6%. Peoples Gas' energy burdens averaged 6 to 7%; PGW's energy burdens averaged 8 to 9%. Peoples Equitable and both UGI utilities also fell within the CAP Policy Statement guidelines for this income level.

[30] PECO switched from a rate discount CAP to a fixed credit percent of income CAP in October 2016, so the energy burdens in this study reflect the previously-structured CAP.

Table 3-5
NGDC CAP Energy Burden Levels for Heating Customers at 101-150% of FPIG 2012-2016



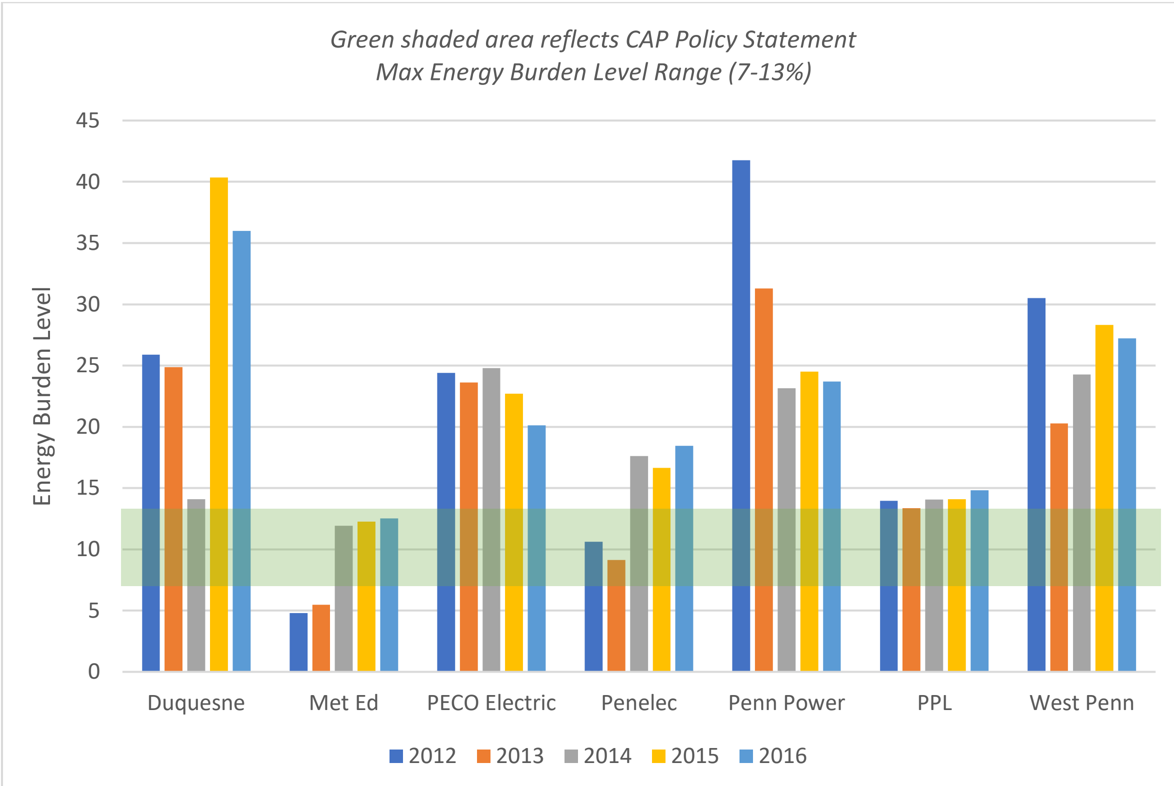
As seen in Table 3-5 above, most NGDC CAP customers with incomes between 101 and 150% of the FPIG had energy burdens at or below the CAP Policy Statement guidelines of 9 to 10%. CAP customers in Columbia, both Peoples utilities, and both UGI utilities had energy burdens of less than 9 to 10%. Columbia had a consistent average energy burden of 3%.[31] Peoples Gas' energy burdens ranged between 5-6%, Peoples Equitable between 5 and 9%, UGI Gas between 4 and 8%, and UGI Penn between 5 and 8%.

PGW CAP customers paid on average between 10% and 11% of income for CAP bills and thus had energy burdens during the five years of this study which were above the range in the CAP Policy Statement guidelines. In-program arrears may have also added to the monthly CAP bill of some PGW CAP customers and may account for why energy burdens were on average over 10%.

[31] Columbia Gas is the only NGDC whose CAP customers with incomes in the 51 to 100% and 101 to 150% FPIG groups were billed on average below the CAP Policy Statement guidelines.

EDC CAP Customers

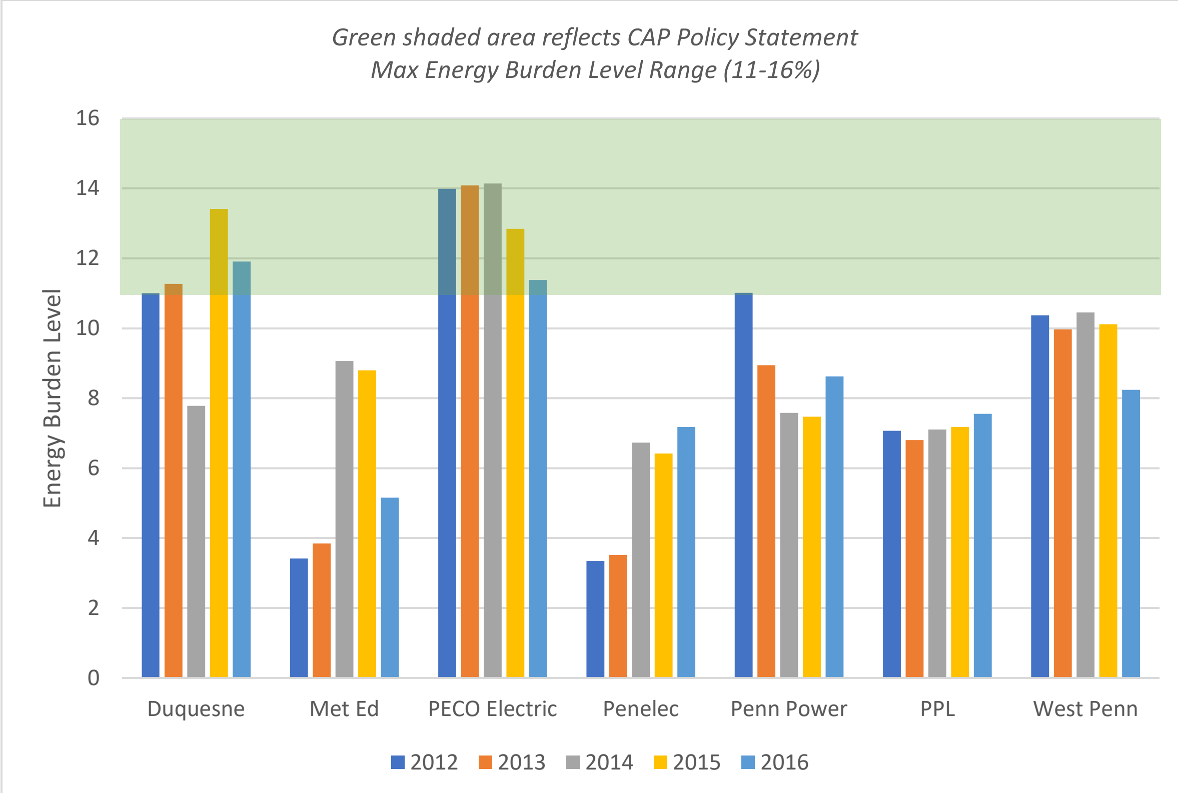
Table 3-6
EDC CAP Energy Burden Levels for Heating Customers at 0-50% of FPIG 2012-2016



As seen in Table 3-6, EDC CAP customers of Duquesne, Penelec, Penn Power, PPL, West Penn, and PECO Electric at the 0 to 50% FPIG level with electric heating accounts exceeded the CAP Policy Statement energy burden range of 7 to 13%. The average energy burdens for most EDC CAP customers at this income level exceeded this range. Met-Ed is the only EDC with energy burden levels within the CAP Policy Statement range for this income category.[32] Most EDC CAP heating customers within this income category had average energy burden levels exceeding 20% for most years in this study. However, it is unclear whether utilities included zero-income customers in the data used for these energy burden calculations.

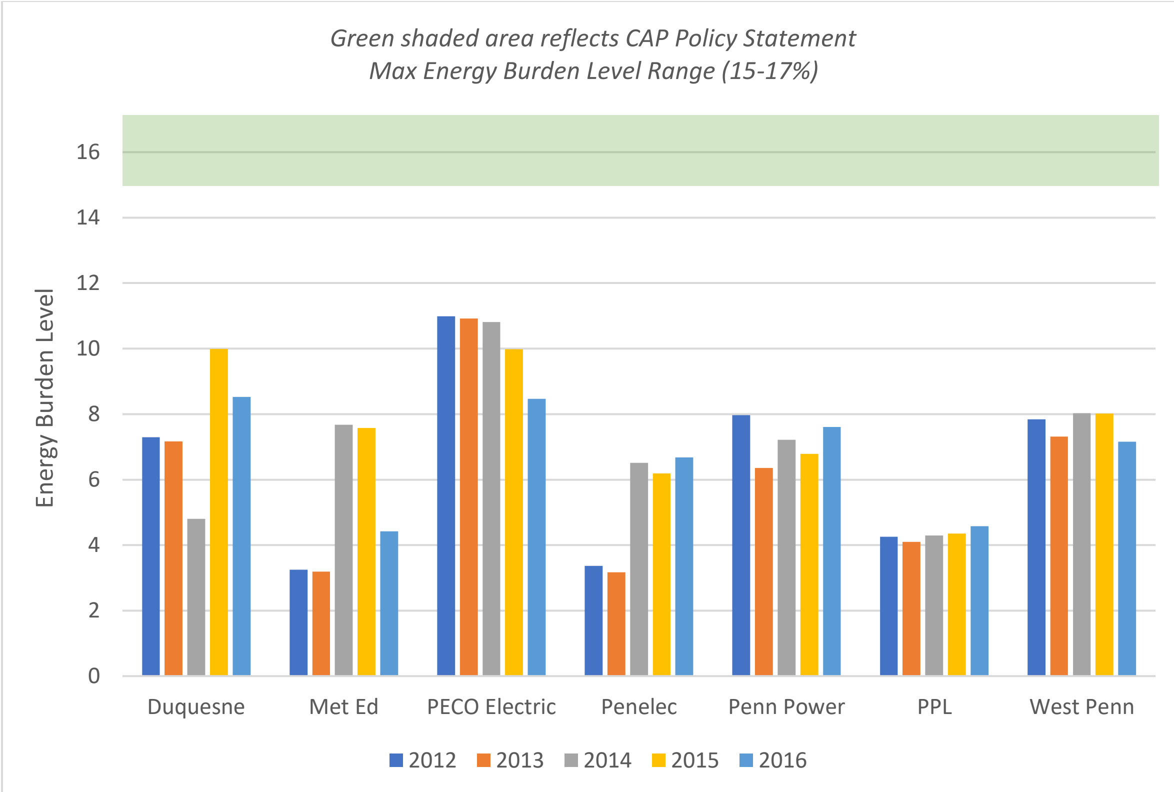
[32] The other FirstEnergy companies (*i.e.*, Penelec, Penn Power, and West Penn) have energy burden levels above the 7 to 13% CAP Policy Statement guidelines. It is not clear why Met-Ed's- energy burden levels are lower. In general, all FirstEnergy Companies calculate a CAP heating bill based on 9% of household income for this FPIG level.

Table 3-7
EDC CAP Energy Burden Levels for Heating Customers at 51-100% of FPIG 2012-2016



As seen in Table 3-7, all utilities were below or within the CAP Policy Statement maximum energy burden range of 11-16%. PECO Electric and Duquesne CAP heating energy burdens were within this range. The remainder of the EDCs had CAP energy burdens at or below 11%.

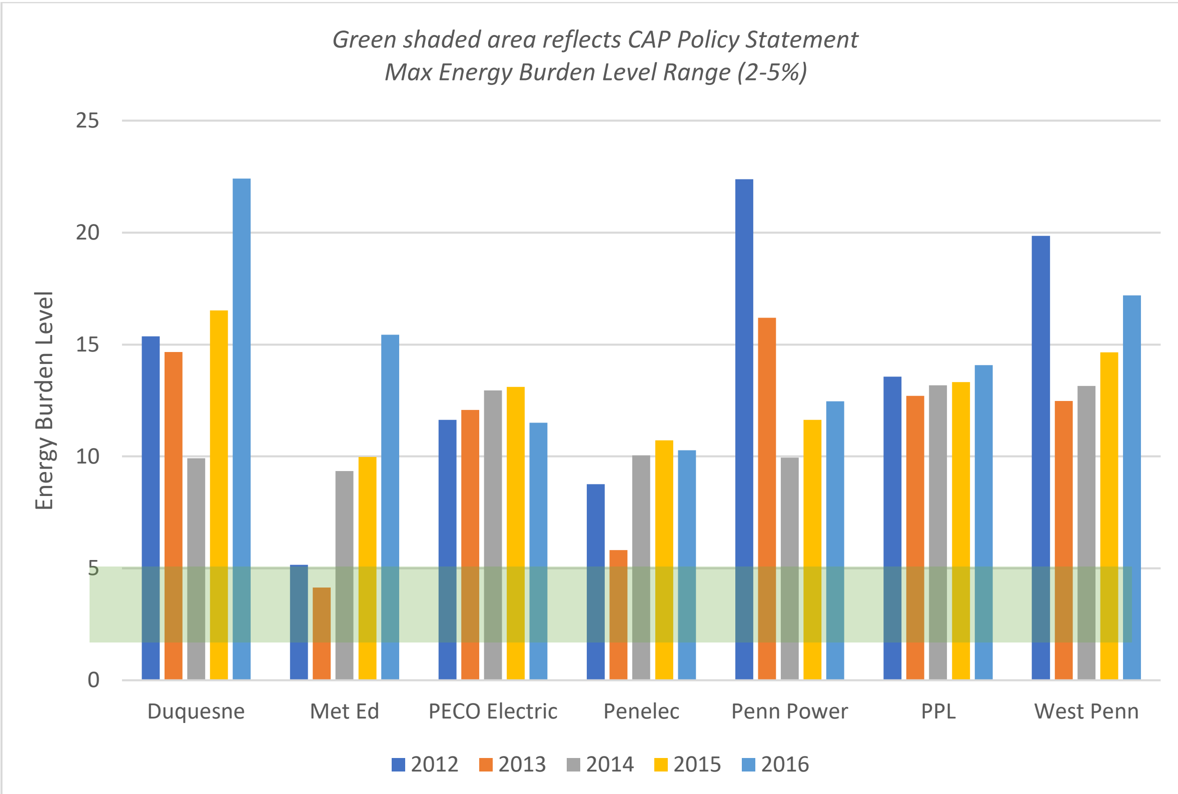
Table 3-8
EDC CAP Energy Burden Levels for Heating Customers at 101-150% of FPIG 2012-2016



The CAP Policy Statement suggests a maximum energy burden of 15-17% for electric heating customers in households in the 101 to 150% FPIG group. Section 69.265(2)(i)(C)(III). On average, EDC CAP heating customers with incomes between 101 to 150% of the FPIG had energy burdens well below the CAP Policy Statement maximum range of 15 to 17%. As seen in Table 3-8, most EDC CAP customers at this income level had energy burdens between 5 and 8% for most years in this study. PECO Electric's energy burden levels dropped from 11% to 9% from 2012 to 2016 for customers in this category.

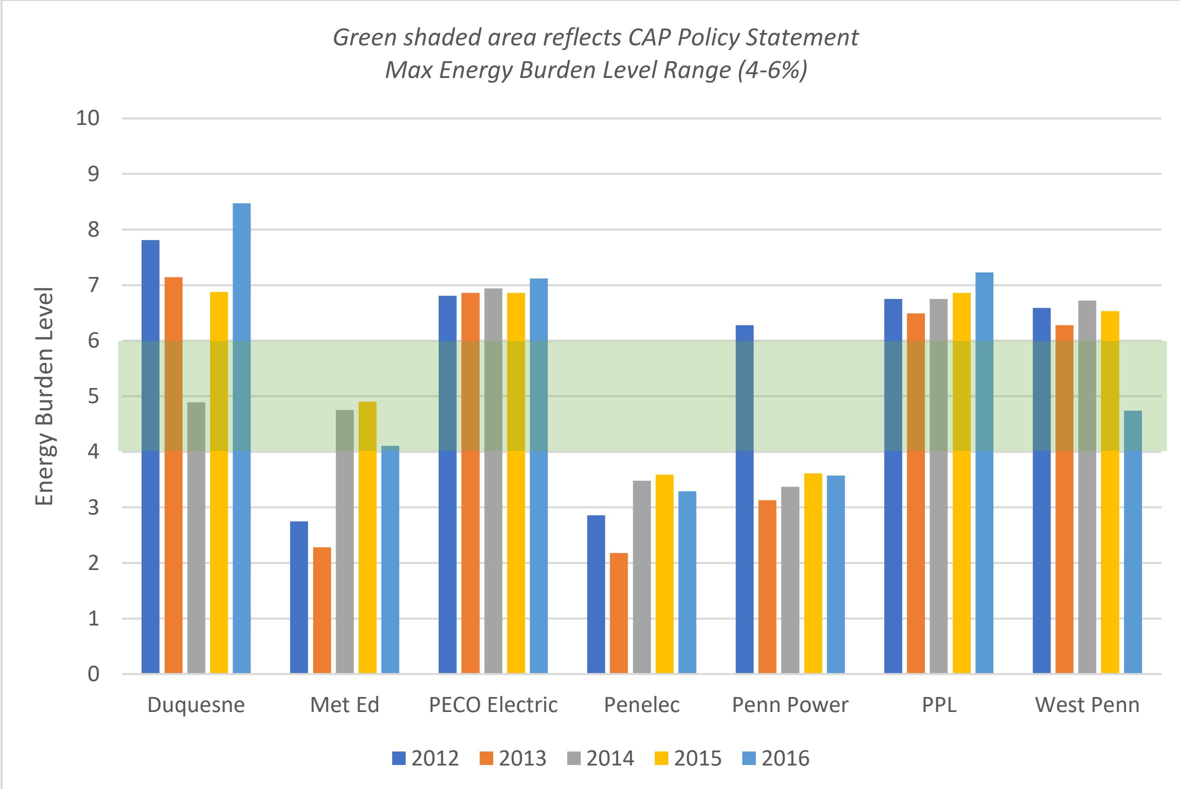
EDC CAP Non-Heating Customers

Table 3-9
EDC CAP Energy Burden Levels for Non-Heating Customers at 0-50% of FPIG 2012-2016



The CAP Policy Statement has a maximum energy burden range of 2-5% for EDC CAP non-heating customers with incomes at or below 50% of the FPIG. As seen in Table 3-9, all EDC CAP customers in this category exceeded this energy burden range, especially in the later years of the study. Most EDC non-heating CAP customers at this income level had energy burdens at or above 10% for most years in this study. However, as with the EDC CAP heating customers, it is unclear whether utilities included the zero-income customers in the data reported for this study.

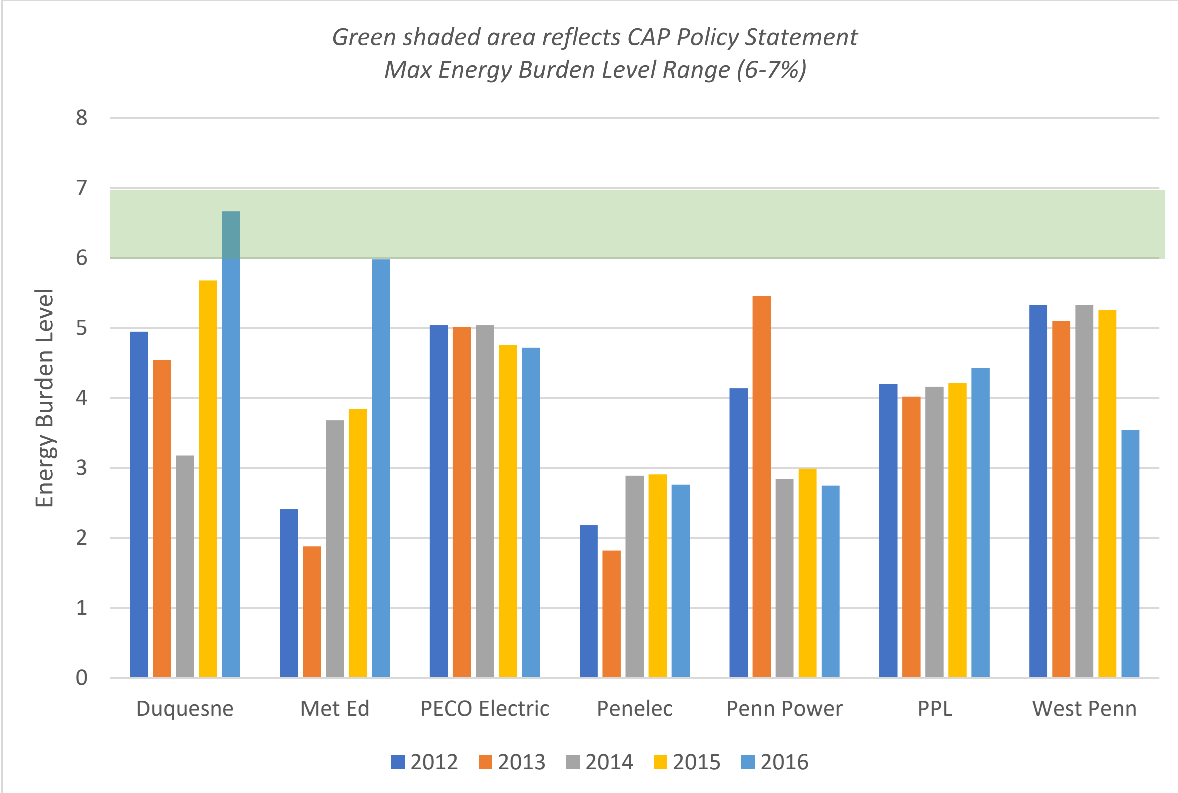
Table 3-10
EDC CAP Energy Burden Levels for Non-Heating Customers at 51-100% of FPIG 2012-2016



The CAP Policy Statement recommends a maximum energy burden range of 4 to 6% for EDC CAP non-heating customers with incomes between 51 and 100% of the FPIG. As seen in Table 3-10, over half of CAP customers in this category had energy burdens slightly above this range for most years of this study. Met-Ed, Penelec, and Penn Power non-heating CAP customers had energy burdens between 3% to 5%, and Duquesne CAP customers in this category increased from 5% to 8% from 2014 to 2016. However, this increase may have been due to Duquesne's budget billing issues that occurred during this time period. [33]

[33] Duquesne introduced a new billing system in November 2014 which did not retain prior usage data. Because its CAP bills were based on a percentage of budget billing, bills were considerably lower for most CAP customers through the beginning of 2015 but increased greatly thereafter, resulting in increased in-program arrears. Duquesne froze collections during this period so that CAP customers were not terminated for non-payment. *See Duquesne 2017-2019 USECP*, Docket No. M-2016-2534323, at 32-34 (order entered on March 23, 2017). CAP bills exceeded the maximum energy burdens in the CAP Policy Statement, and the Commission directed Duquesne to work with stakeholders to address CAP issues. March 23, 2017 Order at 28-31. By order entered on April 19, 2018, the Commission approved Duquesne's proposal to reduce the percent-of-bills discount (*i.e.*, rate discount) for most CAP customers in 2018 and switch to a percent-of-income (*i.e.*, PIPP) CAP by 2020.

Table 3-11
EDC CAP Energy Burden Levels for Non-Heating Customers at 101-150% of FPIG, 2012-2016



The CAP Policy Statement suggests a maximum energy burden range of 6% to7% for electric non-heating customers with income between 101% and 150% of the FPIG. As seen in Table 3-11, the energy burdens for most EDC CAP customers in this category fell below the CAP Policy Statement guidelines for all five years of this study. Duquesne CAP customers' energy burdens increased from 6% in 2015 to 7% in 2016. This increase was likely due to Duquesne's budget billing issues at this time.

Observations

From 2012 to 2016, the average energy burden was 7% to 8% for NGDC CAP heating customers, 5 to 6% for EDC non-heating CAP customers, and 8 to 10% for EDC CAP heating customers. Residential non-CAP customers had an average energy burden of 4% for gas and electric service during this time period.

Although not consistent across all income levels, the staff noted less variance in energy burdens of companies with percentage of income CAPs rather than rate discount CAPs.

On average, NGDC CAP customers at or below 50% of the FPIG level have energy burdens between 8% and 9% of their income, customers with incomes between 51% and 100% of FPIG have energy burdens between 7% and 8% of income, and customers with incomes between 101% and 150% of FPIG have energy burdens between 5% and 7% of their income. These ranges are within the CAP Policy Statement for all except customers at the 0 to 50% FPIG level.

There are numerous generalizations that can be made from the data provided by the EDCs. CAP customers in the lowest FPIG levels had the largest energy burden, and, as income increased, energy burdens tended to decrease across the board.

There has been variability in the energy burdens for CAP customers across Pennsylvania. As each utility determined its own CAP billing calculation, there was no discernable consistency across energy programs.

Customers in the 0 to 50% FPIG level, regardless of heating or non-heating status and energy type, often had energy burdens exceeding the CAP Policy Statement guidelines. Inclusion of zero-income customers by some utilities may have inflated the energy burden calculations for this FPIG level.

For the CAP customers in the 101 to 150% FPIG level, all three types of energy service show that both NGDC and EDC CAPs had energy burdens within the CAP Policy Statement guidelines. However, non-heating EDC CAP customer energy burdens at various FPIG levels seemed to exceed the CAP Policy Statement guidelines at a greater proportion than EDC heating CAP customers.

IV. Impact of LIHEAP Grants on Energy Burden Levels

Objective

As many states rely solely or primarily on LIHEAP funds as a means of energy assistance, this study examined the effect of LIHEAP grants on CAP customer bills to determine its impact on energy burden levels.

Background

LIHEAP is a federally-funded grant[34] that helps low-income households pay for their home energy[35] bills. Pennsylvania's LIHEAP is administered by DHS.[36] LIHEAP is traditionally available in Pennsylvania to eligible households from November through March, although DHS has extended the program into April when funding permits. Other states have summer cooling LIHEAP grants. LIHEAP grants are available to help pay for jurisdictional energy costs as well as deliverable energy costs. To qualify for Pennsylvania's LIHEAP, household income must be at or below 150% of FPIG, and the customer must be responsible for heating costs. 55 Pa. Code § 601.31 (1-2) (1988).[37]

LIHEAP offers two types of grants: Cash and Crisis. A LIHEAP Cash grant is available to all income-eligible customers that pay for their primary heating costs directly to a vendor or indirectly through rent. Section 601.31 (1-2) (1988). The amount of the LIHEAP Cash grant is calculated based on each household's gross income, number of occupants, county of residence, and source of heat (*i.e.*, electric, gas, oil, etc.). Section 601.41 (1988). From 2012 through most of 2016, the minimum amount of a LIHEAP Cash grant was $100, and the maximum amount was $1,000. For the 2016 - 2017 LIHEAP season (beginning November 2016), DHS increased the minimum Cash grant to $200. Households can receive only one LIHEAP Cash grant per LIHEAP season. Section 601.43 (1988).

A LIHEAP Crisis grant is available to all income-eligible households who are (1) responsible for paying for their primary or secondary heating costs directly or indirectly; and (2) are experiencing a home-heating emergency (*i.e.*, currently without heat or in imminent danger of being without heat). Section 601.32 (1-2) (1988). From 2012 through 2016, the minimum amount of a LIHEAP Crisis grant was $25, and the

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[34] *See* 42 U.S.C. §§ 8621 – 8630. Low-Income Home Energy Assistance.
[35] "Home energy" means a source of heating or cooling in residential dwellings. 42 U.S.C. § 8622(6).
[36] Formerly the Department of Public Welfare.
[37] DHS changes aspects of the LIHEAP State Plan yearly, but the changes only affect some of the sections originally codified in Chapter 601 of Title 55 of the Pennsylvania Code. Citations to Title 55 of the Pennsylvania Code will only be to sections that have not changed over the time frame of the study. Citations to changed sections will be to the specific LIHEAP state plan for a given year.

maximum amount was $500.[38] Households could receive more than one Crisis grant, as long as the total amount of these grants did not exceed $500. Section 601.63 (1988).

In August/September of 2015 and 2016, DHS also administered a LIHEAP Summer Turn-On program that provided supplemental Crisis grants (up to $500) to households who had received LIHEAP Cash and/or Crisis grants during the previous season and are experiencing a heating emergency.[39]

Based on historical averages of the data reported by the utilities for 2013 to 2016, low-income CAP customers who assigned their LIHEAP grants to gas utilities received average Cash and/or Crisis grants of $361 for those in the 0 to 50% FGIP level, $258 for those in the 51 to 100% FPIG level, and $216 for those in the 101 to 150% FPIG level. Low-income CAP customers who assigned their LIHEAP grants to electric utilities received slightly more, on average. Cash and/or Crisis grants to electric heating utilities averaged $474 for the 0 to 50% FPIG level, $333 for the 51 to 100% FPIG level, and $282 for the 101 to 150% FPIG level. Non-heating CAP customers received an average of $417 in the 0 to 50% FPIG level, $319 in the 51 to 100% FPIG level, and $298 in the 101 to 150% FPIG level.

Most utilities apply LIHEAP Cash grants directly to the CAP customer's "asked to pay" amount" (ATP), in compliance with the Pennsylvania LIHEAP State Plan.[40] This means the grant is first applied to any in-program arrears, then the current bill. Any remaining amount is kept on the account as a credit toward the next month's bill.

Rather than rely on LIHEAP to address affordability concerns, Pennsylvania CAPs and other universal service programs are funded primarily and significantly through residential ratepayer rates.[41] DHS prohibits utilities from using LIHEAP grants to fund the discounts on a CAP bill or to reduce any debt forgiveness. DHS also prohibits pooling LIHEAP grants to fund CAPs or other universal service benefits.

[38] Households are ineligible for LIHEAP Crisis benefits if the grant does not resolve the home-heating emergency. "Emergency" is defined at 42 U.S.C. § 8622(1).

[39] If DHS determined a household was off or in termination status with both its primary and secondary heating sources (*i.e.*, gas and electric), a supplemental Crisis grant was issued to both utilities, up to $500 each (if the grant(s) resolved the termination or restored service). Thus, some customers received up to $1,000 in supplemental Crisis grants through the LIHEAP Summer Turn-On program.

[40] NFG is the only utility that applied LIHEAP Cash grants differently during this study period. NFG would apply a LIHEAP cash grant toward any past or current CAP charges. However, any remaining amount would be factored into a new budget billing calculation. The Commission ordered NFG to, among other things, comply with the LIHEAP State Plan and apply any remaining LIHEAP grant monies as a credit to the CAP customer's account. NFG 2017-2020 USECP at 10-18, 61-62, 65; Docket No. M-2016-2573847 (order entered on March 1, 2018).

[41] Other states use LIHEAP as the main source of funding for their energy assistance programs.

Methodology

Staff compared the average energy burdens of CAP customers before and after they received a LIHEAP grant to determine the impact that LIHEAP grants have in making CAP bills more affordable. Staff examined the following information for CAP customers who received LIHEAP: total number of customers who received LIHEAP, average usage, average billing, average income, and the total amount of LIHEAP dollars received. Most utilities provided this data by FPIG level and heating type.

The impact of the LIHEAP grants on CAP energy burden levels was determined by comparing the average energy burdens for CAP customers prior to receiving LIHEAP and then after the annual LIHEAP amount is applied to their average bill. This analysis examined the change in energy burdens for each FPIG level and heating type.

The CAP energy burdens in this analysis are not comparable to the average energy burdens for CAP customers identified in Section III, *Energy Burden Levels for Gas and Electric Service*. This inconsistency is primarily due to the count of LIHEAP households during a calendar year. The number of CAP customers who received LIHEAP includes each household that received a LIHEAP Cash and/or Crisis grant during a LIHEAP season. Since a calendar year encompasses two partial LIHEAP seasons (*i.e.*, January to March and November to December), households are counted twice if they received a grant in both seasons for the same calendar year. In 2015 and 2016, a CAP household could be counted three times if it received a grant in both seasons and also received a LIHEAP Summer Turn-On grant.

There could also be differences in the value of LIHEAP grants received during each calendar year by a given household. From 2012 through 2014, a CAP customer may have received multiple LIHEAP grants within a calendar year: two CASH grants (January to March and November to December) and Crisis grant(s) (up to $500 total/season). In 2015 and 2016, a CAP customer may have received an additional one or two Summer Turn-On grants.

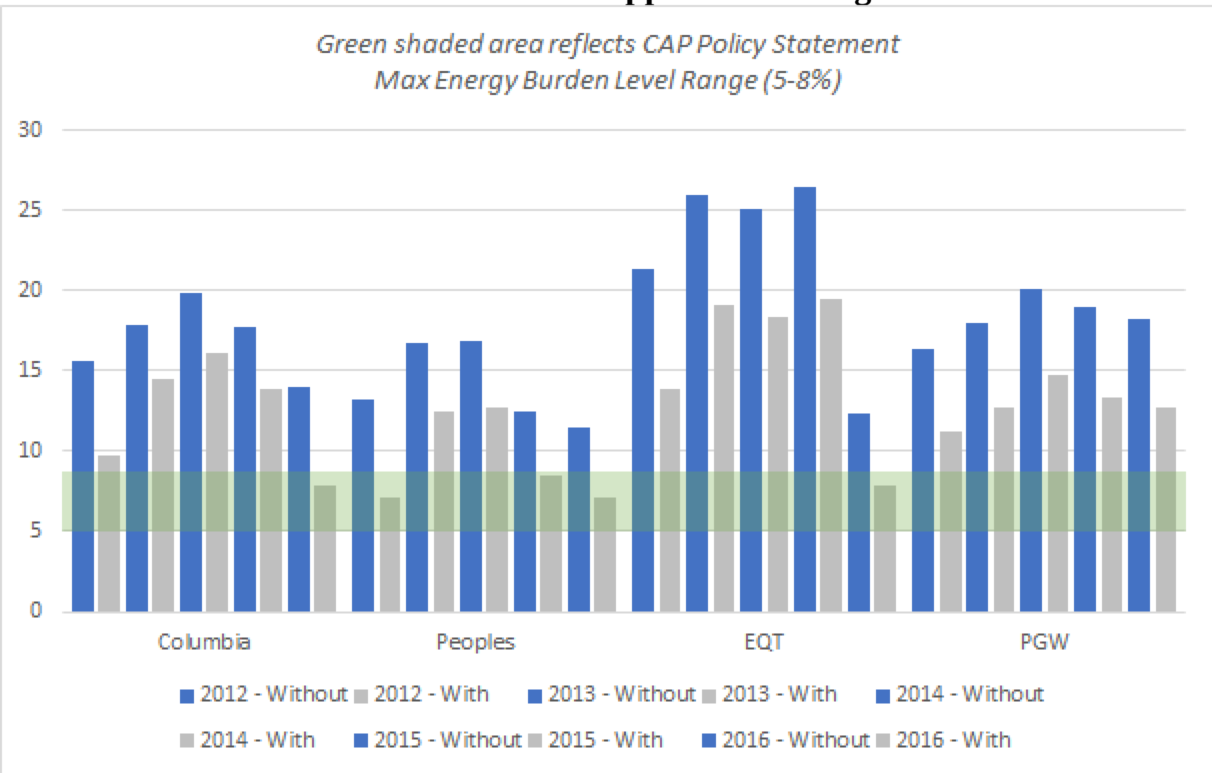
Data Limitations

UGI Gas, UGI PNG, and PECO Gas are not included in this part of the analysis because these utilities could not provide average annual income for CAP customers who received LIHEAP. NFG could not provide data by FPIG level, so it is included only in the analysis of CAP customers at the aggregate income level (*i.e.*, up to 150% of the FPIG).

Analysis

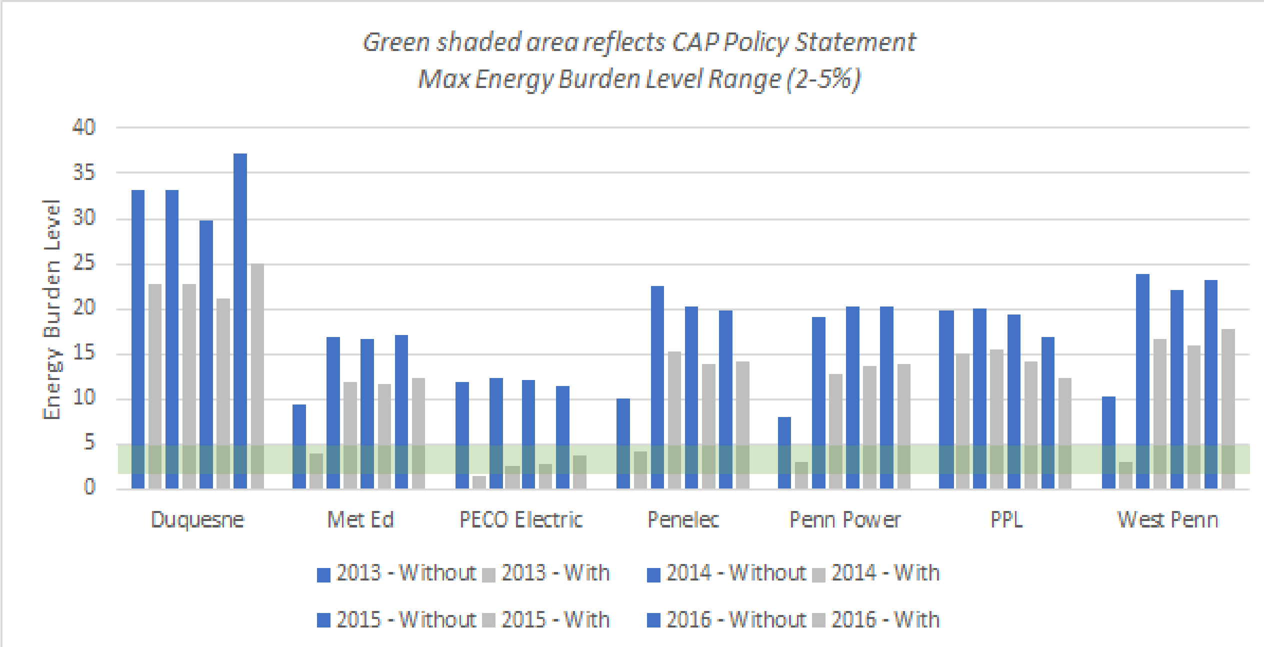
Average Impact of LIHEAP for CAP Customers at 0-50% of FPIG

Table 4-1
NGDC CAP LIHEAP Recipients at 0-50% FPIG
Without & With LIHEAP Grants Applied to Average Bills 2012-2016



The average impact of LIHEAP on energy burdens was greatest for CAP households with the lowest incomes. Based on the industry average, the energy burdens for NGDC CAP customers with incomes at or below 50% of the FPIG decreased by over 5.47 percentage points after receipt of LIHEAP, from 17.74% to 12.27%. For the customers of some individual NGDCs, LIHEAP grants provided a nearly 50% reduction in their energy burdens. Table 4-1 shows the pre- and post-LIHEAP energy burdens for NGDC CAP customers with incomes at 0-50% who received LIHEAP.

Table 4-2
EDC Non-Heating CAP LIHEAP Recipients at 0-50% FPIG
Without & With LIHEAP Grants Applied to Average Bills 2013-2016



EDC non-heating CAP customers at 0% to 50% FPIG experienced an industry average energy burden decrease of over 7.16 percentage points after LIHEAP grants were applied to the average annual bill, from 18.47% to 11.31%. Table 4-2 shows the pre- and post-LIHEAP energy burdens for EDC non-heating CAP customers with incomes at 0 to 50% who received LIHEAP. EDC CAP customers with electric heat at this FPIG level saw the biggest benefits from LIHEAP. Their industry average energy burdens decreased by over 7.68 percentage points after receipt of LIHEAP, from 27.07% to 19.39%.

Table 4-3
EDC Heating CAP LIHEAP Recipients at 0-50% FPIG
Without & With LIHEAP Grants Applied to Average Bills 2013-2016

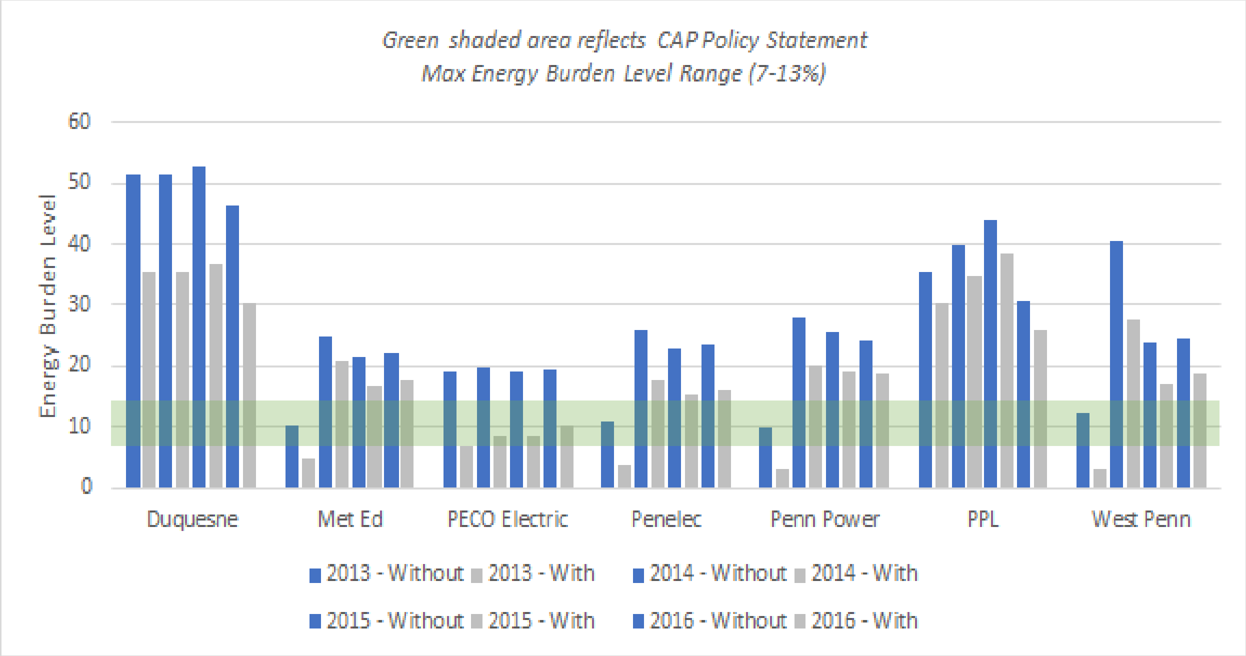
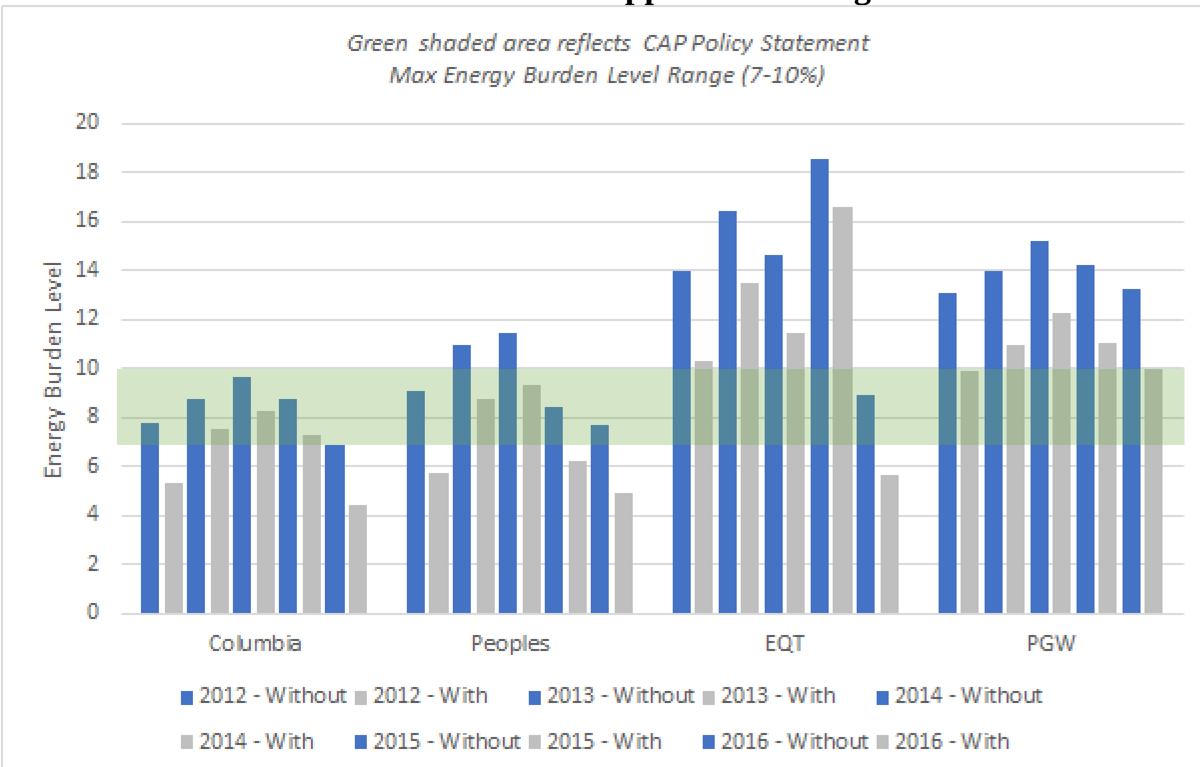


Table 4-3 shows the pre- and post-LIHEAP energy burdens for EDC CAP heating customers with incomes at 0 to 50% who received LIHEAP.

Average Impact of LIHEAP for CAP Customers at 51-100% of FPIG

Table 4-4
NGDC CAP LIHEAP Recipients at 51-100% FPIG
Without & With LIHEAP Grants Applied to Average Bills 2012-2016



As seen in Table 4-4, based on the industry average, LIHEAP reduced the energy burdens for NGDC CAP customers with incomes between 51 and 100% of the FPIG by over 2.69 percentage points, from 11.43% to 8.74%.

Table 4-5
EDC Non-Heating CAP LIHEAP Recipients at 51-100% FPIG
Without & With LIHEAP Grants Applied to Average Bills 2013-2016

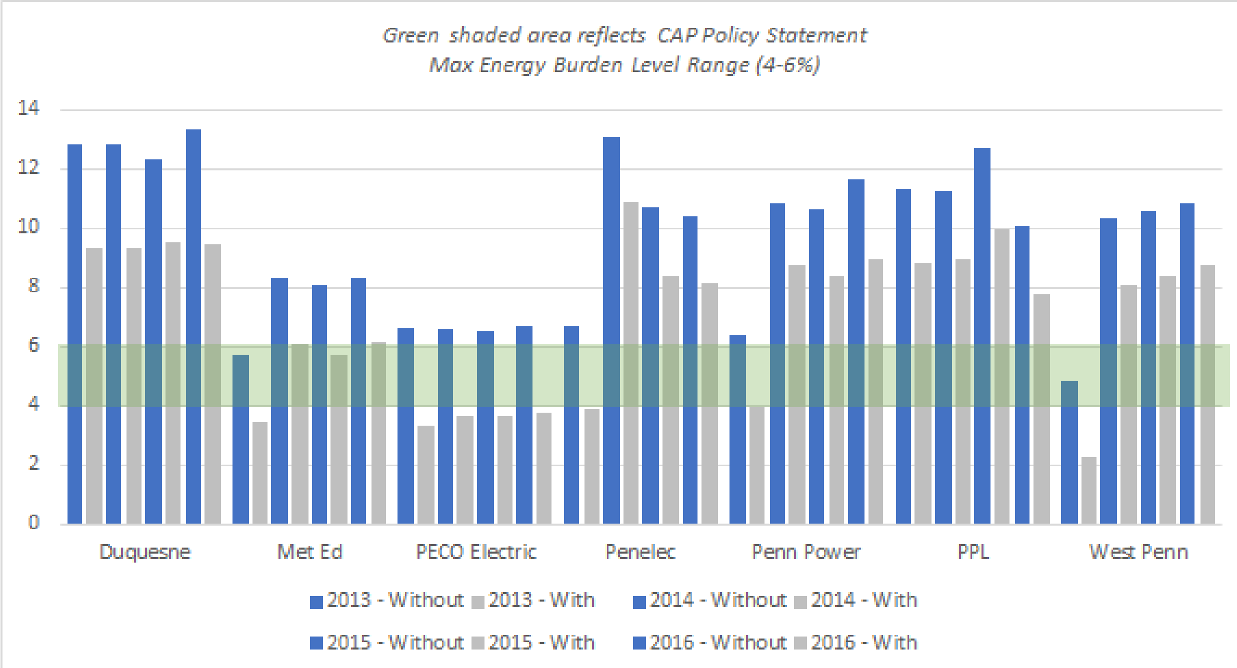
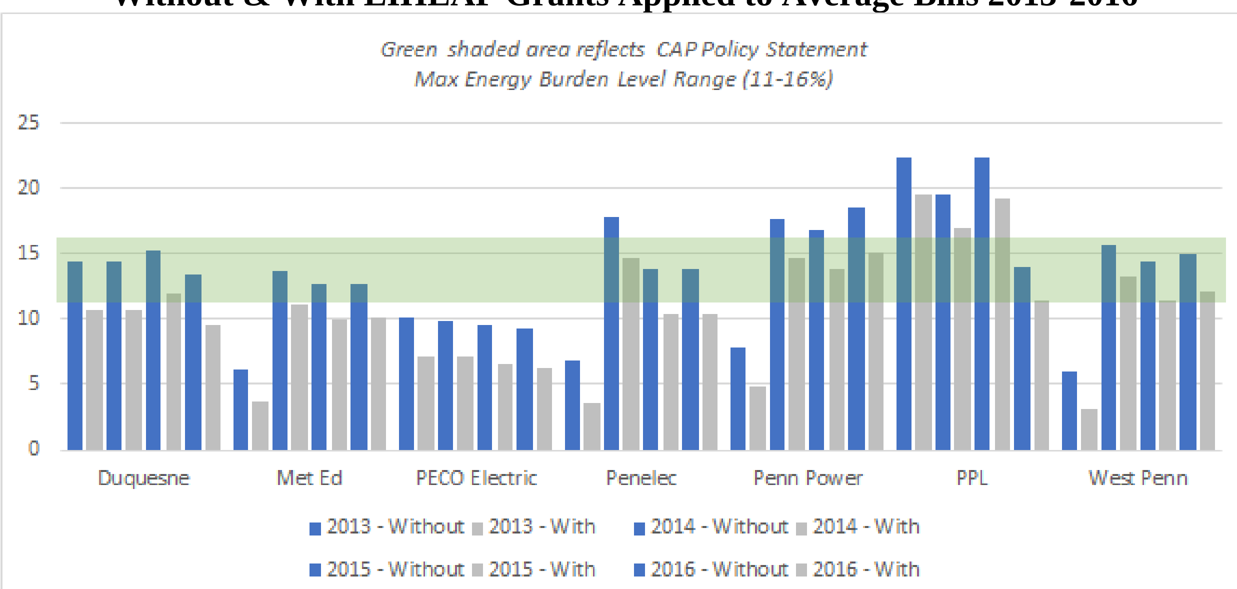


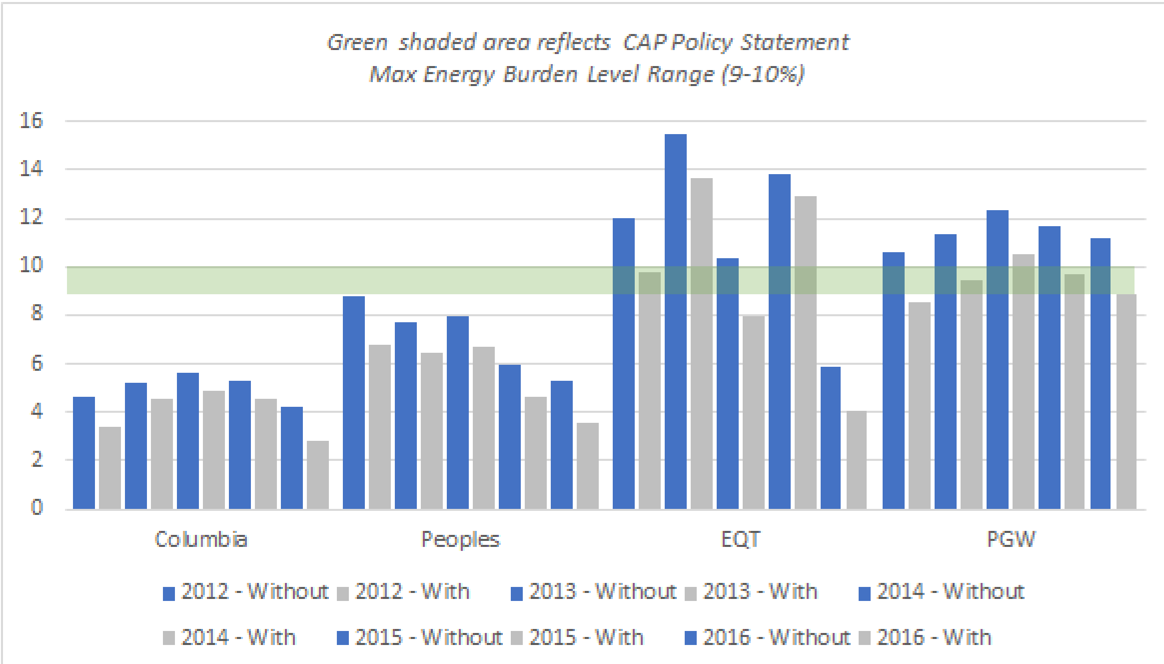
Table 4-6
EDC Heating CAP LIHEAP Recipients at 51-100% FPIG
Without & With LIHEAP Grants Applied to Average Bills 2013-2016



EDC non-heating CAP customers with incomes between 51% and 100% of FPIG level experienced an industry average energy burden decrease of over 2.59 percentage points, from 9.81% to 7.22%, after applying LIHEAP to their average annual bills. The industry average energy burdens for EDC heating CAP customers at this FPIG level decreased by over 2.94 percentage points, from 14.39% to 11.45%, after applying LIHEAP to their average bills. Tables 4-5 and 4-6 show the pre- and post-LIHEAP energy burdens for EDC non-heating and heating CAP customers with incomes between 51 and 100% of FPIG who received LIHEAP.

Average Impact of LIHEAP for CAP Customers at 101 to 150% of FPIG

Table 4-7
NGDC CAP LIHEAP Recipients at 101-150% FPIG
Without & With LIHEAP Grants Applied to Average Bills 2012-2016



NGDC CAP customers with incomes between 101 and 150% of FPIG experienced an industry average decrease of over 1.54 percentage points, from 8.41% to 6.87%, in their energy burden levels after receipt of LIHEAP. Tables 4-7 shows the pre- and post-LIHEAP energy burdens for NGDC CAP customers with incomes at 101% to 150% FPIG level who received LIHEAP.

Table 4-8
EDC Non-Heating CAP LIHEAP Recipients at 101-150% FPIG
Without & With LIHEAP Grants Applied to Average Bills 2013-2016

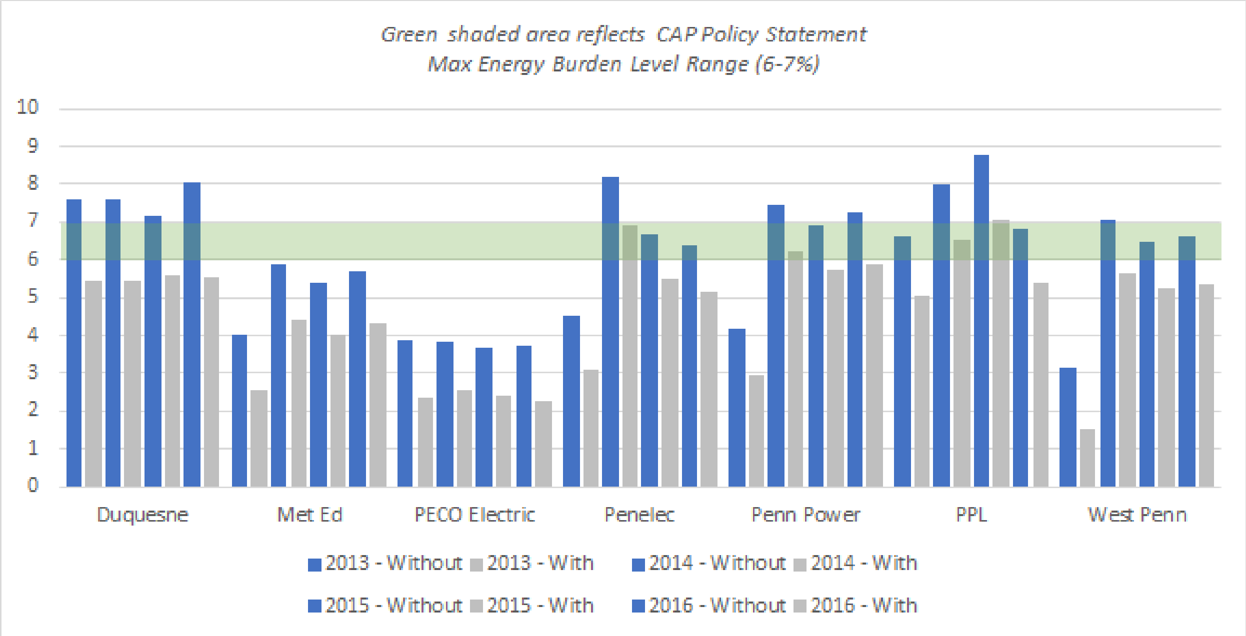
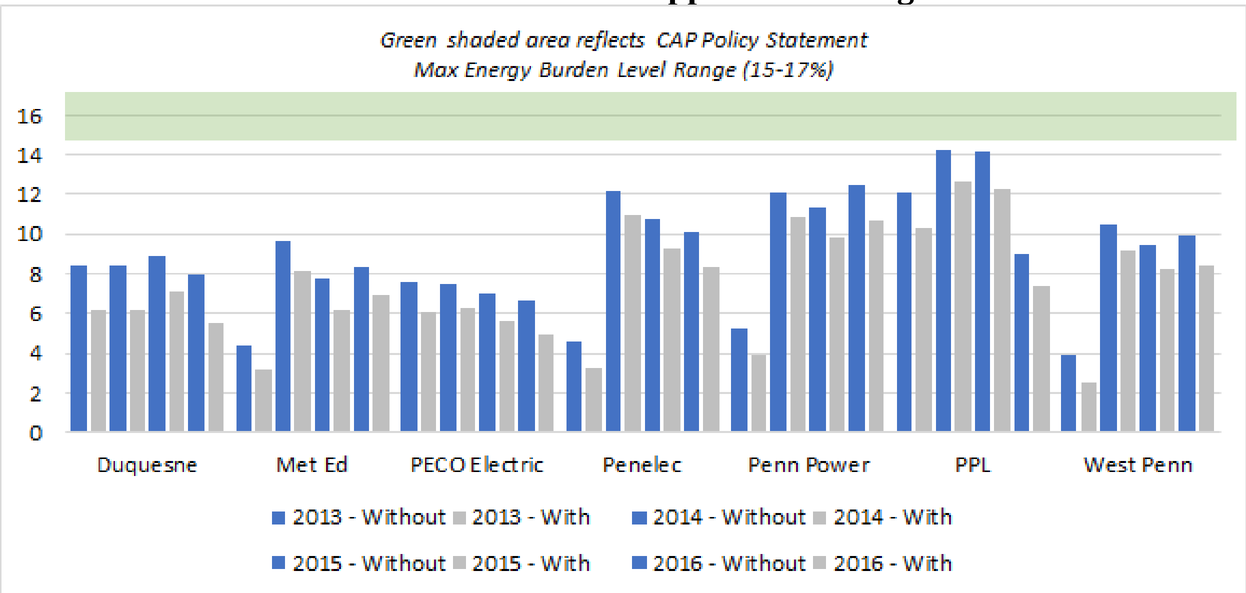


Table 4-9
EDC Heating CAP LIHEAP Recipients at 101-150% FPIG
Without & With LIHEAP Dollars Applied to Average Bill 2013-16



EDC non-heating CAP customers at this FPIG level experienced an industry average energy burden decrease of over 1.5 percentage points, from 6.28% to 4.78%, after LIHEAP grants were applied to their average annual bills. The industry average energy burden for EDC heating CAP customers at this FPIG level decreased by over 1.57 percentage points, from 9.7% to 8.13%, after LIHEAP grants were applied to their average bills. Tables 4-8 and 4-9 show the pre- and post-LIHEAP energy burdens for EDC CAP customers with incomes at 101 to 150% of FPIG who received LIHEAP.

Observations

The analysis reflects that LIHEAP has a measurable impact on energy burdens for CAP customers.

After applying LIHEAP, CAP customers with incomes at or below 50% FPIG level experienced an energy burden decrease of approximately 5 to 6 percentage points for gas heating, 6 to 8 percentage points for electric non-heating, and approximately 7 to 9 percentage points for electric heating. Even with these decreases, however, the average energy burden for CAP households at this FPIG level who received LIHEAP generally exceeded the maximum energy burden guidelines in the CAP Policy Statement.

After applying LIHEAP, CAP customers with incomes between 51 and 100% of the FPIG experienced an energy burden decrease of approximately 2 to 3 percentage points for gas heating and 3 percentage points for electric non-heating and heating. The energy burdens for some NGDC and EDC non-heating CAP customers at this income level remained above the CAP Policy Statement guidelines after application of LIHEAP.

After applying LIHEAP, CAP customers with incomes between 101 and 150% of the FPIG experienced an energy burden decrease of approximately 1 to 2 percentage points for gas heating, electric non-heating, and electric heating. The energy burden levels for NGDC and EDC CAP customers at this FPIG were generally below the CAP Policy Statement guidelines after application of LIHEAP.

LIHEAP had the most impact on reducing energy burdens for NGDC CAP customers in 2016, across all FPIG levels. This may suggest that more CAP customers assigned their LIHEAP grants to their gas utility that year or the introduction of the Summer Turn-On grants increased the amount of LIHEAP monies applied to NGDC CAP accounts.

V. Pre-Program Arrearages (PPAs) and In-Program Arrears

Objective

Determine what the amounts of PPA and/or in-program arrears accrued by CAP customers indicate about the affordability of utility CAPs and customer payment behavior.

Background

Pre-Program Arrearages (PPAs)

When a low-income customer is initially enrolled in a CAP, any balance due which was accrued prior to enrollment (*i.e.*, PPA) is deferred and is not counted as part of the customer's CAP balance. This allows the CAP customer to begin the program with a "clean slate" (*i.e.*, a zero balance).

Table 5-1
Minimum Time frames for Full Forgiveness of PPA

Minimum Time Frame	Utilities
One-year (1/12th forgiveness for each payment)	PECO Electric, PECO Gas
18 months (1/18th forgiveness for each payment)	PPL
Two-years (1/24th forgiveness for each payment)	Duquesne, NFG[42]
Three-years (1/36th forgiveness for each payment)	Columbia, FirstEnergy (Met-Ed, Penelec, Penn Power, and West Penn), Peoples Natural Gas, Peoples Equitable, PGW, UGI Gas, UGI PNG

Table 5-1 reflects the PPA forgiveness time frames for utility CAPs during the 5-year period of this study. Each time a household pays its monthly CAP bill, the utility forgives a portion of the household's deferred PPA balance.[43] The amount of time required for a CAP household to receive full PPA forgiveness differs by utility. The

[42] NFG's PPA forgiveness component was limited to 36 months. NFG forgave 1/24th of PPAs for each month CAP customers pay their CAP monthly bill in-full and forgave any missed months once the in-program CAP balance was satisfied. After 36 months, any remaining PPA balance was added to the customer's account. NFG 2017-2020 USECP at 13, Docket No. M-2016-2573847 (filed on April 2, 2018). No other utility CAPs imposed a time restriction on a CAP customer's opportunity to earn PPA forgiveness.
[43] Some utilities imposed a monthly PPA co-payment. The co-payment goes to reduce the CAP customer's PPA in conjunction with the proportional forgiveness earned by full CAP payments. Thus, a utility with a monthly PPA co-payment is not actually providing full forgiveness of the CAP customer's PPA.

utilities set the minimum period required to earn the PPA forgiveness.[44] Only one utility limited the amount of time a CAP customer can take to achieve full PPA forgiveness.

Higher PPA balances may indicate the unaffordability of pre-CAP bills (*i.e.*, full-tariff bills). Such balances could also indicate poor payment behavior. Customers enrolling in CAPs with higher PPA balances have been found to have less success in payment assistance programs.[45]

In-Program Arrears

One of the benefits of a CAP is that it attempts to provides the customer with an affordable monthly payment while the customer is in CAP. Regardless of any PPA, all customers start with a "clean slate" when they are first enrolled into CAP. If participants continue to accumulate arrearages while in CAP (*i.e.*, in-program arrearages), it may indicate that the monthly CAP payment is not affordable and/or that the customer has poor or ineffective payment habits.

Accrual of in-program arrears may also indicate problems with the utility's collection procedures. Most utilities report initiating collection efforts up to and including service termination activity or removal from CAP after one or two missed CAP payments. If collection activity or program removal is delayed, in-program CAP arrears may continue to accumulate.

Methodology

To determine the average amount of PPA and in-program arrears carried by CAP customers, staff reviewed the following data from NGDCs and EDCs for the period from 2012 through 2016:

- The number of CAP accounts with PPAs and the total dollar amounts of the PPAs; [46] and
- The number of CAP accounts with in-program arrears and the total dollar amount of these arrears.

[44] The CAP Policy Statement recommends PPA forgiveness over 24 to 36 months, contingent upon regular monthly payments by the CAP participant. Section 69.265(6)(ix).

[45] *Pathways to Success in Low-Income Energy Assistance Payment Programs: The Differential Effects of Customer Characteristics and Program Design on Payment Rates* at 8-9. Megan Campbell, Opinion Dynamics (2013). http://www.opiniondynamics.com/wp-content/uploads/2013/08/Pathways-to-Success-in-Low-Income-Energy-Assistance-Payment-Programs1.pdf

[46] These PPA balances reflected the amount of PPAs carried by CAP customers during each year. It does not reflect the average PPA balance of CAP customers when they enrolled in the program with a PPA.

Data Limitations

Some utilities could not provide PPA and in-program arrearage amounts by FPIG level or heating type (*i.e.*, electric heating and electric non-heating). Specifically:

- The FirstEnergy Companies could not provide PPA data by FPIG level.
- The FirstEnergy companies could not provide data by heating type for electric.

Some utilities could not provide PPA and in-program arrears data for every year of this study. Specifically:

- Columbia Gas could not provide data for 2012.
- West Penn could not provide data prior to 2015.
- Duquesne could not provide data prior to 2015.

Further, the PPAs and in-program arrears were not tallied in terms of the age of the debt.

As a result, staff analyzed the PPA and in-program arrearage amounts in the aggregate across all FPIG levels (*i.e.*, 0-150%). Electric heat and electric non-heating CAP accounts are combined.

Analysis

NGDCs–PPAs

For gas heating CAPs, staff found a variance in the amount of PPAs carried by CAP customers. Most gas utilities reported average PPA balances between $400 and $800 for CAP customers with a PPA. Columbia Gas had the lowest average amount of PPAs, ranging from $99 to $133 per CAP customer for the four years of data provided (2013-2016). PGW reported the highest average amount of PPA, ranging from $1,260 to $1,342 per CAP customer for 2012 through 2016.

One possible reason for the variance in the average amounts of PPAs between Columbia Gas and PGW may be the differences in their CAP enrollment restrictions. Columbia Gas will enroll any low-income customer with a heating account into its CAP if the customer is “payment troubled,” which is defined as having received a termination notice or having broken a payment agreement within the past 12 months or having been identified through a utility referral or credit scoring. Columbia Gas 2015-2018 USECP at 17, Docket No. M-2014-2424462 (filed on August 12, 2015). During the time-period of this study, PGW enrolled low-income customers into its CAP only if the percentage-of-income payment (*i.e.*, 8-10%) was the most affordable option. PGW 2014-2016 USECP at 9, Docket No. M-2013-2366301 (filed on September 22, 2014). Thus, low-income customers could qualify for Columbia Gas' CAP after two missed payments, while PGW customers may have had to wait to qualify until CAP offered the most affordable payment.

Overall, PPA balances trended downward for most gas utilities. This decrease may be attributable to the lower cost of natural gas[47] and the warmer winters Pennsylvania experienced after the polar vortex in 2014-2015. Columbia (with the lowest average PPAs) and Peoples have, however, seen their average PPAs trend slightly upward over the five years.

Table 5-2
Average PPAs Carried by NGDC CAP Customers with PPA Balances (Gas Heating Only)

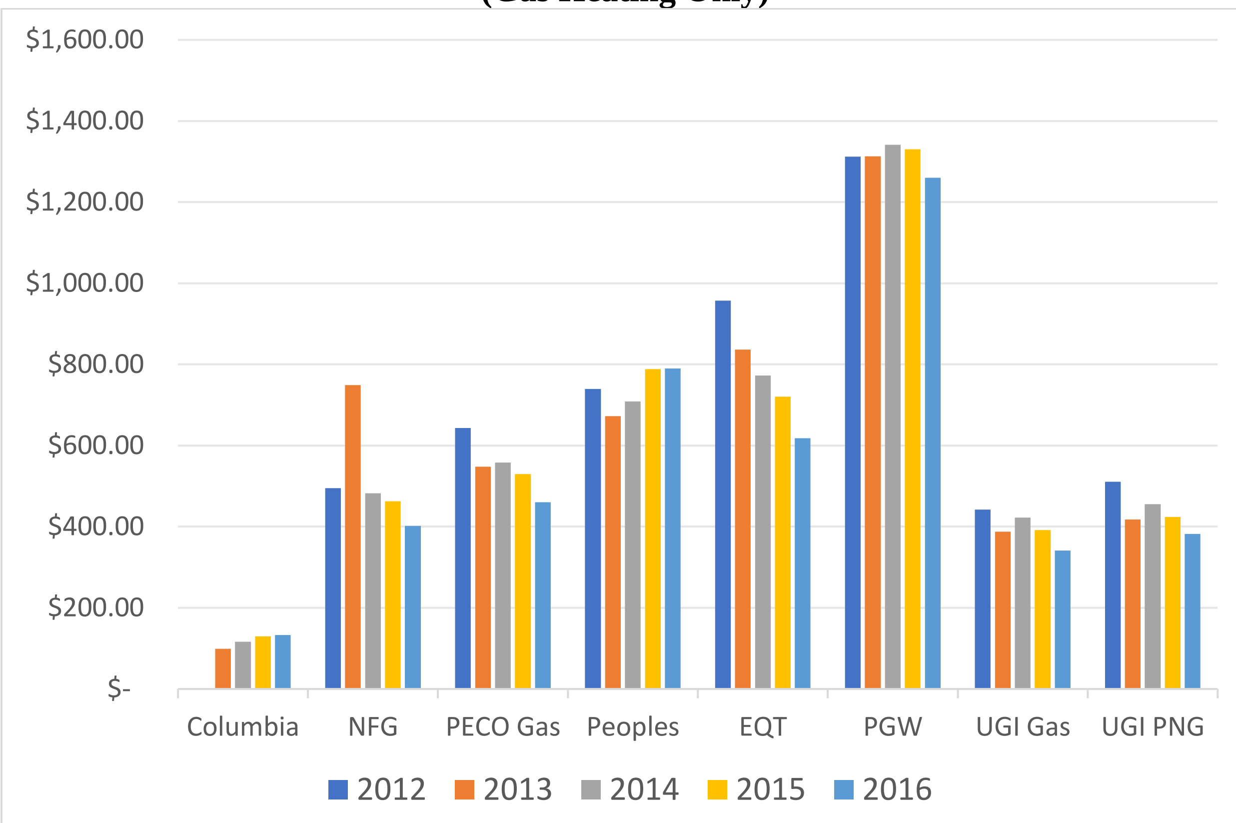


Table 5-2 reflects the average PPA per NGDC CAP customer with a PPA balance during the five-year- period of this study.

NGDCs–In-Program Arrears (IPAs)

Most NGDCs reported in-program arrears averaging from $100 to $400 for CAP customers who carried in-program arrears during 2012-2016. All NGDCs reported

[47] *See* the Commission's *Rate Comparison Reports*, published annually by the Commission's Bureau of Technical Services: http://www.puc.state.pa.us/filing_resources/rate_comparison_report.aspx

decreasing in-program arrearage balances in 2016. In addition to lower natural gas costs and warmer winters in 2015-2016, declining CAP enrollment may also be a factor. The average 2016 CAP enrollment rate for both NFG and Peoples Equitable declined by 43% compared to their average 2012 CAP enrollment rates. PGW's average CAP enrollment in 2016 was 34% lower than 2012. 2012 and 2016 Report on Universal Service Programs & Collections Performance at 39 and 59, respectively.

Table 5-3
Average IPAs Carried by NGDC CAP Customer with IPAs Balances
(Gas Heating Only)

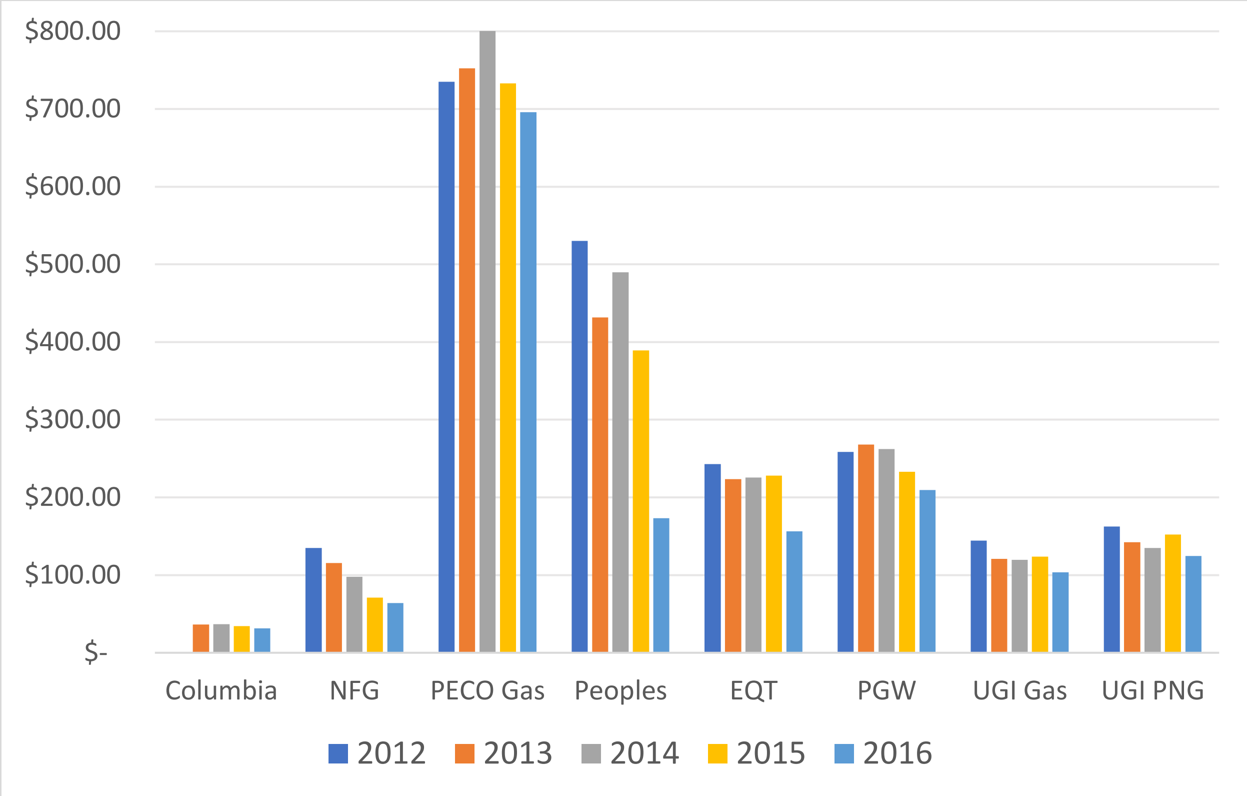


Table 5-3 reflects the average in-program arrears for NGDC CAP customers who carried in-program arrears during the five-year period of this study.

Columbia reported the lowest amount of in-program arrears, ranging from $31 to $36 for CAP customers who carried in-program arrears during the four years of data it provided (2013-2016). Columbia initiated termination procedures after two missed CAP payments,[48] and it also reported higher CAP termination rates, on average, than most other NGDCs. *See* Table 5-3. Beginning collection activity before a CAP customer accrues a sizeable in-program arrears may prevent CAP customers from accruing high in-program arrears balances, but, besides Columbia, this study did not detect a possible correlation between these two variables.

[48] Columbia 2015-2018 USECP at 21, Docket No. M-2014-2424462 (filed on August 12, 2015).

PECO Gas reported the highest amount of in-program arrears, ranging from $643 to $746 for CAP customers who carried in-program arrears for 2012 through 2016. During this period, PECO Gas had allowed CAP customers to obtain payment agreements[49] for in-program arrears which likely is responsible for its higher levels.[50]

EDCs – PPAs

Table 5-4
Average PPAs Carried by EDC CAP Customers with PPA Balances
(Electric Non-Heating and Electric Heating)

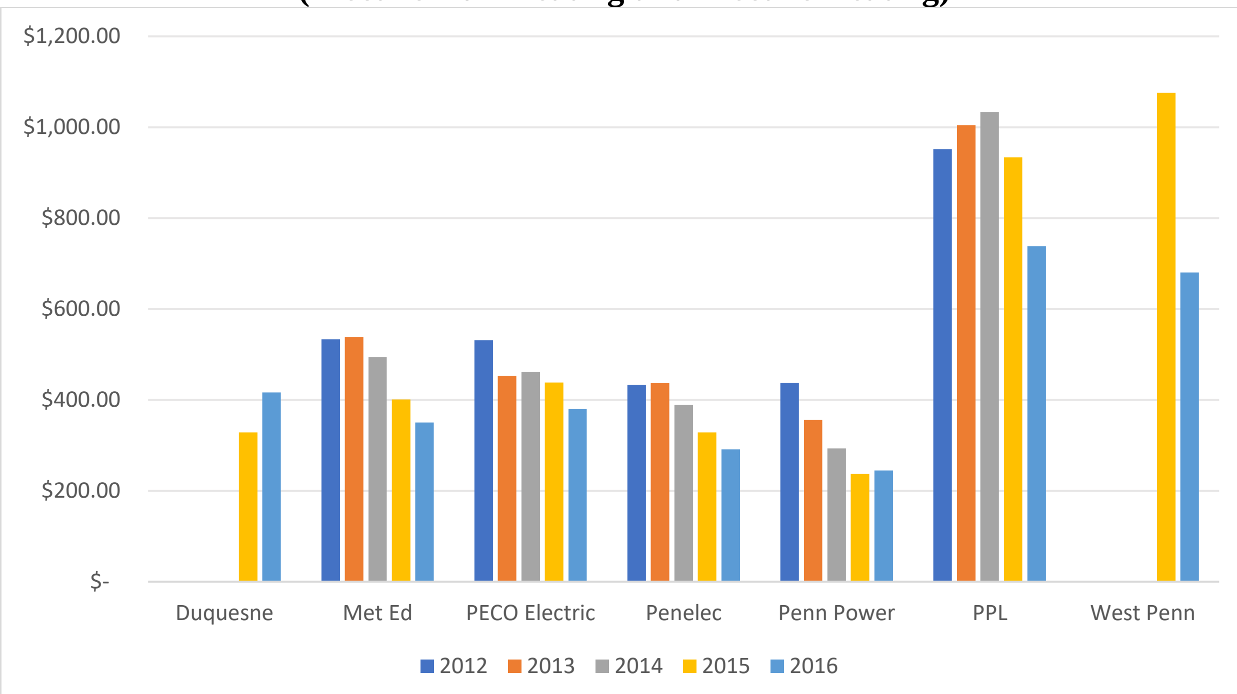


Table 5-4 reflects the average PPA amounts for EDC CAP customers who carried a PPA balance. Most EDCs reported a decrease in the average PPA balances carried by

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[49] The Commission generally uses “arrangements” to refer to Commission-facilitated payment arrangements pursuant to Chapter 14 and “agreements” to refer to accords reached between the customer and the utility without Commission input. In this report, staff shall refer to both as “agreements.”

[50] PECO Gas and Electric allowed CAP customers to obtain payment agreements on in-program arrears as one way to address unaffordability, especially for customers with incomes below 50% of the FPIG. The availability of payment agreements, however, allowed CAP customers to accrue large amounts of in-program arrears. PECO reported that the combined gas and electric in-program arrears balance was approximately $45 million by July 2015. PECO 2016 - 2018 USECP at 36, Docket No. M-2015-2507139 (filed on February 17, 2017). The Commission approved PECO’s 2016 - 2018 USECP by order entered on August 11, 2018, which permitted PECO to alter its CAP structure to improve affordability for its lowest income customers. PECO also eliminated payment agreements for in-program arrears after October 2016. PECO 2016 - 2018 USECP at 9-10.

CAP customers by 2016. PPL and West Penn CAP customers, however, carried the highest amount of average PPAs for EDC customers with PPAs, peaking at $1,034 for PPL in 2014 and $1,076 for West Penn in 2015.[51, 52]

EDCs – In-Program Arrears

Table 5-5
Average IPAs Carried by EDC CAP Customers with IPA Balances
(Electric Non-Heating and Electric Heating)

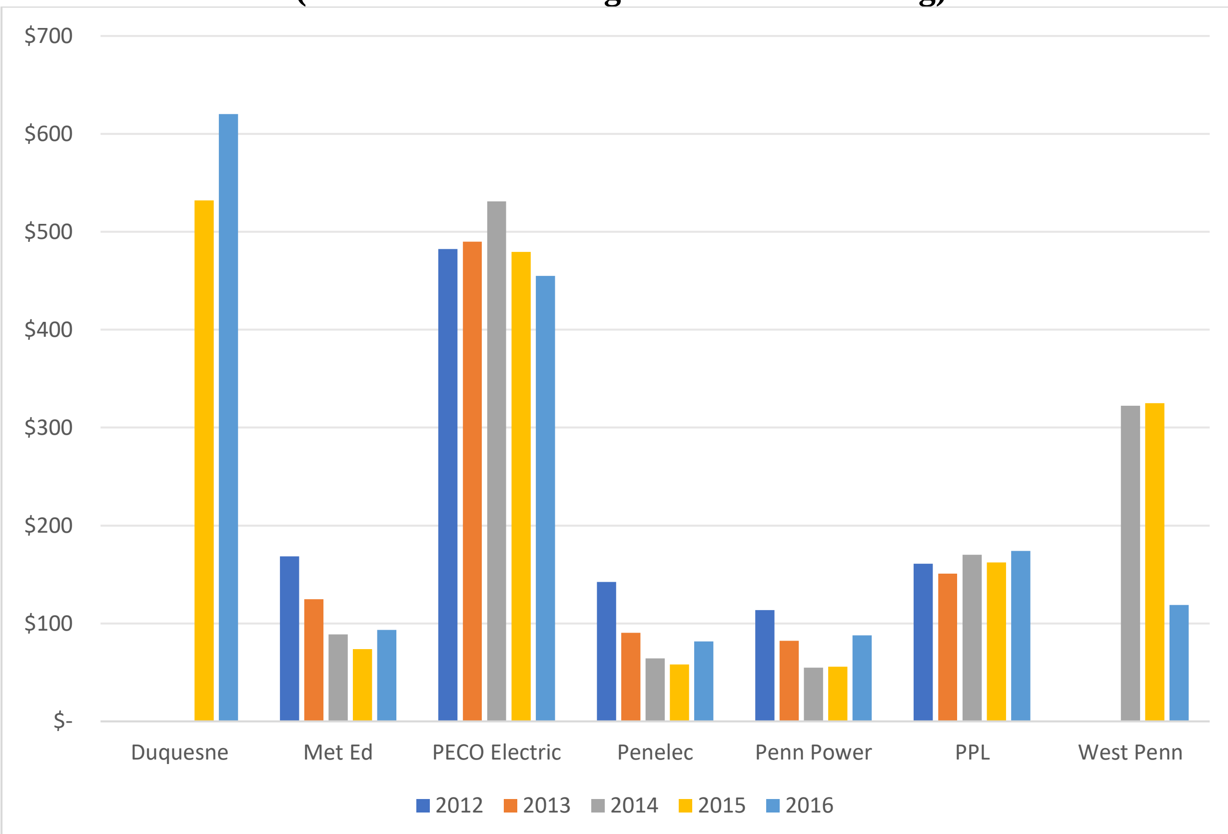

Table 5-5 reflects the average in-program arrears for EDC CAP customers who carried arrears during the five-year period of this study.

[51] PPL's high average PPA balances were likely a result of its CAP eligibility requirements during this time period. From 2011 through September 11, 2014, income-eligible customers must have defaulted on one or more payment agreements to qualify for PPL's CAP. PPL 2011-2013 USECP at 9, Docket No. M-2010-2179796 (filed on February 18, 2011). PPL subsequently amended this requirement by allowing any income-eligible customer who had a payment arrangement within the past 12 months to qualify for CAP. During the time frame of the study, PPL also required that customers have a PPA to enroll in CAP. PPL 2017-2019 USECP at 16-17 (filed on September 11, 2014), Docket No. M-2013-2367021, (order entered on November 6, 2017) at 16-17.

[52] In December 2015, West Penn converted all in-program arrears carried by CAP customers to PPA status. This may explain the high amount of PPAs reported by West Penn in 2015 and 2016.

Most EDCs reported an average in-program arrears balance of less than $200 per customer with an in-program arrears balance. Duquesne and PECO Electric reported the highest average in-program arrears carried by electric CAP customers.

Duquesne's average in-program arrears were $532 in 2015 and increased to $620 in 2016. Duquesne's higher in-program arrearage amounts are most likely result of the budget billing issues Duquesne experienced during this time. [53]

PECO Electric's in-CAP payment agreements, which paralleled its NGDC CAP payment agreements, likely contributed to the higher in-program arrears reported during this time period. [54]

Observations

With the collection and assessment of the data noted above, staff offers several observations:

- CAP eligibility requirements may have impacted the amount of PPA carried by customers when they enroll in the program. Utilities that restricted CAP enrollments to customers with a broken payment agreement to households which would pay less on a percent of income plan or to accounts with existing arrearages reported higher average PPA balances.

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[53] Duquesne introduced a new billing system in November 2014 which did not retain prior usage data. Because its CAP bills were based on a percentage of budget billing, bills were considerably lower for most CAP customers through the beginning of 2015 but increased greatly thereafter, resulting in increased in-program arrears. Duquesne froze collections during this period so that CAP customers were not terminated for non-payment. See Duquesne 2017-2019 USECP, Docket No. M 2016 2534323, at 32-34 (order entered on March 23, 2017). CAP bills exceeded the maximum energy burdens in the CAP Policy Statement, and the Commission directed Duquesne to work with stakeholders to address CAP issues. March 23, 2017 Order at 28-31. By order entered on April 19, 2018, the Commission approved Duquesne's proposal to reduce the percent-of-bills discount (i.e., rate discount) for most CAP customers in 2018 and switch to a percent-of-income (i.e., PIPP) CAP by 2020.

[54] PECO Gas and Electric allowed CAP customers to obtain payment agreements on in-program arrears as one way to address unaffordability, especially for customers with incomes below 50% of the FPIG. The availability of payment agreements, however, allowed CAP customers to accrue large amounts of in-program arrears. PECO reported that the combined gas and electric in-program arrears balance was approximately $45 million by July 2015. PECO 2016 - 2018 USECP at 36, Docket No. M-2015-2507139 (filed on February 17, 2017). The Commission approved PECO's 2016 - 2018 USECP by order entered on August 11, 2018, which permitted PECO to alter its CAP structure to improve affordability for its lowest income customers. PECO also eliminated payment agreements for in-program arrears after October 2016. PECO 2016 2018 USECP at 9-10.

- PPA balances trended downward for most gas utilities. This decrease may be attributable to the lower cost of natural gas and the warmer winters Pennsylvania experienced after the polar vortex in 2014-2015.

- The data show in-program arrears were generally decreasing for all NGDCs from 2012 to 2016. Factors that may have contributed to this trend include lower natural gas costs, warmer winters, and declining CAP enrollments during this study period.

- Most EDC CAP customers with in-program arrears carried a balance of less than $200 during this five-year period.

- Since many utilities were unable to provide data for the PPA and in-program arrears balances by FPIG levels and/or by heating type, staff is unable to determine if customers at specific incomes (*e.g.*, at or below 50% of the FPIG) or with specific heating types carried a disproportionate share of CAP PPA or in-program arrears.

VI. Percentage of CAP Bills Paid In-Full

Objective

Explore whether the percentage of CAP bills paid in-full could be an indicator of energy affordability for CAP customers.

Background

CAPs are designed as alternatives to traditional collection methods for low-income, payment-troubled customers. In exchange for continued utility services, customers participating in CAPs agree to make regular monthly payments, which may be set at an amount less than the customer's current bill based on usage at tariff rates. While participation in a CAP does not guarantee that low-income, payment-troubled customers will receive the most economical bill for utility services, CAPs and other universal service programs are intended and designed to make those energy bills more affordable. Notwithstanding other factors that may affect a household's ability to pay its monthly home energy bills, it is presumed that CAP customers are more likely to pay their monthly home energy bills if those bills do not consume an unmanageable percentage of income for low-income, payment-troubled customers.

As discussed previously in this report, NGDCs and EDCs have discretion in many aspects of the design and operation of their CAPs, including determining the monthly payment amounts of each CAP participant. Section 69.265(2)(i)-(vi) of the CAP Policy Statement provides guidelines for determining how CAP monthly payment plans should be established, including providing maximum home energy burden guidelines for total electric and natural gas home energy costs. A majority of Pennsylvania utilities set CAP payment amounts based on the customer's household family size and gross monthly income or the customer's average monthly bill, whichever is less. *See* Table 3-1 for an overview of how the major utilities determine monthly CAP payment amounts, including the minimum monthly CAP payments established for those customers with no income.

Methodology

To assess whether monthly CAP bills are set at an amount that facilitates low-income customers to pay their monthly electric and/or natural gas bills in-full, the Commission requested CAP billing data from the major EDCs and NGDCs for the years 2012-2016. The data requested included the number of monthly CAP bills issued and the amount (in dollars) of those bills. The data submitted by the utilities were categorized by FPIG level and by account status (electric heating, electric non-heating, gas heating).

Data Limitations

Certain utilities experienced limitations regarding the availability of the data requested. For example, NFG could not provide the data requested for CAP customers by FPIG level; thus, Commission staff was not able to evaluate if there were differences in the percentage of bills paid among the FPIG levels within NFG's CAP. In addition, West Penn was unable to provide data for the years 2012 and 2013, and PPL could only provide estimated data for the years 2012-2015. Furthermore, the EDCs and NGDCs had no meaningful way to distinguish if "payment in full" data exclusively included a full payment on current monthly charges or if "payment in full" data included the full payment of current plus any delinquent or "catch up" amounts. Three of the FirstEnergy Companies, Met-Ed, Penelec, and Penn Power, submitted 2012 to 2015 data that showed several months of billings that were reported as negative dollar amounts. Therefore, although the Commission requested data regarding the dollar amounts of CAP billings and payments, staff was unable to use it in the analyses.

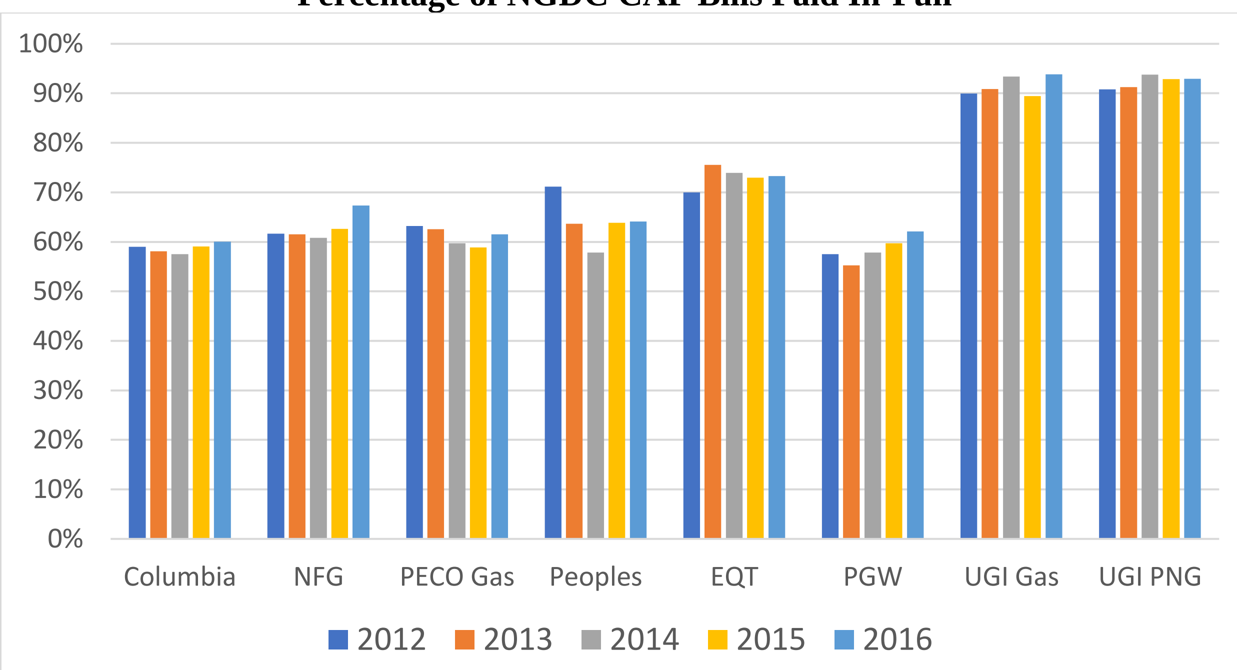
Analysis

CAP Customer Billing Data by Heating Type

This analysis is in two parts. Staff first examined the bill-paying patterns based on heating type. The second part looks at bill-paying patterns based on the customers' income levels.

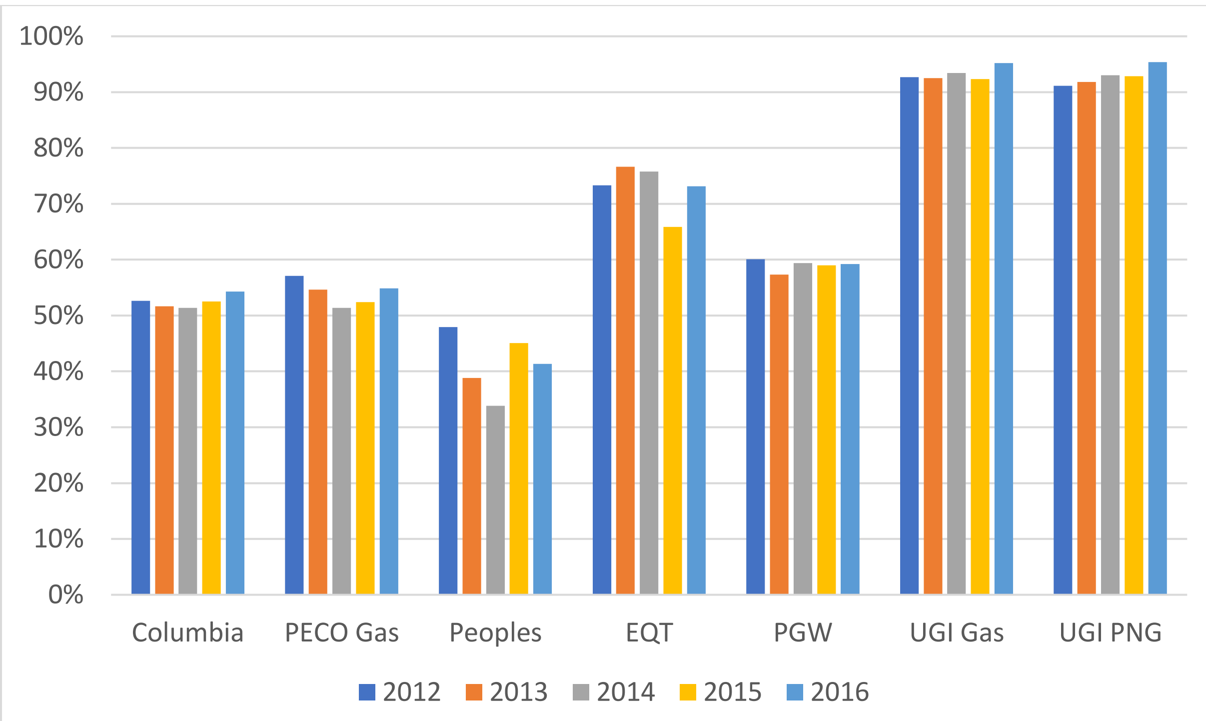
NGDC Percent of CAP Bills Paid

Table 6-1
Percentage of NGDC CAP Bills Paid In-Full



The data depicted in Table 6-1 above includes NGDC CAP customer billing information at all FPIG levels. From this data, it appears that CAP customers of UGI Gas and UGI PNG are the most reliable in paying their natural gas bills in-full. According to annual data submitted by UGI Gas and UGI PNG for the years 2012 to 2016, approximately 89 to 93% of CAP customer bills were paid. If this information is accurate, staff would expect to see lower in-program arrears accrued by UGI Gas and UGI PNG CAP customers, as the majority of the CAP bills should have been paid in full. According to Table 5-3, above, UGI Gas and UGI PNG CAP reported that their customers carried average in-program arrears exceeding $100 during the years 2012 to 2016. Based on the differences between these data points and that UGI Gas and UGI PNG's percentage of CAP bills paid is much higher than any other NGDC, there may be inconsistencies in how these utilities track the number of bills issued and the amount paid by CAP customers.

Table 6-2
Percentage of NGDC CAP Bills Paid In-Full
0-50% FPIG

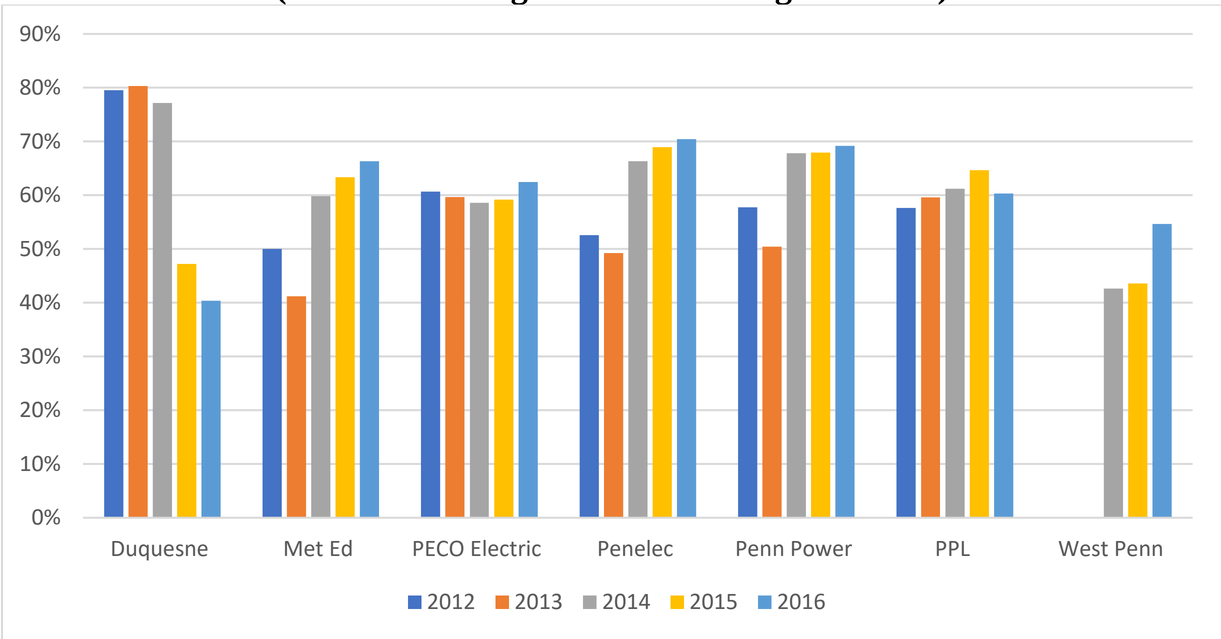


Staff also notes the differences in the percentage of bills paid by Peoples and Peoples Equitable CAP customers. Peoples and Peoples Equitable have maintained the same CAP requirements since at least 2015, including charging CAP customers 8% to 10% of their income or budget billing, whichever is less. Despite these commonalities, the two utilities reported different CAP customer payment behaviors. For example, while Peoples provided information that indicates that 57 to 71% of CAP bills were paid in-full during 2012-2016, Peoples Equitable reported that 69 to 75% of CAP bills were paid in-full during the same time period. The differences between the utilities are particularly noteworthy when one examines and compares their respective data for

CAP customers at or below the 0 to 50% FPIG level. *See* Table 6-2. While Peoples Equitable reported that 65 to 76% of CAP bills for customers at the 0 to 50% FPIG level were paid in-full during 2012-2016, Peoples reported that only 33 to 47% of its CAP bills at this income level were paid in-full. These variances between Peoples and Peoples Equitable may merit additional evaluation.

EDC Percent of CAP Bills Paid

Table 6-3
Percentage of EDC CAP Bills Paid In-Full
(Electric Heating and Non-Heating Accounts)



The information displayed in Table 6-3 includes 2012-2016 EDC CAP customer billing data aggregated from all FPIG levels, as well as by account status, including electric heating and electric non-heating accounts. Notable in this data is the information submitted by Duquesne, which indicates a dramatic decrease in the number of CAP customer bills paid in-full. From a high of nearly 80% in 2012 and 2013, the utility reported that only 40% of CAP customers' bills were paid in full in 2016. While this seemingly substantial decrease may be alarming, it is likely attributable to the changes that the utility implemented to its billing system in November 2014, resulting in higher monthly CAP bills in 2015 and 2016 due to budget bill corrections. *See* Footnote 29.

Aside from the information provided by Duquesne, the data in Table 6-3 nevertheless still shows marked annual and EDC variability, ranging from a low of 40% to a high of 70% of EDC CAP customer bills paid in-full. PECO and PPL appear to have the least variability over the same time frame.

Table 6-4
Percentage of EDC CAP Bills Paid In-Full
(Electric Heating Accounts)

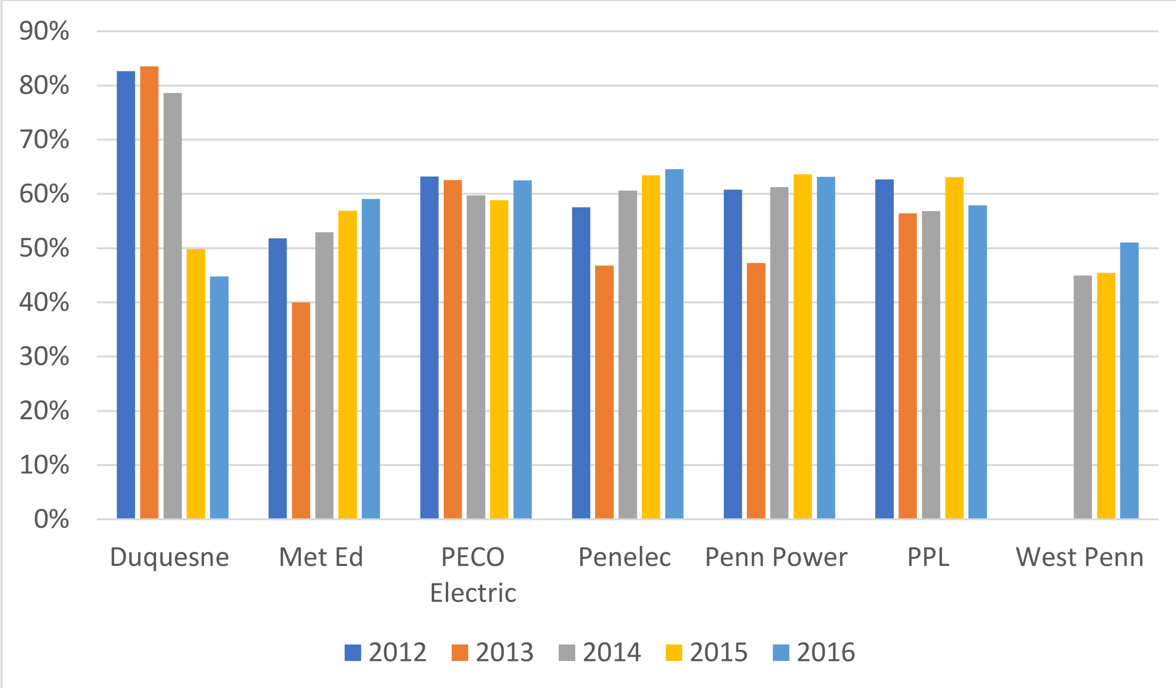
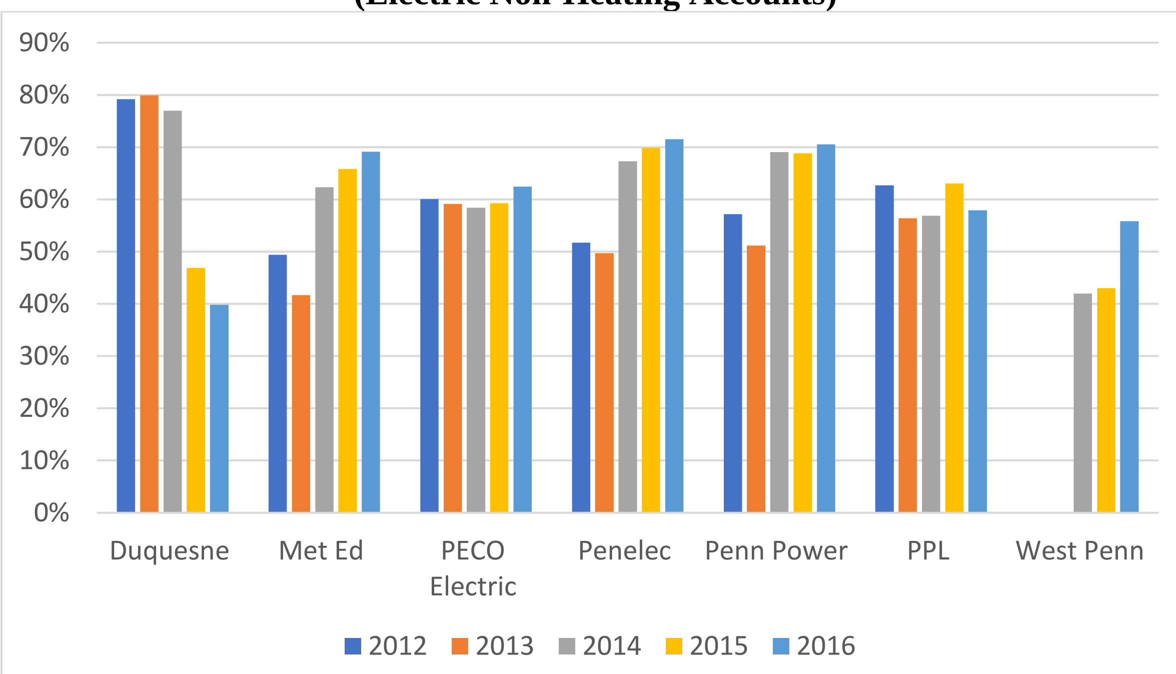


Table 6-5
Percentage of EDC CAP Bills Paid In-Full
(Electric Non-Heating Accounts)



In Tables 6-4 and 6-5 above, the data show some variability between the percentage of CAP electric heating bills paid in-full compared to the percentage of CAP electric non-heating bills paid in-full. While seemingly negligible, there are differences, such as electric heating generally being more expensive than gas heating, that could indicate why a greater percentage of CAP electric non-heating bills were paid in-full compared to the percentage of CAP electric heating bills. This variability warrants further scrutiny and examination.

CAP Customer Billing Data by FPIG Level

Staff also examined the percentage of NGDC and EDC CAP customer bills paid at the 0 to 50%, 51 to 100%, and 101 to 150% FPIG levels. This analysis was conducted to determine if the increased income for CAP customers positively influences the percentage of utility bills paid in-full.

NGDCs

Table 6-6
Percentage of NGDC CAP Bills Paid In-Full
(0-50% FPIG Level)

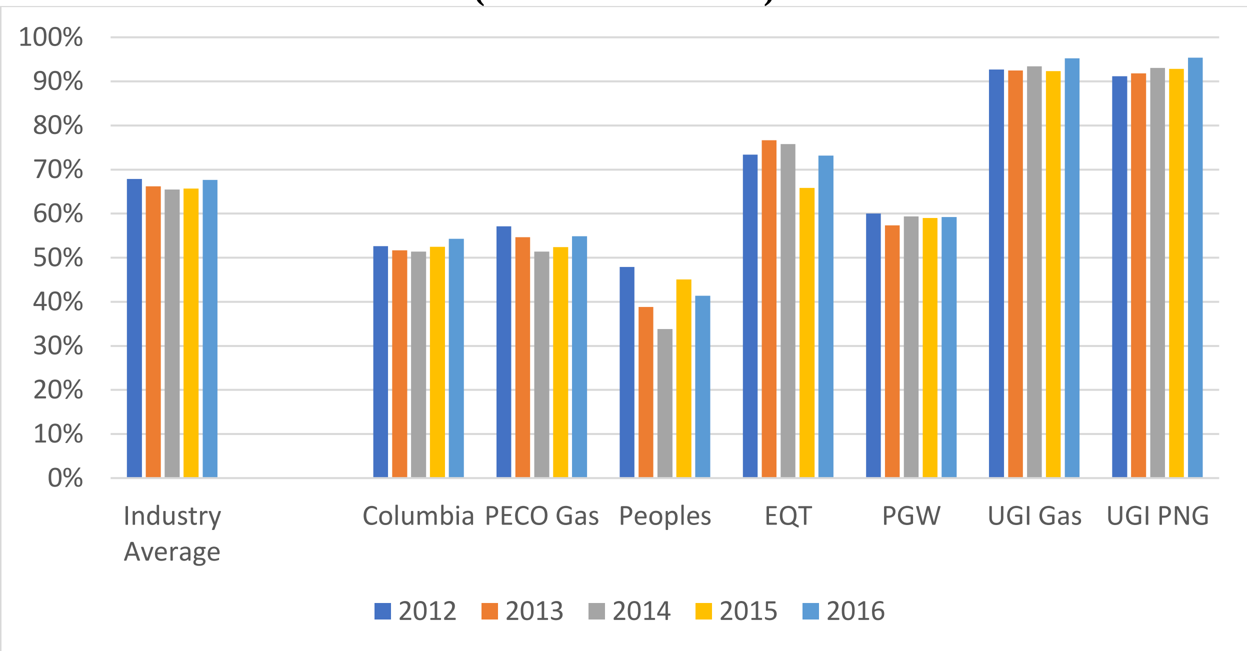


Table 6-7
Percentage of NGDC CAP Bills Paid In-Full
(51-100% FPIG Level)

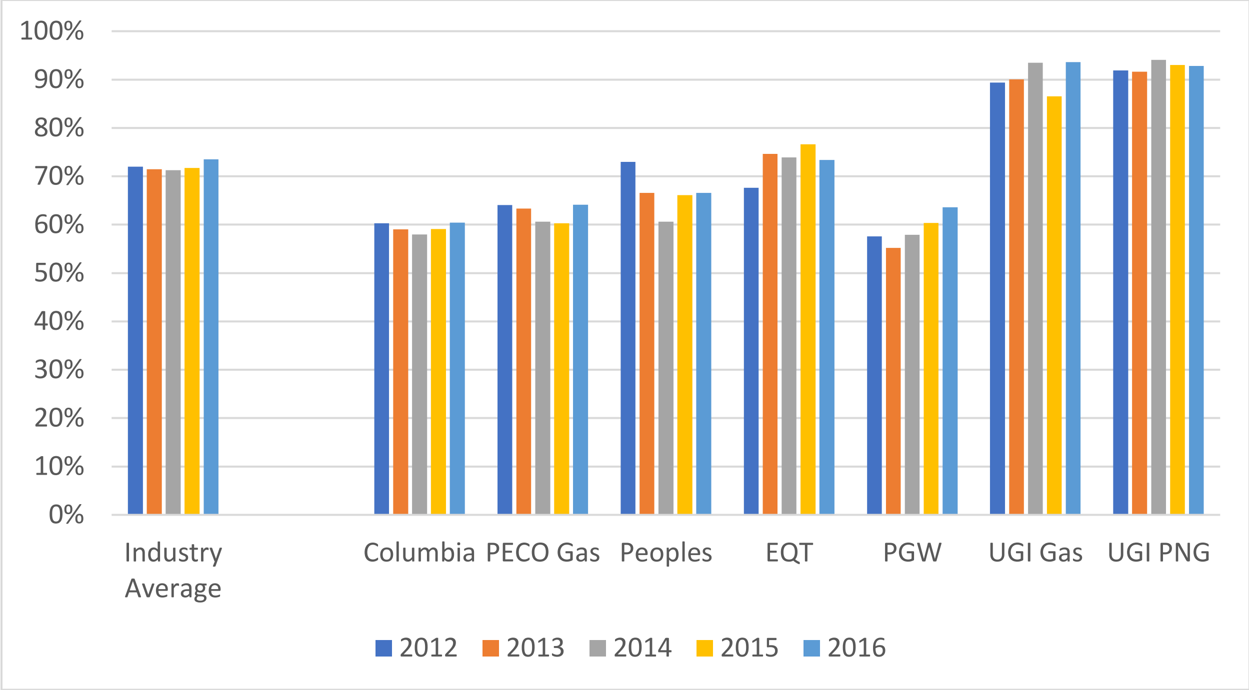
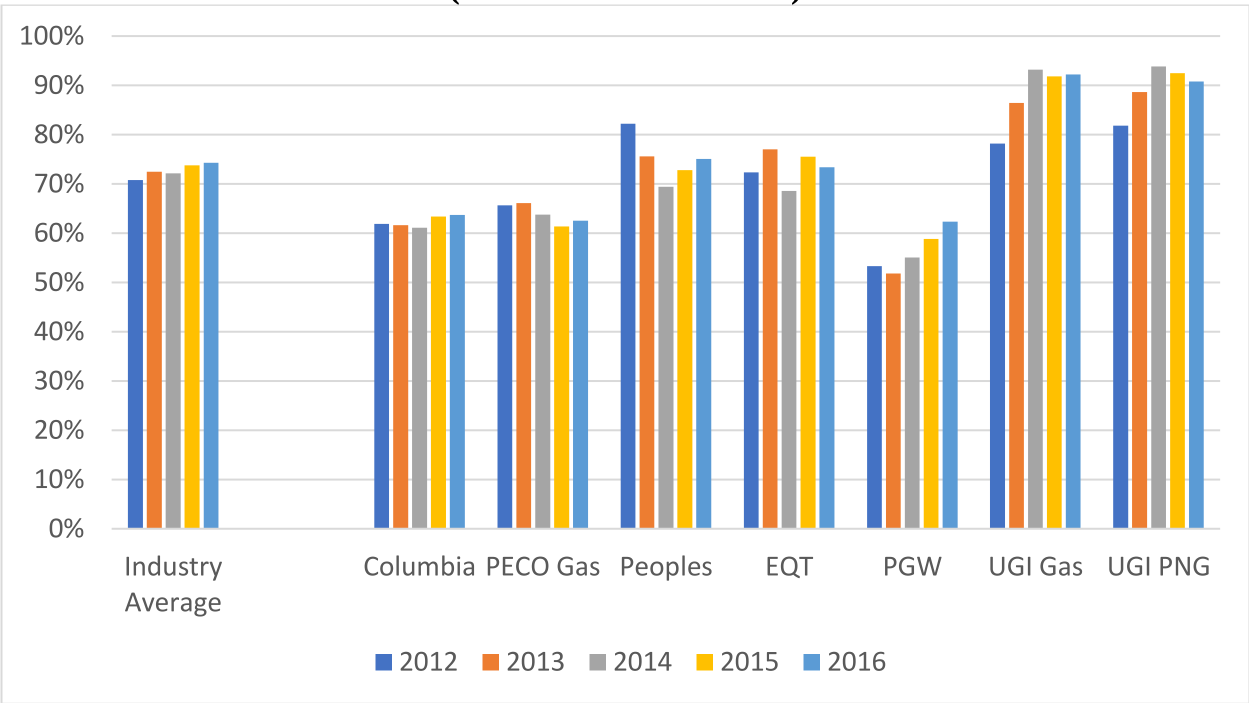


Table 6-8
Percentage of NGDC CAP Bills Paid In-Full
(101-150% FPIG Level)



Tables 6-6, 6-7, and 6-8 include the percent of CAP bills paid for each utility as well as the weighted industry average for CAP NGDC customers at the different FPIG levels (i.e., 0 to 50%, 51 to 100%, and 101 to 150%) for the period 2012-2016. According to the data shown in Table 6-6, approximately 70% of NGDC CAP bills of customers at the 0 to 50% FPIG level were paid in-full. In examining annual data for each NGDC, the range of NGDC CAP bills paid in-full ranged from a low of 33% to a high of 95%.

In contrast, as seen in Table 6-7, a greater percentage of NGDC CAP bills of customers at the 51 to 100% and 101 to 150% FPIG levels were paid in-full; however, the differences appear to be negligible. Nevertheless, it is particularly noteworthy that several NGDCs showed that a lesser percentage of bills were paid in-full by CAP customers at the 101 to 150% FPIG level in comparison to the percentage of CAP bills paid by customers at the 51 to 100% FPIG level. Thus, the extent to which household income impacts or influences the percent of NGDC CAP utility bills paid in-full is unclear. *See* Table 6-8.

EDCs

Table 6-9
Percentage of EDC CAP Heating Bills Paid In-Full
0-50% FPIG Level

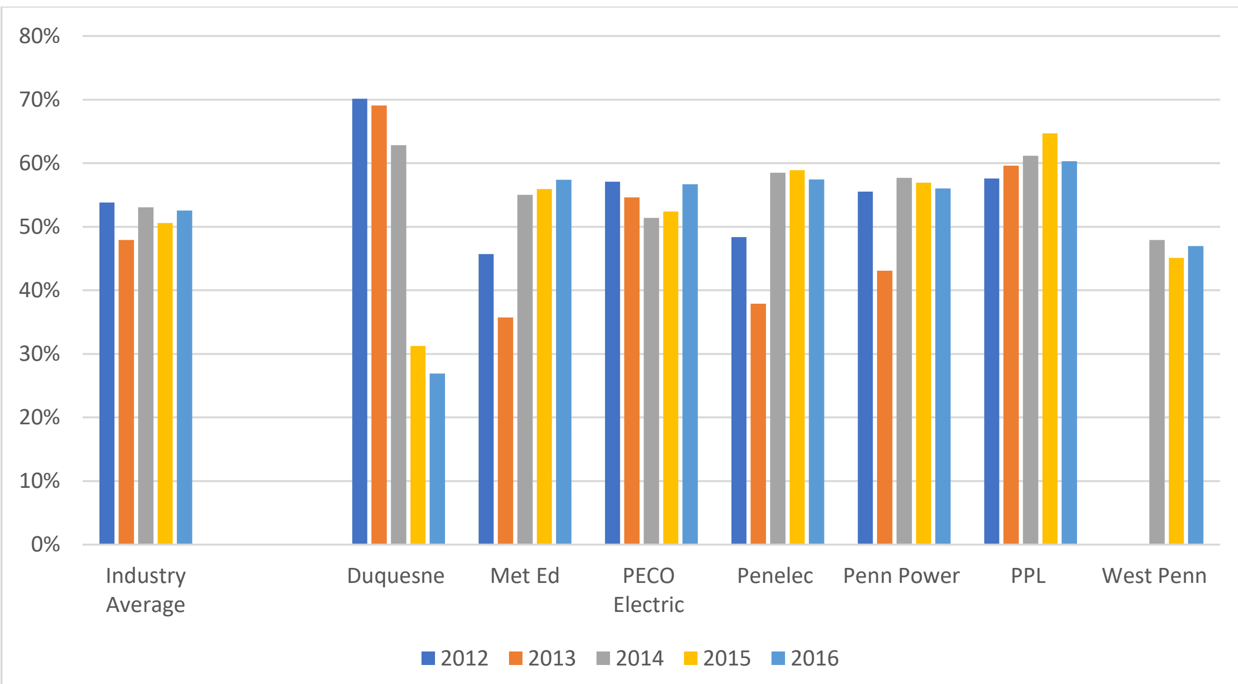


Table 6-10
Percentage of EDC CAP Heating Bills Paid In-Full
(51-100% FPIG Level)

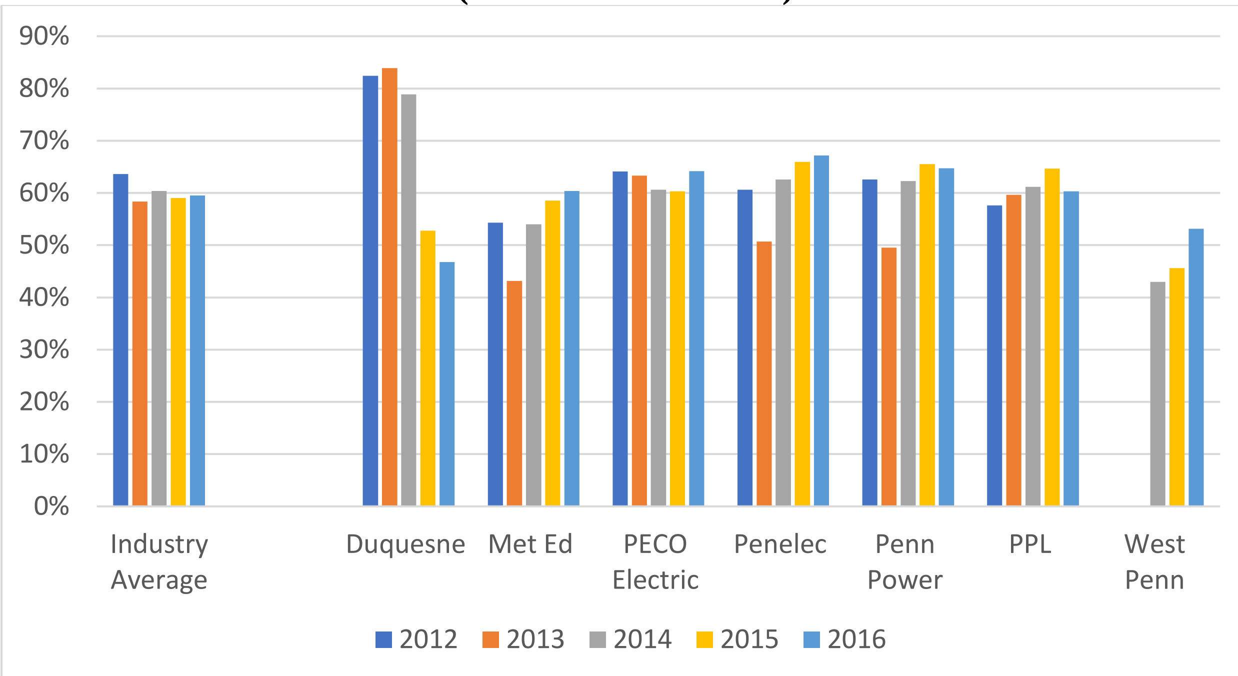
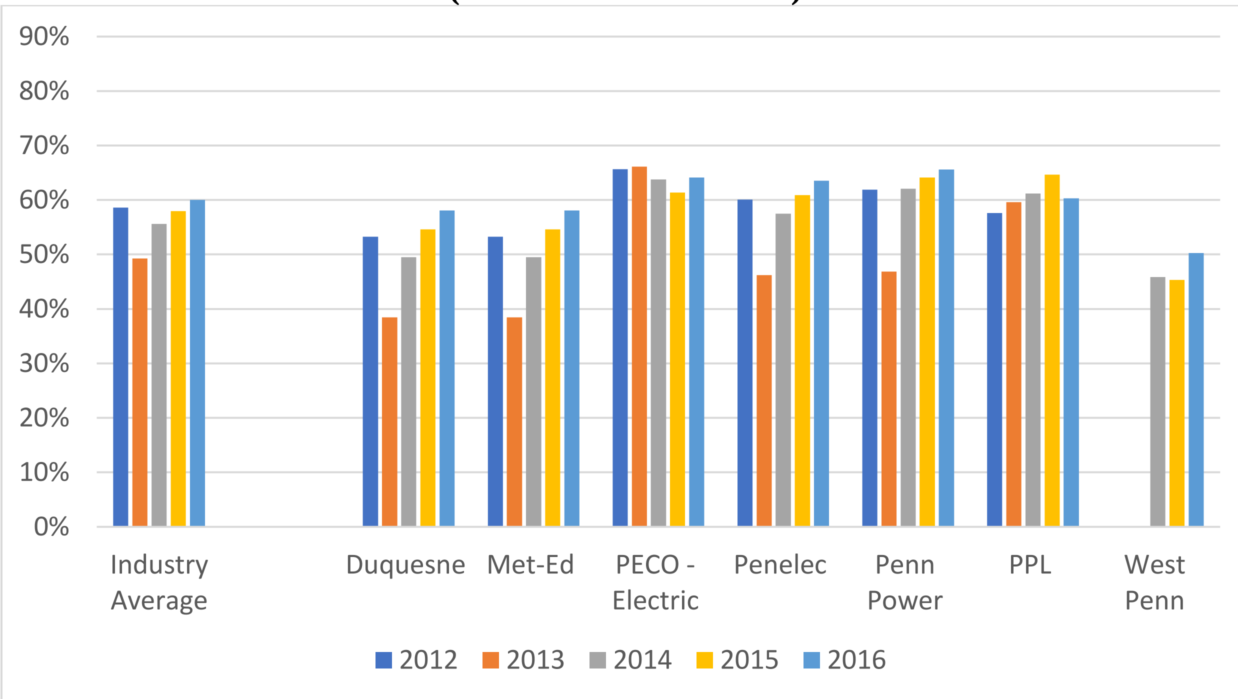


Table 6-11
Percentage of EDC CAP Heating Bills Paid
(101-150% FPIG Level)



Tables 6-9, 6-10, and 6-11 include the percentage of CAP bills paid for each EDC as well as the weighted industry average for CAP electric heating customers at the different FPIG levels for the period 2012 to 2016.

While noticeable variability existed among EDCs, it appeared on average that approximately 50% of electric heating bills are paid by CAP customers at the 0% to 50% FPIG level. This contrasts markedly with the NGDC data, which showed that approximately 70% of bills were paid by CAP customers at the 0% to 50% FPIG level. This difference in the percentage of bills paid could be attributed to the lower price of natural gas in comparison to electricity; however, this point cannot be determined without additional information from the utilities.

In examining annual data for each EDC at the 0 to 50% FPIG level, most EDCs reported that at least 35 to 65% of electric heating bills were paid by CAP customers during this five-year period. Staff notes more variability within the time frame for each EDC than is seen in the industry average. Met-Ed, Penelec, and Penn Power had similar profiles, but the other EDCs display profiles that do not parallel the three FirstEnergy profiles or each other. The data do not provide any explanation for these regional differences or fluctuations.

In contrast, the data at the 51 to 100% and 101 to 150% FPIG levels indicated that a greater percentage of bills were paid by CAP electric heating customers at these FPIG levels in comparison to the percentage of bills paid by CAP electric heating customers at the 0 to 50% FPIG level. Based on weighted industry average data, approximately 60% of CAP bills were paid by CAP electric heating customers at the 51 to 100% and 101 to 150% FPIG levels. While this information showed a positive trend in payments made as household income increases, the increase in the percentage of CAP electric heating bills paid by customers at the 51 to 100% and 101 to 150% FPIG levels was nominal. Particularly noteworthy are the data provided by several EDCs that show *fewer* CAP electric heating customers at the 101 to 150% FPIG level paid their bills in comparison to the percentage of bills paid by CAP electric heating customers at the 51% to 100% FPIG level. Thus, the extent to which household income impacted or influenced the percent of EDC CAP utility bills paid in-full is unclear.

Observations

With the collection and assessment of the data noted above, several observations are offered:

- The billing system changes and upgrades of NGDCs and EDCs appeared to affect CAP monthly billing amounts and thus influenced whether utility bills were paid in-full.

- Some of the data submitted by the NGDCs and NGDCs in response to the data request for this report were inconsistent; therefore staff did not use it.

- Payment behavior of CAP customers did not appear to be strongly or definitively correlated to household income. This observation is particularly applicable to those CAP customers at the 51% to 100% and

101% to 150% FPIG levels where limited variability occurred in payment patterns between the two income levels. This pattern may indicate that other factors – beyond income – may have had an impact on whether CAP utility bills were regularly paid in full.

- At the 0% to 50% FPIG level, a higher percentage of NGDC CAP bills were paid in comparison to the percentage of EDC CAP bills paid at the same FPIG level. Given the low cost of natural gas compared to electricity, this observation may be indicative that the bills of NGDC CAP customers were more affordable in comparison to the bills of EDC CAP customers during this five-year study period; however, to conclusively determine this observation, additional data would need to be obtained from the utilities and evaluated.

VII. CAP Default Exit and Termination Rates

Objective

Evaluate the CAP default exit rates and CAP termination rates as possible affordability indicators to determine customer success in meeting the requirements of CAPs. Determine if a correlation exists between CAP default exit rates and CAP termination rates.

Background

CAP participants are required to, among other things, make timely and in-full monthly payments, allow access to meters, maintain or reduce consumption, participate in LIHEAP, and recertify eligibility information when requested. Failure to meet these program requirements can result in removal from CAP and/or loss of utility service.

The default exit rate is intended to track the number of customers who fail to meet the requirements of CAP. This definition of default exit rate includes all participants who were non-compliant with program requirements, including nonpayment, late payments, missed meter reads, excess consumption, failure to apply for energy assistance if required, and failure to recertify eligibility.[55] A higher default exit rate may indicate affordability issues or that the requirements of the program are not clearly or routinely communicated or understood by the household.

Households that are removed from CAP do not necessarily have their utility service terminated but are often left with debt that includes any non-forgiven PPA which become due as part of the balance when the customer is placed back onto full-tariff rates. Most utilities require customers to pay a balance to re-enroll in CAP. This balance may consist of a CAP catch-up amount (*i.e.*, any in-program arrears and the CAP billing price for the months spent out of the program). Other utilities require CAP customers to pay any in-program arrears and the full-tariff residential rates for any months spent out of the program. When former CAP customers are unable to re-enroll in CAP, pay their balance, or obtain a payment agreement, it can lead to service termination (*i.e.*, loss of utility service).

Service terminations for CAP households are usually a direct result of non-payment. Higher termination rates may indicate that CAP payments are unaffordable or may reflect strong enforcement of collection procedures to ensure customers do not accumulate high in-program arrears. Terminated CAP accounts – or accounts that are terminated after removal from CAP – may add to the amount of uncollectible balances if the customer cannot pay the outstanding balance to get back into CAP and is unable to obtain a payment agreement. In these situations, utility service is terminated, and the debt is eventually written off by utilities and recovered from non-CAP residential ratepayers.

[55] CAP customers who voluntarily leave the program are not counted in the default exit rate.

Methodology

Data regarding the number of CAP default exits are collected as part of the annual universal service and collections reporting (USR). The survey data request called for the number of CAP terminations. Staff anticipated that the number of CAP terminations would be a subset of the default exit number. The intent was to determine the relationship between those CAP customers who default from their CAP responsibilities and those CAP customers who have their service terminated.

To determine the CAP default exit and termination rates per year, the annual number of reported CAP default exits and CAP terminations were each divided by the average number of annual CAP enrollments. This allowed staff to compare these rates across the gas and electric utilities. *See* Appendix 9.C for average NGC and EDC CAP enrollments for 2012 through 2016.

Data Limitations - CAP Default Exits

Upon review of the CAP default exits as documented in the annual USRs and after consulting with several utilities, it became apparent that utilities were not consistently interpreting and reporting these data points. While some utilities counted each default occurrence as part of the default exits total, some utilities did not. Columbia, for example, reported that its system only tracked whether a customer has defaulted from CAP responsibilities during a calendar year (*e.g.*, yes or no). It did not count the number of individual instances a CAP customer was late on a payment or otherwise met the default exit definition. Thus, a Columbia CAP customer who was late with several payments and failed to recertify during a calendar year was only counted once in the utility's number of CAP default exits while other utilities would count each late payment and the failure to timely recertify as a separate occurrence of default exits. Due to the differences in how utilities tracked default exits, this data set could not be evaluated for comparison purposes. However, staff did observe some general trends from the data, as noted below.

Data Limitations - CAP Terminations

The data request called for CAP termination numbers to determine the extent of CAP default exits that eventually ended in termination of service. However, upon review of the reported data, it became apparent that there were inconsistencies in the way CAP terminations were reported. This, in part, appears to be due to the difficulty in determining when a CAP customer is "removed" from CAP versus when a CAP customer has service terminated. Some utilities removed CAP customers from the program but did not immediately terminate service. For example, Met-Ed, Penelec, Penn Power, PPL, and West Penn did not terminate service while a household is enrolled in CAP. Instead, they removed the household from the program if the household failed to meet its CAP payment responsibilities and would terminate service later. Thus, some utilities could only provide an estimate of the number of CAP customers who were removed from the program and subsequently had their service terminated.

In addition to the reporting inconsistencies, several utilities could not provide data due to system limitations. Specifically:

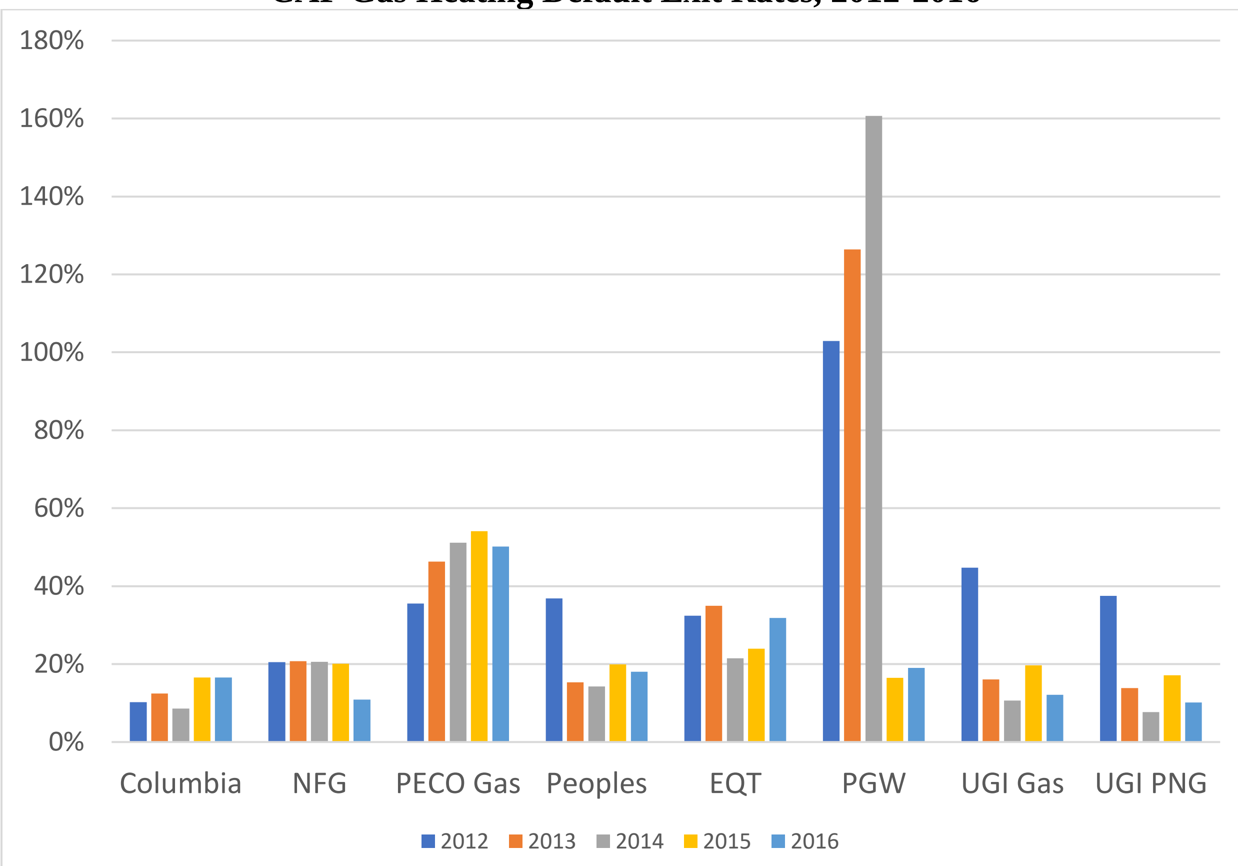
- Met-Ed, Penelec, Penn Power, and West Penn could not provide CAP termination data prior to 2014.

- Peoples Equitable could not provide CAP termination data prior to 2015.

Analysis

NGDCs – Default Exit and CAP Termination Rates

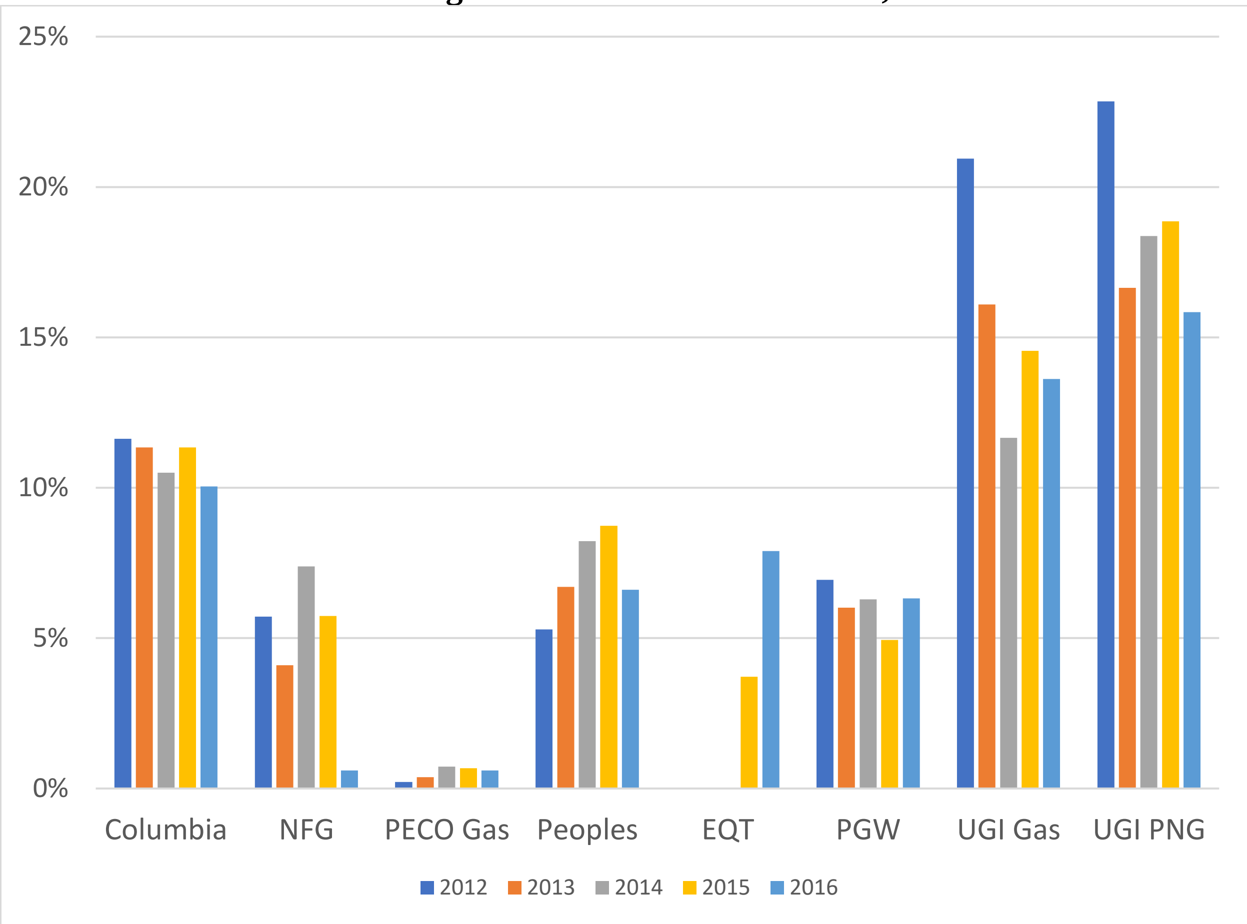
Table 7-1
CAP Gas Heating Default Exit Rates, 2012-2016



Despite the limitations of the reported CAP default exits and CAP termination data, there were some generalized observations that could be made. Table 7-1 shows PGW's default exit rates exceeded 100% of its average annual CAP enrollments from 2012 through 2014. The utility's default exit rate peaked at 161% in 2014 but dropped significantly to 16% and 19% in 2015 and 2016, respectively. PGW's 2015 and 2016 default exit levels were more consistent with the counts reported by other NGDCs.

Columbia reported three years (2012 to 2014) and UGI PNG reported four years (2013 to 2016) where their respective default exit rates exceeded their CAP termination rates; UGI Gas reported its CAP termination rate equaled its default exit rate in 2013 and exceeded this rate in 2016.[56]

Table 7-2
CAP Gas Heating Account Termination Rates, 2012-2016

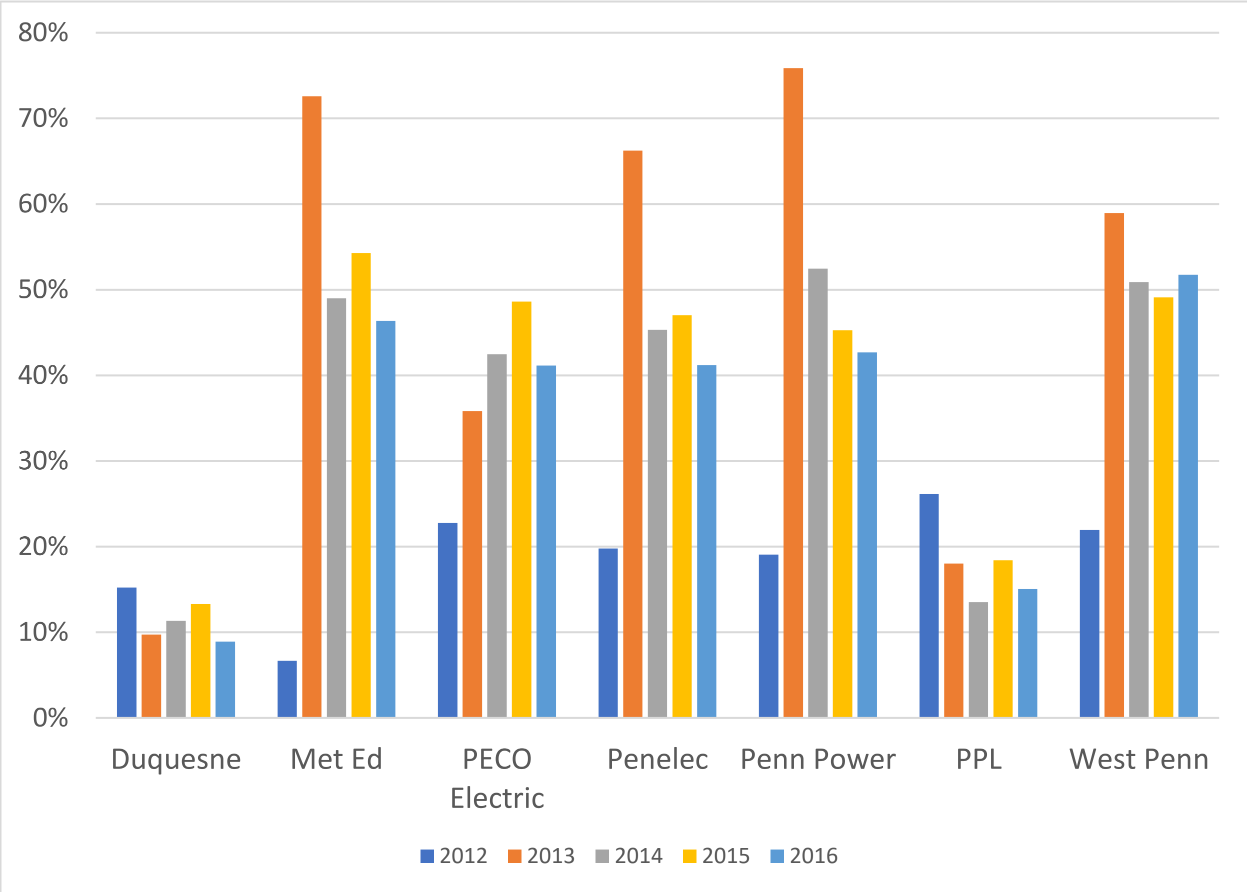


As seen in Table 7-2, UGI Gas and UGI PNG had the highest respective CAP termination rates during the study period, both peaking at 21% and 23% in 2012, respectively. Between 2013 and 2016, CAP termination rates ranged from 12% to 16% for UGI Gas and from 16% to 19% for UGI PNG. Columbia had relatively stable termination rates during this study period, ranging from 10% to 11% annually. Termination rates for half of the NGDCs ranged between 5% and 9%. PECO Gas reported the lowest termination rates, averaging less than 1% annually. This may have been the result of the previous PECO Gas practice (which is shared with PECO Electric) of offering payment arrangements on CAP arrears – instead of issuing termination notices – during this study period.[57]

[56] As explained in *Data Limitations* above, some utilities (*e.g.*, Columbia) do not count each instance of a customer defaulting from their CAP responsibilities. In these situations, the number of times a customer has service terminated could exceed their default exit count.
[57] See Footnote 46.

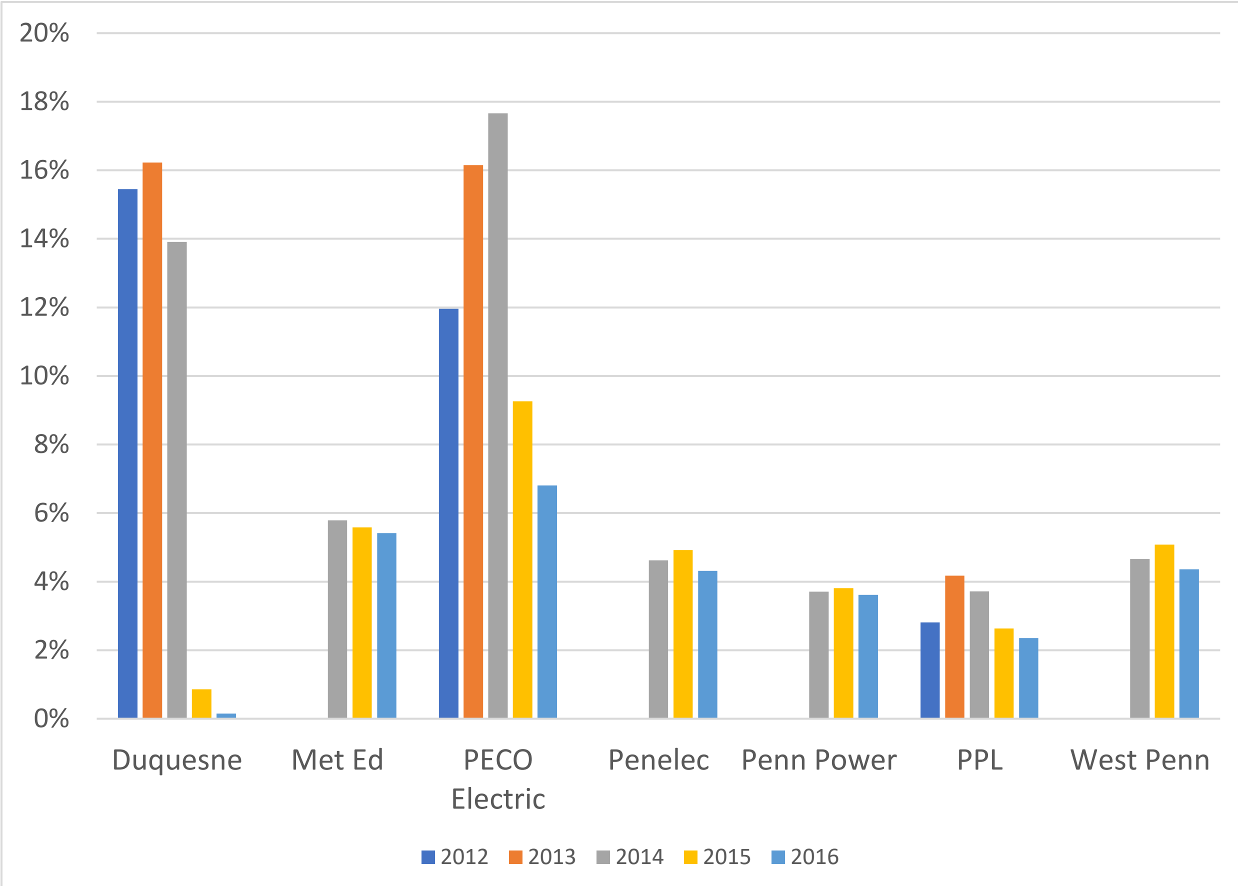
EDCs – Non-Heating Default Exit and CAP Termination Rates

Table 7-3
EDC Non-Heating CAP Default Exit Rates, 2012-2016



As seen in Table 7-3, the default exit rate for Met-Ed and Penelec peaked in 2013, exceeding 50%. However, both utilities' default exit rate declined below 40% for the last three years of this study, which is consistent with PECO Electric. Duquesne and PPL reported CAP default exit rates ranging between 10% to 20% for most years of this study.

Table 7-4
Electric Non-Heating CAP Account Termination Rates, 2012-2016



As seen in Table 7-4, the higher default exit rates reported by Met-Ed and Penelec did not translate into a higher rate of CAP terminations. Both utilities reported CAP termination rates between 4-6% for 2014 to 2016. Duquesne and PECO Electric reported higher CAP termination rates for electric non-heating accounts than other EDCs. Duquesne's termination rates ranged from 14% to 16% from 2012 through 2014 but dropped to less than 1% for 2015 and 2016. This decrease in terminations was likely due to Duquesne's CAP budget billing issues, which caused the utility to place a temporary hold on CAP terminations.[58] PECO Electric's CAP termination rates for non-heating accounts peaked at 18% in 2014 – during the polar vortex – but decreased to 9% and 7% in 2015 and 2016, respectively. Penn Power and PPL reported CAP termination rates of approximately 4% or less. Staff also note a slight increase in CAP terminations for many utilities in 2014, which may be the result of higher usage during the polar vortex.

[58] See Footnote 29.

EDCs – Heating Default Exits and CAP Termination Rates

Table 7-5
EDC Heating CAP Default Exit Rates, 2012-2016

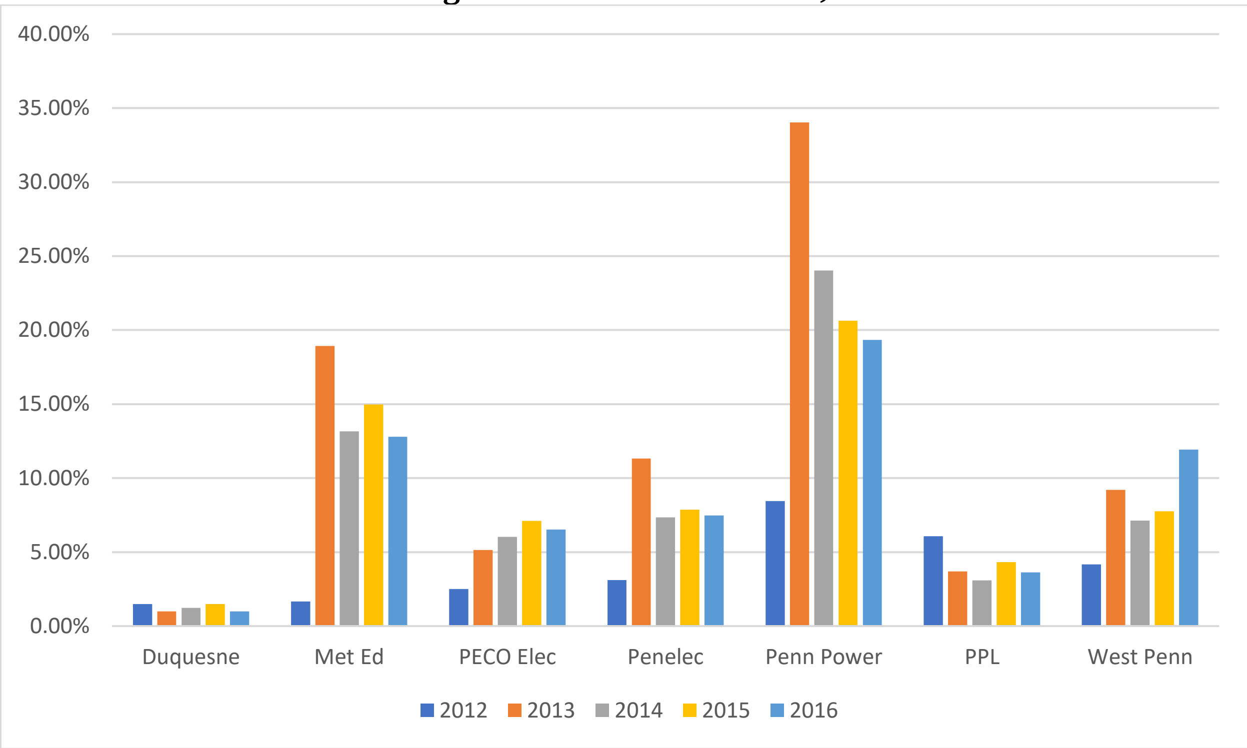


Table 7-5 shows the default exit rates for EDC heating CAP customers. Duquesne reported the lowest default exit rate for these customers at 1% to 2% for the entire five-year period. PECO Electric and Penelec reported default exit rates that ranged between 3% to 7% and 3% to 11%, respectively, for the five-year period. Penn Power reported the highest default exit rate for electric heating CAP customers, peaking at 34% in 2013. However, Penn Power's default exit rate dropped each subsequent year, declining to 19% by 2016.

Table 7-6
Electric Heating CAP Account Termination Rates, 2012-2016

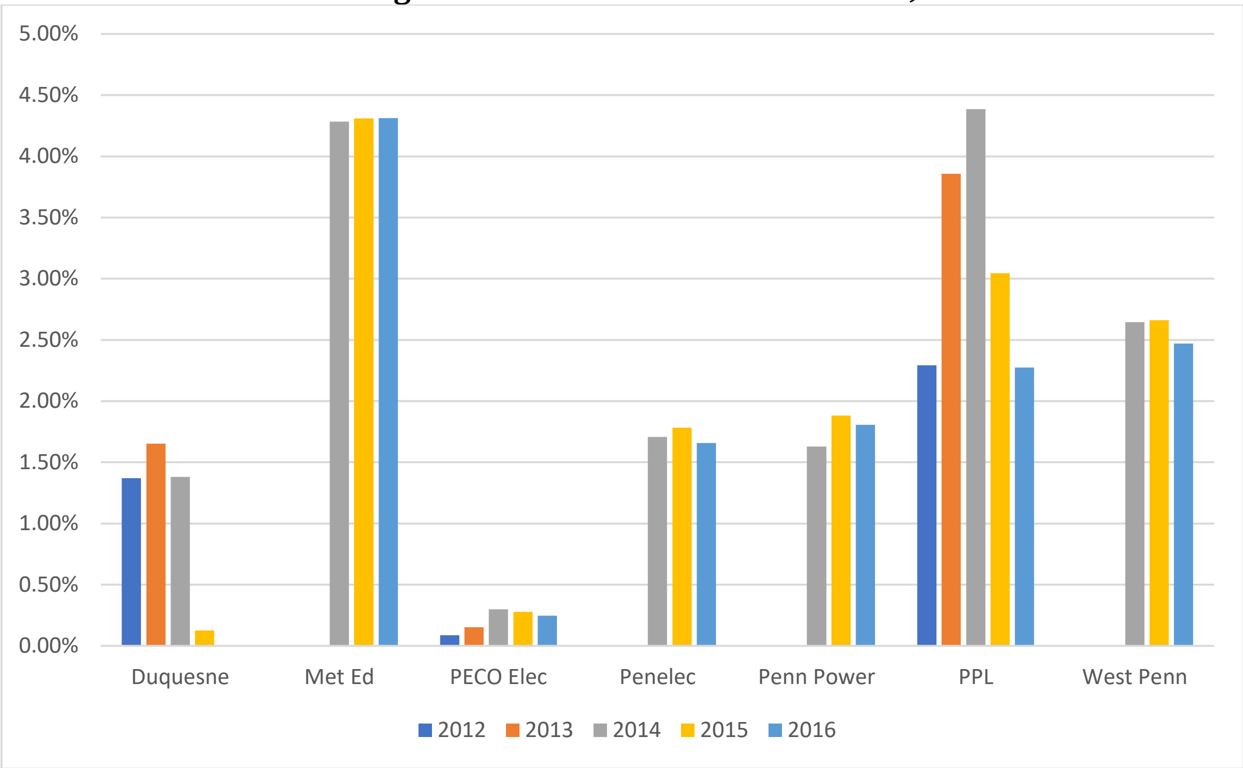


Table 7-6 shows the CAP termination rates for EDC heating CAP customers. Met-Ed had an average termination rate of approximately 4% for electric heating accounts for 2014 to 2016, which is higher than the termination rates for the other FirstEnergy utilities during this time period. West Penn had an average termination rate of less than 3%; Penelec and Penn Power had an average termination rate of less than 2%. This suggests that other factors, besides Met-Ed's CAP design, may have contributed to the higher number of terminations. More than half of the EDCs reported CAP terminations rates of less than 2% for heating customers. PECO Electric's CAP termination rate for electric heating accounts was less than 0.5% for all five years of this study. PECO Electric's low termination rates for CAP heating accounts may be attributable to (1) the utility's previous practice of offering payment agreements on in-program arrears and (2) approximately 80% of PECO Electric CAP customers were non-heating during this time period.[59]

Observations

Given the apparent inconsistencies between how utilities define and track default exits and CAP terminations, staff was unable to compare these data points among utilities or to confidently establish a correlation.

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[59] *See* Table 3-2.

Not all customer removals from CAP resulted in service termination, but utilities were and are currently unable to provide the data to gauge to what extent this has occurred.

Higher CAP terminations for EDC non-heating CAP accounts in 2014 were likely the result of higher usage and/or higher bills during the polar vortex.

Differences between the EDC CAP heating termination rates for Met-Ed and the other FirstEnergy companies suggest that other factors – besides CAP design – contributed to a higher termination rates for CAP customers in the Met-Ed service territory.

VIII. Non-CAP Residential and Confirmed Low-Income Customer Debt

Objective

Determine if the percent of debt from confirmed-low income (CLI) customers is an indicator of CAP customer affordability.

Background

Many factors affect the number of customers in debt, including customer income level and ability to pay, utility collection practices, utility termination practices, and the size of customer bills. Utility collection policies vary and therefore also influence the "overdue" or "in debt" categorization.

The USR categorizes the Residential Class of customers as either non-CAP residential or CAP customers. CLI customers are a subset of non-CAP residential ratepayers, comprising all non-CAP customers *identified* as low-income. These CLI customers are financially vulnerable and the most likely to be in debt. Most CLI households are verified through the customer's receipt of a LIHEAP grant, identified when enrolled in a universal service program, or determined during the course of making a payment agreement.

There are also factors beyond customer choice that determine whether a customer may or may not be on a payment agreement. If customers have defaulted on utility and Commission payment agreements and/or their debt consists of CAP (in-program) arrears, they may not qualify for further payment agreements.[60]

Debt that is on a payment agreement is considered active and is often easier to collect than debt not on a payment agreement. Uncollectible debt represents more risk for the utility and often leads to higher gross write-offs, which are recovered from non-CAP residential ratepayers.

Low-income customers who are removed from CAP are less likely to qualify for additional payment agreements, and their balances are more likely to be written off as uncollectible debt. Thus, the amount of CLI debt not on an agreement may indicate affordability issues within a utility's CAP.

[60] NGDCs and EDCs have discretion in offering payment agreements to customers, but each utility limits the number of payment agreements offered. A utility must offer a payment agreement for restoration or service if the customer has income at or below 300 of the FPIG and has not defaulted on two or more payment agreements. 52 Pa. Code Section 56.191(c)(2). The Commission may establish a payment agreement between the utility and the customer when there is a dispute between the parties. Section 1405(a). However, absent a change in income, a customer cannot receive a second or subsequent payment agreement from the Commission until the most recent one is satisfied. Section 1405(d). The Commission cannot establish a payment agreement on CAP (in-program) arrears. Section 1405(c).

Methodology

For USR reporting, two categories exist for customers overdue and/or in debt. The first includes customers who are on a payment agreement, and the second includes customers who are not on a payment agreement. Those on a payment agreement include customers on both utility and Commission-granted payment agreements.

Consistent with USR reporting, customers enrolled in a CAP have not been counted in this report as part of the number of customers in debt who are on a payment agreement or not on a payment agreement.

The amount of non-CAP residential and CLI debt is shown as a percentage of revenue and is calculated by dividing the total dollars owed for each category by the overall residential revenue of each utility. This is to allow comparison between utilities, regardless of the dollar amount of debt or revenues.

Data Limitations

Two factors affect the uniformity of the data reported regarding the number of overdue customers and the dollars in debt associated with those customers. First, utilities have used, and continue to use, different methods for determining when an account is overdue.

Utilities consider either the due date of the bill or the transmittal date of the bill to be day zero. The transmittal date is 20 days before the due date. For USR reporting and comparative purposes, utilities are requested to consider the due date as day zero and to report debt that is at least 30 days overdue.

Duquesne, Met-Ed, Penelec, Penn Power, West Penn, Columbia, Peoples Equitable, UGI Gas, and UGI PNG reported according to the method requested. The variance among the other EDCs and NGDCs showed a difference of no more than 20 days from that method. PECO Electric and Gas, PPL, Peoples, and PGW report debt that is 10 days old, meaning these utilities are overstating the debt compared to utilities that reported debt as 30 days overdue. NFG reports debt that is about 40 days old, meaning NFG is understating its debt relative to the other utilities. *See* Appendix 2 of the *2016 Report on Universal Service Programs and Collections Performance* (USR) for utility-specific information.[61]

The second factor affecting the arrearage data uniformity is the timing of when a utility moves a terminated or "discontinued" account from active status (included in the USR reporting) to inactive status (excluded from the USR reporting). Utility collection policies and accounting practices affected the timing. *See* Appendix 2 of the *2016* USR for company specific information.

[61] http://www.puc.pa.gov/General/publications_reports/pdf/EDC_NGDC_UniServ_Rpt2016.pdf

Analysis

Non-CAP Residential Debt on Agreement

Table 8-1
NGDC Residential Customers, Debt on Agreement as % of Revenues, 2012-2016

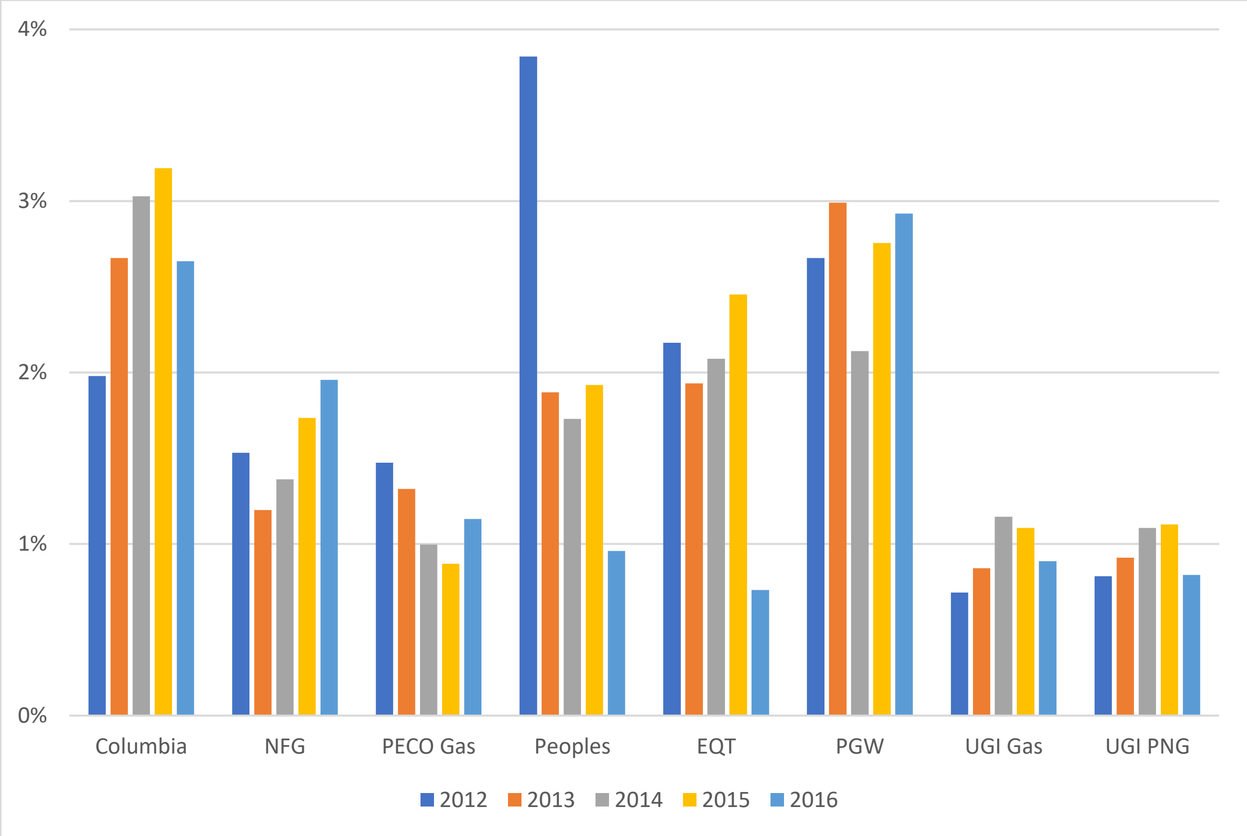
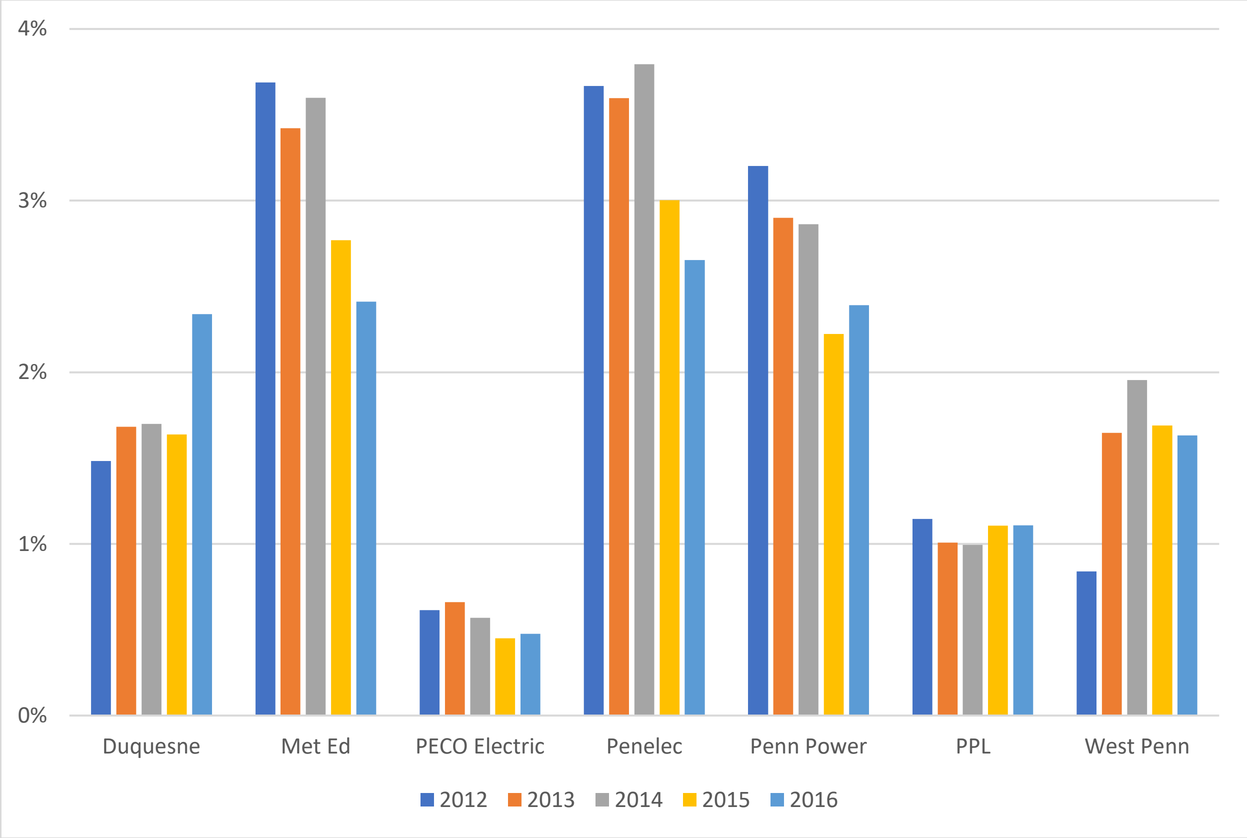


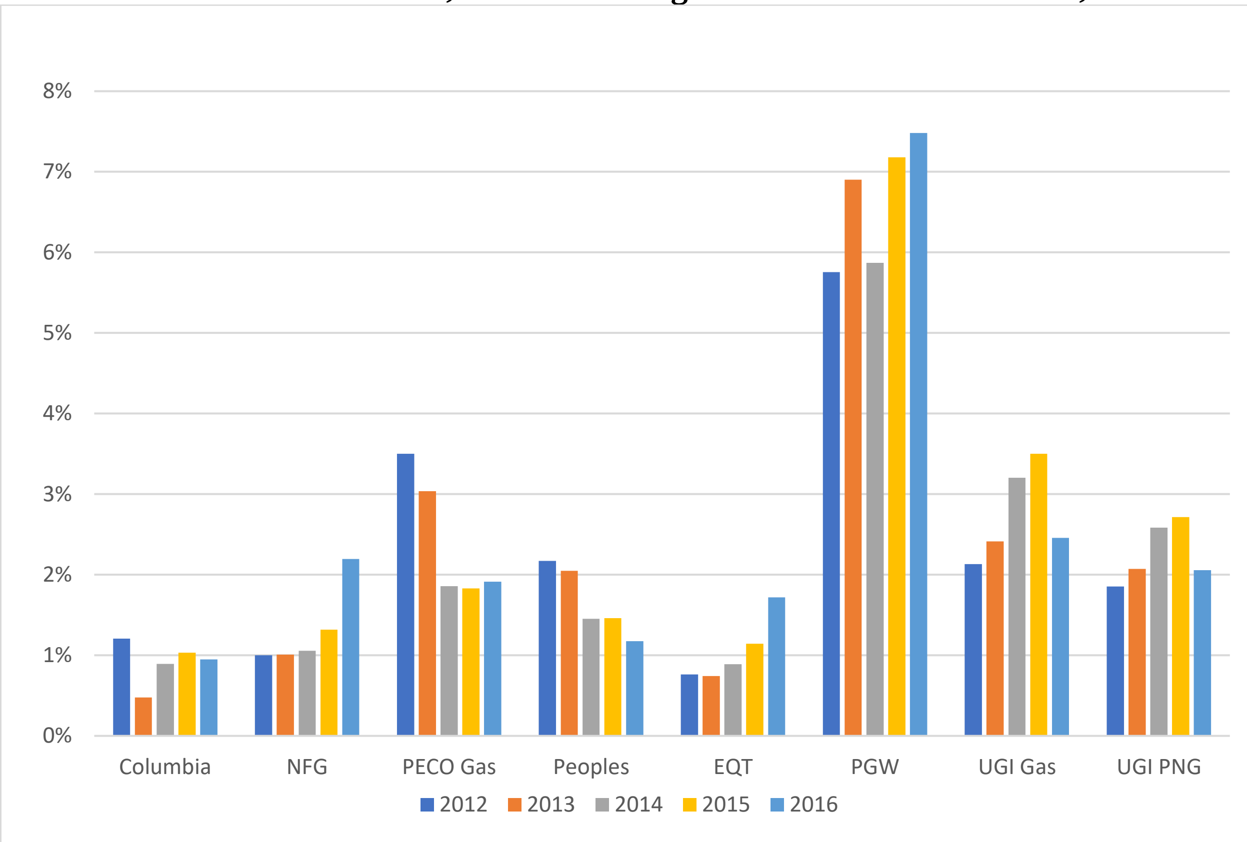
Table 8-2
EDC Residential Customers, Debt on Agreement as % of Revenues, 2012-2016



As seen in Tables 8-1 and 8-2, most NGDCs reported their non-CAP residential debt on agreement comprised less than 2% of revenues. Columbia and PGW's non-CAP residential debt on agreement comprised 2% to 3% of their revenues. Non-CAP residential customer debt on agreement overall for EDCs was less than 3% of residential revenues. Peoples, Peoples Equitable, UGI Gas, and UGI PNG reported decreases in non-CAP residential customer debt on agreement in 2016.

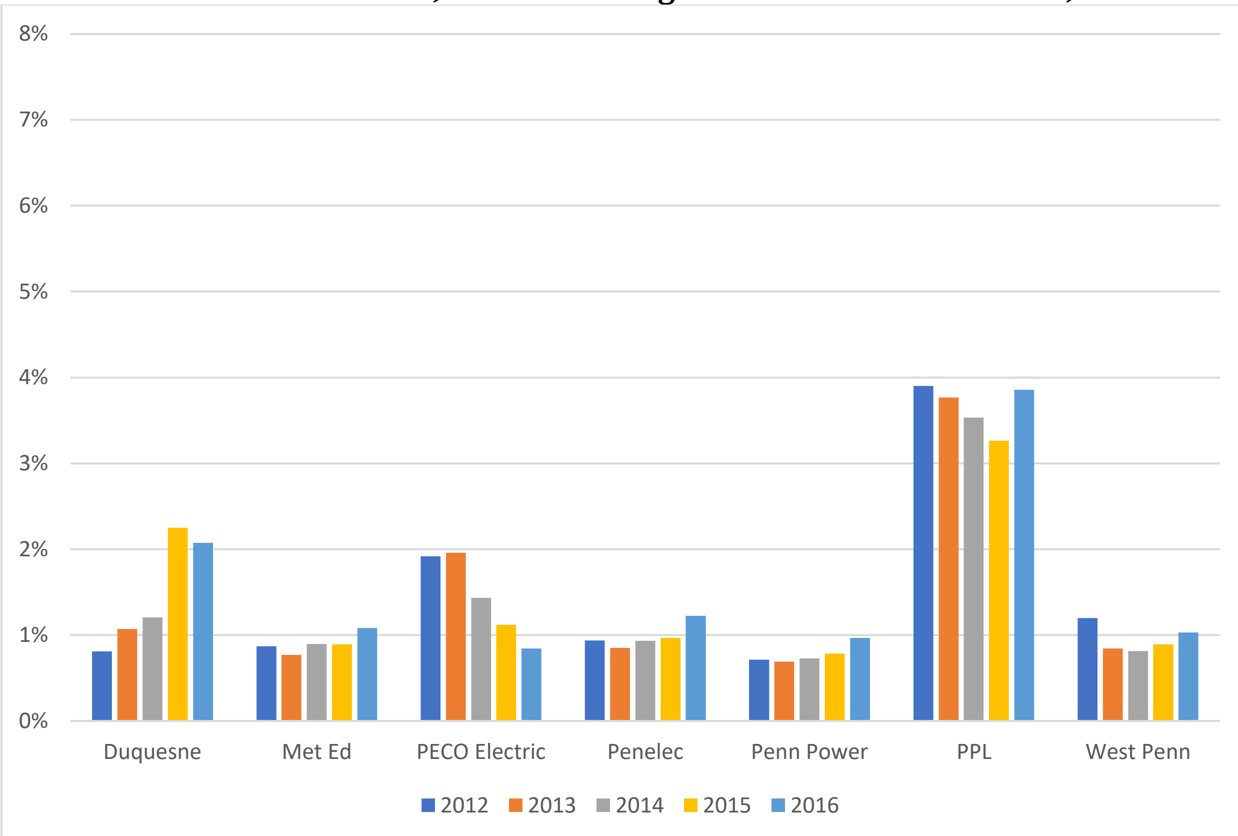
Residential Debt Not On Agreement

Table 8-3
NGDC Residential Customers, Debt not on Agreement as % of Revenues, 2012-2016



As seen in Table 8-3, half of NGDCs reported residential customer debt not on agreements comprised approximately 1% to 2% of their revenues. PECO Gas, UGI Gas, and UGI PNG averaged 2% to 3%, and PGW averaged 6% to 7% for this five-year period.

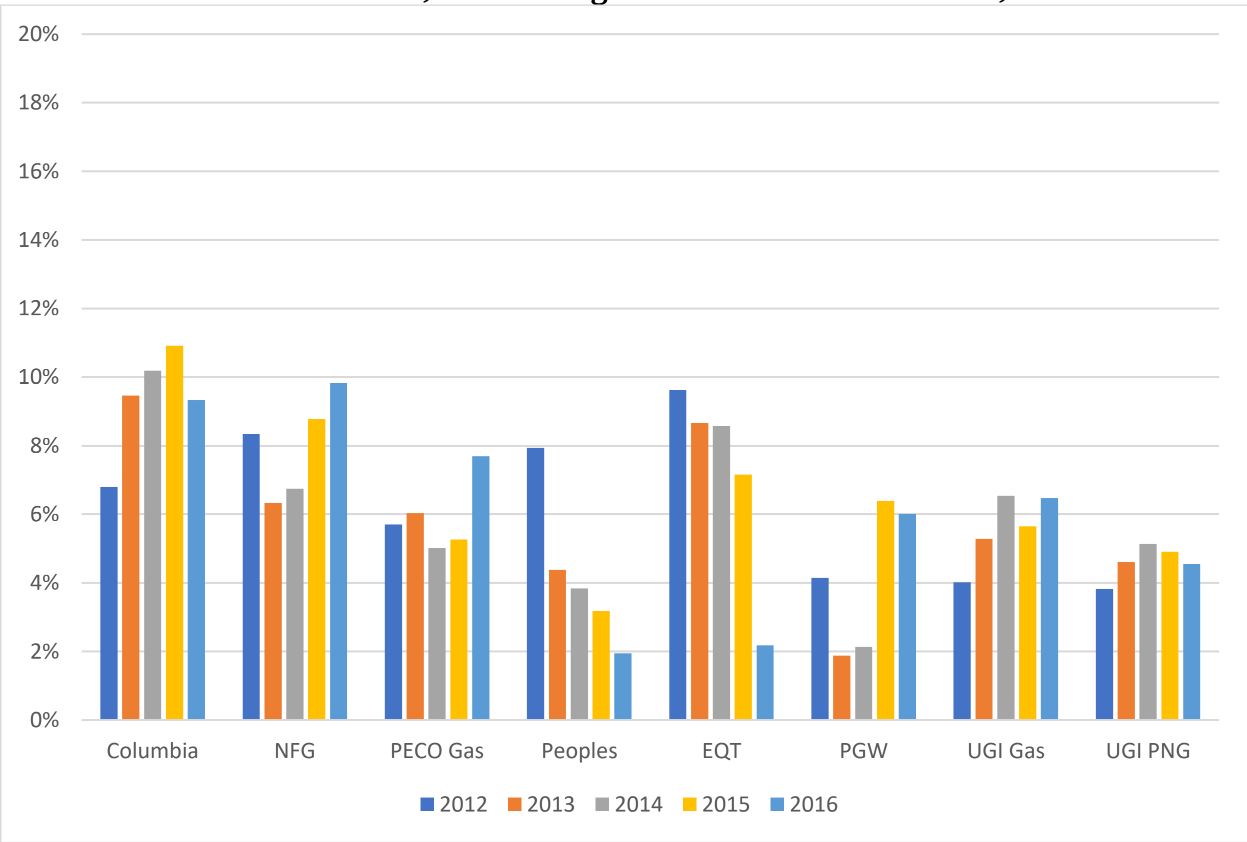
Table 8-4
EDC Residential Customers, Debt not on Agreement as % of Revenues, 2012-2016



As seen in Table 8-4, most EDCs reported that residential customer debt not on agreements comprised approximately 1% to 2% of their revenue. The debt not on agreement for Met-Ed, Penelec, Penn Power, and West Penn was 1% or less for the five-year period. PPL's residential debt not on agreement averaged 3% to 4% of revenue. Met-Ed, Penelec, Penn Power, and PPL reported an increase in residential debt not on agreement in 2016.

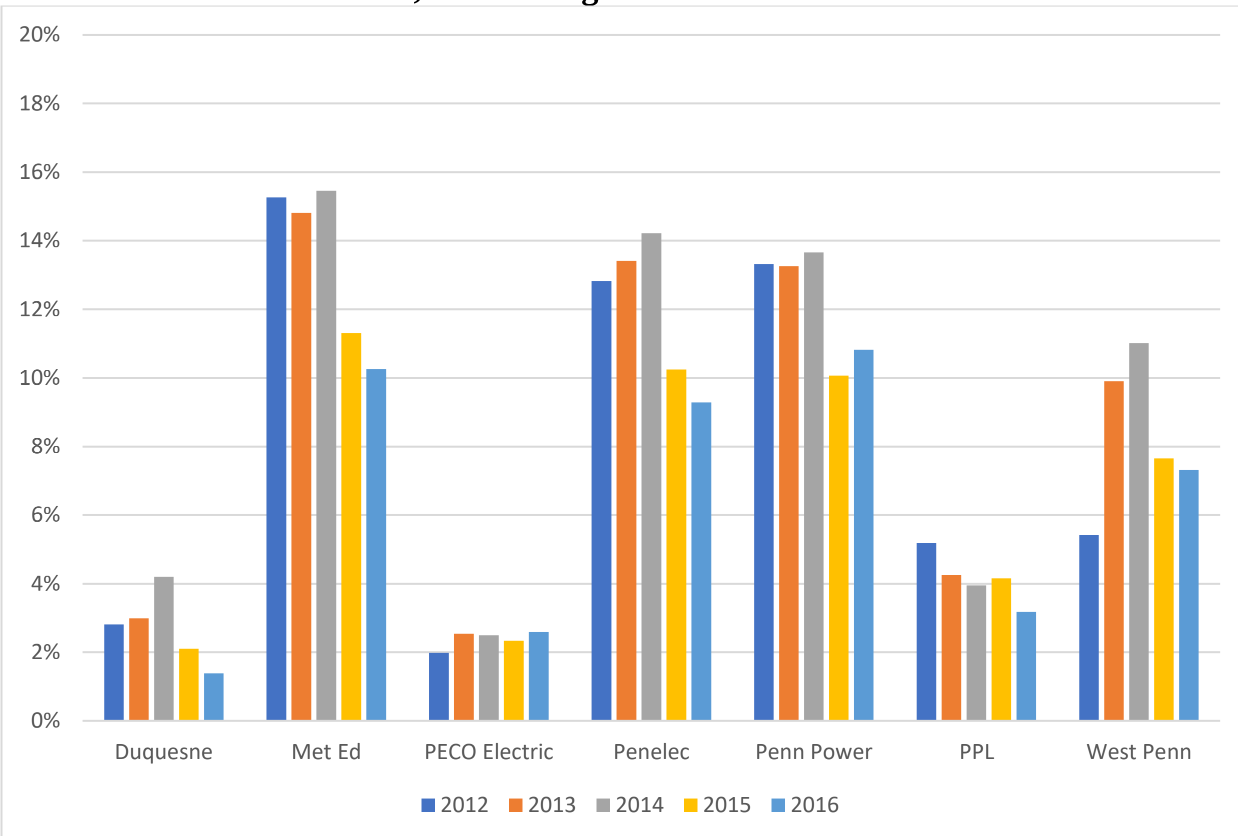
CLI Debt On Agreement

Table 8-5
NGDC CLI Customers, Debt on Agreement as % of Revenues, 2012-2016



As seen in Table 8-5, there appeared to be variability in the amount of CLI customer debt on agreement compared to revenue for NGDCs. Most NGDCs averaged between 4% and 10% of revenue during this five-year period. PGW and UGI Gas gradually increased the number of CLI customers on agreements, compared to revenue.

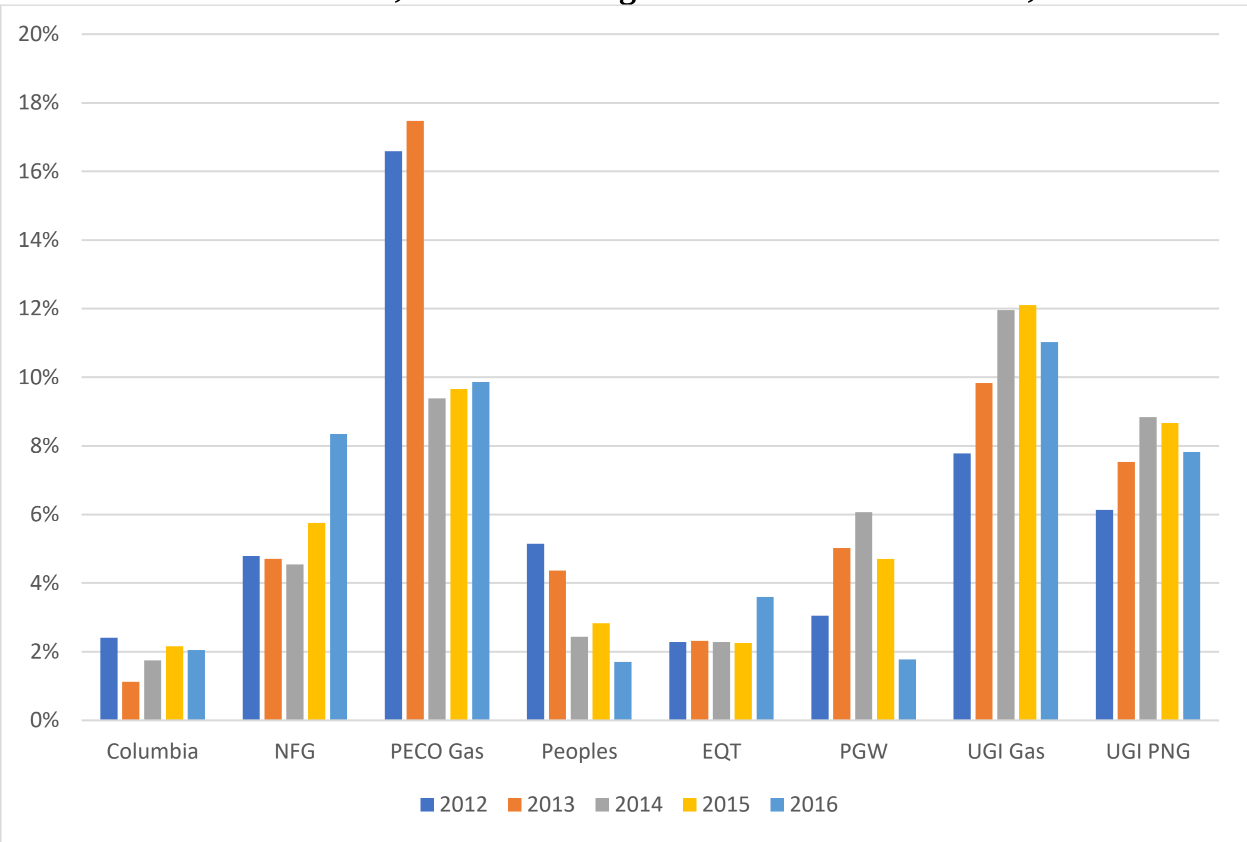
Table 8-6
EDC CLI Customers, Debt on Agreement as % of Revenues 2012-2016



As seen in Table 8-6, the amount of CLI customer debt on agreement compared to revenue also varied by EDC. Met-Ed, Penelec, Penn Power, and West Penn reported CLI debt on agreement as 2% to 3% of revenue. Duquesne's CLI debt on agreement fluctuated between 5% to 9% of revenue during this five-year period. PPL's reported CLI debt on agreement declined annually since 2012, from 17% in 2012 to 10% in 2016.

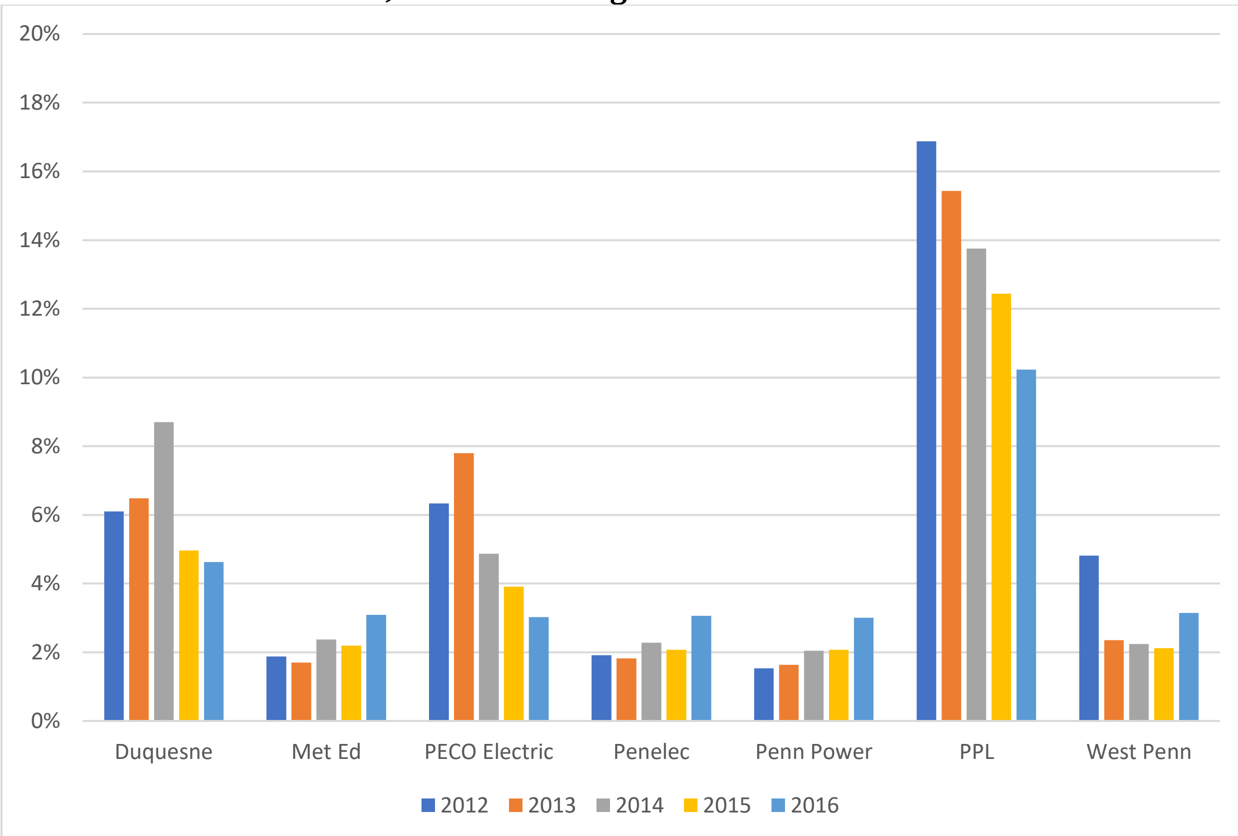
CLI Debt Not On Agreement

Table 8-7
NGDC CLI Customers, Debt not on Agreement as % of Revenues, 2012-2016



As seen in Table 8-7, about half of NGDCs reported their CLI debt not on agreement comprised approximately 2% to 4% of revenues. Columbia had the lowest amount, ranging from 1% to 2% during the five-year period. PECO Gas, UGI Gas, and UGI PNG had the highest amount. PECO Gas' CLI debt not on agreement exceeded 17% of revenue in 2013, but this percentage declined annually after that year; by 2016, the amount was less than 10%. This higher rate could be attributed to affordability issues within PECO Gas and Electric's CAP during this period. *See* Footnote 46. UGI Gas and UGI PNG also experienced increases in CLI debt not on agreement as compared to revenues from 2012-2015, but 2016 showed a decrease in this category for both companies.

Table 8-8
EDC CLI Customers, Debt not on Agreement as % of Revenues 2012-2016



As seen in Table 8-8, the amount of CLI debt not on agreement averaged 4% or less of revenues for most EDCs. PECO Electric and PPL generally reported gradual decreases for this category from 2012 to 2016. Based on a percent of revenue, PECO Electric's CLI debt not on agreement decreased from 6% to 2%, and PPL's decreased from 17% to 10% from 2012 to 2016. The FirstEnergy Companies (Met-Ed, Penelec, Penn Power, and West Penn) reported increases in CLI debt not on agreement in 2016.

Observations

About half of the NGDCs saw a decrease in residential debt on agreements in 2016. However, many of these utilities also saw a decrease in residential debt not on agreements. This could indicate an overall trend of decreasing residential debt carried by NGDC customers.

There did not appear to be a correlation between the different types of CAPs offered by utilities (*e.g.*, percent of income, rate discounts) and the number of CLI customers in debt not on agreement, as compared to income.

The general increases in the percent of CLI debt on agreements corresponded to a decline in the percent of CLI customers not on agreements for many utilities. This may indicate that utilities were having greater success in either enrolling CLI customers in CAPs or establishing payment agreements.

IX. Review of Other State Programs and Relevant Studies

Objective

To understand how other states and the District of Columbia (collectively, states) address energy burdens and affordability issues for their low-income residents and gather information from relevant independent studies.

Background

Pursuant to Commission direction in Docket No. M-2017-2587711, staff developed a survey to gather information on how other states address energy burdens and affordability issues for their low-income residents. The state survey covered an extensive array of factors. The state survey requested information on the jurisdictional utility regulatory low-income programs in each state and collected information on how the utilities treat the relevant variables in their own programs and policies. The state surveys were sent electronically to the various state utility commissions.

Staff worked with the Commission's CSIS Project to collect and collate the results of the state surveys and to review independent studies that may provide further insight into energy affordability issues.

Additionally, several published independent reports and studies were reviewed. Most of the independent reports and studies reviewed were performed by APPRISE[62] or by Fisher, Sheehan, and Colton. The CSIS Project assisted with the review of the published reports and studies.

Methodology

To determine which states most closely resemble Pennsylvania in terms of energy burden, FPIG levels, residential profiles, and other relevant factors, the Commission's CSIS Project collected the following U.S. Census data for each state:

- Urban/Rural population
- Age Distribution
- Education Level
- Fuel Type
- Household Size
- Poverty Status
- Retirement Population
- Substandard Housing

62 Applied Public Policy Research Institute for Study and Evaluation Inc. (APPRISE). www.appriseinc.org

Information was requested on 27 variables for the past five years. The data were combined into a rating system to calculate overall scores for each state. Seven states and the District of Columbia (D.C.) responded. Each respondent was then compared to Pennsylvania, with the highest possible comparison score being 27. The state most closely resembling Pennsylvania on these factors was Ohio, with a score of 14.

Data Limitations

No respondent answered every survey question. No respondent provided average energy burdens for low-income or non-low-income households or for heating/non-heating households for all five years.

None of the independent reports or studies reviewed considered all of the variables identified for this report. Several studies did, however, examine the relationship between subsets of the identified variables, as well as several studies that dealt with similar topics and had findings related to this study.

Analysis

Energy Burden Levels of Neighboring States

Although respondents to the survey did not provide average energy burden levels for their low-income and residential utility customers, each respondent provided valuable information about its own payment assistance programs.[63]

Information provided by Ohio, a state similar (and geographically close) to Pennsylvania, is of particular interest. Ohio has a mandated Percentage of Income Payment Plan (PIPP Plus)[64] which limits the amount spent on gas and electric service to 10% of the participating household's gross monthly income:

> Ohio's PIPP Plus is an extended payment arrangement that requires regulated gas and electric companies to accept payments based on a percentage of the household income for those customers who are at or below 150% of the federal income guidelines. The PIPP Plus payment amount is based on the household's countable income received during the previous 30 days. If a gas customer qualifies for PIPP Plus, he or she would pay 6% of the household's current gross monthly income to the gas company or a minimum of ten dollars, whichever is greater, year-round. If electricity is not the primary heat source, a customer pays 6% of the household's current gross monthly income to the electric company or a minimum of ten dollars, whichever is greater, year-round. The customer of

63 A summary of responses is included in Appendix 7.
64 *See* https://development.ohio.gov/is/is_pipp.htm for further information on Ohio's PIPP Plus.

an all-electric household pays 10% of the household's monthly income or a minimum of ten dollars, whichever is greater, year-round.

Ohio's 10% electric heating energy burden and its combined gas/electric energy burden are the highest levels compared to Pennsylvania's other neighboring states. The maximum energy burden for New York's payment assistance program is 6% for gas and electric service.[65, 66] New Jersey's maximum energy burden for its Universal Service Fund is also 6%.[67, 68] Maryland has an Electric Universal Service Program which provides an annual grant to reduce a low-income customer's budget bill amount based on household income and electric usage over the past 12 months.[69]

Pennsylvania's Home Energy Affordability Gap

Fisher, Sheehan, and Colton compile and publish annually a Home Energy Affordability Gap report for each state annually that reflects energy burden information for each state, using information from several sources, including the U.S. Census and the

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[65] *See* New York Public Service Commission's *Order Adopting Low Income Program Modifications and Directing Utility Filings* at 3, Case 14-M-0565 (effective May 20, 2016). NOTE: New York also limited the budget for each utility's payment assistance program to 2% of revenues for sales to end-use customers. These costs are recovered from all ratepayer classes. May 20 Order at 3-4.

[66] The New York Public Service Commission favored a 6% energy burden level because it appears to be a widely accepted limit for utility payments:

> There is no universal measure of energy affordability; however, a widely accepted principle is that total shelter costs should not exceed 30% of income. For example, this percentage is often used by lenders to determine affordability of mortgage payments. It is further reasonable to expect that utility costs should not exceed 20% of shelter costs, leading to the conclusion that an affordable energy burden should be at or below 6% of household income (20% x 30% = 6%). A 6% energy burden is the target energy burden used for affordability programs in several states (e.g., New Jersey and Ohio), and thus appears to be reasonable. It also corresponds to what U.S. Energy Information Administration data reflects is the upper end of middle and upper income customer household energy burdens (generally in the range of 1 to 5%). The Commission therefore adopts a policy that an energy burden at or below 6% of household income shall be the target level for all low[-]income customers.

May 20 Order at 7-48.

[67] New Jersey requires USF customers to pay 3% for natural gas service, 3% for electric non-heating, and 6% for electric heating. The discount provided to customers is based on the difference between their annual utility bill (after LIHEAP is applied) and required percentage of household income. https://www.state.nj.us/dca/divisions/dhcr/faq/usf.html#q1

[68] Although not a neighboring state, Illinois also administers a PIP that charges customers a maximum of 6% of their income for gas and electric service. The maximum PIP credit is $150 per month or $1,800 annually. Illinois Senate Bill 1918 at 108-109. http://www.ilga.gov/legislation/96/SB/PDF/09600SB1918lv.pdf

[69] *See* http://dhr.maryland.gov/office-of-home-energy-programs/how-are-grants-determined/ for more information about the Maryland grants.

five-year American Community Survey (ACS).[70] Information is compiled for each county in a state which is then used to calculate an statewide energy burden value.[71] Additionally, Fisher, Sheehan and Colton report gross LIHEAP dollars, the number of households at or below 150 percent of the poverty level, and the number of heating/cooling bills covered by LIHEAP.

The energy burden levels in the Fisher, Sheehan, and Colton reports reflect the cost of various household energy sources (*e.g.*, natural gas, electric, propane, oil, coal, etc.). Thus, the energy burdens they calculate for Pennsylvania will not match precisely with the energy burdens reflected in this staff report.

Table 9-1
Energy Burden for Pennsylvania Households, 2012 to 2016[72]

	Energy Burden				
Poverty Level	**2012**	**2013**	**2014**	**2015**	**2016**
Below 50%	34%	33%	33%	30%	28%
50-100%	19%	18%	18%	16%	15%
100-125%	13%	12%	12%	11%	10%
125-150%	10%	10%	10%	9%	8%
150-185%	9%	8%	8%	7%	7%
185-200%	7%	7%	7%	7%	6%

Source: *Home Energy Affordability Gap, 2012-2016*

As seen in Table 9-1 above, Pennsylvania households with incomes at or below 50% of the FPIG had energy burden levels ranging from 34% in 2012 to 28% in 2016. Household with incomes between 50-100% and 100-150% had energy burdens ranging from 19% to 15% and from 10% to 8%, respectively, during this five-year period.

[70] Fisher, Sheehan & Colton. "Home Energy Affordability Gap," *Public Finance and General Economics*. Retrieved from http://www.homeenergyaffordabilitygap.com/index.html.
[71] Fisher, Sheehan & Colton explain the affordability gap as *actual home energy bills* minus *affordable home energy bills* (defined as 6% gross household income) equals the *home energy affordability gap* (calculated through segmenting each state's counties into FPIG sections).
[72] Includes households using various heating sources (*e.g.*, natural gas, electric, oil, propane, coal, wood, etc.). This is not restricted to jurisdictional gas and electric customers

Table 9-2
LIHEAP Allocation, Households Below Poverty Level, and Covered Bills for Pennsylvania, 2012-2016

	Gross LIHEAP Allocation (in millions)	# of Households ≤150% FPIG	Average Energy Bills "Covered" by LIHEAP
2012	$209,548	1,034,276	182,533
2013	$184,642	1,063,068	166,644
2014	$175,603	1,080,857	150,862
2015	$204,099	1,092,514	207,840
2016	$182,170	1,085,999	216,354

Source: *Home Energy Affordability Gap*, 2012-2016

Although there appeared to be a decrease in household energy burden levels from 2012 to 2016, the number of LIHEAP-income-eligible Pennsylvania households reportedly increased. Table 9-2 above shows that households with incomes at or below 150% of the FPIG increased from approximately 1 million in 2012 to approximately 1.1 million in 2016.

Table 9-3
Energy Burden for Pennsylvania and Similar States, 2016

Energy Burden 2016				
	Below 50%	50-100%	100-125%	125-150%
Pennsylvania	28%	15%	10%	8%
Ohio	29%	15%	10%	8%
Kansas	29%	16%	11%	9%
Michigan	33%	18%	12%	10%
Virginia	32%	17%	12%	9%
Missouri	27%	15%	10%	8%
Wisconsin	33%	17%	12%	10%
Rhode Island	36%	19%	13%	10%
Delaware	39%	21%	14%	11%
New York	32%	17%	11%	9%
West Virginia	31%	17%	11%	9%

Source: *Home Energy Affordability Gap*, 2012-2016

Table 9-4
LIHEAP Allocation, Households Below Poverty Level, and Covered Bills for Pennsylvania and Similar States, 2016

	Gross LIHEAP Allocation (in millions)	# of Households below 150% FPIG	Heating/Cooling Bills "Covered" by LIHEAP
Pennsylvania	182,170	1,085,999	216,354
Ohio	131,709	1,142,393	181,919
Kansas	28,576	251,395	41,595
Michigan	140,599	995,442	155,015
Virginia	75,278	599,916	74,019
Missouri	65,662	602,511	101,018
Wisconsin	91,667	492,434	103,931
Rhode Island	23,271	91,177	23,365
Delaware	11,280	69,369	8,945
New York	325,976	1,790,231	373,826
West Virginia	25,927	213,221	25,798

Source: *Home Energy Affordability Gap*, 2012-2016

Of those states with similar energy burdens, none have demographic/energy profiles similar to Pennsylvania. However, Ohio is close, with identical energy burden for several poverty categories. Only six states, including Ohio and New York, had a greater number of households at or below 150% of the poverty level. As seen in Table 9-4 above, New York was the only state to receive a larger gross LIHEAP allocation in 2016, and only California (not shown) and New York covered a greater number of heating/cooling bills.

Examining all 50 states (plus the District of Columbia) reveals that Pennsylvania's average energy burdens for all energy sources were among the highest in the country for households below 150% of the poverty level.

Review of Other Relevant Studies

Several independent studies examined relationships between subsets of variables examined in this report. Other studies dealt with similar topics and had findings related to this report. These independent studies are summarized below:

The High Cost of Energy in Rural America (2018)[73]

This study examines the energy burden levels for households living in rural areas in the United States. Rural households have a higher median energy burden (4.4%) than

[73] Ross, L., Drehobl, A., and Stickles B. (July 2018). The High Cost of Energy in Rural America: Household Energy Burdens and Opportunities for Energy Efficiency. Retrieved from https://aceee.org/research-report/u1806

the national median energy burden (3.3%). Low-income households in rural areas spend the highest portion of their income on energy bills. In the Mid-Atlantic states, the median energy burden level for these households is 9.5%. Demographics also pay a factor in energy burden levels. Rural elderly households have a median energy burden 44% higher than non-elderly households; rural renters have a median energy burden 29% higher than owners; and non-white households have a median energy burden 19% higher than white households. Other factors, besides income level, may contribute to higher energy burden levels for rural households such as the condition of the home, a household's ability to invest in energy efficient equipment, and the availability of energy efficiency programs. Energy efficiency upgrades were found to reduce energy burden levels up to 25%. The study recommends, among other things, exploring low-risk or no-risk efficiency financing options, incorporating regional workshop development initiatives, and building relationships with area service providers to enhance program delivery.

Lifting the High Energy Burden in America's Largest Cities (2016)[74]

This study examined the energy burden levels of households living in 48 of the largest cities across the United States, including Philadelphia and Pittsburgh. The median energy burden for all households in this sample was 3.5%, but the median energy burden for low-income households was more than twice as high at 7.2%. The study promotes the use of weatherization programs to help improve housing stock for low-income households, noting that raising household efficiency to the median level could reduce the energy burden level by 35%. Benefits to energy efficiency programs include improved health and safety, reduced risk of rate increases, reduced costs associated with collections and shutoffs, and investment in the local economy. The study recommends that utilities track program participation by income level, renter versus owner, multifamily versus single family, and race/ethnicity to assess the impacts on different segments of the population. It also recommends regulators set goals and guidelines for energy savings, cost recovery, and cost-effectiveness testing.

PPL Electric Evaluation Report (2014) [75]

This study concluded that an energy conservation program, CARES, and a hardship fund can have a positive impact on reducing bills, increasing the ability to pay, and reducing arrearage.

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[74] Drehobl, A and Ross, L. (April 2016). Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low Income and Underserved Communities. Retrieved from http://energyefficiencyforall.org/sites/default/files/Lifting%20the%20High%20Energy%20Burden_0.pdf.

[75] The Cadmus Group (November 2014). Process Evaluation Report, PPL Electric, EE&C Plan, Program Year Five. Retrieved from https://www.pplelectric.com/-/media/PPLElectric/Save-Energy-and-Money/Docs/Act129_Phase2/pplpy5processevaluation212015.pdf?la=enE

Opinion Dynamics Low-Income Assistance Program Evaluation (2013)[76]

This study evaluated an anonymous utility's energy assistance program that provided reduced monthly payments and debt forgiveness to payment-troubled households based on family size, income, and electric use. The study noted that customers frequently left and re-entered the program (46% enrolled more than once). Participants who also received LIHEAP had a 14% lower average on-time payment rate than non-LIHEAP participants. Customers with lower PPAs had higher on-time payment rates, and more of these customers had on-time payment rates higher than the average. A sampling of customers found that 81% of the respondents reported taking action to try to reduce their energy usage after enrolling in the program; 70% reported that their electric usage either stayed the same or increased during this period.

UGI Gas and Penn Natural Gas Evaluation Report (2012) [77]

This study concludes that CAP participation has a large impact on energy affordability, decreasing energy burden, and improving payment behavior. On average, energy burdens among CAP participants declined from 15 to 10 percentage points. Compared to the pre-enrollment period, CAP customers were nearly twice as likely to pay their bills in full compared to their payment behavior prior to enrolling in CAP.

Home Energy Affordability in New York: The Affordability Gap (2011)[78]

This study defined an "affordable" energy burden as 6%, based on the theory that shelter costs should not exceed 30% of household income and that utility costs should not exceed 20% of shelter costs. 20% of 30% is 6%. Based on this measure, the study examined the energy affordability of New York households. Among other things, the study found demographic patterns correlated to energy affordability, including age, education, and gender. Elderly households were found to have smaller family sizes and less income; two-thirds of men and women living below the poverty level had only a high school diploma or less; and approximately 11% of men with full-time jobs live in poverty, compared to 6.5% of women.

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[76] Opinion Dynamics Corporation (March 2013). Low Income Assistance Program Evaluation. Retrieved from http://www.opiniondynamics.com/wp-content/uploads/2013/06/Low-Income-Payment-Assistance-Program-Evaluation.pdf..
[77] APPRISE (July 2012). UGI Utilities Universal Service Program Final Evaluation Report. Retrieved from https://www.puc.state.pa.us/general/pdf/USP_Evaluation-UGI.pdf.
[78] Fisher, Sheehan, & Colton. (August 2012). Home Energy Affordability in New York: The Affordability Gap (2011). Retrieved from https://www.nyserda.ny.gov/-/media/Files/EDPPP/LIFE/Resources/2011-affordability-gap.pdf.

Allegheny Power Universal Services Evaluation Report (2010) [79]

This study found that participation in CAP improved payment behavior; the average number of monthly payments per year increased from 8.6 to 9.4, while the coverage of the total bill – from cash and assistance payments - increased from 88% to 111%. While roughly 33% of participants paid their full bill in the prior year, 68% paid their full bill in the year after enrolling in CAP. Other positive results included a reduction in arrearage and the number of customers receiving termination notices; however, the actual termination rate did not change.

The Illinois PIPP Program Impact Evaluation (2009)[80]

This study found that enrollment in a PIP can increase the amount of energy used by households. Increased energy usage generally falls between 0.9% and 3.8%. However, data showed that a significant number of those households that increase their energy usage reported keeping their household temperature at unsafe heating levels prior to enrolling in a PIP. The study recommended coordinating PIP participants with weatherization and other energy conservation programs to offset any increases in energy usage.

LIHEAP Energy Burden Evaluation Study (2005)[81]

This study found that LIHEAP was effectively targeting the highest burden households (62% of LIHEAP recipients had high energy burdens) but that LIHEAP was not as successful in furnishing sufficient benefits to highly burdened and vulnerable households. The distinction was vulnerability. Vulnerable households are sensitive to the characteristics of household members, particularly households with at least one member aged 60 or over or with one or more members who are age 5 or younger. Under certain circumstances, non-low-income households can be vulnerable, and not all low-income households are vulnerable. This highlighted the need to consider other factors in addition to household income and to segment the eligible population to identify certain characteristics, such as the elderly. Geographic location, home ownership, and household size played important roles.

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[79] APPRISE (July 2010). Allegheny Power Universal Service Programs Final Evaluation Report at ES4. Retrieved from http://www.appriseinc.org/wp-content/uploads/2016/05/Final-Allegheny-Universal-Service-Program-Evaluation-Report.pdf

[80] APPRISE (December 2009). Illinois PIPP Program Impact Evaluation. Retrieved from http://appriseinc.org/reports/Illinois%20PIPP%20Impact%20Report%20-%20FINAL.pdf.

[81] APPRISE (July 2005). LIHEAP Energy Burden Evaluation Study. Retrieved from http://www.appriseinc.org/reports/LIHEAP%20BURDEN.pdf.

Measuring LIHEAP's Results: Responding to Home Energy Unaffordability (1999)[82]

This study tested empirically whether it would be accurate to equate "unaffordability" and "bill nonpayment" and concluded that the two are not the same. According to this study, paying utility bills in full and on time does not mean that these bills are affordable. Households may strive to make these utility payments and then struggle to afford other things such as food or medical care. The authors concluded that payment rates did not necessarily reflect the affordability of utility bills and recommended that "the concept of bill affordability should be replaced with a concept of bill sustainability" when evaluating the impact of energy assistance programs such as LIHEAP.

Determining the Cost-Effectiveness of Utility Late Payment Charges (1994)[83]

This study, which included analysis of households in Columbia Gas' Budget Plus Plan, determined that late charges for non-payment do not necessarily provide an incentive for more timely payments.

Observations

Pennsylvania's maximum energy burdens for CAPs, which range from 5% to 17% of household income, are much higher than neighboring states. Ohio has the second highest energy burden level for its utility payment assistance programs at 10% of household income. New York and New Jersey's utility payment assistance programs both have a maximum energy burden of 6%.

Pennsylvania households with incomes at or below 150% of the FPIG experience some of the highest energy burdens in the country. When counting the costs of all sources of energy, Pennsylvania residents with incomes at or below 50% of the FPIG had energy burden levels at 30% or higher for four of the five years of this study. Households that use electric non-heating may have higher energy burden levels than those reflected in this study if they use more expensive heating fuels, such as oil or propane.

A review of the other independent studies referenced above provides the following guidance:

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[82] Fisher, Sheehan, & Colton. (May 1999). "Measuring LIHEAP's Results: Responding to Home Energy Unaffordability," *Public Finance and General Economics*. Retrieved from http://www.fsconline.com/downloads/Papers/1999%2005%20measure-liheap.pdf. Measuring LIHEAP's Results at i.

[83] Fisher, Sheehan, & Colton. (June 1994). "Determining the Cost-Effectiveness of Utility Late Payment Charges," *Public Finance and General Economics*. Retrieved from http://www.fsconline.com/downloads/Papers/1994%2007%20LATE-FEE.pdf. Determining the Cost-Effectiveness of Utility Late Payment Charges at 15.

- Although nearly eight-in-ten Pennsylvanians live in an urban area (78.7%),[84] households in rural areas may experience the highest energy burden levels due to poor housing stock in these areas. Focusing energy-efficiency education and weatherization services can help to reduce the energy burden disparity in these areas and help make CAPs more effective.

- Policymakers should not confuse unaffordability with non-payment behavior. Customers can make payments in full and on time, yet their bills may still not be affordable when other (possibly neglected) household expenses are taken into account.

- Not every household in poverty or with high energy burdens will automatically experience energy bill payment problems.

- Although LIHEAP does serve the lowest income households with the highest energy burden, the concept of vulnerability must also be considered. Some populations, such as the elderly and families with young children or members with certain medical conditions, are more vulnerable than others.

- Knowing the characteristics of the intended population enables prioritization according to need. Demographic patterns – including age, education, and gender – may correlate to energy affordability. Elderly households may be more vulnerable to high energy burdens because they are more likely to live in smaller family sizes and with limited and fixed income.

- Factors other than income and customer characteristics will play a role in determining the effectiveness of an assistance program. Program design is important, including the application process and leveraging of resources.

- The ability to coordinate multiple programs so that the strengths and goals of one can offset or compensate for weaknesses of another is crucial.

- Customers enrolled in CAPs with lower arrearages are more likely to successfully improve their payment behavior. Lower PPAs at the time of entry into a program result in a greater likelihood of making payments in full and on time. The average account balance can potentially predict the likelihood that program participants will be successful or unsuccessful.

- CAPs can reduce energy burdens and improve payment behavior. Customers in a CAP will be more likely to pay their bills in full or on time.

[84] Pennsylvania State Data Center, Penn State Harrisburg. (October 2012). Pennsylvania's Urban and Rural Population. Retrieved from http://pasdc.hbg.psu.edu/sdc/pasdc_files/researchbriefs/Urban_Rural_SF1_RB.pdf.

- Negative penalties such as late charges have little impact on encouraging more timely payment behavior.

X. CAP Costs and Forecasts

Objective

To identify the cost components of CAP and forecast the future costs of the program under current conditions and with adjustments to CAP enrollment numbers and energy burdens.

Background

The Univeral Service Reporting Requirements (USRR)[85] require the major gas and electric utilities to report data on the three components of CAP program costs: CAP administration and monitoring, CAP credits, and arrearage forgiveness.

Administrative costs include: contract and utility staffing, account monitoring, intake, outreach, consumer education and conservation training, recertification processing, computer programming, program evaluation, and other fixed overhead costs. Account monitoring costs include collection expenses, as well as other operation and maintenance expenses.

Of the three CAP cost components, CAP credits comprise the largest portion. CAP credits are the difference between the cost of utility service at tariff rates and price of utility service that CAP participants are asked to pay. Another key factor that drives the total cost of a CAP is the average CAP enrollment.

The cost of arrearage forgiveness is dependent on the PPAs of households when they enroll in CAPs and their adherence to CAP requirements. The more frequently the CAP customers pay their bills in full and on-time, the greater the amount of PPA forgiveness.

Methodology

To perform the analysis of total CAP costs, staff reviewed the total gross cost of all CAP components, average CAP enrollments, and the average number of residential customers for each of the EDC and NGDC utilities as reported in the *Universal Service Programs and Collection Performance Reports* (USRs) from 2012-2017.[86]

CAP budgets from approved or proposed utility USECPs were used to determine cost projections four years into the future, until 2021.[87] These projections are shown two

[85] 52 Pa. Code § 62.5 (2)(ii)(C)(III) for NGDCs and 52 Pa. Code § 54.75(2)(ii)(C)(III) for EDCs.
[86] http://www.puc.pa.gov/filing_resources/universal_service_reports.aspx
[87] Staff used projected CAP costs for 2018 to 2021 from the utilities' USECPs, rather than using regression to forecast CAP costs from the 2012-2016 data. Staff determined that the USECP

ways: (1) the total CAP costs from utility USECPs and (2) the impact of the CAP costs per non-CAP residential customer. Staff forecast the 2018-2021 average CAP enrollment and residential customer numbers. Staff then adjusted the costs to show a range of potential increases and decreases (+10%, +5%, +1%, -1%, -5%, -10%) to the 2018-2021 projected residential non-CAP costs.

Finally, staff created a model based on actual 2012-2016 CAP costs and energy burden levels. Staff was able to adjust the energy burden levels, holding the other variables static, and estimate the incremental CAP costs based on potential new percent-of-income energy burden levels. The model can be used to examine other potential percent-of-income energy burdens.

Data Limitations

The total CAP cost data and cost components were reviewed in aggregate for each utility, as the utilities do not report costs broken down by heating/non-heating or by poverty level as part of the USR.

Analysis

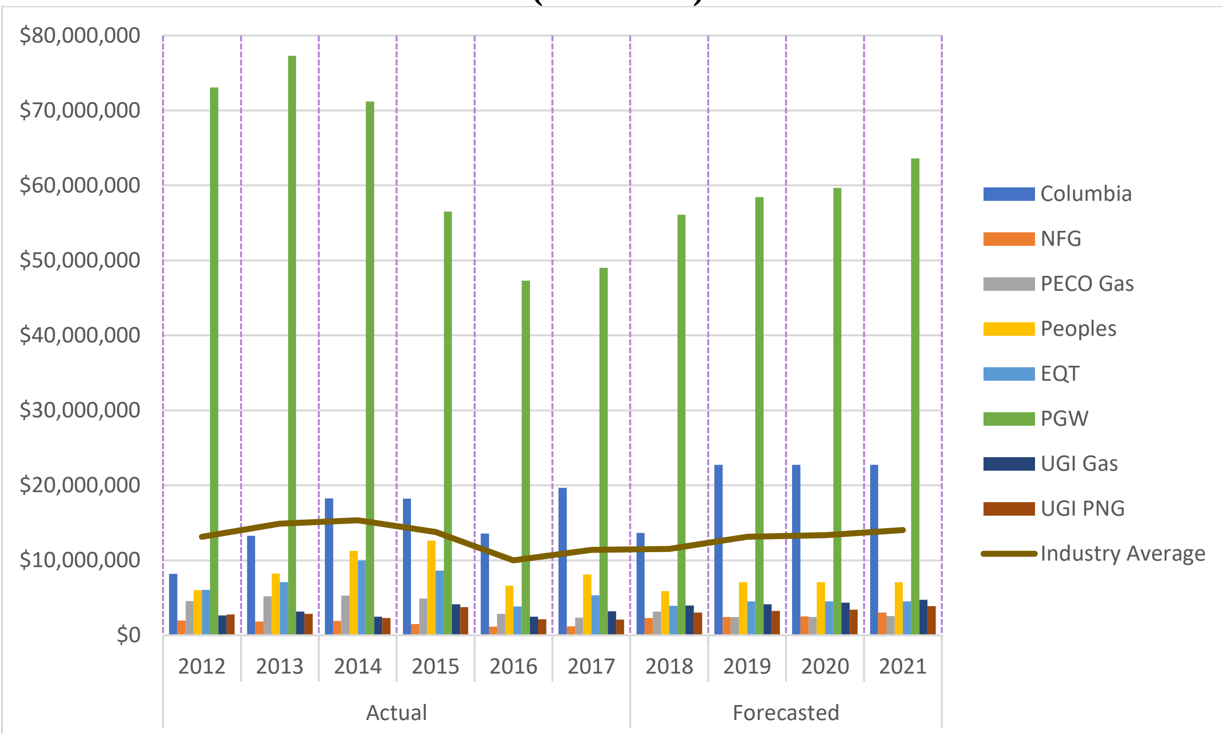
Staff analyzed the actual 2012-2017 costs of CAPs, number of residential customers, and average CAP enrollments from USR data in order to determine the costs of CAPs per non-CAP residential customer, calculated: CAP costs/(residential customers-average CAP enrollment). Staff used approved and proposed USECP CAP budgets for 2018-2021 and then forecast the 2018-2021 residential customer and average CAP enrollment levels using a regression analysis (when necessary).

Staff also created a separate model to estimate the impacts of adjusting the energy burden levels going forward.

CAP budgets were approximately 7% higher than actual CAP costs for 2015 through 2017. *See* Appendix 9.M.1: Variance between USECP CAP Cost Projections and Actual CAP Costs – Energy Industry as a Whole. Staff did not factor this variance into the model.

NGDC CAP Costs

Table 10-1
NGDC - CAP Totals With 4-Year Forecasting
(2018-2021)

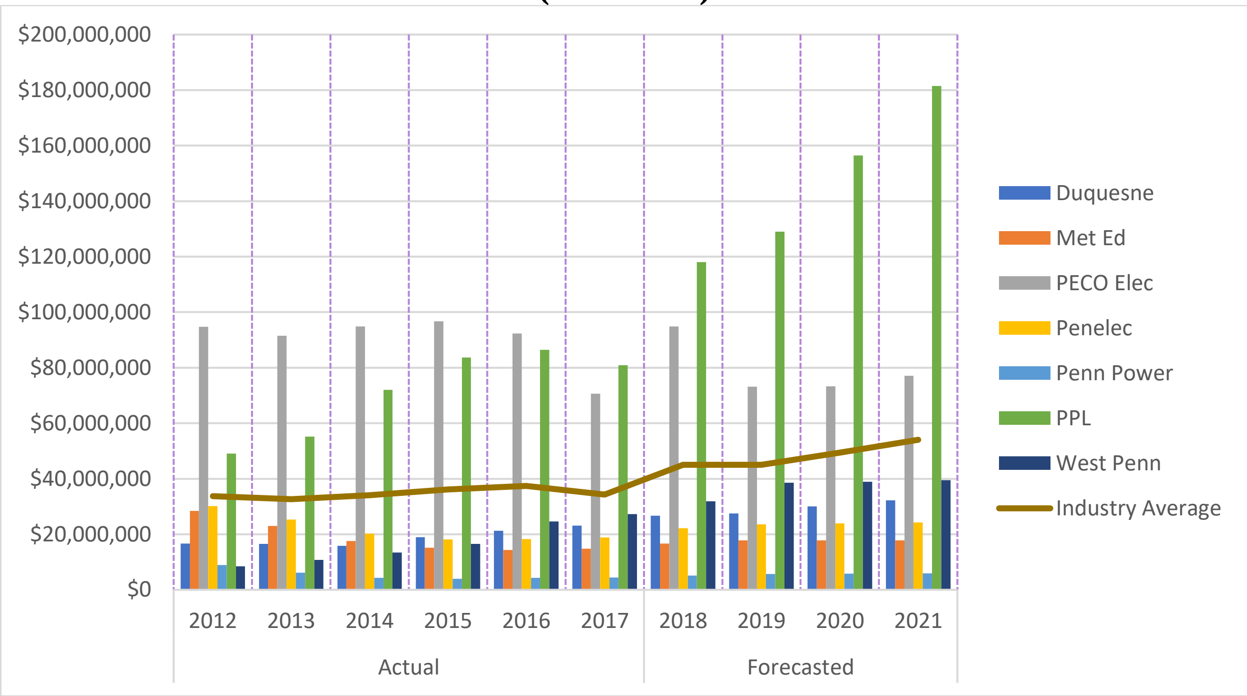


The historic CAP cost data show that PGW had the highest CAP costs of the NGDCs. PGW's CAP costs are recovered from rate classes other than just residential.[88] While CAP costs for PGW were still much higher than any other NGDC, they decreased from a peak of over $77.2 million in 2013 to $47.3 million in 2016. However, based on PGW's projected CAP budgets in its 2017-2020 USECP, PGW's CAP costs are anticipated to increase annually, growing to $63.6 million by 2021. Peoples' CAP costs have remained fairly steady since 2012 and are projected to remain fairly constant. Columbia Gas' CAP costs have risen from $8.1 million in 2012 and may reach a projected cost of over $22.7 million in 2021; Columbia Gas has the second highest NGDC CAP costs overall. NFG's CAP costs are forecast to increase from $1.2 million in 2017 to just over $3 million in 2021. The forecasting model projects the overall industry average for NGDC CAP costs will increase annually over the next four years, from $11.4 million in 2017 to over $14 million in 2021. *See* Table 10-1.

[88] PGW, as a city NGDC, is able to recover its CAP and other universal service program costs from the following classes, at different allocation percentages each year: residential, commercial, industrial, municipal service, and the Philadelphia Housing Authority (PHA).

EDC CAP Costs

Table 10-2
EDC - Total Gross CAP Totals With 4-Year Forecasting
(2018-2021)



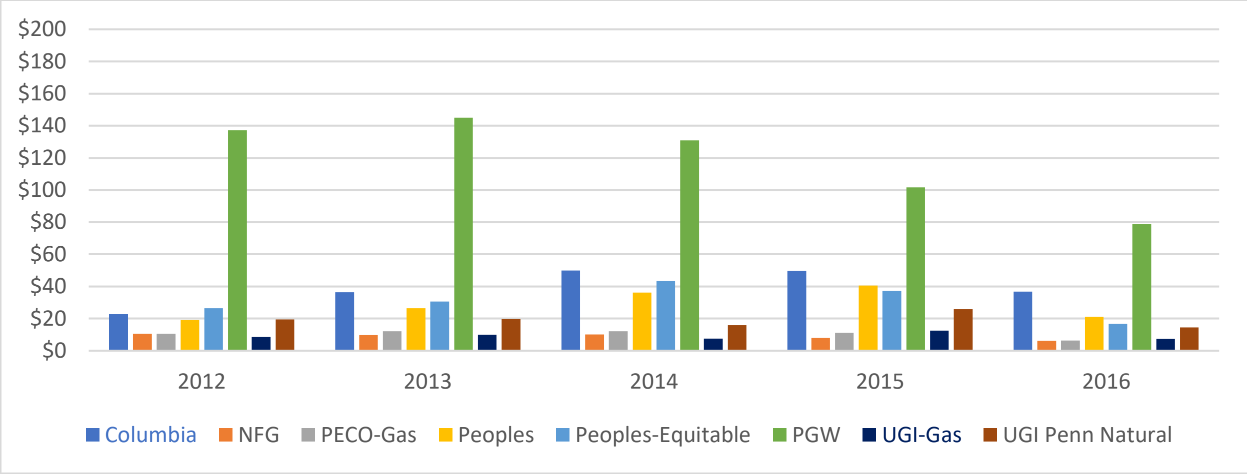
The historic CAP cost data show that PECO Electric and PPL had the highest CAP costs of the EDCs. PECO Electric's CAP costs remained fairly steady (between $92 to 96 million) from2012 through 2016. However, PECO Electric changed from a rate discount to a percent of income (PIP) CAP billing structure in October 2016, and this change is reflected in the lower projected CAP costs (between $73 to $77 million) through 2021. PPL's CAP costs have risen from $49.1 million in 2012 and may reach a projected cost of over $181.4 million in 2021. While PPL's 2020 and 2021 CAP costs are based on staff forecasting that does not take into account all possible factors, PPL's costs will likely continue to increase.

Forecasting shows the overall industry average for electric CAP costs will experience a sizeable increase over the next four years; from $34.3 million in 2017 to over $54 million by 2021. *See* Table 10-2.

Costs of CAP per Non-CAP Residential Customer

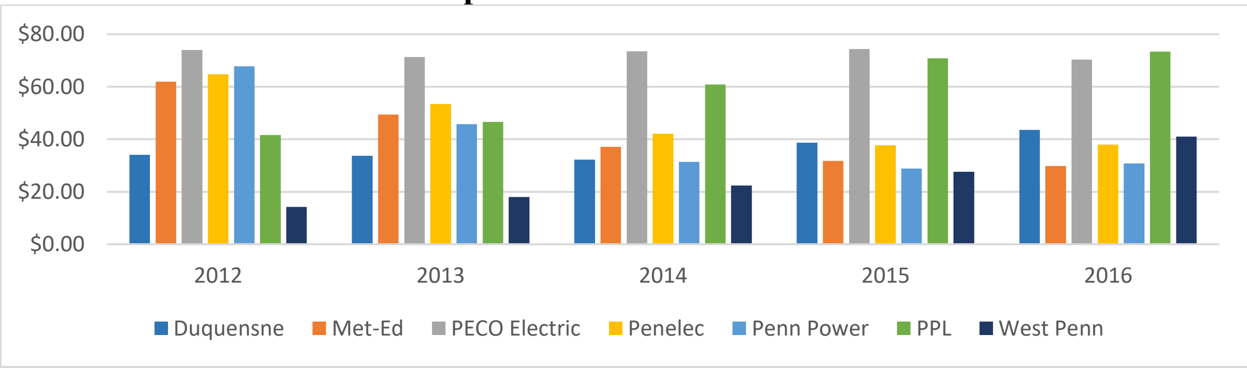
Another way to show the impact of CAP costs is to calculate costs per non-CAP residential customer. To do this, staff subtracted the average CAP enrollment from the number of residential customers to obtain the non-CAP residential customer totals. Staff then divided the total CAP cost by the average number of non-CAP residential customers for each utility: (*i.e.*, Total CAP Costs/Residential Customers-Average CAP Enrollment).

Table 10-3
Annual NGDC CAP Costs per Non-CAP Residential Customer 2012-2016



Based on historic data from 2012 to 2016, PGW had significantly higher costs per non-CAP residential customer than other NGDCs, even though PGW recovered its universal service program costs from other rate classes in addition to its residential class. The costs in the table above reflect only the historic residential portion of CAP costs for all utilities. *See* Table 10-3.

Table 10-4
Annual EDC CAP Costs per Non-CAP Residential Customer 2012-2016



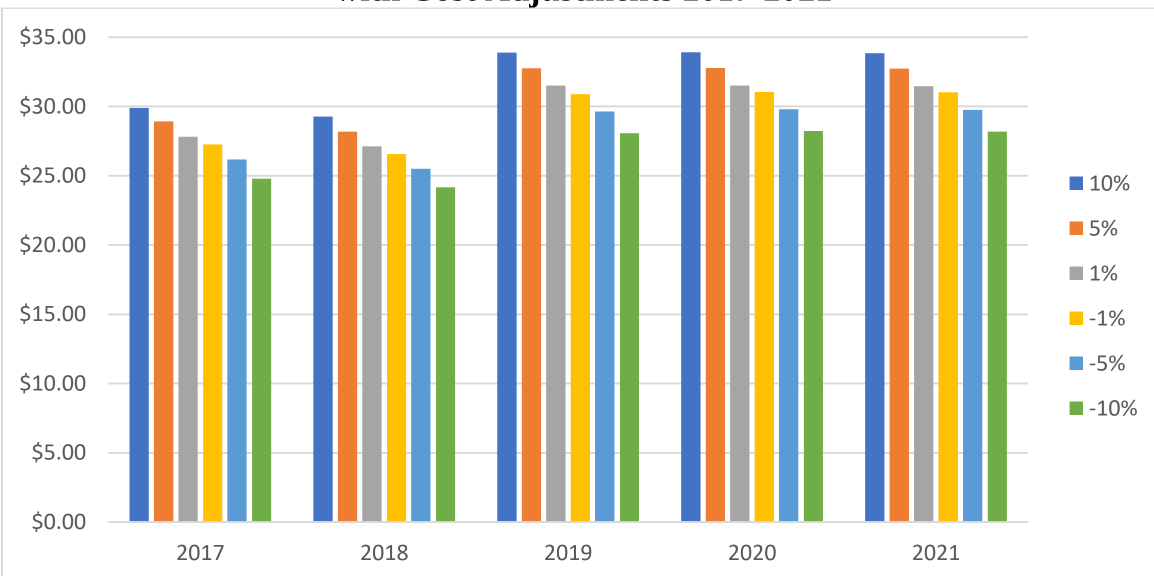
PECO Electric had the highest annual cost per non-CAP residential customer throughout the first four years of the study and was second highest in 2016. PPL's costs rose steadily and by the end of the study period were higher than PECO Electric's. Met-Ed's and Duquesne's annual CAP costs appear to have declined over the five-year period while West Penn's appear to have increased. *See* Table 10-4.

Projected Costs of CAPs Per Non-CAP Residential Customers with Cost Adjustments

Staff used projected CAP budgets from utility USECPs and regression analysis (for years in which no projected CAP budget was available) to forecast CAP costs for

2018 to 2021. Staff used the following adjustments to the costs per non-CAP residential customer: +10%, +5%, +1%, -1%, -5%, -10%. Due to the wide range in individual utility CAP costs, staff chose to perform this forecast at the EDC and NGDC industry level. The tables below show the energy industry CAP costs to non-CAP residential customers, as forecast for 2018 to 2021, but include the actual CAP costs for 2017, which were obtained from USR data. Staff has included the individual utility forecasts for non-CAP residential costs in the Appendix.[89]

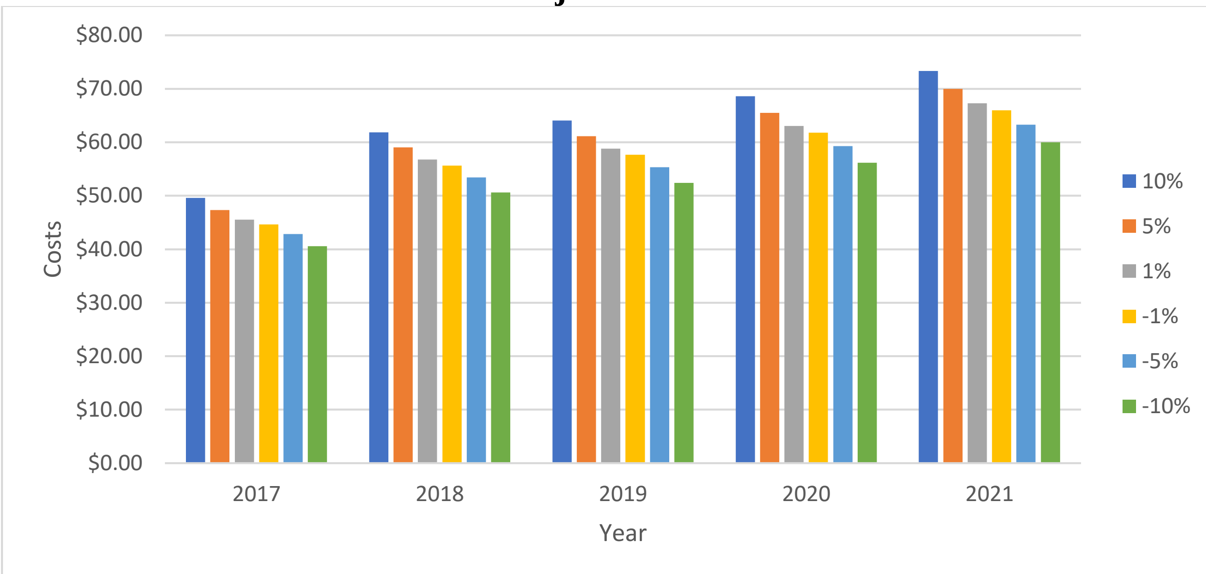
Table 10-5
NGDC Industry Predictions per Non-CAP Residential Customer with Cost Adjustments 2017-2021



By presenting the NGDC forecast at the industry level in Table 10-5 above, staff notes NGDC CAP costs per non-CAP residential customer will increase slightly by 2019, but otherwise remain relatively stable through 2021.

[89] See Appendices 9.D and 9.E.

Table 10-6
EDC Industry Predictions per Non-CAP Residential Customer with Cost Adjustments 2017-2021



By presenting the EDC forecast at the industry level in Table 10-6 above, staff notes an overall slightly increasing annual trend in the CAP costs per non-CAP residential customer. This increasing trend is consistent with the forecast trend noted above in the forecast for each individual EDC's CAP costs from 2018 to 2021.

Energy Burden Model

Staff developed a model that estimates the incremental costs to a CAP if energy burdens are adjusted. As noted earlier, most of Pennsylvania's neighboring states use lower maximum energy burdens. Ohio has a maximum energy burden of 10%, New York and New Jersey have maximums of 6%. For comparison purposes, staff projected the impact to Pennsylvania's CAP costs as if it adopted Ohio's 10% maximum energy burden based on the following levels: 10% for electric heating accounts, 4% for electric non-heating accounts, and 6% for gas heating accounts.

This model is based on the data collected from the utilities for this report from 2012 to 2016. The components used included the 2012 to 2016 calculated energy burdens by FPIG level for each utility, the 2012 to 2016 average annual CAP bill amounts, the 2012 to 2016 average annual CAP customer income, and the 2012 to 2016 average annual number of CAP accounts billed.

Staff did not incorporate any national energy prices[90] or usage forecasts into the model, as that data would be outdated by the time this report is released. Staff has,

[90] **Source:** U.S. Energy Information Administration (EIA)

however, included a summary table and links to the most recent NGDC and EDC forecasts, published in their respective reports on the PUC website.[91]

Additionally, staff's energy burden model does not take into consideration: (1) any possible reductions in CAP costs if some CAP customers are required to pay more at the selected energy burdens; (2) whether rate discount pricing might be better for some CAP customers; (3) CAP costs borne by PGW's non-residential ratepayers; (4) utility CAP credit limits; (5) system/administrative costs associated with adopting new energy burdens; and (6) factors specific to each utility.

The average energy burdens during the study period were calculated by dividing the average annual CAP bill by the average annual CAP income. New average annual CAP bills (by FPIG level), tied to a percent of income, were calculated using average annual CAP income.

Staff used Columbia Gas data to demonstrate this energy burden model. Dollar amounts and numbers may have been rounded to nearest whole amounts for the following example:

Step 1: Columbia Gas' Average Annual CAP Bill by FPIG Level

AVG 2012-2016		
50	100	150
$585.40	$694.00	$725.40

Step 2: Columbia Gas' Average Annual CAP Income by FPIG Level

AVG 2012-2016		
50	100	150
$5,582	$12,505	$22,354

Step 3: Columbia Gas' Calculated Average Energy Burden by FPIG Level

AVG 2012-2016		
50	100	150
10.49	5.55	3.24

https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2018&region=1-0&cases=ref2018&start=2016&end=2030&f=A&linechart=&map=ref2018-d121317a.4-3-AEO2018.1-0&ctype=linechart&sourcekey=0
[91] *See* Appendix 9.L.

Step 4: Columbia Gas' Estimated Average Annual CAP Bill at 6% by FPIG Level

AVG 2012-2016		
50	100	150
$334.93	$750.29	$1,341.26

The model compares the resulting estimated average CAP bill amounts to the corresponding actual annual average CAP bill amounts, by FPIG level, for 2012 to 2016. Some FPIG levels showed the difference as a negative number – which represents the amount of discount/CAP Credit/LIHEAP that would be needed to ***decrease*** the average annual CAP bill to the new estimated average CAP bill amount. Some FPIG levels show the difference as a positive number – which means that the average CAP bill is already below the selected energy burdens. This would not add directly to the CAP costs in this model, as CAP customers would have to pay the incremental increases in the bill. Staff set the estimated average CAP bills for those FPIG levels to $0 in the model and then calculated the change needed to obtain the average cost of change for each FPIG level.

Step 5: Columbia Gas' Change Needed to Reach 6% CAP Bill by FPIG Level

Columbia Gas	AVG 2012-2016		
	50	100	150
Estimated 6% CAP Bill	$334.93	$750.29	$1,341.26
Average CAP Bill	$585.40	$694.00	$725.40
Change to Reach 6%	-$250.47	$0.00	$0.00

Staff then multiplied the average estimated change in CAP billing by the average number of CAP accounts billed from 2012 to 2016 for each FPIG level.

Step 6: Columbia Gas' Incremental CAP Cost for Customers in < 50% FPIG

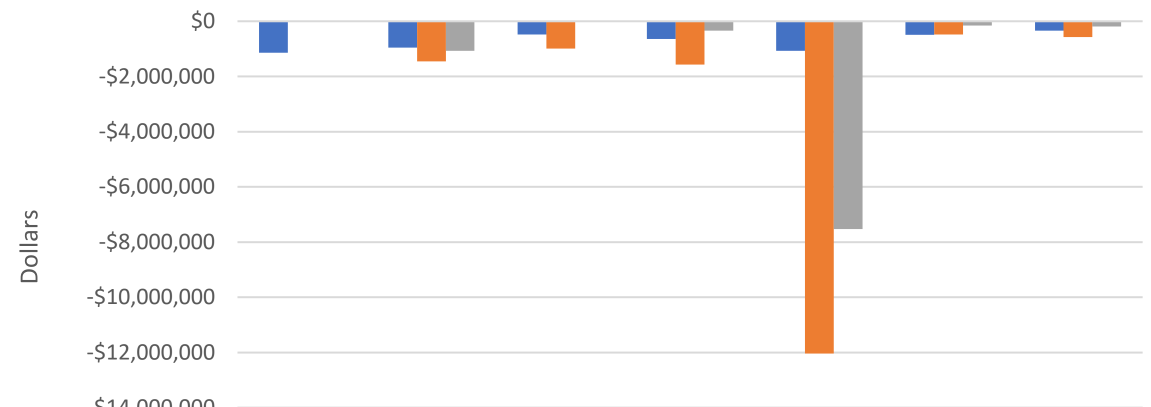
50		50		50
-$250.47	X	4558.15	=	-$1,141,680

The resulting dollar amounts represent the incremental cost that would be necessary to bring the average CAP bills in each FPIG level to the selected energy burdens. The dollar amounts are presented in the graphs below by individual utility and are expressed as negative numbers because they represent the additional discount (*i.e.*, CAP credits). The customers in the FPIG levels that were currently under the selected energy burdens are represented with $0 and may see an increase in average CAP bills.

The cost projections presented in the following graphs do not take into account any administrative or programming costs that the utilities would incur to transition the CAP customers to new energy burdens. In addition, these estimated costs do not consider any limits placed on CAP credits by individual utilities. The model does not consider the possibility of a reduction in CAP credits resulting from increased payments from those

CAP customers who currently have less than a 10% energy burden. Further, this model does not consider rate discount pricing. The estimates in this model are not meant to be inclusive of all costs or factors but are provided to give an approximation of costs and are based on the data reported by the utilities for this study.

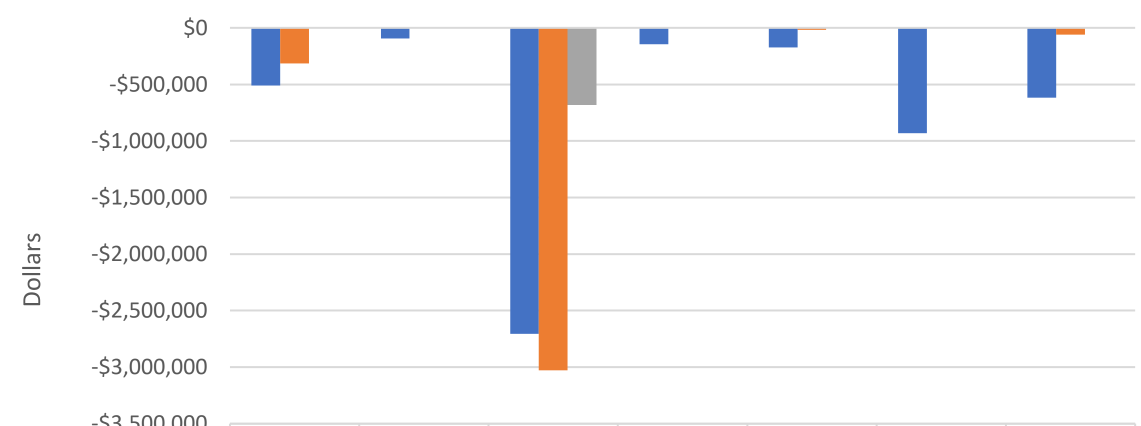
Table 10-7
NGDC CAP Heating – Discount Needed To Reach 6% Energy Burden



	Columbia	PECO Gas	Peoples	EQT	PGW	UGI Gas	UGI PNG
Poverty Level 0-50%	-$1,141,671	-$949,472	-$482,898	-$644,602	-$1,070,907	-$495,780	-$340,481
Poverty Level 51-100%	$0	-$1,455,171	-$988,893	-$1,571,350	-$12,030,42	-$473,414	-$576,603
Poverty Level 101-150%	$0	-$1,071,488	$0	-$338,627	-$7,526,891	-$156,751	-$191,032

Columbia Gas would only incur costs in this model for customers at the 0 to 50% FPIG level. Peoples Gas would incur costs from the 0 to 50% and 51 to 100% FPIG levels but not from the 101 to 150% FPIG level. PGW would incur the costliest transition, particularly in the 51 to 100% FPIG level. *See* Table 10-7.

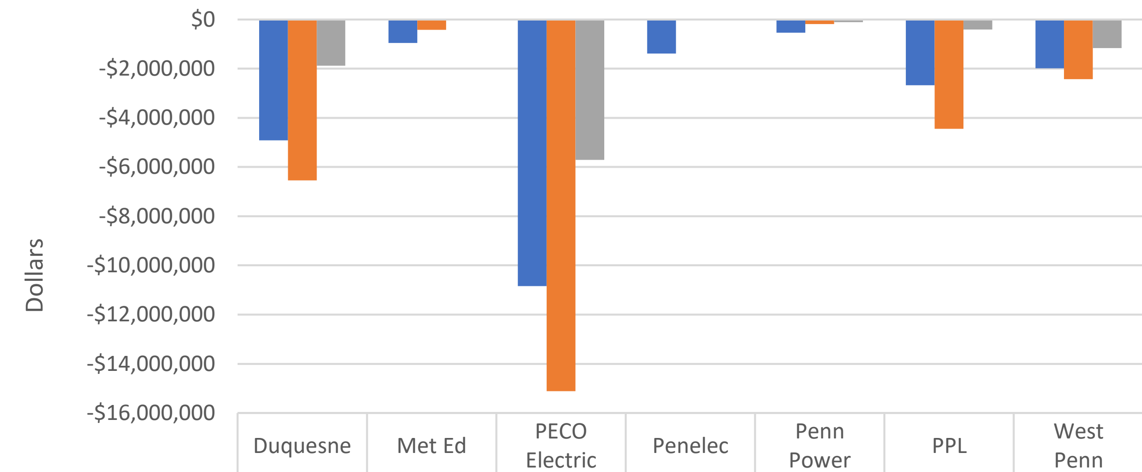
Table 10-8
EDC CAP Electric Heating – Additional Discount Needed for 10% Energy Burden



	Duquesne	Met Ed	PECO Electric	Penelec	Penn Power	PPL	West Penn
Poverty Level 0-50%	-$508,936	-$94,059	-$2,704,923	-$145,120	-$173,337	-$931,182	-$617,331
Poverty Level 51-100%	-$314,354	$0	-$3,027,842	$0	-$17,530	$0	-$60,351
Poverty Level 101-150%	$0	$0	-$680,776	$0	$0	$0	$0

All EDCs would incur costs at the 0 to 50% FPIG level to bring all of the CAP electric heating customers to a 10% energy burden. PECO Electric and PPL would incur the largest overall costs to align all heating customers to a 10% energy burden. However, all the EDCs except for PECO Electric would have no incremental change of costs in the 101 to 150% FPIG level. *See* Table 10-8.

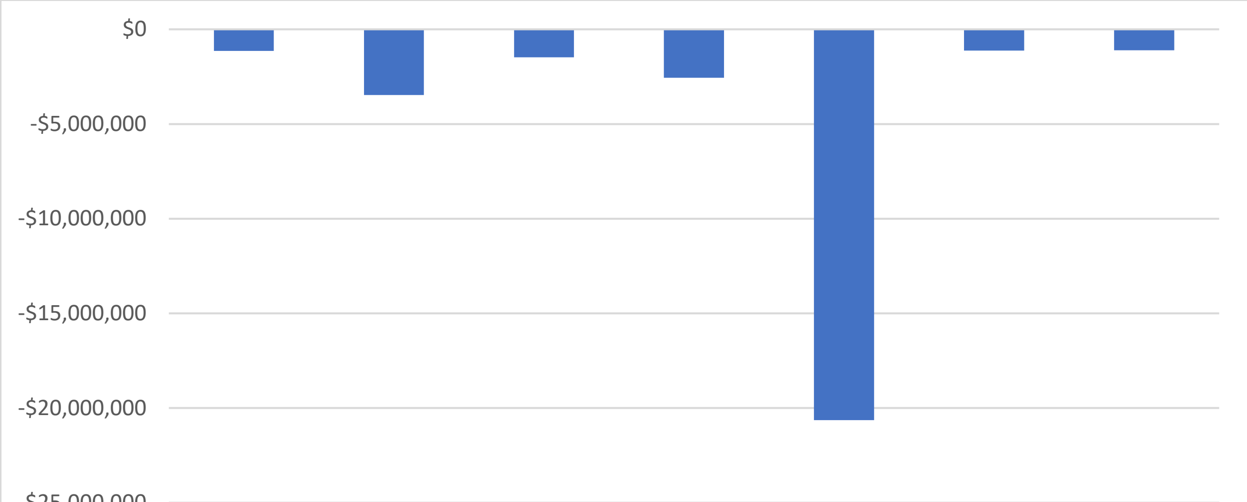
Table 10-9
EDC CAP Electric Non-Heat – Discount Needed To Reach 4% Energy Burden



	Duquesne	Met Ed	PECO Electric	Penelec	Penn Power	PPL	West Penn
Poverty Level 0-50%	-$4,912,741	-$952,977	-$10,837,68	-$1,381,508	-$542,033	-$2,676,214	-$1,979,613
Poverty Level 51-100%	-$6,543,038	-$414,068	-$15,107,48	$0	-$187,418	-$4,442,829	-$2,430,374
Poverty Level 101-150%	-$1,872,303	$0	-$5,708,105	$0	-$108,075	-$402,887	-$1,158,215

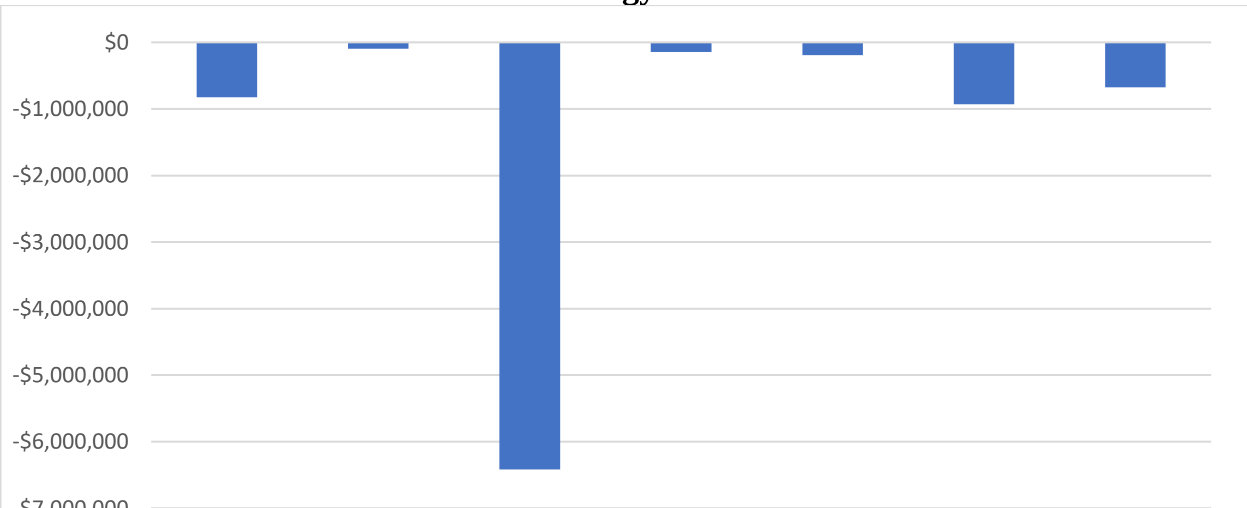
The CAP electric non-heating customers make up the costliest of the account types to transition to a lower energy burden. Currently, the majority of EDC non-heating CAP customers have energy burdens that would exceed 4%. Penelec would have the fewest CAP customers to transition and would only incur increased costs from the 0 to 50% FPIG level. *See* Table 10-9.

Table 10-10
Estimated Total Cost to Change All FPIG Levels of CAP Gas Heating Customers to Energy Burdens of 6%



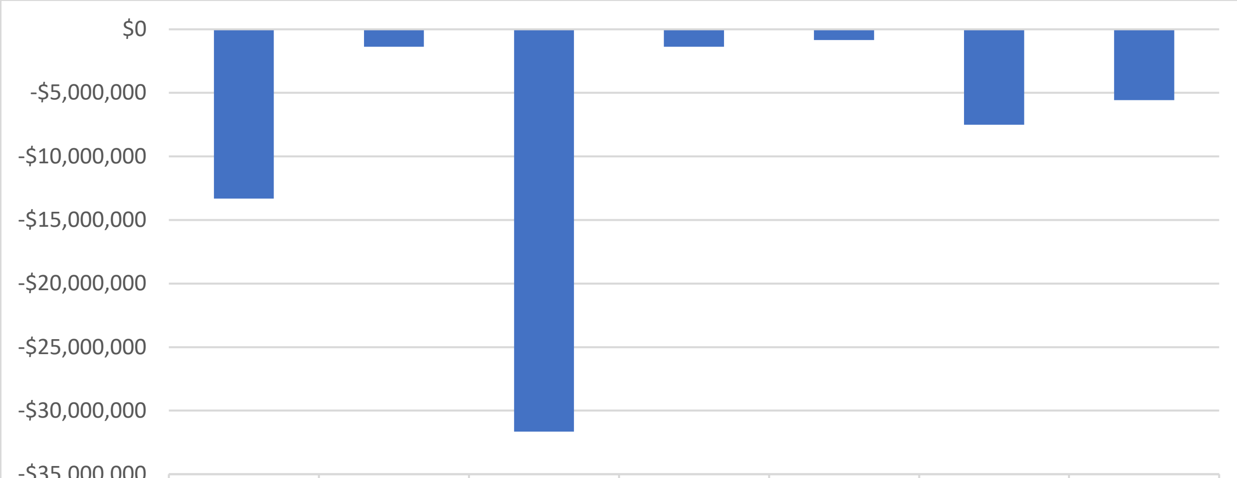
	Columbia	PECO Gas	Peoples	EQT	PGW	UGI Gas	UGI PNG
Amount	-$1,141,671	-$3,476,132	-$1,471,791	-$2,554,578	-$20,628,225	-$1,125,945	-$1,108,115

Table 10-11
Estimated Total Cost to Change All FPIG Levels of CAP Electric Heating Customers to Energy Burdens of 10%



	Duquesne	Met Ed	PECO Electric	Penelec	Penn Power	PPL	West Penn
Amount	-$823,290	-$94,059	-$6,413,541	-$145,120	-$190,867	-$931,182	-$677,682

Table 10-12
Estimated Total Cost to Change All FPIG Levels of CAP Electric Non-Heating Customers to Energy Burdens of 4%



	Duquesne	Met Ed	PECO Electric	Penelec	Penn Power	PPL	West Penn
Amount	-$13,328,083	-$1,367,045	-$31,653,275	-$1,381,508	-$837,526	-$7,521,930	-$5,568,203

The total costs for each utility within the respective CAP segment are illustrated in the previous tables presented in Tables 10-10 to 10-12.

Most NGDCs would see CAP cost increases of approximately $1 million. PGW's CAP budget, however, would increase by approximately $21 million. The EDCs would have more overall costs because of the need to transition both heating and non-heating CAP customers from current energy burdens to new lower energy burdens. *See* Table 10-10

Most EDCs would see CAP cost increases of less than $9 million. Met-Ed, Penn Power, and Penelec CAP costs would increase between $1 to 2 million. PECO Electric would experience a $38 million increase to its CAP costs. *See* Table 10-11 and 10-12.

The total cost to change all CAP customers in each segment represented in Tables 10-10 to 10-12 are summarized in Table 10-13 below.

Table 10-13
Incremental Cost to Change Current CAP Customers in Each Segment with Energy Burdens Higher than 10%, 6%, 4%, to the Targeted Energy Burdens Levels

CAP Customer Segment	Segment Cost	Incremental Additional Cost per Non-CAP Residential Customer	2012-2016	
			Average Number Residential Customers	Average CAP Enrollment
EDC Heating Segment (10%)	$9,275,741	$2.00	4,938,754	293,023
EDC Non-Heating Segment (4%)	$61,657,570	$13.27		
EDC Total		$15.27		
Gas Heating Segment (6%)	$31,506,457	$13.08	2,574,806	165,392
Total for EDC and NGDC Segments (10%, 4%, 6%)	$102,439,768		7,513,560	458,415
Weighted Average of Annual Cost Impact to Each EDC and NGDC Residential Non-CAP Customer		$14.52		

The incremental cost to non-CAP residential customers is calculated by first subtracting the average CAP enrollment from the average number of residential customers to get the non-CAP customer number. Then, the segment cost is divided by the non-CAP residential customer number to produce an incremental cost for each segment. The weighted cost represents the incremental cost across all EDC and NGDC non-CAP residential customers.

The additional CAP discounts, based on the 2012 to 2016 data used in the staff model, would have resulted in a weighted average annual increase of $14.52 to non-CAP residential ratepayer energy bills for the utilities in this study based on average customer counts from 2012 through 2016.[92]

Observations

Depending on the utility, NGDC non-CAP residential customers have paid between $10 and $145 annually to cover CAP costs over the study period. This does not factor in how much PGW commercial and industrial customers paid to cover CAP costs.

Depending on the utility, EDC non-CAP residential customers have paid between $15 and nearly $80 annually to cover CAP costs over the study period.

Despite an industry drop in CAP expenditures from 2012-2016, NDGC and EDC CAP costs are projected to increase annually through 2021.

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[92] The results of this model are not projections of future CAP costs at a maximum energy burden of 10%. To use this model to forecast future CAP costs at various energy burden maximums would require additional data from the utilities.

The overall average costs per non-CAP residential customer are also anticipated to increase through 2021, varying by CAP enrollments levels. EDC customers will experience the biggest increase, with average annual CAP costs recovered from non-CAP residential customers increasing by approximately $20 from 2017 to 2021.

Based on average CAP bill and income levels, the total amount of additional discounts (*i.e.*, CAP credits) needed to establish maximum energy burdens of 6% for gas heating, 4% for electric non-heating, and 10% for electric heating would be approximately $102 million. This amount breaks down to approximately $32 million for gas heating, $62 million for electric non-heating, and $9 million for electric heating. This additional CAP cost would increase gas and electric bills for non-CAP residential ratepayers by approximately $15 as a statewide average for customers of the larger energy utilities.

The energy burden model, developed by staff, used in this study does not take into consideration: (1) any possible reductions in CAP costs if some CAP customers are required to pay more at the selected energy burdens; (2) whether rate discount pricing might be better for some CAP customers; (3) CAP costs borne by PGW's non-residential ratepayers; (4) utility CAP credit limits; (5) system/administrative costs associated with adopting new energy burdens; and (6) factors specific to each utility.

XI. Conclusion

The Commission initiated a study of energy affordability for low-income customers in Pennsylvania in its Order at Docket No. M-2017-2587711 entered on May 5, 2017. This staff report, notice of which will be published in the *Pennsylvania Bulletin* with provisions for comment and reply comment periods as necessary, will be published to the Commission's website. This report is a staff work product and is not binding on the Commission. Nor is this staff report indicative of how the Commission may decide to act on universal service matters in this or other dockets. 52 Pa. Code § 1.96. The legal, policy, and procedural issues regarding energy burdens remain under Commission review and may be factored into a subsequent order at this or other dockets.

This study serves as a starting point for the Commission's review of energy burdens.[93] It provides insight into the effectiveness of CAPs in serving Pennsylvania's low-income population. Although this study does not identify an "affordable" energy burden level for customers enrolled in customer assistance programs, it attempts to measure whether the various CAP payment designs met universal service goals such as reducing debt, improving customer payment habits, reducing defaults and terminations, and reducing the number of customers in debt who are not on payment agreements.

Staff identified inconsistencies and limitations in the reported data that impacted the analysis. Reasons for data variations included policy and procedure changes implemented by the utilities during the five-year time frame, specific enhancements to their systems, changes to their low-income programs, and mergers/acquisitions. Staff also found many utilities interpreted, tracked, and reported information differently.

The report notes a wide disparity in the average percent of household income spent on natural gas and electric services by non-CAP residential and CAP customers. Non-CAP residential accounts had an average energy burden of 4% for gas heating and electric non-heating or 4% for electric heating. In comparison, CAP customers with gas heating and electric non-heating had a combined average energy burden of 12% to 14%,[94] and CAP customers with electric heat have an average energy burden of 8 to 10%.

Many CAP customers with incomes in the 0% to 50% FPIG level were billed, on average, at energy burdens higher than the maximum ranges in the CAP Policy Statement. This pattern was not as apparent for CAP customers at the higher FPIG levels.

[93] In regard to energy burdens for all low-income customers, the utilities that were queried for this study were unable to identify or provide income information on low-income households that did not participate in their CAPs or other universal service programs.
[94] The average energy burden was 7 to 8% for NGDC CAP heating customers and 5 to 6% for EDC non-heating CAP customers.

Despite the LIHEAP impacts on energy burdens for CAP customers across all FPIG levels and energy types, average CAP households at 0 to 50% FPIG level had average energy burdens that exceeded the CAP Policy Statement guidelines.

Utilities with CAP enrollment restrictions beyond income-qualifications reported higher PPA balances. EDCs reported *fewer* CAP heating customers at the 101 to 150% FPIG level paid their bills in comparison to the percentage of bills paid by customers at the 51 to 100% FPIG level.

There was little consistency in the way the utilities report, track, and respond to CAP defaults. Further, utilities varied in how they tracked and reported CAP terminations.

The number of CLI customers in debt and not on a payment agreement generally decreased across utilities during this study period, which suggests that CLI customers were enrolling in CAPs or payment agreements and were thus less vulnerable to service termination.

Despite an industry drop in CAP expenditures from 2012-2016, NDGC and EDC CAP costs are projected to increase annually through 2021. The overall average costs per non-CAP residential customer are also anticipated to increase through 2021, varying by CAP enrollments levels. EDC customers will experience the biggest increase, with average annual CAP costs recovered from non-CAP residential customers increasing by approximately $20 from 2017 to 2021.

Historically, non-CAP residential customers have paid on average between approximately $10/year and $145/year to cover CAP costs over the study period. CAP costs borne by PGW non-residential customers have not been factored in.

Pennsylvania's maximum energy burdens in the CAP Policy Statement are higher than maximum energy burdens used by neighboring states. Ohio – a state with similar climate, energy use, and demographics – has a maximum energy burden of 10% for its payment assistance program. Based on a model developed by staff, adopting a 10% maximum energy burden[95] across all FPIG levels in Pennsylvania would increase CAP discounts (*i.e.*, the costs borne by non-CAP residential customers) by approximately $102 million per year. This staff forecast, however, does not factor in all the impacts associated with an energy burden change (*e.g.*, costs of implementing a system change, whether rate discount pricing might be better for some CAP customers, etc.). Further, the staff forecast does not consider the possibility of a reduction in CAP credits resulting from increased payments from those CAP customers who currently have less than a 10% energy burden.

Staff further notes that, in addition to changes implemented during the study time frame, utilities have also implemented changes in their CAPs and other universal service

[95] Specifically, 10% for electric heating, 6% for gas heating, and 4% for electric non-heating.

programs since 2016. Such changes are on-going and may have an impact on the observations drawn by this study. Inspection of future data may substantiate trends as well as identify the aspects of CAPs that appear to work well or that produce better customer outcomes. Collection of valid data that can be compared across income levels, within industry groups, and between industry groups would increase the reliability of projections and better evaluate the success of CAPs.

The appendices that follow provide more details on the data, third-party articles, staff models, and demographics referenced in this staff report.

XII. Appendices

Table of Appendices

Appendix 1 – NGDC and EDC Demographic Profiles

Appendix 1.A: NGDC Service Territory Demographic Profiles

This Appendix provides a demographic profile of each EDC and NGDC service territory. In many cases, the jurisdictional boundary of a utility's service territory does not match municipal and county boundaries. The demographic data is not based on utility service area boundaries

Staff worked with Pennsylvania Spatial Data Access (PASDA) to create a census-based profile for each utility, based on a service area Geographic Information System (GIS) layer provided to the Commission by the utilities. PASDA utilized the GIS service area layers along with data from the Environmental Systems Research Institute (Esri) and the American Community Survey (ACS). The demographic data provided for each utility is data from the latest ACS survey (2012-2016) unless otherwise noted. The ACS demographic data is presented by households and/or population.[96]

Each service area profile is specific to the utility, although staff recognizes that the utility service areas overlap and, therefore, some demographic data will be counted in multiple service areas. This section also includes data about median and *per capita* incomes.[97]

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[96] As defined by ACS, a household is composed of one or more people who occupy a housing unit. See https://www.census.gov/programs-surveys/acs/technical-documentation/code-lists.html. Population is defined as the whole number of inhabitants of a particular town, area, or country.
[97] "*Per capita* income" is defined as the average income earned by each person in a given area. Example, two income earners in the same household would be counted separately when measuring *per capita* income.

Appendix 1.A.1: **Columbia Service Territory Demographic Profile**

Columbia	**Households 2012-2016 ACS**		**Combined # in Household**	**Population 2012-2016 ACS**			**Household Income Range - Esri**		
64.20%	**Family**	**# in Household**		**Income to Poverty Ratio**		**%**	**2018 Estimated Income Data**		**%**
297,900	31.0%	2		<0.5	122,979	5.3%	<$15,000	98,960	10.0%
141,398	14.7%	3		0.50-0.99	146,419	6.3%	$15,000-$24,999	99,195	10.1%
113,212	11.8%	4		1.00-1.24	85,423	3.7%	$25,000-$34,999	94,579	9.6%
43,564	4.5%	5		1.25-1.49	88,530	3.8%	$35,000-$49,999	129,768	13.2%
13,827	1.4%	6		1.50-1.84	131,701	5.7%	$50,000-$74,999	186,287	18.9%
6,464	0.7%	7		1.85-1.99**	58,502	2.5%	$75,000-$99,999	128,863	13.1%
35.80%	**Non-Family**			2.00+	1,674,040	72.5%	$100,000-$149,999	144,832	14.7%
285,067	29.7%	1	29.7%		**2,307,594**		$150,000-$199,999	54,475	5.5%
47,804	5.0%	2	36.0%				$200,000 or greater	48,942	5.0%
7,037	0.7%	3	15.5%	**Household Fuel Type**	**2011-2015 ACS**	**%**		**985,901**	
3,191	0.3%	4	12.1%	Utility Gas	619,353	64.5%	**Median Income**	$57,222	
800	0.1%	5	4.6%	Bottled/Tank/LP Gas	32,160	3.3%	**Average Income**	$78,414	
144	0.0%	6	1.5%	Electricity	174,950	18.2%	**Per Capita Income**	$32,380	
152	0.0%	7	0.7%	Fuel Oil/Kerosene	95,151	9.9%	**Columbia Service Area 2012-2016 ACS**		
960,561				Coal	5,762	0.6%	**Households**	**Population Age:**	**%**
Columbia Service Area - 2012-2016 ACS				Wood	24,013	2.5%	260,904	With < 18	**37.3%**
Households	**Poverty (100% FPIG)**			Solar	189	0.0%	699,655	W/No < 18	62.7%
109,903	11.4%	Below Poverty Level		Other	6,191	0.6%	294,787	With Age 65+	**44.3%**
850,656	88.6%	At/Above Poverty		No Fuel Used	2,791	0.3%	665,772	W/No Age 65+	55.7%
960,559					**960,560**		**960,559**		

Appendix 1.A.2: **NFG Service Territory Demographic Profile**

NFG	**Households 2012-2016 ACS**		**Combined # in Household**	**Population 2012-2016 ACS**			**Household Income Range - Esri**		
62.50%	**Family**	**# in Household**		**Income to Poverty Ratio**		**%**	**2018 Estimated Income Data**		**%**
501,413	30.9%	2		<0.5	224,686	5.9%	<$15,000	194,181	11.8%
229,798	14.2%	3		0.50-0.99	279,535	7.4%	$15,000-$24,999	185,379	11.2%
177,621	11.0%	4		1.00-1.24	154,805	4.1%	$25,000-$34,999	170,317	10.3%
69,664	4.3%	5		1.25-1.49	162,221	4.3%	$35,000-$49,999	227,295	13.8%
22,867	1.4%	6		1.50-1.84	240,025	6.3%	$50,000-$74,999	307,008	18.6%
11,519	0.7%	7		1.85-1.99**	100,664	2.7%	$75,000-$99,999	204,399	12.4%
37.50%	**Non-Family**			2.00+	2,636,607	69.4%	$100,000-$149,999	213,949	13.0%
505,705	31.2%	1	31.2%		**3,798,543**		$150,000-$199,999	75,661	4.6%
83,070	5.1%	2	36.1%				$200,000 or greater	70,353	4.3%
11,593	0.7%	3	14.9%	**Household Fuel Type**	**2011-2015 ACS**	**%**		**1,648,542**	
5,142	0.3%	4	11.3%	Utility Gas	1,085,439	67.0%	**Median Income**	$52,662	
1,332	0.1%	5	4.4%	Bottled/Tank/LP Gas	44,815	2.8%	**Average Income**	$72,608	
245	0.0%	6	1.4%	Electricity	240,348	14.8%	**Per Capita Income**	$30,649	
175	0.0%	7	0.7%	Fuel Oil/Kerosene	163,326	10.1%	**NFG Service Area 2012-2016 ACS**		
1,620,145				Coal	16,933	1.0%	**Households**	**Population Age:**	**%**
NFG Service Area - 2012-2016 ACS				Wood	51,423	3.2%	421,154	With < 18	**35.1%**
Households	**Poverty (100% FPIG)**			Solar	235	0.0%	1,198,991	W/No < 18	64.9%
212,600	13.12%	Below Poverty Level		Other	13,043	0.8%	505,617	With Age 65+	**45.4%**
1,407,546	86.88%	At/Above Poverty		No Fuel Used	4,582	0.3%	1,114,529	W/No Age 65+	54.6%
1,620,146					**1,620,144**		**1,620,146**		

Appendix 1.A.3: **Peoples Service Territory Demographic Profile**

Peoples	**Households 2012-2016 ACS**		**Combined # in Household**	**Population 2012-2016 ACS**			**Household Income Range - Esri**		
61.90%	**Family**	**# in Household**		**Income to Poverty Ratio**		**%**	**2018 Estimated Income Data**		**%**
282,341	30.6%	2		<0.5	118,930	5.5%	<$15,000	106,088	11.3%
131,207	14.2%	3		0.50-0.99	141,784	6.6%	$15,000-$24,999	99,777	10.6%
101,053	10.9%	4		1.00-1.24	78,484	3.7%	$25,000-$34,999	91,634	9.8%
39,202	4.2%	5		1.25-1.49	83,273	3.9%	$35,000-$49,999	121,631	12.9%
12,297	1.3%	6		1.50-1.84	121,762	5.7%	$50,000-$74,999	169,983	18.1%
5,405	0.6%	7		1.85-1.99**	52,308	2.4%	$75,000-$99,999	117,131	12.5%
38.10%	**Non-Family**			2.00+	1,546,825	72.2%	$100,000-$149,999	131,274	14.0%
294,208	31.9%	1	31.9%		**2,143,366**		$150,000-$199,999	51,807	5.5%
47,721	5.2%	2	35.8%				$200,000 or greater	50,231	5.3%
6,436	0.7%	3	14.9%	**Household Fuel Type**	**2011-2015 ACS**	**%**		**939,556**	
2,445	0.3%	4	11.2%	Utility Gas	669,291	72.5%	**Median Income**	$55,534	
516	0.1%	5	4.3%	Bottled/Tank/LP Gas	16,958	1.8%	**Average Income**	$78,189	
159	0.0%	6	1.3%	Electricity	130,845	14.2%	**Per Capita Income**	$33,384	
93	0.0%	7	0.6%	Fuel Oil/Kerosene	76,684	8.3%	**Peoples Service Area 2012-2016 ACS**		
923,084				Coal	6,046	0.7%	**Households**	**Population Age:**	**%**
Peoples Service Area - 2012-2016 ACS				Wood	15,162	1.6%	235,713	With < 18	**34.3%**
Households	**Poverty (100% FPIG)**			Solar	91	0.0%	687,370	W/No < 18	65.7%
115,250	12.49%	Below Poverty Level		Other	5,455	0.6%	289,898	With Age 65+	**45.8%**
807,832	87.51%	At/Above Poverty		No Fuel Used	2,552	0.3%	633,185	W/No Age 65+	54.2%
923,082					**923,084**		**923,083**		

Appendix 1.A.4: **Peoples Equitable Service Territory Demographic Profile**

EQT	**Households 2012-2016 ACS**		**Combined # in Household**	**Population 2012-2016 ACS**			**Household Income Range - Esri**		
60.00%	**Family**	**# in Household**		**Income to Poverty Ratio**		**%**	**2018 Estimated Income Data**		**%**
191,872	29.2%	2		<0.5	84,109	5.6%	<$15,000	76,358	11.4%
92,921	14.1%	3		0.50-0.99	100,023	6.6%	$15,000-$24,999	69,354	10.3%
71,876	10.9%	4		1.00-1.24	52,672	3.5%	$25,000-$34,999	63,283	9.4%
26,640	4.0%	5		1.25-1.49	56,022	3.7%	$35,000-$49,999	84,300	12.5%
8,310	1.3%	6		1.50-1.84	81,143	5.4%	$50,000-$74,999	119,670	17.8%
3,579	0.5%	7		1.85-1.99**	35,603	2.4%	$75,000-$99,999	83,337	12.4%
40.00%	**Non-Family**			2.00+	1,103,565	72.9%	$100,000-$149,999	95,691	14.2%
219,049	33.3%	1	33.3%		**1,513,137**		$150,000-$199,999	40,222	6.0%
36,751	5.6%	2	34.7%				$200,000 or greater	40,515	6.0%
4,750	0.7%	3	14.8%	**Household Fuel Type**	**2011-2015 ACS**	**%**		**672,730**	
1,772	0.3%	4	11.2%	Utility Gas	530,197	80.6%	**Median Income**	$56,881	
396	0.1%	5	4.1%	Bottled/Tank/LP Gas	8,606	1.3%	**Average Income**	$81,139	
150	0.0%	6	1.3%	Electricity	86,007	13.1%	**Per Capita Income**	$35,192	
63	0.0%	7	0.6%	Fuel Oil/Kerosene	21,314	3.2%	**EQT Service Area 2012-2016 ACS**		
658,130				Coal	771	0.1%	**Households**	**Population Age:**	**%**
EQT Service Area - 2012-2016 ACS				Wood	5,895	0.9%	169,447	With < 18	**34.7%**
Households	**Poverty (100% FPIG)**			Solar	31	0.0%	488,684	W/No < 18	65.3%
81,511	12.39%	Below Poverty Level		Other	3,418	0.5%	196,039	With Age 65+	**42.4%**
576,620	87.61%	At/Above Poverty		No Fuel Used	1,893	0.3%	462,093	W/No Age 65+	57.6%
658,131					**658,132**		**658,132**		

Appendix 1.A.5: **PGW Service Territory Demographic Profile**

PGW	**Households 2012-2016 ACS**		**Combined # in Household**	**Population 2012-2016 ACS**			**Household Income Range - Esri**		
53.30%	**Family**	**# in Household**		**Income to Poverty Ratio**		**%**	**2018 Estimated Income Data**		**%**
127,582	21.9%	2		<0.5	183,208	12.1%	<$15,000	120,095	19.3%
80,726	13.9%	3		0.50-0.99	209,148	13.8%	$15,000-$24,999	78,242	12.6%
56,658	9.7%	4		1.00-1.24	89,098	5.9%	$25,000-$34,999	69,545	11.2%
27,168	4.7%	5		1.25-1.49	85,794	5.7%	$35,000-$49,999	83,827	13.5%
11,453	2.0%	6		1.50-1.84	111,039	7.3%	$50,000-$74,999	100,542	16.2%
7,142	1.2%	7		1.85-1.99**	45,712	3.0%	$75,000-$99,999	61,623	9.9%
46.70%	**Non-Family**			2.00+	793,070	52.3%	$100,000-$149,999	63,232	10.2%
225,587	38.7%	1	38.7%		**1,517,069**		$150,000-$199,999	23,317	3.8%
36,661	6.3%	2	28.2%				$200,000 or greater	21,142	3.4%
6,264	1.1%	3	14.9%	**Household Fuel Type**	**2011-2015 ACS**	**%**		**621,565**	
2,189	0.4%	4	10.1%	Utility Gas	441,669	75.8%	**Median Income**	$41,506	
744	0.1%	5	4.8%	Bottled/Tank/LP Gas	5,794	1.0%	**Average Income**	$62,170	
262	0.0%	6	2.0%	Electricity	101,885	17.5%	**Per Capita Income**	$24,833	
158	0.0%	7	1.3%	Fuel Oil/Kerosene	27,472	4.7%	**PGW Service Area 2012-2016 ACS**		
582,595				Coal	332	0.1%	**Households**	**Population Age:**	**%**
PGW Service Area - 2012-2016 ACS				Wood	758	0.1%	157,858	With < 18	**37.2%**
Households	**Poverty (100% FPIG)**			Solar	100	0.0%	424,736	W/No < 18	62.8%
139,782	23.99%	Below Poverty Level		Other	1,446	0.2%	144,664	With Age 65+	**33.0%**
442,812	76.01%	At/Above Poverty		No Fuel Used	3,138	0.5%	437,930	W/No Age 65+	67.0%
582,594					**582,594**		**582,594**		

Appendix 1.A.6: **UGI Gas Service Territory Demographic Profile**

UGI Gas	**Households 2012-2016 ACS**		**Combined # in Household**	**Population 2012-2016 ACS**			**Household Income Range - Esri**		
67.50%	**Family**	**# in Household**		**Income to Poverty Ratio**		**%**	**2018 Estimated Income Data**		**%**
263,089	30.2%	2		<0.5	115,384	5.2%	<$15,000	77,251	8.5%
135,314	15.5%	3		0.50-0.99	144,445	6.5%	$15,000-$24,999	76,829	8.5%
111,164	12.8%	4		1.00-1.24	85,763	3.9%	$25,000-$34,999	80,520	8.9%
48,630	5.6%	5		1.25-1.49	93,233	4.2%	$35,000-$49,999	115,440	12.8%
18,435	2.1%	6		1.50-1.84	134,524	6.0%	$50,000-$74,999	175,964	19.5%
11,194	1.3%	7		1.85-1.99**	55,268	2.5%	$75,000-$99,999	127,049	14.1%
32.50%	**Non-Family**			2.00+	1,595,288	71.7%	$100,000-$149,999	147,363	16.3%
232,255	26.7%	1	26.7%		**2,223,905**		$150,000-$199,999	56,770	6.3%
42,948	4.9%	2	35.2%				$200,000 or greater	46,543	5.2%
5,080	0.6%	3	16.1%	**Household Fuel Type**	**2011-2015 ACS**	**%**		**903,729**	
1,895	0.2%	4	13.0%	Utility Gas	303,201	34.8%	**Median Income**	$62,021	
369	0.0%	5	5.6%	Bottled/Tank/LP Gas	38,580	4.4%	**Average Income**	$82,471	
133	0.0%	6	2.1%	Electricity	280,280	32.2%	**Per Capita Income**	$32,143	
113	0.0%	7	1.3%	Fuel Oil/Kerosene	210,903	24.2%	**UGI Service Area 2012-2016 ACS**		
870,620				Coal	10,358	1.2%	**Households**	**Population Age:**	**%**
UGI Service Area - 2012-2016 ACS				Wood	17,935	2.1%	270,495	With < 18	**45.1%**
Households	**Poverty (100% FPIG)**			Solar	410	0.0%	600,124	W/No < 18	54.9%
92,287	10.60%	Below Poverty Level		Other	6,111	0.7%	255,037	With Age 65+	**41.4%**
778,332	89.40%	At/Above Poverty		No Fuel Used	2,842	0.3%	615,582	W/No Age 65+	58.6%
870,619					**870,620**		**870,619**		

Appendix 1.A.7: **UGI PNG Service Territory Demographic Profile**

UGI PNG	**Households 2012-2016 ACS**		**Population 2012-2016 ACS**	**Household Income Range - Esri**

62.20%	Family	# in Household	Combined # in Household	Income to Poverty Ratio		%	2018 Estimated Income Data		%
86,322	29.8%	2		<0.5	47,570	6.9%	<$15,000	38,108	12.8%
41,576	14.4%	3		0.50-0.99	55,949	8.1%	$15,000-$24,999	35,859	12.1%
32,685	11.3%	4		1.00-1.24	30,928	4.5%	$25,000-$34,999	32,977	11.1%
12,530	4.3%	5		1.25-1.49	33,386	4.8%	$35,000-$49,999	42,347	14.2%
4,515	1.6%	6		1.50-1.84	48,458	7.0%	$50,000-$74,999	55,024	18.5%
2,348	0.8%	7		1.85-1.99**	20,259	2.9%	$75,000-$99,999	36,137	12.2%
37.80%	**Non-Family**			2.00+	452,768	65.7%	$100,000-$149,999	35,800	12.0%
92,507	32.0%	1	32.0%		**689,318**		$150,000-$199,999	10,867	3.7%
13,972	4.8%	2	34.7%				$200,000 or greater	10,089	3.4%
1,831	0.6%	3	15.0%	**Household Fuel Type**	**2011-2015 ACS**	**%**		**297,208**	
652	0.2%	4	11.5%	Utility Gas	145,950	50.4%	**Median Income**	$49,673	
206	0.1%	5	4.4%	Bottled/Tank/LP Gas	12,997	4.5%	**Average Income**	$67,154	
123	0.0%	6	1.6%	Electricity	64,503	22.3%	**Per Capita Income**	$27,753	
112	0.0%	7	0.9%	Fuel Oil/Kerosene	48,144	16.6%	**UGI PNG Service Area 2012-2016 ACS**		
289,380				Coal	7,117	2.5%	**Households**	**Population Age:**	**%**
UGI PNG Service Area - 2012-2016 ACS				Wood	8,083	2.8%	76,697	With < 18	**45.1%**
Households	**Poverty (100% FPIG)**			Solar	125	0.0%	212,682	W/No < 18	54.9%
41,731	14.42%	Below Poverty Level		Other	1,645	0.6%	94,502	With Age 65+	**41.4%**
247,647	85.58%	At/Above Poverty		No Fuel Used	815	0.3%	194,877	W/No Age 65+	58.6%
289,378					**289,379**		**289,379**		

Appendix 1.B: EDC Service Territory Demographic Profiles

Appendix 1.B.1: **Duquesne Service Territory Demographic Profile**

Duquesne	**Households 2012-2016 ACS**		**Combined # in Household**	**Population 2012-2016 ACS**			**Household Income Range - Esri**		
55.80%	**Family**	**# in Household**		**Income to Poverty Ratio**		**%**	**2018 Estimated Income Data**		**%**
130,220	27.5%	2		<0.5	68,666	6.5%	<$15,000	62,010	12.9%
63,804	13.5%	3		0.50-0.99	79,258	7.5%	$15,000-$24,999	53,857	11.2%
44,829	9.5%	4		1.00-1.24	43,392	4.1%	$25,000-$34,999	48,790	10.1%
17,122	3.6%	5		1.25-1.49	42,228	4.0%	$35,000-$49,999	63,058	13.1%
5,315	1.1%	6		1.50-1.84	61,396	5.8%	$50,000-$74,999	85,800	17.8%
2,644	0.6%	7		1.85-1.99**	26,686	2.5%	$75,000-$99,999	58,403	12.1%
44.20%	**Non-Family**			2.00+	730,750	69.4%	$100,000-$149,999	62,756	13.0%
172,945	36.6%	1	36.6%		**1,052,376**		$150,000-$199,999	23,719	4.9%
29,793	6.3%	2	33.8%				$200,000 or greater	24,143	5.0%
4,186	0.9%	3	14.4%	**Household Fuel Type**	**2011-2015 ACS**	**%**		**482,536**	
1,366	0.3%	4	9.8%	Utility Gas	390,142	**82.5%**	**Median Income**	$52,773	
394	0.1%	5	3.7%	Bottled/Tank/LP Gas	5,673	1.2%	**Average Income**	$75,024	
128	0.0%	6	1.2%	Electricity	60,902	**12.9%**	**Per Capita Income**	$33,673	
59	0.0%	7	0.6%	Fuel Oil/Kerosene	9,870	2.1%	**Duquesne Service Area 2012-2016 ACS**		
472,806				Coal	316	0.1%	**Households**	**Population Age:**	**%**
Duquesne Service Area - 2012-2016 ACS				Wood	2,010	0.4%	112,377	With < 18	**31.2%**
Households	**Poverty (100% FPIG)**			Solar	36	0.0%	360,429	W/No < 18	68.8%
66,319	**14.03%**	Below Poverty Level		Other	2,203	0.5%	138,890	With Age 65+	**41.6%**
406,486	**85.97%**	At/Above Poverty		No Fuel Used	1,652	0.3%	333,915	W/No Age 65+	58.4%
472,805					**472,804**		**472,805**		

Appendix 1.B.2: **Met-Ed Service Territory Demographic Profile**

Met-Ed	**Households 2012-2016 ACS**		**Combined # in Household**	**Population 2012-2016 ACS**			**Household Income Range - Esri**		
69.70%	**Family**	**# in Household**		**Income to Poverty Ratio**		**%**	**2018 Estimated Income Data**		**%**
157,779	31.3%	2		<0.5	65,671	5.0%	<$15,000	41,454	8.1%
82,714	16.4%	3		0.50-0.99	84,021	6.4%	$15,000-$24,999	44,425	8.6%
65,906	13.1%	4		1.00-1.24	50,976	3.9%	$25,000-$34,999	46,330	9.0%
28,192	5.6%	5		1.25-1.49	50,168	3.8%	$35,000-$49,999	65,555	12.8%
11,112	2.2%	6		1.50-1.84	76,218	5.8%	$50,000-$74,999	105,259	20.5%
5,978	1.2%	7		1.85-1.99**	34,515	2.6%	$75,000-$99,999	75,728	14.7%
30.30%	**Non-Family**			2.00+	950,693	72.4%	$100,000-$149,999	87,931	17.1%
124,202	24.6%	1	24.6%		**1,312,262**		$150,000-$199,999	23,238	4.5%
24,249	4.8%	2	36.1%				$200,000 or greater	24,143	4.7%
2,727	0.5%	3	16.9%	**Household Fuel Type**	**2011-2015 ACS**	**%**		**514,063**	
1,255	0.2%	4	13.3%	Utility Gas	186,045	**36.9%**	**Median Income**	$62,473	
314	0.1%	5	5.6%	Bottled/Tank/LP Gas	36,307	7.2%	**Average Income**	$80,923	
167	0.0%	6	2.2%	Electricity	119,815	**23.7%**	**Per Capita Income**	$30,956	
74	0.0%	7	1.2%	Fuel Oil/Kerosene	130,035	25.8%	**Met-Ed Service Area 2012-2016 ACS**		
504,670				Coal	6,126	1.2%	**Households**	**Population Age:**	**%**
Duquesne Service Area - 2012-2016 ACS				Wood	19,526	3.9%	157,458	With < 18	**45.3%**
Households	**Poverty (100% FPIG)**			Solar	236	0.0%	347,211	W/No < 18	54.7%
52,556	10.41%	Below Poverty Level		Other	4,889	1.0%	150,558	With Age 65+	**42.5%**
452,113	89.59%	At/Above Poverty		No Fuel Used	1,689	0.3%	354,110	W/No Age 65+	57.5%
504,669					**504,668**		**504,668**		

Appendix 1.B.3: **PECO Electric/Gas Service Territory Demographic Profile**

PECO	Households 2012-2016 ACS		Combined # in Household	Population 2012-2016 ACS			Household Income Range - Esri		
62.80%	**Family**	**# in Household**		**Income to Poverty Ratio**		**%**	**2018 Estimated Income Data**		**%**
380,161	26.2%	2		<0.5	262,641	6.9%	<$15,000	172,224	11.4%
220,307	15.2%	3		0.50-0.99	302,734	8.0%	$15,000-$24,999	131,420	8.7%
183,519	12.7%	4		1.00-1.24	146,755	3.9%	$25,000-$34,999	126,181	8.3%
81,357	5.6%	5		1.25-1.49	148,933	3.9%	$35,000-$49,999	170,172	11.2%
28,398	2.0%	6		1.50-1.84	203,076	5.3%	$50,000-$74,999	239,114	15.8%
16,724	1.2%	7		1.85-1.99	87,309	2.3%	$75,000-$99,999	178,274	11.8%
37.20%	**Non-Family**			2.00+	2,648,613	69.7%	$100,000-$149,999	240,367	15.9%
449,457	31.0%	1	31.0%		**3,800,061**		$150,000-$199,999	122,604	8.1%
73,919	5.1%	2	31.3%				$200,000 or greater	136,010	9.0%
10,826	0.7%	3	15.9%	**Household Fuel Type**	**2011-2015 ACS**	**%**		**1,516,366**	
4,087	0.3%	4	12.9%	Utility Gas	854,361	58.9%	**Median Income**	$64,465	
1,236	0.1%	5	5.7%	Bottled/Tank/LP Gas	44,545	3.1%	**Average Income**	$94,559	
357	0.0%	6	2.0%	Electricity	313,847	21.6%	**Per Capita Income**	$36,515	
279	0.0%	7	1.2%	Fuel Oil/Kerosene	214,214	14.8%	**PECO Service Area 2012-2016 ACS**		
1,450,628				Coal	2,038	0.1%	**Households**	**Population Age:**	**%**
PECO Service Area - 2012-2016 ACS				Wood	8,461	0.6%	437,333	With < 18	**43.2%**
Households	**Poverty (100% FPIG)**			Solar	428	0.0%	1,013,294	W/No < 18	56.8%
205,429	14.16%	Below Poverty Level		Other	6,514	0.4%	399,725	With Age 65+	**38.0%**
1,245,198	85.84%	At/Above Poverty		No Fuel Used	6,218	0.4%	1,050,901	W/No Age 65+	62.0%
1,450,627					**1,450,626**		**1,450,626**		

Appendix 1.B.4: **Penelec Service Territory Demographic Profile**

Penelec	**Households 2012-2016 ACS**		**Combined # in Household**	**Population 2012-2016 ACS**			**Household Income Range - Esri**		
65.30%	**Family**	**# in Household**		**Income to Poverty Ratio**		**%**	**2018 Estimated Income Data**		**%**
189,949	32.6%	2		<0.5	85,594	6.1%	<$15,000	74,921	12.7%
82,882	14.2%	3		0.50-0.99	124,857	8.9%	$15,000-$24,999	74,694	12.7%
64,392	11.0%	4		1.00-1.24	70,731	5.0%	$25,000-$34,999	68,316	11.6%
27,632	4.7%	5		1.25-1.49	75,459	5.4%	$35,000-$49,999	88,825	15.1%
9,627	1.7%	6		1.50-1.84	103,382	7.4%	$50,000-$74,999	115,741	19.7%
6,171	1.1%	7		1.85-1.99**	44,388	3.2%	$75,000-$99,999	70,989	12.1%
34.70%	**Non-Family**			2.00+	896,218	64.0%	$100,000-$149,999	64,699	11.0%
169,244	29.0%	1	29.0%		**1,400,629**		$150,000-$199,999	16,742	2.8%
27,439	4.7%	2	37.3%				$200,000 or greater	13,867	2.4%
3,589	0.6%	3	14.8%	**Household Fuel Type**	**2011-2015 ACS**	**%**		**588,794**	
1,707	0.3%	4	11.3%	Utility Gas	278,187	47.7%	**Median Income**	$47,283	
402	0.1%	5	4.8%	Bottled/Tank/LP Gas	31,432	5.4%	**Average Income**	$62,173	
41	0.0%	6	1.7%	Electricity	77,576	13.3%	**Per Capita Income**	$25,492	
60	0.0%	7	1.1%	Fuel Oil/Kerosene	123,687	21.2%	**Penelec Service Area 2012-2016 ACS**		
583,136				Coal	17,676	3.0%	**Households**	**Population Age:**	**%**
Penelec Service Area - 2012-2016 ACS				Wood	45,125	7.7%	157,357	With < 18	**37.0%**
Households	**Poverty (100% FPIG)**			Solar	183	0.0%	425,778	W/No < 18	63.0%
84,510	14.49%	Below Poverty Level		Other	7,307	1.3%	189,674	With Age 65+	**48.2%**
498,625	85.51%	At/Above Poverty		No Fuel Used	1,962	0.3%	393,461	W/No Age 65+	51.8%
583,135					**583,135**		**583,135**		

Appendix 1.B.5: **Penn Power Service Territory Demographic Profile**

Penn Power	**Households 2012-2016 ACS**		**Combined # in Household**	**Population 2012-2016 ACS**			**Household Income Range - Esri**		
67.90%	**Family**	**# in Household**		**Income to Poverty Ratio**		**%**	**2018 Estimated Income Data**		**%**
53,346	32.2%	2		<0.5	16,765	4.2%	<$15,000	14,792	8.8%
25,169	15.2%	3		0.50-0.99	22,868	5.7%	$15,000-$24,999	16,363	9.7%
21,766	13.1%	4		1.00-1.24	13,609	3.4%	$25,000-$34,999	16,056	9.5%
8,393	5.1%	5		1.25-1.49	14,548	3.6%	$35,000-$49,999	21,641	12.8%
2,508	1.5%	6		1.50-1.84	24,178	6.0%	$50,000-$74,999	30,391	18.0%
1,384	0.8%	7		1.85-1.99**	9,002	2.2%	$75,000-$99,999	21,059	12.5%
32.10%	**Non-Family**			2.00+	301,663	74.9%	$100,000-$149,999	25,209	15.0%
46,118	27.8%	1	27.8%		**402,633**		$150,000-$199,999	10,968	6.5%
6,408	3.9%	2	36.0%				$200,000 or greater	12,015	7.1%
557	0.3%	3	15.5%	**Household Fuel Type**	**2011-2015 ACS**	**%**		**168,494**	
185	0.1%	4	13.2%	Utility Gas	111,763	67.4%	**Median Income**	$60,283	
17	0.0%	5	5.1%	Bottled/Tank/LP Gas	3,826	2.3%	**Average Income**	$86,487	
7	0.0%	6	1.5%	Electricity	29,869	18.0%	**Per Capita Income**	$35,231	
5	0.0%	7	0.8%	Fuel Oil/Kerosene	13,707	8.3%	**Penn Power Service Area 2012-2016 ACS**		
165,864				Coal	468	0.3%	**Households**	**Population Age:**	**%**
Penn Power Service Area - 2012-2016 ACS				Wood	4,793	2.9%	48,123	With < 18	**40.9%**
Households	**Poverty (100% FPIG)**			Solar	17	0.0%	117,738	W/No < 18	59.1%
16,911	10.20%	Below Poverty Level		Other	1,107	0.7%	52,743	With Age 65+	**46.6%**
148,951	89.80%	At/Above Poverty		No Fuel Used	311	0.2%	113,119	W/No Age 65+	53.4%
165,862					**165,861**		**165,862**		

Appendix 1.B.6: **PPL Service Territory Demographic Profile**

PPL	**Households 2012-2016 ACS**		**Combined # in Household**	**Population 2012-2016 ACS**			**Household Income Range - Esri**		
66.20%	**Family**	**# in Household**		**Income to Poverty Ratio**		**%**	**2018 Estimated Income Data**		**%**
367,396	30.8%	2		<0.5	159,904	5.4%	<$15,000	119,336	9.7%
177,668	14.9%	3		0.50-0.99	203,496	6.8%	$15,000-$24,999	120,434	9.8%
145,656	12.2%	4		1.00-1.24	121,023	4.1%	$25,000-$34,999	119,585	9.7%
61,298	5.1%	5		1.25-1.49	135,725	4.6%	$35,000-$49,999	168,890	13.7%
22,724	1.9%	6		1.50-1.84	196,254	6.6%	$50,000-$74,999	241,492	19.6%
14,926	1.3%	7		1.85-1.99**	80,290	2.7%	$75,000-$99,999	166,732	13.5%
33.80%	**Non-Family**			2.00+	2,083,847	69.9%	$100,000-$149,999	180,535	14.6%
334,490	28.1%	1	28.1%		**2,980,539**		$150,000-$199,999	63,086	5.1%
58,059	4.9%	2	35.7%				$200,000 or greater	52,366	4.2%
6,597	0.6%	3	15.5%	**Household Fuel Type**	**2011-2015 ACS**	**%**		**1,232,456**	
2,614	0.2%	4	12.4%	Utility Gas	381,987	32.0%	**Median Income**	$56,876	
639	0.1%	5	5.2%	Bottled/Tank/LP Gas	61,365	5.1%	**Average Income**	$76,148	
151	0.0%	6	1.9%	Electricity	365,875	30.7%	**Per Capita Income**	$30,256	
230	0.0%	7	1.3%	Fuel Oil/Kerosene	295,170	24.8%	**PPL Service Area 2012-2016 ACS**		
1,192,449				Coal	34,414	2.9%	**Households**	**Population Age:**	**%**
PPL Service Area - 2012-2016 ACS				Wood	40,210	3.4%	347,645	With < 18	**41.2%**
Households	**Poverty (100% FPIG)**			Solar	620	0.1%	844,801	W/No < 18	58.8%
136,351	11.43%	Below Poverty Level		Other	9,044	0.8%	367,166	With Age 65+	**44.5%**
1,056,095	88.57%	At/Above Poverty		No Fuel Used	3,760	0.3%	825,280	W/No Age 65+	55.5%
1,192,446					**1,192,445**		**1,192,446**		

Appendix 1.B.7: **West Penn Service Territory Demographic Profile**

West Penn	**Households 2012-2016 ACS**		**Combined # in Household**	**Population 2012-2016 ACS**			**Household Income Range - Esri**		
65.20%	**Family**	**# in Household**		**Income to Poverty Ratio**		**%**	**2018 Estimated Income Data**		**%**
193,278	32.7%	2		<0.5	78,883	5.6%	<$15,000	64,792	10.7%
85,766	14.5%	3		0.50-0.99	92,617	6.5%	$15,000-$24,999	64,386	10.6%
68,845	11.6%	4		1.00-1.24	51,552	3.6%	$25,000-$34,999	59,747	9.9%
25,594	4.3%	5		1.25-1.49	56,807	4.0%	$35,000-$49,999	82,636	13.6%
8,726	1.5%	6		1.50-1.84	84,419	6.0%	$50,000-$74,999	115,379	19.0%
3,450	0.6%	7		1.85-1.99**	35,452	2.5%	$75,000-$99,999	78,147	12.9%
34.80%	**Non-Family**			2.00+	1,018,280	71.8%	$100,000-$149,999	85,125	14.1%
170,696	28.9%	1	28.9%		**1,418,010**		$150,000-$199,999	30,726	5.1%
27,325	4.6%	2	37.3%				$200,000 or greater	24,889	4.1%
4,387	0.7%	3	15.2%	**Household Fuel Type**	**2011-2015 ACS**	**%**		**605,827**	
2,328	0.4%	4	12.0%	Utility Gas	335,838	56.8%	**Median Income**	$54,946	
646	0.1%	5	4.4%	Bottled/Tank/LP Gas	17,561	3.0%	**Average Income**	$74,259	
107	0.0%	6	1.5%	Electricity	125,957	21.3%	**Per Capita Income**	$30,709	
91	0.0%	7	0.6%	Fuel Oil/Kerosene	78,979	13.4%	**West Penn Service Area 2012-2016 ACS**		
591,240				Coal	4,088	0.7%	**Households**	**Population Age:**	**%**
West Penn Service Area - 2012-2016 ACS				Wood	22,863	3.9%	156,215	With < 18	**35.9%**
Households	**Poverty (100% FPIG)**			Solar	86	0.0%	435,024	W/No < 18	64.1%
70,708	11.96%	Below Poverty Level		Other	4,308	0.7%	190,465	With Age 65+	**47.5%**
520,531	88.04%	At/Above Poverty		No Fuel Used	1,560	0.3%	400,775	W/No Age 65+	52.5%
591,239					**591,240**		**591,240**		

Appendix 2 –Energy Burdens for Gas and Electric Service

Appendix 2.A: Non-CAP Residential NGDC and EDC Average Energy Burdens

The average energy burdens of gas and electric non-CAP customers are shown as a percentage, to include heat type and FPIG levels for the period from 2012 through 2016.

Appendix 2.A.1: **NGDC Non-CAP Residential Heating Average Energy Burdens**

NGDC Non-CAP Residential Heating Accounts Average Energy Burdens (%)					
Total by Year	**2012**	**2013**	**2014**	**2015**	**2016**
	**	**	**	**	**
GAS Industry Average	1.86	2.07	2.29	2.06	1.75
Columbia	1.47	1.81	2.14	2.03	1.89
NFG	1.49	1.62	1.78	1.41	1.18
PECO Gas	3.58	3.73	3.85	3.71	3.37
Peoples	1.53	1.81	2.16	1.89	1.47
Peoples EQT	1.61	1.76	2.03	1.75	1.33
PGW	2.67	2.90	3.08	2.70	2.36
UGI Gas	1.18	1.30	1.42	1.26	0.99
UGI PNG	2.09	2.32	2.53	2.34	1.76

Appendix 2.A.2: **EDC Non-CAP Residential Average Energy Burdens**

EDC Non-CAP Residential Heating and Non-Heating Average Energy Burden (%)										
Total by Year	**2012**		**2013**		**2014**		**2015**		**2016**	
	Heat	**Non Heat**	**Heat**	**Non Heat**	**Heat**	**Non Heat**	**Heat**	**Non Heat**	**Heat**	**Non Heat**
	*	*	**	**	**	**	**	**	**	**
Electric Industry			3.02	2.02	3.23	2.06	3.33	2.24	3.21	2.27
Duquesne			2.17	1.43	2.17	1.47	2.60	1.78	2.42	1.83
Met-Ed			2.50	2.12	3.05	2.07	2.99	2.16	2.83	2.11
PECO			3.73	1.95	3.85	1.95	3.71	1.99	3.37	1.97
Penelec			2.70	2.29	3.35	2.35	3.35	2.46	3.31	2.5
Penn			2.34	1.8	3.12	1.9	3.32	2.15	3.57	2.28
PPL			2.42	2.42	2.55	2.55	2.91	2.91	2.92	2.92
West Penn			2.11	1.72	2.80	1.82	2.91	2.01	3.02	2.14

*No data available for the year.

**Median Annual Income for Residential cases is from the ESRI (Environmental Systems Research Institute) system and does not distinguish between heat and non-heat accounts and is an average from 2012-2016. Since the Number of Bills Issued and Billings are available for heating and non-heating accounts for all of the years, the total Median Annual Income is used as the base for calculating Energy Burden by heating status and year.

Appendix 2.B: CAP Industry Average NGDC and EDC Energy Burdens

The industry average energy burdens of gas and electric CAP customers are shown as a percentage, to include heating type and FPIG levels for the period from 2012 through 2016.

Appendix 2.B.1: **NGDC CAP Heating Average Energy Burdens**

NGDC CAP Heating Average Energy Burdens (%)					
Total by Year	**2012**	**2013**	**2014**	**2015**	**2016**
Gas Industry Average	7.93	7.89	7.57	7.00	6.93
Columbia	5.09	5.13	5.16	5.04	4.78
NFG	5.57	6.05	6.57	5.20	4.14
PECO Gas	12.37	12.30	12.31	11.20	9.36
Peoples	6.98	6.34	6.41	6.94	6.22
Peoples EQT	8.16	7.21	6.13	4.38	6.74
PGW	8.06	8.08	8.50	8.60	8.45
UGI Gas	7.02	6.81	6.07	5.99	5.04
UGI PNG	7.78	7.76	7.11	7.20	6.03

Appendix 2.B.2: **EDC CAP Heating and Non-Heating Average Energy Burdens**

EDC CAP Heating and Non-Heating Average Energy Burdens (%)										
Total by Year	**2012**		**2013**		**2014**		**2015**		**2016**	
	Heat	**Non Heat**	**Heat**	**Non Heat**	**Heat**	**Non Heat**	**Heat**	**Non Heat**	**Heat**	**Non Heat**
Electric Industry	8.38	5.39	8.18	5.18	9.02	5.5	9.75	5.89	8.87	6.04
Duquesne	11.15	7.52	11.12	6.95	7.29	4.79	14.48	7.27	12.68	9.06
Met-Ed	3.47	2.92	3.73	2.37	8.85	4.95	8.78	5.19	5.62	5.88
PECO	14.43	6.47	14.34	6.51	14.36	6.65	13.07	6.45	11.38	6.39
Penelec	3.88	3.02	3.86	2.40	7.62	3.92	7.30	4.03	8.04	3.75
Penn	11.98	6.65	9.62	5.29	8.84	6.73	8.56	4.14	9.57	4.03
PPL	6.70	6.52	6.44	6.23	6.74	6.46	6.81	6.54	7.18	6.90
West Penn	10.65	7.01	9.77	6.34	10.58	6.72	10.82	6.76	9.27	5.18

Appendix 2.C: Tables 3-3 to 3-5 NGDC CAP Energy Burdens

The average energy burdens of gas CAP heating customers are shown as a percentage by FPIG level for the period from 2012 through 2016.

Appendix 2.C.1: **NGDC CAP Energy Burdens for Heating Customers by FPIG Level**

2012 NGDC CAP Energy Burdens for Heating Customers by FPIG Level (%)			
FPIG Level	**50%**	**100%**	**150%**
Gas Industry Average	8.60	8.07	6.92
Columbia	10.42	5.54	3.27
PECO Gas	21.43	11.65	9.51
Peoples	8.03	7.29	5.64
Peoples EQT	9.45	9.63	8.75
PGW	5.82	8.64	10.38
UGI Gas	9.81	8.35	8.15
UGI PNG	11.43	8.55	8.35

Appendix 2.C.2: **NGDC CAP Energy Burdens by FPIG Levels**

2013 NGDC CAP Energy Burdens for Heating Customers by FPIG Levels (%)			
FPIG Level	**50%**	**100%**	**150%**
Gas Industry Average	8.55	7.90	6.90
Columbia	10.73	5.69	3.27
PECO Gas	20.76	11.72	9.46
Peoples	7.21	6.73	5.15
Peoples EQT	9.31	9.25	7.60
PGW	6.07	8.73	10.35
UGI Gas	9.33	7.77	7.69
UGI PNG	9.95	7.90	8.05

Appendix 2.C.3: **NGDC CAP Energy Burdens by FPIG Levels**

2014 NGDC CAP Energy Burdens for Heating Customers by FPIG Levels (%)			
FPIG Level	50%	100%	150%
Gas Industry Average	8.64	7.51	6.21
Columbia	10.55	5.70	3.35
PECO Gas	21.81	11.77	9.37
Peoples	7.27	6.75	5.26
Peoples EQT	8.01	7.33	6.54
PGW	6.60	9.02	10.52
UGI Gas	9.51	6.70	5.09
UGI PNG	9.99	7.98	5.81

Appendix 2.C.4: **NGDC CAP Energy Burdens by FPIG Levels**

2015 NGDC CAP Energy Burdens for Heating Customers by FPIG Levels (%)			
FPIG Level	50%	100%	150%
Gas Industry Average	8.26	6.98	5.74
Columbia	10.36	5.55	3.27
PECO Gas	19.95	10.68	8.64
Peoples	8.28	7.31	5.61
Peoples EQT	5.29	5.13	4.52
PGW	7.20	9.21	10.58
UGI Gas	9.17	6.54	4.82
UGI PNG	9.89	7.32	5.99

Appendix 2.C.5: **NGDC CAP Energy Burdens by FPIG Levels**

2016 NGDC CAP Energy Burdens for Heating Customers by FPIG Levels (%)			
FPIG Level	50%	100%	150%
Gas Industry Average	8.87	7.08	5.44
Columbia	10.37	5.27	3.06
PECO Gas	17.17	9.05	7.23
Peoples	8.18	6.62	4.76
Peoples EQT	8.63	7.58	5.70
PGW	7.82	9.22	10.48
UGI Gas	7.39	5.65	4.07
UGI PNG	7.50	6.43	5.10

Appendix 2.D: Tables 3-6 to 3-11 EDC CAP Energy Burdens

The average energy burdens of electric CAP heating and non-heating customers are shown as a percentage by FPIG level for the period from 2012 through 2016.

Appendix 2.D.1: **EDC CAP Energy Burdens by FPIG Level**

2012 EDC CAP Energy Burdens by FPIG Level (%)						
	Heat			Non Heat		
FPIG Level	50%	100%	150%	50%	100%	150%
Electric Industry Average	17.67	7.93	6.27	11.39	5.33	3.93
Duquesne	25.90	11.00	7.29	15.36	7.81	4.95
Met-Ed	4.80	3.42	3.25	5.16	2.75	2.41
PECO Electric	24.39	13.99	10.99	11.64	6.81	5.04
Penelec	10.62	3.35	3.37	8.76	2.86	2.18
Penn Power	41.75	11.01	7.97	22.38	6.28	4.14
PPL	13.96	7.07	4.26	13.57	6.75	4.20
West Penn	30.51	10.37	7.84	19.85	6.59	5.33

Appendix 2.D.2: **EDC CAP Energy Burdens by FPIG Level**

2013 EDC CAP Energy Burdens by FPIG Level (%)						
	Heat			Non Heat		
FPIG Level	50%	100%	150%	50%	100%	150%
Electric Industry Average	16.3	7.93	6.07	10.5	4.64	4.06
Duquesne	24.87	11.27	7.17	14.67	7.14	4.54
Met-Ed	5.48	3.85	3.19	4.14	2.28	1.88
PECO Electric	23.61	14.09	10.92	12.08	6.86	5.01
Penelec	9.13	3.52	3.17	5.81	2.18	1.82
Penn Power	31.29	8.94	6.36	16.20	3.13	5.46
PPL	13.36	6.80	4.10	12.70	6.49	4.02
West Penn	20.27	9.97	7.31	12.47	6.28	5.10

Appendix 2.D.3: **EDC CAP Energy Burdens by FPIG Level**

2014 EDC CAP Energy Burdens by FPIG Level (%)						
	Heat			Non Heat		
FPIG Level	50%	100%	150%	50%	100%	150%
Electric Industry Average	17.79	8.9	6.53	11.49	5.31	4.07
Duquesne	14.08	7.78	4.80	9.92	4.89	3.18
Met-Ed	11.92	9.06	7.68	9.34	4.75	3.68
PECO Electric	24.80	14.14	10.81	12.95	6.94	5.04
Penelec	17.61	6.73	6.51	10.04	3.48	2.89
Penn Power	23.15	7.58	7.22	9.95	3.37	2.84
PPL	14.06	7.11	4.29	13.18	6.75	4.16
West Penn	24.28	10.45	8.03	13.15	6.72	5.33

Appendix 2.D.4: **EDC CAP Energy Burdens by FPIG Level**

2015 EDC CAP Energy Burdens by FPIG Level (%)						
	Heat			Non Heat		
FPIG Level	50%	100%	150%	50%	100%	150%
Electric Industry Average	21.61	9.38	6.98	13.05	5.6	4.41
Duquesne	40.36	13.41	9.99	16.52	6.88	5.68
Met-Ed	12.27	8.80	7.58	9.97	4.90	3.84
PECO Electric	22.71	12.84	9.98	13.11	6.86	4.76
Penelec	16.64	6.42	6.19	10.72	3.59	2.91
Penn Power	24.51	7.47	6.79	11.63	3.61	2.99
PPL	14.09	7.18	4.35	13.32	6.86	4.21
West Penn	28.33	10.12	8.02	14.65	6.53	5.26

Appendix 2.D.5: **EDC CAP Energy Burdens by FPIG Level**

2016 EDC CAP Energy Burdens by FPIG Level (%)						
	Heat			Non Heat		
FPIG Level	**50%**	**100%**	**150%**	**50%**	**100%**	**150%**
Electric Industry Average	20.37	8.47	6.25	14.23	5.72	4.37
Duquesne	36.00	11.91	8.53	22.41	8.47	6.67
Met-Ed	12.52	5.16	4.42	15.43	4.11	5.98
PECO Electric	20.13	11.38	8.47	11.50	7.12	4.72
Penelec	18.44	7.18	6.68	10.28	3.29	2.76
Penn Power	23.69	8.62	7.61	12.46	3.57	2.75
PPL	14.82	7.55	4.58	14.08	7.23	4.43
West Penn	27.23	8.24	7.16	17.19	4.74	3.54

Appendix 3 – Impact of LIHEAP Grants on Energy Burden Levels

Appendix 3.A: Tables 4-1 to 4-9 Impact of LIHEAP Grants on Energy Burdens for CAP Customers

The impact of LIHEAP on energy burdens is shown for gas and electric heating and non-heating LIHEAP recipients for all FPIG levels using the average dollar amount of LIHEAP grants applied and the average CAP bill. The utilities that did not provide all three of the data points (LIHEAP Recipient CAP Bill, LIHEAP Dollars and LIHEAP Recipient CAP Income) necessary for this analysis by heat type or poverty level are excluded. Some utilities provided estimates for some data points.

Appendix 3.A.1: **NGDC Energy Burden of CAP LIHEAP Recipients at 0-50% FPIG**

NGDC Energy Burden of CAP LIHEAP Recipients at 0-50% FPIG										
	Without LIHEAP Dollars Applied					With LIHEAP Dollars Applied				
	2012	2013	2014	2015	2016	2012	2013	2014	2015	2016
Columbia	15.54	17.79	19.88	17.66	13.95	9.77	14.43	16.08	13.79	7.82
Peoples	21.36	26.00	25.03	26.41	12.39	13.85	19.13	18.34	19.46	7.82
Peoples EQT	13.20	16.77	16.79	12.49	11.45	7.07	12.47	12.70	8.43	7.17
PGW	16.37	17.93	20.13	18.97	18.24	11.25	12.76	14.76	13.30	12.69

Appendix 3.A.2: **NGDC Energy Burden of CAP LIHEAP Recipients at 51-100% FPIG**

NGDC Energy Burden of CAP LIHEAP Recipients at 51-100% FPIG										
	Without LIHEAP Dollars Applied					With LIHEAP Dollars Applied				
	2012	2013	2014	2015	2016	2012	2013	2014	2015	2016
Columbia	7.73	8.72	9.67	8.72	6.87	5.32	7.48	8.24	7.25	4.45
Peoples	13.98	16.42	14.61	18.57	8.92	10.26	13.48	11.43	16.57	5.68
Peoples EQT	9.06	10.92	11.43	8.40	7.66	5.75	8.75	9.30	6.25	4.91
PGW	13.05	13.99	15.19	14.20	13.26	9.91	10.92	12.24	11.00	9.96

Appendix 3.A.3: **NGDC Energy Burden of CAP LIHEAP Recipients at 101-150% FPIG**

NGDC Energy Burden of CAP LIHEAP Recipients at 101-150% FPIG										
	Without LIHEAP Dollars Applied					With LIHEAP Dollars Applied				
	2012	2013	2014	2015	2016	2012	2013	2014	2015	2016
Columbia	4.68	5.22	5.66	5.33	4.19	3.36	4.58	4.89	4.56	2.85
Peoples	11.97	15.45	10.32	13.81	5.90	9.78	13.68	7.99	12.91	4.06
Peoples EQT	8.76	7.66	7.96	5.96	5.33	6.81	6.43	6.69	4.67	3.58
PGW	10.61	11.34	12.32	11.67	11.17	8.53	9.44	10.53	9.66	8.85

Appendix 3.A.4: **NGDC CAP LIHEAP Recipients at 0-50% FPIG**

NGDC CAP LIHEAP Recipients at 0-50% FPIG								
	Average CAP Bill				Average LIHEAP Dollars Applied			
	2013	2014	2015	2016	2013	2014	2015	2016
Columbia	$1,132.63	$1,273.17	$1,154.95	$876.05	$214.25	$242.62	$253.15	$385.43
Peoples	$1,264.90	$1,422.06	$1,111.98	$1,025.44	$323.66	$345.90	$362.16	$383.22
Peoples EQT	$1,596.00	$1,540.08	$1,618.72	$1,018.48	$422.25	$412.31	$425.61	$375.31
PGW	$1,634.64	$1,741.74	$1,548.10	$1,418.20	$471.12	$465.16	$462.78	$430.77

Appendix 3.A.5: **NGDC CAP LIHEAP Recipients – Average Annual CAP Income at 0-50% FPIG**

NGDC CAP LIHEAP Recipients – Average Annual CAP Income at 0-50% FPIG				
	2013	2014	2015	2016
Columbia	$6,370	$6,405	$6,539	$6,280
Peoples	$7,544	$8,471	$8,902	$8,955
Peoples EQT	$6,138	$6,152	$6,131	$8,219
PGW	$9,120	$8,652	$8,160	$7,776

Appendix 3.A.6: **NGDC CAP LIHEAP Recipients at 51-100% FPIG**

NGDC CAP LIHEAP Recipients at 51-100% FPIG								
	Average CAP Bill				Average LIHEAP Dollars Applied			
	2013	2014	2015	2016	2013	2014	2015	2016
Columbia	$1,119.30	$1,279.16	$1,154.26	$896.09	$159.21	$189.26	$195.34	$316.25
Peoples	$1,265.87	$1,390.92	$1,060.26	$981.24	$251.13	$259.34	$271.00	$351.70
Peoples EQT	$1,617.66	$1,565.75	$1,979.98	$1,009.70	$289.50	$340.64	$213.45	$367.37
PGW	$1,587.60	$1,697.41	$1,527.55	$1,398.60	$347.75	$328.54	$343.85	$347.88

Appendix 3.A.7: **NGDC CAP LIHEAP Recipients – Average Annual CAP Income at 51-100% FPIG**

NGDC CAP LIHEAP Recipients – Average Annual CAP Income at 51-100% FPIG				
	2013	2014	2015	2016
Columbia	$12,831	$13,229	$13,233	$13,046
Peoples	$11,595	$12,168	$12,622	$12,808
Peoples EQT	$9,854	$10,716	$10,664	$11,328
PGW	$11,352	$11,172	$10,764	$10,548

Appendix 3.A.8: **NGDC CAP LIHEAP Recipients at 101-150% FPIG**

NGDC CAP LIHEAP Recipients at 101-150% FPIG								
	Average CAP Bill				Average LIHEAP Dollars Applied			
	2013	2014	2015	2016	2013	2014	2015	2016
Columbia	$1,104.06	$1,222.55	$1,117.46	$883.47	$136.28	$166.96	$162.08	$282.96
Peoples	$1,303.82	$1,390.92	$1,051.64	$954.72	$209.01	$221.78	$227.28	$313.89
Peoples EQT	$2,158.02	$1,632.71	$2,220.11	$992.58	$247.98	$368.72	$145.31	$309.56
PGW	$1,724.31	$1,880.45	$1,738.53	$1,649.20	$288.36	$272.92	$298.92	$342.69

Appendix 3.A.9: **NGDC CAP LIHEAP Recipients – Average Annual CAP Income at 101-150% FPIG**

NGDC CAP LIHEAP Recipients – Average Annual CAP Income at 101-150% FPIG				
	2013	**2014**	**2015**	**2016**
Columbia	$21,134	$21,589	$20,943	$21,086
Peoples	$17,031	$17,471	$17,656	$17,909
Peoples EQT	$13,964	$15,822	$16,077	$16,819
PGW	$15,204	$15,264	$14,904	$14,760

Appendix 3.A.10: **EDC Non-Heating Energy Burden of CAP LIHEAP Recipients at 0-50% FPIG**

EDC Non-Heating Energy Burden of CAP LIHEAP Recipients at 0-50% FPIG								
	Without LIHEAP Dollars Applied				**With LIHEAP Dollars Applied**			
	2013	**2014**	**2015**	**2016**	**2013**	**2014**	**2015**	**2016**
Duquesne	33.21	33.21	29.83	37.18	22.64	22.64	21.17	24.91
Met-Ed	9.44	16.78	16.59	16.98	3.96	11.78	11.59	12.32
PECO Electric	11.92	12.17	12.12	11.29	1.29	2.49	2.78	3.58
Penelec	10.10	22.49	20.22	19.84	4.14	15.30	13.91	14.14
Penn Power	7.92	19.02	20.17	20.21	2.88	12.74	13.71	13.78
PPL	19.78	19.91	19.24	16.74	15.03	15.46	14.13	12.27
West Penn	10.12	23.80	22.08	23.20	3.04	16.49	15.93	17.76

Appendix 3.A.11: **EDC Non-Heating Energy Burden of CAP LIHEAP Recipients at 51-100% FPIG**

EDC Non-Heating Energy Burden of CAP LIHEAP Recipients at 51-100% FPIG								
	Without LIHEAP Dollars Applied				**With LIHEAP Dollars Applied**			
	2013	**2014**	**2015**	**2016**	**2013**	**2014**	**2015**	**2016**
Duquesne	12.83	12.83	12.35	13.33	9.33	9.33	9.48	9.45
Met-Ed	5.73	8.31	8.10	8.35	3.44	6.09	5.70	6.11
PECO Electric	6.66	6.57	6.50	6.69	3.34	3.61	3.61	3.77
Penelec	6.69	13.10	10.69	10.37	3.87	10.90	8.41	8.14
Penn Power	6.37	10.81	10.61	11.63	3.93	8.73	8.36	8.97
PPL	11.33	11.26	12.68	10.06	8.85	8.94	9.97	7.73
West Penn	4.81	10.33	10.59	10.80	2.27	8.09	8.39	8.75

Appendix 3.A.12: **EDC Non-Heating Energy Burden of CAP LIHEAP Recipients at 101-150% FPIG**

EDC Energy Burden of Non-Heating CAP LIHEAP Recipients at 101-150% FPIG								
	Without LIHEAP Dollars Applied				With LIHEAP Dollars Applied			
	2013	2014	2015	2016	2013	2014	2015	2016
Duquesne	7.60	7.60	7.18	8.05	5.44	5.44	5.62	5.57
Met-Ed	4.05	5.90	5.42	5.69	2.57	4.43	4.02	4.31
PECO Electric	3.86	3.85	3.70	3.73	2.36	2.57	2.39	2.26
Penelec	4.52	8.19	6.67	6.36	3.11	6.93	5.48	5.14
Penn Power	4.17	7.46	6.91	7.26	2.97	6.23	5.72	5.88
PPL	6.64	8.02	8.76	6.83	5.04	6.54	7.09	5.38
West Penn	3.14	7.07	6.48	6.64	1.51	5.65	5.26	5.33

Appendix 3.A.13: **EDC CAP Non-Heating LIHEAP Recipients 0-50% FPIG**

EDC CAP Non-Heating LIHEAP Recipients 0-50% FPIG								
	Average CAP Bill				Average LIHEAP Dollars Applied			
	2013	2014	2015	2016	2013	2014	2015	2016
Duquesne**	$1,181.	$1,181.46	$1,148.98	$1,213.94	$375.87	$375.87	$333.50	$400.55
Met-Ed	$825.1	$1,155.83	$1,139.06	$1,185.08	$478.84	$344.77	$343.20	$325.05
PECO Electric*	$644.1	$644.14	$644.14	$644.14	$574.30	$512.27	$496.46	$439.97
Penelec	$839.7	$1,495.78	$1,393.98	$1,362.06	$495.19	$477.84	$435.39	$391.23
Penn Power	$708.9	$1,378.63	$1,310.04	$1,427.53	$451.36	$455.29	$419.71	$454.63
PPL	$1,479.	$1,540.08	$1,450.80	$1,260.00	$355.42	$344.38	$385.41	$336.36
West Penn	$637.8	$1,324.60	$1,498.97	$1,695.72	$446.17	$406.93	$417.64	$397.55

*PECO Average CAP Bill for 2012-2015 is estimated.

**Duquesne Average CAP Bill for 2012-2013 is estimated.

Appendix 3.A.14: **EDC Non-Heating LIHEAP Recipients – Average Annual CAP Income at 0-50% FPIG**

EDC Non-Heating LIHEAP Recipients – Average Annual CAP Income at 0-50% FPIG				
	2013	2014	2015	2016
Duquesne*	$3,558	$3,558	$3,852	$3,265
Met-Ed	$8,739	$6,888	$6,865	$6,979
PECO Electric	$5,406	$5,291	$5,316	$5,704
Penelec	$8,317	$6,652	$6,893	$6,864
Penn Power	$8,951	$7,250	$6,495	$7,062
PPL	$7,480	$7,736	$7,541	$7,528
West Penn	$6,301	$5,565	$6,790	$7,308

*Duquesne Average CAP Income for 2012-2013 is estimated.

Appendix 3.A.15: **EDC Non-Heating LIHEAP Recipients at 51-100% FPIG**

EDC Non-Heating LIHEAP Recipients at 51-100% FPIG								
	Average CAP Bill				Average LIHEAP Dollars Applied			
	2013	2014	2015	2016	2013	2014	2015	2016
Duquesne**	$1,115.70	$1,115.70	$1,099.20	$1,132.05	$303.83	$303.83	$255.24	$329.69
Met-Ed	$802.10	$1,184.95	$1,127.88	$1,191.84	$319.81	$317.32	$335.02	$320.00
PECO	$713.25	$713.25	$713.25	$713.25	$354.84	$321.17	$316.82	$311.79
Penelec	$838.74	$1,768.78	$1,434.86	$1,425.90	$353.50	$296.83	$305.93	$306.36
Penn Power	$851.84	$1,384.68	$1,379.76	$1,478.62	$325.82	$265.59	$292.87	$338.39
PPL	$1,628.40	$1,671.84	$1,798.80	$1,452.00	$355.38	$344.56	$385.37	$336.26
West Penn	$650.79	$1,438.90	$1,480.49	$1,499.30	$343.40	$311.63	$307.39	$283.82

*PECO Average CAP Bill for 2012-2015 is estimated.

**Duquesne Average CAP Bill for 2012-2013 is estimated.

Appendix 3.A.16: **EDC Non-Heating LIHEAP Recipients – Average Annual CAP Income at 51-100% FPIG**

EDC Non-Heating LIHEAP Recipients – Average Annual CAP Income at 51-100% FPIG				
	2013	2014	2015	2016
Duquesne*	$8,699	$8,699	$8,904	$8,494
Met-Ed	$14,010	$14,252	$13,921	$14,269
PECO Electric	$10,716	$10,854	$10,978	$10,656
Penelec	$12,539	$13,503	$13,427	$13,748
Penn Power	$13,379	$12,813	$13,000	$12,715
PPL	$14,378	$14,851	$14,182	$14,431
West Penn	$13,541	$13,934	$13,981	$13,885

*Duquesne Average CAP Income for 2012-2013 is estimated.

Appendix 3.A.17: **EDC Non-Heating LIHEAP Recipients at 101-150% FPIG**

EDC Non-Heating LIHEAP Recipients at 101-150% FPIG								
	Average CAP Bill				Average LIHEAP Dollars Applied			
	2013	2014	2015	2016	2013	2014	2015	2016
Duquesne**	$990.00	$990.00	$955.95	$1,023.90	$282.02	$282.02	$207.24	$315.07
Met-Ed	$835.77	$1,301.95	$1,218.23	$1,296.49	$306.11	$325.90	$314.50	$313.97
PECO Electric*	$819.96	$819.96	$819.96	$819.96	$318.68	$272.88	$290.81	$323.44
Penelec	$924.98	$1,675.31	$1,488.76	$1,419.60	$289.60	$257.81	$264.10	$271.73
Penn Power	$852.20	$1,502.40	$1,470.84	$1,461.20	$244.86	$247.79	$254.62	$278.29
PPL	$1,474.2	$1,867.32	$2,015.64	$1,576.08	$355.29	$344.57	$385.27	$336.15
West Penn	$708.57	$1,503.00	$1,526.91	$1,514.26	$367.30	$301.21	$286.46	$297.32

*PECO Average CAP Bill for 2012-2015 is estimated.

**Duquesne Average CAP Bill for 2012-2013 is estimated.

Appendix 3.A.18: **EDC Non-Heating LIHEAP Recipients – Average Annual CAP Income at 101-150% FPIG**

EDC Non-Heating LIHEAP Recipients – Average Annual CAP Income at 101-150% FPIG				
	2013	**2014**	**2015**	**2016**
Duquesne*	$13,021	$13,021	$13,319	$12,722
Met-Ed	$20,629	$22,054	$22,480	$22,773
PECO Electric	$21,238	$21,273	$22,167	$22,011
Penelec	$20,463	$20,457	$22,332	$22,319
Penn Power	$20,427	$20,139	$21,275	$20,132
PPL	$22,209	$23,281	$23,005	$23,061
West Penn	$22,557	$21,259	$23,581	$22,814

*Duquesne Average CAP Income for 2012-2013 is estimated.

Appendix 3.A.19: **EDC Heating Energy Burden of CAP LIHEAP Recipients at 0-50% FPIG**

EDC Energy Burden of Heating CAP LIHEAP Recipients at 0-50% FPIG								
	Without LIHEAP Dollars Applied				**With LIHEAP Dollars Applied**			
	2013	**2014**	**2015**	**2016**	**2013**	**2014**	**2015**	**2016**
Duquesne	51.40	51.40	52.59	46.43	35.44	35.44	36.64	30.47
Met-Ed	10.08	24.95	21.45	21.98	4.90	20.62	16.80	17.66
PECO Electric	19.02	19.70	18.93	19.27	6.70	8.66	8.55	10.22
Penelec	10.85	25.96	22.69	23.46	3.72	17.79	15.33	16.03
Penn Power	9.81	27.79	25.49	24.24	3.10	20.12	19.21	18.79
PPL	35.55	39.66	44.07	30.54	30.27	34.55	38.41	25.72
West Penn	12.41	40.51	23.92	24.59	3.05	27.71	17.09	18.66

Appendix 3.A.20: **EDC Heating Energy Burden of CAP LIHEAP Recipients at 51-100% FPIG**

EDC Energy Burden of Heating CAP LIHEAP Recipients at 51-100% FPIG								
	Without LIHEAP Dollars Applied				**With LIHEAP Dollars Applied**			
	2013	**2014**	**2015**	**2016**	**2013**	**2014**	**2015**	**2016**
Duquesne	14.35	14.35	15.31	13.46	10.68	10.68	11.96	9.58
Met-Ed	6.20	13.73	12.67	12.72	3.67	11.11	10.04	10.19
PECO Electric	10.19	9.90	9.60	9.22	7.11	7.13	6.59	6.27
Penelec	6.87	17.87	13.86	13.78	3.56	14.73	10.47	10.36
Penn Power	7.79	17.62	16.79	18.48	4.88	14.76	13.85	15.16
PPL	22.37	19.56	22.36	14.04	19.61	16.94	19.28	11.42
West Penn	5.96	15.74	14.35	14.93	3.19	13.23	11.48	12.08

Appendix 3.A.21: **EDC Heating Energy Burden of CAP LIHEAP Recipients at 101-150% FPIG**

EDC Energy Burden of Heating CAP LIHEAP Recipients at 101-150% FPIG								
	Without LIHEAP Dollars Applied				With LIHEAP Dollars Applied			
	2013	2014	2015	2016	2013	2014	2015	2016
Duquesne	8.39	8.39	8.91	7.93	6.20	6.20	7.14	5.54
Met-Ed	4.41	9.61	7.77	8.37	3.17	8.14	6.20	6.94
PECO Electric	7.59	7.48	7.07	6.61	6.13	6.25	5.58	4.95
Penelec	4.63	12.17	10.76	10.11	3.31	10.96	9.33	8.34
Penn Power	5.20	12.12	11.31	12.45	3.91	10.85	9.88	10.71
PPL	12.05	14.27	14.15	9.00	10.35	12.63	12.25	7.37
West Penn	3.90	10.49	9.45	9.97	2.56	9.20	8.20	8.41

Appendix 3.A.22: **EDC Heating LIHEAP Recipients at 0-50% FPIG**

EDC Heating LIHEAP Recipients at 0-50% FPIG								
	Average CAP Bill				Average LIHEAP Dollars Applied			
	2013	2014	2015	2016	2013	2014	2015	2016
Duquesne**	$1,559.0	$1,559.0	$1,547.7	$1,449.4	$484.13	$484.13	$469.48	$498.30
Met-Ed	$864.24	$1,732.2	$1,563.2	$1,627.7	$444.26	$300.76	$338.39	$319.87
PECO	$958.37	$958.37	$958.37	$958.37	$620.71	$536.93	$525.46	$450.02
Penelec	$813.82	$1,850.2	$1,685.9	$1,710.3	$534.59	$582.06	$546.76	$541.93
Penn Power	$791.10	$2,038.9	$1,960.7	$2,061.6	$541.34	$562.34	$483.55	$463.76
PPL	$2,394.0	$2,674.5	$3,001.3	$2,131.2	$355.25	$344.37	$385.22	$336.15
West Penn	$722.79	$1,944.8	$1,782.5	$1,913.3	$545.16	$614.49	$508.92	$461.69

*PECO Average CAP Bill for 2012-2015 is estimated.
**Duquesne Average CAP Bill for 2012-2013 is estimated.

Appendix 3.A.23: **EDC Heating LIHEAP Recipients – Average Annual CAP Income at 0-50% FPIG**

EDC Heating LIHEAP Recipients – Average Annual CAP Income at 0-50% FPIG				
	2013	2014	2015	2016
Duquesne*	$3,033	$3,033	$2,943	$3,122
Met-Ed	$8,570	$6,942	$7,289	$7,404
PECO Electric	$5,040	$4,866	$5,063	$4,973
Penelec	$7,504	$7,127	$7,429	$7,291
Penn Power	$8,061	$7,337	$7,691	$8,506
PPL	$6,735	$6,744	$6,811	$6,978
West Penn	$5,826	$4,801	$7,451	$7,781

*Duquesne Average CAP Income for 2012-2013 is estimated.

Appendix 3.A.24: **EDC Heating LIHEAP Recipients at 51-100% FPIG**

EDC Heating LIHEAP Recipients at 51-100% FPIG								
	Average CAP Bill				Average LIHEAP Dollars Applied			
	2013	2014	2015	2016	2013	2014	2015	2016
Duquesne**	$1,212.25	$1,212.25	$1,250.21	$1,174.29	$309.81	$309.81	$274.03	$338.61
Met-Ed	$746.07	$1,745.90	$1,585.44	$1,591.07	$304.42	$332.84	$329.84	$316.05
PECO Electric*	$1,033.90	$1,033.90	$1,033.90	$1,033.90	$312.38	$289.01	$324.00	$330.50
Penelec	$711.62	$1,919.97	$1,463.41	$1,461.04	$342.40	$337.32	$358.36	$362.91
Penn Power	$887.30	$2,091.90	$1,973.95	$2,119.39	$331.41	$339.10	$346.29	$381.23
PPL	$2,880.36	$2,574.72	$2,793.60	$1,801.20	$355.35	$344.54	$385.33	$336.22
West Penn	$729.63	$1,981.00	$1,751.70	$1,761.10	$339.48	$315.49	$350.21	$336.94

*PECO Average CAP Bill for 2012-2015 is estimated.

**Duquesne Average CAP Bill for 2012-2013 is estimated.

Appendix 3.A.25: **EDC Heating LIHEAP Recipients – Average Annual CAP Income at 51-100% FPIG**

EDC Heating LIHEAP Recipients – Average Annual CAP Income at 51-100% FPIG				
	2013	2014	2015	2016
Duquesne*	$8,446	$8,446	$8,165	$8,727
Met-Ed	$12,034	$12,714	$12,509	$12,510
PECO Electric	$10,147	$10,445	$10,775	$11,214
Penelec	$10,357	$10,744	$10,557	$10,603
Penn Power	$11,388	$11,873	$11,754	$11,466
PPL	$12,878	$13,164	$12,493	$12,831
West Penn	$12,245	$12,586	$12,208	$11,793

*Duquesne Average CAP Income for 2012-2013 is estimated.

Appendix 3.A.26: **EDC Heating LIHEAP Recipients at 101-150% FPIG**

EDC Heating LIHEAP Recipients at 101-150% FPIG								
	Average CAP Bill				Average LIHEAP Dollars Applied			
	2013	2014	2015	2016	2013	2014	2015	2016
Duquesne**	$1,023.75	$1,023.75	$1,017.90	$1,029.60	$267.12	$267.12	$201.95	$310.25
Met-Ed	$834.21	$2,046.46	$1,712.16	$1,832.74	$235.14	$313.59	$345.70	$314.13
PECO Electric*	$1,262.80	$1,262.80	$1,262.80	$1,262.80	$242.68	$207.74	$265.21	$317.96
Penelec	$801.45	$2,094.43	$1,915.16	$1,817.62	$228.23	$208.74	$254.70	$319.04
Penn Power	$962.00	$2,330.70	$2,196.80	$2,425.28	$239.51	$244.76	$277.35	$338.82
PPL	$2,517.12	$3,003.48	$2,868.00	$1,856.40	$355.39	$344.51	$385.37	$336.13
West Penn	$791.46	$2,039.50	$1,931.00	$1,980.44	$270.89	$250.66	$255.08	$308.36

*PECO Average CAP Bill for 2012-2015 is estimated.

**Duquesne Average CAP Bill for 2012-2013 is estimated.

Appendix 3.A.27: **EDC Heating LIHEAP Recipients – Average Annual CAP Income 101-150% FPIG**

EDC Heating LIHEAP Recipients – Average Annual CAP Income 101-150% FPIG				
	2013	**2014**	**2015**	**2016**
Duquesne*	$12,209	$12,209	$11,430	$12,987
Met-Ed	$18,904	$21,292	$22,024	$21,886
PECO Electric	$16,644	$16,878	$17,862	$19,090
Penelec	$17,305	$17,210	$17,804	$17,977
Penn Power	$18,500	$19,225	$19,429	$19,477
PPL	$20,896	$21,048	$20,263	$20,619
West Penn	$20,317	$19,440	$20,430	$19,872

*Duquesne Average CAP Income for 2012-2013 is estimated.

Appendix 4 – Pre-Program Arrearages and In-Program Arrears

Appendix 4.A: Tables 5-2 to 5-3 NGDCs – Pre-Program Arrearages (PPAs) and In-Program Arrears (IPAs)

The average dollar amount of PPA and IPA per NGDC CAP customer with a PPA or IPA balance for the period from 2012 through 2016.

Appendix 4.A.1: **Average PPAs of NGDC CAP Customers with PPA Balances**

Average PPAs of NGDC CAP Customers with PPA Balances					
	2012	**2013**	**2014**	**2015**	**2016**
Columbia	N/A	$98.82	$116.10	$129.75	$132.68
NFG	$494.67	$748.73	$482.39	$462.53	$402.23
PECO Gas	$643.44	$547.45	$558.27	$529.35	$460.25
Peoples	$739.63	$672.09	$708.84	$788.27	$790.31
Peoples EQT	$957.40	$836.29	$772.38	$720.76	$617.82
PGW	$1,311.98	$1,313.29	$1,341.56	$1,330.32	$1,259.90
UGI Gas	$442.05	$387.83	$422.16	$391.41	$341.31
UGI PNG	$510.36	$417.54	$455.35	$424.22	$382.21

Appendix 4.A.2: **Average IPAs of NGDC CAP Customer with IPAs Balances**

Average IPAs of NGDC CAP Customer with IPAs Balances					
	2012	**2013**	**2014**	**2015**	**2016**
Columbia	N/A	$36.34	$36.70	$34.52	$31.44
NFG	$135.01	$115.55	$97.84	$71.20	$64.05
PECO Gas	$735.19	$752.26	$817.09	$733.08	$695.76
Peoples	$530.05	$431.47	$489.81	$389.34	$173.39
Peoples EQT	$242.76	$223.62	$225.45	$227.99	$156.17
PGW	$258.49	$268.01	$262.17	$232.92	$209.43
UGI Gas	$144.28	$121.03	$119.53	$123.74	$103.65
UGI PNG	$162.34	$142.13	$134.91	$152.30	$124.42

Appendix 4.B: Tables 5-4 to 5-5 EDCs – PPAs and IPAs

The average dollar amounts of PPA and IPA per EDC CAP customer with a PPA or IPA balance for the period from 2012 through 2016.

Appendix 4.B.1: **Average PPAs of EDC CAP Customers with PPA Balances**

Average PPAs of EDC CAP Customers with PPA Balances (Electric Non-Heating and Electric Heating)					
	2012	**2013**	**2014**	**2015**	**2016**
Duquesne	N/A	N/A	N/A	$328.53	$416.79
Met-Ed	$533.60	$538.38	$493.74	$401.09	$350.28
PECO Electric	$531.49	$452.80	$461.66	$438.01	$379.88
Penelec	$433.54	$436.86	$389.19	$328.54	$291.44
Penn Power	$437.92	$356.14	$293.22	$237.27	$244.90
PPL	$951.95	$1,004.51	$1,033.51	$933.57	$737.80
West Penn	N/A	N/A	N/A	$1,076.08	$680.65

Appendix 4.B.2: **Average IPAs of EDC CAP Customers with IPA Balances**

Average IPAs of EDC CAP Customers with IPA Balances (Electric Non-Heating and Electric Heating)					
	2012	**2013**	**2014**	**2015**	**2016**
Duquesne	N/A	N/A	N/A	$531.96	$620.40
Met-Ed	$168.39	$124.72	$88.94	$73.82	$93.52
PECO Electric	$482.35	$489.86	$531.00	$479.45	$454.84
Penelec	$142.46	$90.49	$64.30	$58.09	$81.71
Penn Power	$113.75	$82.21	$54.77	$55.77	$87.91
PPL	$160.96	$150.77	$170.09	$162.48	$173.93
West Penn	N/A	N/A	$322.42	$325.04	$118.76

Appendix 5 – Percentage of CAP Bills Paid In-Full

Appendix 5.A: Table 6-1 Percentage of NGDC CAP Bills Paid In-Full

The percentage of NGDC CAP bills paid in full for all FPIG levels for the period from 2012 through 2016.

Appendix 5.A.1: **Percentage of NGDC CAP Bills Paid In-Full**

	Percentage of NGDC CAP Bills Paid In-Full				
	2012	**2013**	**2014**	**2015**	**2016**
Columbia	59.01%	58.10%	57.48%	59.08%	60.04%
NFG	61.65%	61.54%	60.82%	62.61%	67.31%
PECO Gas	63.19%	62.55%	59.73%	58.86%	61.52%
Peoples	71.18%	63.65%	57.83%	63.82%	64.10%
Peoples EQT	69.99%	75.53%	73.96%	72.94%	73.31%
PGW	57.52%	55.23%	57.82%	59.73%	62.08%
UGI Gas	89.94%	90.85%	93.41%	89.41%	93.82%
UGI PNG	90.78%	91.27%	93.75%	92.84%	92.93%

Appendix 5.B: Tables 6-2, 6-6 to 6-8 NGDCs Number of CAP Bills Paid

The total number of NGDC CAP bills issued and paid in full by FPIG level for the period from 2012 through 2016.

Appendix 5.B.1: **NGDC CAP Bills Issued and Paid In-Full**

2012	**NGDC CAP Bills Issued and Paid In-Full**		
	50% FPIG	**100% FPIG**	**150% FPIG**
Columbia			
Bills Issued	56,406	115,349	73,202
Bills Paid in Full	29,692	69,567	45,296
NFG*			
Bills Issued	N/A	N/A	138,215
Bills Paid in Full	N/A	N/A	85,208
PECO Gas			
Bills Issued	15,541	30,399	27,343
Bills Paid in Full	8,875	19,480	17,955
Peoples			
Bills Issued	36,560	86,858	62,487
Bills Paid in Full	17,526	63,412	51,382
Peoples EQT			
Bills Issued	49,842	89,824	19,246
Bills Paid in Full	36,558	60,750	13,916
PGW			
Bills Issued	275,373	509,535	172,026
Bills Paid in Full	165,391	293,355	91,710
UGI Gas			
Bills Issued	25,936	40,935	4,046
Bills Paid in Full	24,043	36,578	3,162
UGI PNG			
Bills Issued	12,240	33,413	4,557
Bills Paid in Full	11,157	30,699	3,727

*NFG only provided aggregate data for the 0-150% FPIG level.

Appendix 5.B.2: **NGDC CAP Bills Issued and Paid In-Full**

2013	NGDC CAP Bills Issued and Paid In-Full		
	50% FPIG	100% FPIG	150% FPIG
Columbia			
Bills Issued	53,518	110,862	68,823
Bills Paid in Full	27,642	65,457	42,395
NFG*			
Bills Issued	N/A	N/A	123,033
Bills Paid in Full	N/A	N/A	75,715
PECO Gas			
Bills Issued	12,767	26,346	22,637
Bills Paid in Full	6,975	16,684	14,965
Peoples			
Bills Issued	42,615	94,826	65,519
Bills Paid in Full	16,544	63,133	49,503
Peoples EQT			
Bills Issued	47,433	76,015	11,547
Bills Paid in Full	36,366	56,708	8,891
PGW			
Bills Issued	257,298	481,593	150,414
Bills Paid in Full	147,522	265,712	77,920
UGI Gas			
Bills Issued	24,630	27,918	4,046
Bills Paid in Full	22,780	25,140	3,497
UGI PNG			
Bills Issued	12,971	25,385	6,374
Bills Paid in Full	11,912	23,264	5,648

*NFG only provided aggregate data for the 0-150% FPIG level.

Appendix 5.B.3: **NGDC CAP Bills Issued and Paid In-Full**

2014	NGDC CAP Bills Issued and Paid In-Full		
	50% FPIG	100% FPIG	150% FPIG
Columbia			
Bills Issued	54,428	115,013	76,092
Bills Paid in Full	27,971	66,677	46,496
NFG*			
Bills Issued	N/A	N/A	120,792
Bills Paid in Full	N/A	N/A	73,471
PECO Gas			
Bills Issued	12,412	24,802	20,118
Bills Paid in Full	6,379	15,033	12,834
Peoples			
Bills Issued	48,937	107,919	75,416
Bills Paid in Full	16,552	65,429	52,338
Peoples EQT			
Bills Issued	52,590	88,101	16,951
Bills Paid in Full	39,866	65,102	11,625
PGW			
Bills Issued	197,379	429,460	130,952
Bills Paid in Full	117,250	248,825	72,113
UGI Gas			
Bills Issued	27,305	37,417	11,452
Bills Paid in Full	25,515	34,970	10,669
UGI PNG			
Bills Issued	16,109	31,781	13,461
Bills Paid in Full	14,986	29,904	12,628

*NFG only provided aggregate data for the 0-150% FPIG level.

Appendix 5.B.4: **NGDC CAP Bills Issued and Paid In-Full**

2015	NGDC CAP Bills Issued and Paid In-Full		
	50% FPIG	**100% FPIG**	**150% FPIG**
Columbia			
Bills Issued	52,153	116,624	78,941
Bills Paid in Full	27,385	68,927	50,048
NFG*			
Bills Issued	N/A	N/A	118,250
Bills Paid in Full	N/A	N/A	74,035
PECO Gas			
Bills Issued	14,612	27,378	22,228
Bills Paid in Full	7,657	16,507	13,638
Peoples			
Bills Issued	51,344	111,399	79,184
Bills Paid in Full	23,135	73,640	57,627
Peoples EQT			
Bills Issued	55,568	91,192	23,218
Bills Paid in Full	36,593	69,857	17,527
PGW			
Bills Issued	202,086	407,460	113,047
Bills Paid in Full	119,192	245,869	66,509
UGI Gas			
Bills Issued	30,827	48,390	20,187
Bills Paid in Full	28,470	41,870	18,539
UGI PNG			
Bills Issued	17,932	39,051	21,731
Bills Paid in Full	16,654	36,326	20,097

*NFG only provided aggregate data for the 0-150% FPIG level.

Appendix 5.B.5: **NGDC CAP Bills Issued and Paid In-Full**

2016	NGDC CAP Bills Issued and Paid In-Full		
	50% FPIG	**100% FPIG**	**150% FPIG**
Columbia			
Bills Issued	56,984	111,311	78,139
Bills Paid in Full	30,926	67,237	49,795
NFG*			
Bills Issued	N/A	N/A	**104,325**
Bills Paid in Full	N/A	N/A	**70,224**
PECO Gas			
Bills Issued	15,919	31,839	23,011
Bills Paid in Full	8,734	20,408	14,392
Peoples			
Bills Issued	48,534	107,200	76,958
Bills Paid in Full	20,060	71,340	57,748
Peoples EQT			
Bills Issued	45,515	80,316	33,151
Bills Paid in Full	33,303	58,918	24,323
PGW			
Bills Issued	195,629	353,907	82,091
Bills Paid in Full	115,830	225,104	51,192
UGI Gas			
Bills Issued	29,346	44,404	19,297
Bills Paid in Full	27,943	41,557	17,795
UGI PNG			
Bills Issued	18,096	35,532	18,904
Bills Paid in Full	17,261	32,990	17,156

*NFG only provided aggregate data for the 0-150% FPIG level.

Appendix 5.C: Table 6-3 EDC Percentage of CAP Bills Paid

The percentage of EDC heating and non-heating accounts CAP bills paid in full for all FPIG levels for the period from 2012 through 2016.

Appendix 5.C.1: **EDC CAP Electric Accounts – Percent of Bills Paid in-Full**

	EDC CAP Electric Heating and Non-Heating Accounts Percent of Bills Paid in-Full				
	2012	**2013**	**2014**	**2015**	**2016**
Duquesne					
Heat	82.65%	83.52%	78.65%	49.83%	44.80%
Non-Heat	79.18%	79.92%	77.00%	46.86%	39.82%
Aggregate	79.52%	80.29%	77.18%	47.20%	40.38%
Met-Ed					
Heat	51.82%	40.03%	52.96%	56.87%	59.09%
Non-Heat	49.40%	41.64%	62.35%	65.79%	69.13%
Aggregate	50.01%	41.22%	59.82%	63.32%	66.31%
PECO Electric					
Heat	63.19%	62.55%	59.73%	58.86%	62.49%
Non-Heat	60.07%	59.12%	58.42%	59.26%	62.43%
Aggregate	60.67%	59.65%	58.60%	59.20%	62.44%
Penelec					
Heat	57.54%	46.77%	60.61%	63.45%	64.55%
Non-Heat	51.74%	49.68%	67.28%	69.86%	71.54%
Aggregate	52.55%	49.24%	66.33%	68.92%	70.45%
Penn Power					
Heat	60.80%	47.27%	61.27%	63.65%	63.13%
Non-Heat	57.20%	51.14%	69.09%	68.80%	70.57%
Aggregate	57.77%	50.44%	67.82%	67.94%	69.16%
PPL					
Heat	62.71%	56.40%	56.86%	63.09%	57.91%
Non-Heat	62.71%	56.40%	56.86%	63.09%	57.91%
Aggregate	57.60%	59.62%	61.18%	64.65%	60.32%
West Penn					
Heat	N/A	N/A	44.98%	45.43%	51.04%
Non-Heat	N/A	N/A	41.97%	43.00%	55.80%
Aggregate	N/A	N/A	42.66%	43.57%	54.65%

Appendix 5.D: Tables 6-9 to 6-11 EDCs Number of CAP Bills Paid in Full

The total number of EDCs CAP bills issued and paid in full by FPIG level for the period from 2012 through 2016.

Appendix 5.D.1: CAP Electric – Bills Paid in Full

2012	CAP Heating Accounts Number of Bills Paid In-Full			CAP Non-Heating Accounts Number of Bills Paid In-Full		
	50% FPIG	100% FPIG	150% FPIG	50% FPIG	100% FPIG	150% FPIG
Duquesne						
Bills Issued	6,291	23,117	11,834	61,402	206,767	110,544
Bills Paid in Full	4,412	19,050	10,623	42,716	164,544	92,613
Met-Ed						
Bills Issued	27,218	50,954	27,033	86,501	133,170	91,517
Bills Paid in Full	12,439	27,682	14,396	36,410	67,866	49,449
PECO Electric						
Bills Issued	60,950	119,219	107,234	294,333	581,666	349,000
Bills Paid in Full	34,808	76,395	70,414	157,739	366,853	211,315
Penelec						
Bills Issued	18,033	39,022	17,631	119,727	209,479	131,850
Bills Paid in Full	8,721	23,660	10,592	50,484	112,763	75,305
Penn Power						
Bills Issued	4,639	9,712	6,703	24,881	49,396	38,616
Bills Paid in Full	2,575	6,076	4,149	11,295	29,019	24,266
PPL						
Bills Issued	2,437	6,600	4,748	3,655	9,900	7,122
Bills Paid in Full	1,404	3,802	2,735	2,105	5,703	4,102
West Penn						
Bills Issued	N/A	N/A	N/A	N/A	N/A	N/A
Bills Paid in Full	N/A	N/A	N/A	N/A	N/A	N/A

Appendix 5.D.2: CAP Electric – Bills Paid in Full

2013	CAP Heating Accounts Number of Bills Paid In-Full			CAP Non-Heating Accounts Number of Bills Paid In-Full		
	50% FPIG	100% FPIG	150% FPIG	50% FPIG	100% FPIG	150% FPIG
Duquesne						
Bills Issued	6,540	24,216	12,369	61,234	199,823	113,902
Bills Paid in Full	4,518	20,321	11,181	42,525	160,740	96,384
Met-Ed						
Bills Issued	26,353	50,172	27,605	75,793	126,381	92,702
Bills Paid in Full	9,421	21,641	10,623	25,526	55,304	41,958
PECO Electric						
Bills Issued	50,070	103,323	88,775	308,649	624,959	376,571
Bills Paid in Full	27,355	65,431	58,688	162,168	385,588	226,757
Penelec						
Bills Issued	16,043	38,967	18,033	94,126	186,754	125,237
Bills Paid in Full	6,076	19,751	8,335	35,172	98,109	68,473
Penn Power						
Bills Issued	4,985	10,563	6,703	21,786	45,529	34,709
Bills Paid in Full	2,149	5,229	3,139	8,905	24,076	19,191
PPL						
Bills Issued	2,503	6,791	4,785	3,755	10,186	7,177
Bills Paid in Full	1,492	4,049	2,852	2,239	6,074	4,278
West Penn						
Bills Issued	N/A	N/A	N/A	N/A	N/A	N/A
Bills Paid in Full	N/A	N/A	N/A	N/A	N/A	N/A

Appendix 5.D.3: CAP Electric Number of Bills Paid in Full

2014	CAP Heating Accounts Number of Bills Paid In-Full			CAP Non-Heating Accounts Number of Bills Paid In-Full		
	50% FPIG	100% FPIG	150% FPIG	50% FPIG	100% FPIG	150% FPIG
Duquesne						
Bills Issued	6,165	24,119	12,570	62,945	183,857	107,078
Bills Paid in Full	3,874	19,028	10,804	39,954	144,047	88,491
Met-Ed						
Bills Issued	11,699	28,583	15,497	32,249	67,845	51,087
Bills Paid in Full	6,440	15,433	7,667	18,250	43,082	32,925
PECO Electric						
Bills Issued	48,676	97,267	78,899	330,499	651,536	400,191
Bills Paid in Full	25,017	58,955	50,330	171,394	397,984	238,060
Penelec						
Bills Issued	6,851	23,514	9,945	44,804	118,909	78,870
Bills Paid in Full	4,007	14,708	5,718	26,106	81,831	55,265
Penn Power						
Bills Issued	2,123	5,237	2,952	9,205	25,450	18,380
Bills Paid in Full	1,225	3,260	1,833	5,533	17,743	13,367
PPL						
Bills Issued	2,631	7,295	5,423	3,947	10,943	8,134
Bills Paid in Full	1,610	4,463	3,317	2,415	6,695	4,976
West Penn						
Bills Issued	13,943	28,265	17,207	48,491	94,702	57,558
Bills Paid in Full	6,682	12,149	7,894	19,917	40,947	23,386

Appendix 5.D.4: CAP Electric Number of Bills Paid in Full

2015	CAP Heating Accounts Number of Bills Paid In-Full			CAP Non-Heating Accounts Number of Bills Paid In-Full		
	50% FPIG	100% FPIG	150% FPIG	50% FPIG	100% FPIG	150% FPIG
Duquesne						
Bills Issued	10,113	25,009	12,853	110,550	179,294	88,904
Bills Paid in Full	3,160	13,196	7,548	38,822	90,940	47,733
Met-Ed						
Bills Issued	10,572	26,602	15,187	26,945	62,073	47,411
Bills Paid in Full	5,915	15,563	8,298	15,980	41,622	32,159
PECO Electric						
Bills Issued	57,305	107,370	87,174	320,905	634,576	387,979
Bills Paid in Full	30,027	64,737	53,484	167,905	395,153	233,123
Penelec						
Bills Issued	6,483	22,312	9,986	39,445	109,541	75,600
Bills Paid in Full	3,820	14,708	6,080	23,327	78,188	55,390
Penn Power						
Bills Issued	1,605	5,079	2,706	7,743	22,344	16,705
Bills Paid in Full	914	3,328	1,735	4,477	15,588	12,128
PPL						
Bills Issued	2,996	8,679	6,645	4,494	13,019	9,967
Bills Paid in Full	1,938	5,612	4,294	2,907	8,418	6,442
West Penn						
Bills Issued	12,887	31,842	20,191	48,995	95,651	65,519
Bills Paid in Full	5,809	14,531	9,156	20,040	42,699	27,631

Appendix 5.D.5: CAP Electric Number of Bills Paid in Full

2016	CAP Heating Accounts Bills Issued and Paid In-Full			CAP Non-Heating Accounts Number of Bills Paid In-Full		
	50% FPIG	100% FPIG	150% FPIG	50% FPIG	100% FPIG	150% FPIG
Duquesne						
Bills Issued	10,770	27,806	15,570	121,892	201,209	104,890
Bills Paid in Full	2,897	13,006	8,355	33,948	87,547	48,924
Met-Ed						
Bills Issued	10,583	25,101	14,298	25,758	57,689	44,705
Bills Paid in Full	6,076	15,157	8,302	16,316	40,492	31,785
PECO Electric						
Bills Issued	57,230	107,807	93,388	203,232	407,344	57,230
Bills Paid in Full	32,433	69,152	59,911	112,881	266,429	32,433
Penelec						
Bills Issued	6,854	22,842	10,324	37,574	106,106	72,655
Bills Paid in Full	3,938	15,337	6,558	23,121	77,723	53,920
Penn Power						
Bills Issued	2,213	5,208	3,038	6,824	20,822	17,006
Bills Paid in Full	1,240	3,370	1,993	4,076	14,809	12,626
PPL						
Bills Issued	3,452	10,096	8,040	5,177	15,144	12,061
Bills Paid in Full	2,082	6,091	4,850	3,123	9,136	7,275
West Penn						
Bills Issued	14,251	35,047	19,872	50,472	98,383	67,337
Bills Paid in Full	6,692	18,628	9,987	24,306	57,240	39,090

Appendix 6 – CAP Default Exit and Termination Rates

Appendix 6.A: Tables 7-1 to 7-2 NGDCs Default Exit and CAP Termination Rates

The number and percentage of NGDC CAP default exits and default exit rates for the period from 2012 through 2016.

Appendix 6.A.1: **NGDC Aggregate Total CAP Default Exits 0%-150% FPIG**

NGDC Aggregate Total CAP Default Exits 0%-150% FPIG								
	Columbia	**Equitable**	**NFG**	**PECO Gas**	**Peoples**	**PGW**	**UGI Gas**	**UGI PNG**
2012	2,166	4,249	2,298	8,481	5,530	82,662	2,744	1,580
2013	2,461	3,940	2,063	11,002	2,788	94,173	782	522
2014	1,841	2,861	2,020	12,608	2,819	102,156	715	406
2015	3,638	3,438	1,922	13,422	4,067	9,975	1,712	1,153
2016	3,565	4,322	935	11,997	3,573	10,027	974	622

Appendix 6.A.2: **Percent of NGDC Aggregate Total CAP Default Exit Rates 0%-150% FPIG**

Percent of NGDC Aggregate Total CAP Default Exit Rates 0%-150% FPIG								
	Columbia	**Equitable**	**NFG**	**PECO Gas**	**Peoples**	**PGW**	**UGI Gas**	**UGI PNG**
2012	10.25%	32.38%	20.50%	35.56%	36.84%	102.89%	44.73%	37.49%
2013	12.43%	34.93%	20.71%	46.34%	15.34%	126.39%	16.09%	13.88%
2014	8.60%	21.46%	20.62%	51.11%	14.26%	160.68%	10.66%	7.69%
2015	16.59%	23.99%	20.07%	54.09%	19.91%	16.49%	19.69%	17.17%
2016	16.57%	31.86%	10.85%	50.17%	18.04%	19.00%	12.14%	10.17%

The number and percentage of NGDC CAP gas heating terminations and termination rates for the period from 2012 through 2016.

Appendix 6.A.3: **NGDC Aggregate Total CAP Terminations 0%-150% FPIG**

NGDC Aggregate Total CAP Terminations 0%-150% FPIG								
	Columbia	**Equitable**	**NFG**	**PECO Gas**	**Peoples**	**PGW**	**UGI Gas**	**UGI PNG**
2012	2,458	N/A	641	52	794	5,571	1,285	963
2013	2,245	N/A	408	89	1,218	4,484	782	626
2014	2,250	N/A	723	180	1,626	3,999	782	970
2015	2,486	532	549	166	1,785	2,991	1,265	1,267
2016	2,161	1,071	52	144	1,309	3,333	1,093	969

Appendix 6.A.4: **Percent of NGDC Aggregate Total CAP Termination Rates 0%-150% FPIG**

Percent of NGDC Aggregate Total CAP Termination Rates 0%-150% FPIG								
	Columbia	**Equitable**	**NFG**	**PECO Gas**	**Peoples**	**PGW**	**UGI Gas**	**UGI PNG**
2012	11.63%	N/A	5.72%	0.22%	5.29%	6.93%	20.95%	22.85%
2013	11.34%	N/A	4.10%	0.37%	6.70%	6.02%	16.09%	16.65%
2014	10.51%	N/A	7.38%	0.73%	8.23%	6.29%	11.66%	18.37%
2015	11.34%	3.71%	5.73%	0.67%	8.74%	4.94%	14.55%	18.86%
2016	10.05%	7.90%	0.60%	0.60%	6.61%	6.32%	13.62%	15.84%

Appendix 6.*B: Tables 7-3 to 7-6 EDCs Default Exit and CAP Termination Rates*

The number and percentage of EDCs CAP electric non-heating default exits and default exit rates for the period from 2012 through 2016.

Appendix 6.B.1: **EDC Non-Heating Aggregate CAP Estimated* Default Exits 0%-150% FPIG**

EDC Non-Heating Aggregate CAP Estimated* Default Exits 0%-150% FPIG							
	Duquesne	**Met-Ed**	**PECO Electric**	**Penelec**	**Penn Power**	**PPL**	**West Penn**
2012	4,954	1,484	28,067	6,503	1,045	6,920	3,906
2013	3,188	12,497	42,332	16,848	3,038	5,041	10,266
2014	3,581	6,126	51,469	8,900	1,500	3,998	9,553
2015	4,198	6,148	58,302	8,562	1,151	6,447	9,537
2016	3,068	4,955	47,340	7,173	1,073	6,165	9,514

*Default Exits were split Heating/Non-Heating based on allocation of CAP Heating/Non-Heating accounts for this analysis.

Appendix 6.B.2: **Percent of EDC Non-Heating Aggregate CAP Estimated* Default Exit Rates 0%-150% FPIG**

Percent of EDC Non-Heating Aggregate CAP Estimated* Default Exit Rates 0%-150% FPIG							
	Duquesne	**Met-Ed**	**PECO Electric**	**Penelec**	**Penn Power**	**PPL**	**West Penn**
2012	13.73%	5.02%	20.24%	16.69%	10.63%	20.08%	17.79%
2013	8.72%	53.66%	30.66%	54.90%	41.83%	14.32%	49.77%
2014	10.13%	35.80%	36.43%	37.97%	28.42%	10.42%	43.78%
2015	11.79%	39.32%	41.51%	39.16%	24.61%	14.08%	41.34%
2016	7.92%	33.59%	34.60%	33.69%	23.34%	11.42%	39.82%

*Default Exits were split Heating/Non-Heating based on allocation of CAP Heating/Non-Heating accounts for this analysis.

The number and percentage of EDCs CAP electric non-heating terminations and termination rates for the period from 2012 through 2016.

Appendix 6.B.3: **EDC Non-Heating Aggregate CAP Terminations 0%-150% FPIG**

EDC Non-Heating Aggregate CAP Terminations 0%-150% FPIG							
	Duquesne	**Met-Ed**	**PECO Electric**	**Penelec**	**Penn Power**	**PPL**	**West Penn**
2012	5,575	N/A	16,590	N/A	N/A	970	N/A
2013	5,930	N/A	22,301	N/A	N/A	1,467	N/A
2014	4,918	991	24,948	1,082	196	1,428	1,017
2015	306	873	13,012	1,075	178	1,206	1,172
2016	59	799	9,326	918	166	1,269	1,041

Appendix 6.B.4: **Percent of EDC Non-Heating Aggregate CAP Termination Rates 0%-150% FPIG**

Percent of EDC Non-Heating Aggregate CAP Termination Rates 0%-150% FPIG							
	Duquesne	Met-Ed	PECO Electric	Penelec	Penn Power	PPL	West Penn
2012	15.45%	N/A	11.96%	N/A	N/A	2.81%	N/A
2013	16.23%	N/A	16.15%	N/A	N/A	4.17%	N/A
2014	13.91%	5.79%	17.66%	4.62%	3.71%	3.72%	4.66%
2015	0.86%	5.58%	9.26%	4.92%	3.81%	2.63%	5.08%
2016	0.15%	5.42%	6.82%	4.31%	3.61%	2.35%	4.36%

The number and percentage of EDCs CAP electric heating default exits and default exit rates for the period from 2012 through 2016.

Appendix 6.B.5: **EDC Heating Aggregate CAP Estimated* Default Exits 0%-150% FPIG**

EDC Heating Aggregate CAP Estimated* Default Exits 0%-150% FPIG							
	Duquesne	Met-Ed	PECO Electric	Penelec	Penn Power	PPL	West Penn
2012	540	489	3,490	1,209	831	2,092	917
2013	367	4,406	7,110	3,477	2,472	1,300	1,897
2014	434	2,253	8,505	1,722	1,268	1,183	1,554
2015	529	2,342	9,996	1,719	966	1,977	1,788
2016	387	1,887	8,938	1,593	888	1,960	2,848

*Default Exits were split Heating/Non-Heating based on allocation of CAP Heating/Non-Heating accounts for this analysis.

Appendix 6.B.6: **Percent of EDC Heating Aggregate CAP Estimated* Default Exit Rates 0%-150% FPIG**

Percent of EDC Heating Aggregate CAP Estimated* Default Exit Rates 0%-150% FPIG							
	Duquesne	**Met-Ed**	**PECO Electric**	**Penelec**	**Penn Power**	**PPL**	**West Penn**
2012	1.50%	1.65%	2.52%	3.10%	8.45%	6.07%	4.17%
2013	1.00%	18.92%	5.15%	11.33%	34.04%	3.69%	9.20%
2014	1.23%	13.17%	6.02%	7.35%	24.03%	3.08%	7.12%
2015	1.49%	14.97%	7.12%	7.86%	20.64%	4.32%	7.75%
2016	1.00%	12.79%	6.53%	7.48%	19.33%	3.63%	11.92%

*Default Exits were split Heating/Non-Heating based on allocation of CAP Heating/Non-Heating accounts for this analysis.

The number and percentage of EDCs CAP electric heating terminations and termination rates for the period from 2012 through 2016

Appendix 6.B.7: **EDC Heating Aggregate CAP Terminations 0%-150% FPIG**

EDC Heating Aggregate CAP Terminations 0%-150% FPIG							
	Duquesne	**Met-Ed**	**PECO Electric**	**Penelec**	**Penn Power**	**PPL**	**West Penn**
2012	494	N/A	121	N/A	N/A	790	N/A
2013	604	N/A	209	N/A	N/A	1,358	N/A
2014	488	733	423	400	86	1,683	577
2015	45	674	390	390	88	1,395	614
2016	1	636	339	353	83	1,227	590

Appendix 6.B.8: **Percent of EDC Heating Aggregate CAP Termination Rates 0%-150% FPIG**

Percent of EDC Heating Aggregate CAP Termination Rates 0%-150% FPIG							
	Duquesne	**Met-Ed**	**PECO Electric**	**Penelec**	**Penn Power**	**PPL**	**West Penn**
2012	1.37%	N/A	0.09%	N/A	N/A	2.29%	N/A
2013	1.65%	N/A	0.15%	N/A	N/A	3.86%	N/A
2014	1.38%	4.28%	0.30%	1.71%	1.63%	4.39%	2.64%
2015	0.13%	4.31%	0.28%	1.78%	1.88%	3.05%	2.66%
2016	0.00%	4.31%	0.25%	1.66%	1.81%	2.27%	2.47%

Appendix 7 – Non-CAP Residential and Confirmed Low-Income (CLI) Customer Debt

Source: All data for tables in Appendix 7 from Universal Service Programs & Collections Performance Reports 2012-2016.

Appendix 7.A: Industry Averages NGDC and EDC Non-CAP Residential and CLI Customer Debt

Appendix 7.A.1: **NGDC Non-CAP Residential and CLI Total Debt & Debt Ratios**

NGDC Non-CAP Residential and Confirmed Low-Income Total Debt & Debt Ratios								
	Residential Customers				CLI Customers			
	Dollars in Debt on Agreement	Debt Ratio on Agreement	Dollars in Debt Not on Agreement	Debt Ratio Not on Agreement	Dollars in Debt on Agreement	Debt Ratio on Agreement	Dollars in Debt Not on Agreement	Debt Ratio Not on Agreement
2012	$41,301,35	2.04%	$56,594,66	2.80%	$22,755,986	5.74%	$17,645,29	4.45%
2013	$44,364,73	1.91%	$65,690,14	2.83%	$19,546,385	5.00%	$20,259,97	5.18%
2014	$45,636,68	1.78%	$63,722,92	2.49%	$22,168,530	5.38%	$20,951,88	5.08%
2015	$46,348,66	2.02%	$66,600,47	2.91%	$26,817,387	6.48%	$20,349,97	4.92%
2016	$33,110,04	1.74%	$55,419,02	2.91%	$19,373,791	5.67%	$12,103,64	3.54%

Appendix 7.A.2: **EDC Non-CAP Residential and CLI Total Debt & Debt Ratios**

EDC Non-CAP Residential and Confirmed Low-Income Total Debt & Debt Ratios								
	Residential Customers				CLI Customers			
	Dollars in Debt on Agreement	Debt Ratio on Agreement	Dollars in Debt Not on Agreement	Debt Ratio Not on Agreement	Dollars in Debt on Agreement	Debt Ratio on Agreement	Dollars in Debt Not on Agreement	Debt Ratio Not on Agreement
2012	$87,933,654	1.50%	$121,967,5	2.08%	$49,252,71	7.13%	$60,096,962	8.70%
2013	$86,497,160	1.48%	$123,492,7	2.11%	$49,749,02	6.91%	$63,385,552	8.81%
2014	$88,622,175	1.46%	$117,253,6	1.93%	$52,146,78	6.89%	$63,456,151	8.39%
2015	$85,684,424	1.31%	$118,382,2	1.81%	$49,875,76	5.89%	$59,078,750	6.98%
2016	$88,010,703	1.33%	$128,615,1	1.95%	$44,425,96	5.19%	$53,936,970	6.30%

Appendix 7.B: Tables 8-1 and 8-3 NGDC Non-CAP Residential Customers

Appendix 7.B.1: **NGDC Non-CAP Residential Customers Debt & Debt Ratio**

	Dollars in Debt on Agreement	Debt Ratio on Agreement	Dollars in Debt Not on Agreement	Debt Ratio Not on Agreement
Columbia				
2012	$3,164,943	6.80%	$1,121,775	2.41%
2013	$5,282,905	9.46%	$628,897	1.13%
2014	$6,756,013	10.19%	$1,159,968	1.75%
2015	$7,232,765	10.92%	$1,427,095	2.15%
2016	$5,341,059	9.33%	$1,171,674	2.05%
NFG				
2012	$1,495,326	8.35%	$858,526	4.79%
2013	$1,229,077	6.33%	$915,782	4.72%
2014	$1,468,095	6.75%	$988,370	4.54%
2015	$1,496,516	8.78%	$981,719	5.76%
2016	$1,335,709	9.83%	$1,133,617	8.35%
PECO-Gas				
2012	$882,306	5.71%	$2,565,367	16.59%
2013	$1,031,022	6.03%	$2,989,994	17.48%
2014	$993,347	5.02%	$1,856,335	9.38%
2015	$919,207	5.27%	$1,686,623	9.66%
2016	$1,056,220	7.69%	$1,355,545	9.87%
Peoples				
2012	$5,175,426	7.94%	$3,358,032	5.15%
2013	$3,412,550	4.38%	$3,402,725	4.37%
2014	$3,289,065	3.84%	$2,087,002	2.44%
2015	$2,387,402	3.18%	$2,125,573	2.83%
2016	$1,181,803	1.95%	$1,036,381	1.71%
Peoples EQT				
2012	$3,046,495	9.63%	$722,376	2.28%
2013	$3,268,826	8.67%	$875,335	2.32%
2014	$3,230,526	8.58%	$858,822	2.28%
2015	$2,641,103	7.16%	$829,595	2.25%
2016	$647,581	2.18%	$1,066,339	3.59%
PGW				
2012	$6,700,882	4.15%	$4,932,157	3.05%
2013	$2,288,750	1.88%	$6,105,622	5.02%
2014	$2,410,536	2.14%	$6,835,691	6.06%
2015	$8,618,074	6.40%	$6,340,821	4.71%
2016	$7,384,073	6.01%	$2,188,203	1.78%
UGI Gas				
2012	$1,245,209	4.02%	$2,408,765	7.78%
2013	$1,684,812	5.28%	$3,133,749	9.83%
2014	$2,354,783	6.54%	$4,302,184	11.95%
2015	$1,956,803	5.65%	$4,193,699	12.10%
2016	$1,489,546	6.47%	$2,536,577	11.02%
UGI PNG				
2012	$1,045,398	3.82%	$1,678,300	6.14%
2013	$1,348,443	4.60%	$2,207,866	7.54%
2014	$1,666,165	5.14%	$2,863,510	8.83%
2015	$1,565,517	4.91%	$2,764,845	8.68%
2016	$937,800	4.55%	$1,615,307	7.83%

Appendix 7.C: Tables 8-2 and 8-4 EDCs Non-CAP Residential Customers Debt

Appendix 7.C.1: **EDC Non-CAP Residential Customers Debt & Debt Ratios**

	Dollars in Debt on Agreement	Debt Ratio on Agreement	Dollars in Debt Not on Agreement	Debt Ratio Not on Agreement
Duquesne				
2012	$7,111,396	1.48%	$3,893,461	0.81%
2013	$6,881,436	1.68%	$4,390,065	1.07%
2014	$7,413,769	1.70%	$5,256,987	1.20%
2015	$8,475,599	1.64%	$11,655,027	2.25%
2016	$12,409,870	2.34%	$11,011,293	2.07%
Met-Ed				
2012	$22,176,919	3.69%	$5,228,520	0.87%
2013	$19,375,229	3.42%	$4,365,518	0.77%
2014	$19,051,671	3.60%	$4,740,501	0.90%
2015	$16,068,324	2.77%	$5,188,397	0.89%
2016	$13,865,755	2.41%	$6,223,947	1.08%
PECO Electric				
2012	$12,422,305	0.61%	$38,874,965	1.92%
2013	$13,362,308	0.66%	$39,668,475	1.96%
2014	$11,820,927	0.57%	$29,714,134	1.43%
2015	$9,496,265	0.45%	$23,695,090	1.12%
2016	$9,907,906	0.48%	$17,552,052	0.84%
Penelec				
2012	$18,891,292	3.67%	$4,824,677	0.94%
2013	$16,991,387	3.60%	$4,024,969	0.85%
2014	$17,104,959	3.79%	$4,217,542	0.94%
2015	$15,044,320	3.00%	$4,842,244	0.97%
2016	$14,022,529	2.65%	$6,465,524	1.22%
Penn Power				
2012	$4,825,654	3.20%	$1,073,501	0.71%
2013	$4,050,249	2.90%	$964,919	0.69%
2014	$3,923,847	2.86%	$998,328	0.73%
2015	$3,846,100	2.22%	$1,355,800	0.78%
2016	$4,403,138	2.39%	$1,779,980	0.97%
PPL				
2012	$18,143,704	1.14%	$61,844,995	3.90%
2013	$17,617,784	1.01%	$65,872,581	3.77%
2014	$19,161,432	0.99%	$68,105,839	3.53%
2015	$22,412,561	1.11%	$66,174,920	3.26%
2016	$22,619,415	1.11%	$78,760,112	3.86%
West Penn				
2012	$4,362,384	0.84%	$6,227,461	1.20%
2013	$8,218,767	1.65%	$4,206,199	0.84%
2014	$10,145,570	1.95%	$4,220,365	0.81%
2015	$10,341,255	1.69%	$5,470,722	0.89%
2016	$10,782,090	1.63%	$6,822,278	1.03%

Appendix 7.D: Tables 8-5 and 8-7 NGDC CLI Customers Debt

Appendix 7.D.1: **NGDC Confirmed Low-Income Customers Debt & Debt Ratios**

	Dollars in Debt on Agreement	Debt Ratio on Agreement	Dollars in Debt Not on Agreement	Debt Ratio Not on Agreement
Columbia				
2012	$3,164,943	6.80%	$1,121,775	2.41%
2013	$5,282,905	9.46%	$628,897	1.13%
2014	$6,756,013	10.19%	$1,159,968	1.75%
2015	$7,232,765	10.92%	$1,427,095	2.15%
2016	$5,341,059	9.33%	$1,171,674	2.05%
NFG				
2012	$1,495,326	8.35%	$858,526	4.79%
2013	$1,229,077	6.33%	$915,782	4.72%
2014	$1,468,095	6.75%	$988,370	4.54%
2015	$1,496,516	8.78%	$981,719	5.76%
2016	$1,335,709	9.83%	$1,133,617	8.35%
PECO Gas				
2012	$882,306	5.71%	$2,565,367	16.59%
2013	$1,031,022	6.03%	$2,989,994	17.48%
2014	$993,347	5.02%	$1,856,335	9.38%
2015	$919,207	5.27%	$1,686,623	9.66%
2016	$1,056,220	7.69%	$1,355,545	9.87%
Peoples				
2012	$5,175,426	7.94%	$3,358,032	5.15%
2013	$3,412,550	4.38%	$3,402,725	4.37%
2014	$3,289,065	3.84%	$2,087,002	2.44%
2015	$2,387,402	3.18%	$2,125,573	2.83%
2016	$1,181,803	1.95%	$1,036,381	1.71%
Peoples EQT				
2012	$3,046,495	9.63%	$722,376	2.28%
2013	$3,268,826	8.67%	$875,335	2.32%
2014	$3,230,526	8.58%	$858,822	2.28%
2015	$2,641,103	7.16%	$829,595	2.25%
2016	$647,581	2.18%	$1,066,339	3.59%
PGW				
2012	$6,700,882	4.15%	$4,932,157	3.05%
2013	$2,288,750	1.88%	$6,105,622	5.02%
2014	$2,410,536	2.14%	$6,835,691	6.06%
2015	$8,618,074	6.40%	$6,340,821	4.71%
2016	$7,384,073	6.01%	$2,188,203	1.78%
UGI Gas				
2012	$1,245,209	4.02%	$2,408,765	7.78%
2013	$1,684,812	5.28%	$3,133,749	9.83%
2014	$2,354,783	6.54%	$4,302,184	11.95%
2015	$1,956,803	5.65%	$4,193,699	12.10%
2016	$1,489,546	6.47%	$2,536,577	11.02%
UGI PNG				
2012	$1,045,398	3.82%	$1,678,300	6.14%
2013	$1,348,443	4.60%	$2,207,866	7.54%
2014	$1,666,165	5.14%	$2,863,510	8.83%
2015	$1,565,517	4.91%	$2,764,845	8.68%
2016	$937,800	4.55%	$1,615,307	7.83%

Appendix 7.E: Tables 8-6 and 8-8 EDCs CLI Customers Debt

Appendix 7.E.1: **EDC Confirmed Low-Income Customers Debt & Debt Ratios**

	Dollars in Debt on Agreement	Debt Ratio on Agreement	Dollars in Debt Not on Agreement	Debt Ratio Not on Agreement
Duquesne				
2012	$1,763,408	2.81%	$3,818,908	6.10%
2013	$1,831,381	2.99%	$3,971,232	6.48%
2014	$2,204,174	4.20%	$4,565,510	8.70%
2015	$1,061,156	2.11%	$2,499,669	4.96%
2016	$780,301	1.38%	$2,612,553	4.63%
Met-Ed				
2012	$13,573,213	15.27%	$1,672,475	1.88%
2013	$12,491,100	14.81%	$1,432,428	1.70%
2014	$12,364,042	15.46%	$1,894,114	2.37%
2015	$10,947,284	11.31%	$2,122,143	2.19%
2016	$9,434,155	10.26%	$2,844,351	3.09%
PECO Electric				
2012	$2,233,654	1.98%	$7,131,993	6.33%
2013	$2,926,340	2.54%	$8,961,442	7.79%
2014	$2,904,709	2.49%	$5,675,610	4.87%
2015	$2,789,568	2.33%	$4,674,494	3.91%
2016	$2,874,058	2.59%	$3,355,357	3.02%
Penelec				
2012	$12,630,650	12.83%	$1,886,507	1.92%
2013	$11,990,862	13.42%	$1,630,552	1.82%
2014	$12,162,602	14.22%	$1,946,277	2.28%
2015	$11,050,780	10.24%	$2,236,890	2.07%
2016	$10,200,122	9.28%	$3,362,454	3.06%
Penn Power				
2012	$3,173,251	13.32%	$365,630	1.53%
2013	$2,837,341	13.26%	$350,002	1.64%
2014	$2,790,788	13.66%	$417,487	2.04%
2015	$2,725,270	10.07%	$562,532	2.08%
2016	$3,000,987	10.83%	$833,929	3.01%
PPL				
2012	$13,150,465	5.19%	$42,798,103	16.88%
2013	$12,622,149	4.25%	$45,838,694	15.43%
2014	$13,692,419	3.95%	$47,729,889	13.75%
2015	$15,116,573	4.15%	$45,269,005	12.44%
2016	$11,882,724	3.18%	$38,238,163	10.23%
West Penn				
2012	$2,728,070	5.42%	$2,423,346	4.81%
2013	$5,049,855	9.90%	$1,201,202	2.35%
2014	$6,028,055	11.01%	$1,227,264	2.24%
2015	$6,185,136	7.65%	$1,714,017	2.12%
2016	$6,253,617	7.31%	$2,690,163	3.15%

Appendix 8 – State Survey Responses

Staff received eight responses to the survey. None of the responders provided data for every question.[98] These summaries have been supplemented by limited staff research.

Question 1: Excluding LIHEAP, what utility and/or energy assistance programs does your state offer to low-income customers?

<u>Colorado:</u>

Energy Outreach Colorado
- Low-income assistance
- Program specifically targeted to low-income customers for each utility
- Paid by rate charged to each residential non-participant monthly bill

<u>Michigan:</u>

Michigan Energy Assistance Program
- Implemented by utilities
- Funded by state's Low-Income Energy Assistance Fund
- Utilities can opt in or out on an annual basis

<u>Indiana:</u>

A state-funded energy assistance program which provides benefits to homeowners only.[99]

<u>District of Columbia:</u>

Residential Aid Discount Program
- Offered by Pepco for electric customers. This program offers a credit that covers full customer charges for energy distribution and exemption for several surcharges. The combined discount equals about 30% of the typical bill for eligible customers.

Residential Essential Service Program (RES)
- Offered for gas customers of Washington Gas. The program offers a discount to eligible Pepco residential customers in D.C. The discount is a percentage reduction in the distribution portion of the customer's bill

[98] The actual survey questions and responses have been summarized in this Appendix.
[99] Staff notes that additional information about Indiana's program is available at: https://www.in.gov/ihcda/2329.htm.

for the winter months, November through April, resulting in approximately 25% reduction in charges. RES also provides for an automatic short-term increase in this reduction if gas prices increase above a specific historical average.

Ohio:

PIPP Plus

- Customers are eligible if their household income is at or below 150% of the FPIG level. (Ohio LIHEAP income eligibility guidelines are set at or below 175% of the FPIG level.)

Winter Reconnect Orders

- Issued annually by the Public Utility Commission of Ohio, allowing customers who are disconnected or being threatened with disconnection to pay a maximum of $175 to maintain or restore their utility service once per winter heating season.

The electric and gas companies offer their own specific programs to assist eligible customers with paying their utility bills.

Question 2: Does your state have a definition for an "affordable" energy burden?

No respondents reported a definition for an affordable energy burden.

Question 3: Please provide an explanation of how your state calculates a household's energy burden (i.e., statewide; includes housing expenses) and if there is a difference based on fuel type (i.e., electric or gas; heating/non-heating account).

Colorado:

Eligible participants are limited to those with a household income at or below 186% of the current federal poverty level, or, if the utility applies Low-Income Energy Assistance Program (LEAP) benefits to offset the costs of the unaffordable portion of the participating customer's utility bill, the percent of the current federal poverty level set by the Colorado Department of Human Services, Division of Low-Income Energy Assistance for eligibility in the LEAP program.

Participant payments for natural gas bills rendered to participants shall not exceed an "affordable PIPP." For accounts for which natural gas is the primary heating fuel, participant payments shall be no lower than 2% and not greater than 3% of the participant's household income.

Participant payments for electric bills rendered to participants shall not exceed an "affordable PIPP." The percentage of a participant's household income for which the participant is responsible shall be determined as follows:

A. For electric accounts for which electricity is the primary heating fuel, participant payments shall be no lower than 3% and not greater than 6% of the participant's household income; and

B. For electric accounts for which electricity is not the primary heating fuel, participant payments shall be no lower than 2% and not greater than 3% of the participant's household income.

Colorado does not perform any calculations. Each utility is required to calculate the total bill and the "affordable" portion of the average bill for each eligible participant. There is a small difference in the calculation for gas versus gas/electric.

Indiana:

Indiana does not calculate energy burden except for its Performance Measure Reporting. This is simply the total cost of energy compared to income.

Ohio:

Ohio does not calculate a household's energy burden. Electric and natural gas customers who qualify pay $10 or 6% of their gross monthly household income, whichever is greater, to the utility each month. If the utility provides both gas and electric services or if the customer has an all-electric home, the payment is $10 or 10% of the gross monthly income, whichever is greater. (*See* https://www.puco.ohio.gov/be-informed/consumer-topics/energy-assistance-programs-help-with-paying-your-utility-bills/) The eligibility threshold for LIHEAP is 60% of the State Median Income which is roughly 175% of the FPIG.

Question 4: Do you establish a target energy burden level for your utility and/or energy assistance programs?

Colorado and New Hampshire establish target energy burdens.
Colorado includes LIHEAP payments in the calculation for target energy burden levels.

Question5: Does your state use the same target energy burden for all programs, or are there different levels for each program or fuel type?

New Hampshire:

New Hampshire does not use energy burden as described above. The discount levels are set to bring the amount that the average participating customer pays between 4% and 5% of the average income for that discount tier. There are five discount tiers with discounts ranging from 8% to 76%.

Colorado:

In Colorado, a participant's minimum payment for an electric heating account shall be no more than $20 per month, and the minimum payment for a non-heating electric account shall be no more than $10 per month. For gas heating customers, with a household income of zero dollars, a utility may establish a minimum monthly payment amount of $10 per month or less.

Question 6: Does your state provide a CAP program? If yes, please describe program.

South Dakota does not offer CAPs.

New Hampshire

New Hampshire has CAPs but provided no additional information. Staff notes that additional information may be found at:
https://www.puc.nh.gov/consumer/electricassistanceprogram.htm

District of Columbia:

For electric, D.C. has the Residential Aid Discount (RAD) Program offered by Pepco. The credit covers the following charges: the full customer charge and energy charge for distribution and exemption from the following surcharges: the RAD Surcharge, the Sustainable Energy Trust Fund, and the Energy Assistance Trust Fund. Credits for these charges are individually listed on the customer's bills as "Residential Aid Credit (RAC) – Distribution" and "RAC Surcharges." Customers will receive the RAC whether or not they have a retail supplier. The full RAC is equal to approximately 30% of a typical RAD customer's bill. In addition, the D.C. Commission is working with stakeholders to develop an arrearage management plan.

For gas, D.C. has the Residential Essential Service (RES) offered by Washington Gas. The program offers eligible Pepco D.C. residential customers a discount on the distribution portion of the customer's bill from November through April. The discount is achieved through a percentage reduction of the distribution portion of a customer's bill, resulting in an approximately 25% reduction in the total bill. The RES additionally provides for an automatic short-term increase in the reduction to the distribution portion of the bill when purchased gas prices rise above a specified historic percentage. RES customer bills also indicate the costs of surcharges that RES customers are exempt from paying, specifically: RES surcharge; Sustainable Energy Trust Fund surcharge, and Energy Assistance Trust Fund surcharge. Customers can enroll in the RES program year-round; the enrollment year begins on October 1.

<u>Ohio:</u>

Ohio provided detailed information on three variations of its PIPP programs.

PIPP Plus is an extended payment arrangement that requires regulated gas and electric companies to accept payments based on a percentage of the household income for those customers who are at or below 150% of FPIG. The PIPP Plus payment amount is based on the household's countable income received during the previous 30 days. If a gas customer qualifies for PIPP Plus, he or she would pay 6% of the household's current gross monthly income to the gas company or a minimum of $10, whichever is greater, year-round. If electricity is not the primary heat source, a customer pays 6% of the household's current gross monthly income or a minimum of $10, whichever is greater, year-round. The customer of an all-electric household pays 10% of the household's monthly income or a minimum of $10, whichever is greater, year-round.

Graduate PIPP Plus allows customers who are no longer eligible to participate in PIPP Plus as a result of an increase in the household income or a change in the household size to continue to receive a reduction in their outstanding arrearages in return for making timely payments. Graduate PIPP Plus customers receive arrearage reduction for on-time and in-full payments. Customer will earn 1/12th credit on arrearages. Graduate PIPP Plus customer bills will be adjusted for the difference between the required installment payment and the current month's utility charges.

Post PIPP Plus is a 12-month payment plan for former PIPP Plus or former Graduate PIPP Plus customers who are no longer customers of the utility but still have an arrearage. Post PIPP Plus is only available in the 12 months immediately after a PIPP Plus account is closed. The customer enters into a payment plan to pay at least 1/60th of the final account arrears for 12 months. For each payment made, the utility will credit 1/12th of the customer's arrears. *See* https://development.ohio.gov/is/is_PIPP_plus_review.htm

Colorado:

Debt forgiveness is included in Colorado's authorized low-income assistance program.

Utility A: Customers must pay down the PPA to $300 before being allowed to enroll in the program and receive 1/24th PPA forgiveness per month over 24 months.

Utility B: PPAs of $500 or less are "retired" over 12 months; larger PPAs are retired over 24 months. This utility also offers a one-time forgiveness of up to $200.

Other utilities offer credit designed to reduce PPAs to zero over 12 months.

Regarding rate assistance, one utility offers a fixed monthly credit to customers who are LIHEAP recipients with income below 150% of the FPIG level and who agree to participate in a weatherization program and enroll in a budget billing plan.

Some utilities offer percentage of income plans for customers who receive LIHEAP and have incomes at or below 150% of the FPIG level, based on a utility formula.

For another utility, households at or below 100% of the FPIG level can receive a 25% discount based on their prior 12 months of usage, while customers between 100 and 150% of the FPIG level receive a 20% discount.

A gas utility offers customers who are LIHEAP recipients with household income at or below 125% of the FPIG level a tiered-maximum payment option:

- 2% of income if household income is at or below 75% of the FPIG level

- 2.5% of income if income is between 76 and 125% of the FPIG level

- 3% of income for households with incomes between 126 and 185% of the FPIG level

Question 7: If the state has a CAP program, what are the eligibility requirements?

New Hampshire:

For New Hampshire's Energy Assistance Program (EAP), the eligibility level is at or below 200% of the FPIG. For the gas discount program, it is categorical eligibility, with participation in one of 13 programs qualifying a customer.

District of Columbia:

Household Size	FY 2018 Maximum Annual Income
1	$30,142
2	$39,416
3	$48,691
4	$57,965
5	$67,239
6	$76,514
7	$78,253
8	$79,992

Ohio:

PIPP Plus eligibility - The customer must be at or below 150% of the FPIG and have an active account with a regulated utility.

Graduate PIPP Plus eligibility - The customer may elect to enroll on graduate PIPP Plus, or the customer must be income-ineligible for PIPP Plus. The customer must be current with all PIPP Plus payments.

Post PIPP eligibility - Plus-PIPP Plus or Graduate PIPP customers who contact the utility to close their account for the following reason(s):

a. Moving beyond the utility companies service territory.
b. Transferring to a residence where utility service is not in the former PIPP Plus or Graduate PIPP Plus customer's name.
c. Moving to a master-metered residence.

Question 8: How is your CAP program funded (i.e., through LIHEAP, residential rates, commercial rates, industrial rates, etc.)?

New Hampshire:

The EAP is funded through a per kWh system benefits charge on all electric bills, both residential and commercial. The gas low-income program is funded through a component of the local distribution adjustment clause (LDAC) assessed to all customer classes.

Ohio:

PIPP Plus is funded through all ratepayers based on kWh or Mcf.

Question 9: What is the total CAP program cost for your state for 2012-2016?

New Hampshire:

Year	CAP Cost
2012	$16,227,754 (10/1/2012 through 9/30/2013)
2013	$16,213,338 (10/1/2013 through 9/30/2014)
2014	$16,351,717 (10/1/2014 through 9/30/2015)
2015	$16,057,192 (10/1/2015 through 9/30/2016)
2016	$15,797,509 (10/1/2016 through 9/30/2017)

Question 10: If funded through residential rates, for each of the past five years (2012-2016), what is the average spending/cost per residential customer in your state to support the CAP program?

New Hampshire:

Year	CAP Cost per Residential Customer
2012	0.0015 mills per kWh
2013	0.0015 mills per kWh
2014	0.0015 mills per kWh
2015	0.0015 mills per kWh
2016	0.0015 mills per kWh

Question 11: How do you define collections expenses for utility companies?

Colorado:

> Administrative costs are considered part of the cost included in the low-income program.

New Hampshire:

> Collection expenses are reviewed during rate cases, not as part of assistance programs or energy efficiency programs.

Ohio:

> Collection expenses are defined as the cost labor, materials, and expenses incurred in work on collections as recorded in the Federal Energy Regulatory Commission (FERC) 903 account during a rate case. Collection expenses may also include uncollectible expenses.

Question 12: Questions about utility collections expenses:

Colorado, New Hampshire, and Ohio track utility collections expenses. Only Colorado includes CAP expenses in their utility collections expenses.

None of these states reported seeing a corresponding reduction in utility collections expenses for increased enrollment of low-income customers in their CAP programs.

Only Colorado reported having different collections procedures for CAP, non-CAP low-income, and non-low-income residential customers. For low-income customers, expenses are included in the low-income program while all other collection expenses are included in base rates.

None of the responding states reported observing better payment patterns for low-income customers who are in CAP compared to low-income customers not in CAP.

Question 13: On the average over each of the past five years (2012-2016), what percent of monthly payments for CAP customers are paid in full?

Ohio

Percent of Monthly CAP Bills Paid in Full		
Year	**Electric**	**Gas**
2012	52%	50%
2013	52%	51%
2014	53%	53%
2015	55%	59%
2016	55%	59%

Question 14: For each of the past five years (2012-2016), what were the service termination rates?

Ohio:

Ohio CAP Termination Rates			
Year	**CAP Customers**	**CLI Customers**	**Non-CAP Residential**
2012	11%	**No Response**	3%
2013	17%	**No Response**	6%
2014	9%	**No Response**	5%
2015	3%	**No Response**	3%
2016	11%	**No Response**	5%

Appendix 9 –CAP Costs and Forecasts

Appendix 9.A: Table 10-3 NGDC Residential Customers and Average CAP Enrollment Used to Calculate NGDC Non-CAP Residential Customers

Appendix 9.A.1: **NGDC Residential Customers**

NGDC Residential Customers						
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Columbia	382,677	384,213	386,150	387,782	390,394	393,410
NFG	198,663	198,763	198,681	199,061	197,992	196,950
PECO Gas	454,583	456,331	461,173	465,404	470,133	480,586
Peoples	329,809	330,123	330,459	331,587	331,814	333,761
Peoples EQT	241,778	242,632	243,610	245,930	243,371	247,930
PGW	479,889	468,943	469,283	470,788	473,019	474,960
UGI Gas	317,170	324,576	331,583	338,929	345,693	352,720
UGI PNG	147,046	149,097	150,495	151,648	152,761	154,319

Source: Universal Service Programs & Collections Performance Reports 2012-2017.

Appendix 9.A.2: **NGDC Annual Average CAP Enrollment**

NGDC Average CAP Enrollment						
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Columbia	21,137	19,803	21,418	21,925	21,509	22,921
NFG	11,208	9,961	9,797	9,577	8,615	8,014
PECO Gas	23,847	23,744	24,667	24,813	23,915	21,898
Peoples	15,009	18,170	19,762	20,432	19,807	18,194
Peoples EQT	13,122	11,280	13,334	14,333	13,564	13,009
PGW	80,343	74,507	63,578	60,507	52,767	48,471
UGI Gas	6,135	4,859	6,709	8,693	8,026	8,326
UGI PNG	4,214	3,760	5,279	6,717	6,116	5,666

Source: Universal Service Programs & Collections Performance Reports 2012-2017.

Appendix 9.B: Table 10-1 NGDCs CAP Total Costs with 5-Year Forecasting

Appendix 9.B.1: **NGDC Actual Total Gross CAP Costs**

Actual Total Gross CAP Costs						
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Columbia	$8,167,972	$13,272,158	$18,237,407	$18,204,869	$13,544,667	$19,668,704
NFG	$1,958,376	$1,838,472	$1,934,109	$1,489,477	$1,169,595	$1,199,650
PECO Gas	$4,555,567	$5,219,029	$5,294,959	$4,905,156	$2,857,660	$2,357,836
Peoples	$6,022,673	$8,227,588	$11,270,401	$12,607,004	$6,606,963	$8,102,420
Peoples EQT	$6,055,041	$7,090,722	$9,988,104	$8,614,710	$3,826,459	$5,328,722
PGW	$73,059,396	$77,281,237	$71,187,450	$56,502,542	$47,310,248	$49,005,928
UGI Gas	$2,662,779	$3,176,112	$2,482,458	$4,145,889	$2,470,474	$3,187,005
UGI PNG	$2,782,805	$2,852,339	$2,299,074	$3,747,453	$2,137,095	$2,088,411
Industry Average	**$13,158,076.13**	**$14,869,707.13**	**$15,336,745.25**	**$13,777,137.50**	**$9,990,395.13**	**$11,367,334,50**

Source: Universal Service Programs & Collections Performance Reports 2012-2017.

Appendix 9.B.2: **NGDC Forecast Total Gross CAP Costs***

Forecast Total Gross CAP Costs				
	2018	**2019**	**2020**	**2021**
Columbia	$13,650,000	*$22,718,175*	*$22,718,175*	*$22,718,175*
NFG	$2,323,457	$2,434,767	$2,535,559	*$3,011,408*
PECO Gas	*$3,154,191*	*$2,435,981*	*$2,439,918*	*$2,564,742*
Peoples	$5,897,531	*$7,064,231*	*$7,065,818*	*$7,067,452*
Peoples EQT	$3,907,618	*$4,531,268*	*$4,532,356*	*$4,533,476*
PGW	$56,071,383	$58,428,965	$59,694,816	$63,614,524
UGI Gas	*$3,970,000*	*$4,135,000*	*$4,341,750*	$4,735,391
UGI PNG	*$3,025,000*	*$3,235,000*	*$3,396,750*	$3,863,164
Industry Average	**$11,367,334,50**	**$13,122,923.43**	**$13,340,642.77**	**$14,013,541.41**

*Italicized numbers reflect projected CAP costs from USECPs that the Commission has not yet approved.

Appendix 9.C: Table 10-4 EDC Residential Customers and Average CAP Enrollment Used to Calculate EDC Non-CAP Residential Customers

Appendix 9.C.1: **EDC Residential Customers**

EDC Residential Customers						
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Duquesne	525,683	526,817	527,390	525,714	526,283	532,204
Met-Ed	487,312	488,375	490,059	492,501	495,698	499,192
PECO Electric	1,418,715	1,421,426	1,430,397	1,440,188	1,450,942	1,463,266
Penelec	505,013	504,543	503,596	502,415	501,820	501,533
Penn Power	140,666	141,147	141,745	142,591	143,536	144,286
PPL	1,215,950	1,218,734	1,221,960	1,226,583	1,231,155	1,223,076
West Penn	618,033	619,531	621,020	622,404	623,830	624,914

Source: Universal Service Programs & Collections Performance Reports 2012-2017.

Appendix 9.C.2: **EDC Annual Average CAP Enrollment**

EDC Average CAP Enrollment						
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Duquesne	36,085	36,544	35,352	35,602	38,719	37,596
Met-Ed	29,574	23,290	17,111	15,639	14,750	14,875
PECO Electric	138,691	138,086	141,297	140,469	136,841	126,401
Penelec	38,962	30,687	23,440	21,865	21,291	21,154
Penn Power	9,830	7,262	5,277	4,678	4,596	4,667
PPL	34,462	35,197	38,373	45,801	53,970	52,726
West Penn	21,965	20,627	21,820	23,071	23,892	25,568

Source: Universal Service Programs & Collections Performance Reports 2012-2017.

Appendix 9.D: Table 10-2 EDCs CAP Total Costs with 5-Year Forecasting

Appendix 9.D.1: **EDC Actual Total Gross CAP Costs**

Actual Total Gross CAP Costs						
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Duquesne	$16,680,684	$16,549,705	$15,888,626	$18,984,666	$21,244,454	$23,083,236
Met-Ed	$28,356,979	$22,984,906	$17,525,198	$15,113,962	$14,313,820	$14,758,527
PECO Electric	$94,760,602	$91,508,724	$94,812,522	$96,675,303	$92,369,577	$70,653,278
Penelec	$30,152,302	$25,303,288	$20,236,493	$18,127,221	$18,254,884	$18,852,006
Penn Power	$8,861,651	$6,116,965	$4,287,789	$3,970,526	$4,275,287	$4,435,519
PPL	$49,106,215	$55,223,019	$72,016,857	$83,614,471	$86,446,411	$80,923,575
West Penn	$8,495,135	$10,768,235	$13,385,035	$16,540,073	$24,609,316	$27,280,111
Industry Average	**$33,773,366.86**	**$32,636,406.00**	**$34,021,788.57**	**$36,146,603.14**	**$37,359,107.00**	**$34,283,750.29**

Source: Universal Service Programs & Collections Performance Reports 2012-2017.

Appendix 9.D.2: **EDC Forecast Total Gross CAP Costs***

Forecast Total Gross CAP Costs				
	2018	**2019**	**2020**	**2021**
Duquesne	$26,652,524	$27,434,572	$29,970,350	$32,256,531
Met-Ed	$16,652,500	*$17,818,900*	*$17,791,600*	*$17,791,600*
PECO Electric	$94,802,060	$73,215,616	$73,333,937	$77,085,620
Penelec	$22,202,500	*$23,556,250*	*$23,874,650*	*$24,228,000*
Penn Power	$5,068,000	*$5,681,250*	*$5,773,800*	*$5,879,000*
PPL	$118,000,000	$129,000,000	$156,407,274	$181,479,403
West Penn	$31,855,500	*$38,511,900*	*$38,916,350*	*$39,465,800*
Industry Average	**$45,033,297.67**	**$45,031,212.51**	**$49,438,280.07**	**$54,026,564.90**

*Italicized numbers reflect projected CAP costs from USECPs that the Commission has not yet approved.

Appendix 9.E: Table 10-5 NGDC Annual CAP Costs per Non-CAP Residential Customer 2012-2016 and 5-Year Forecasting if CAP Enrollment Adjustments Ranged between a Decrease of 10% and an Increase of 10%

Appendix 9.E.1: **Actual Data and Forecasts – Columbia**

	Actual Data						Forecasts			
Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Avg Annual CAP Cost per Non-CAP Residential Customer	$22.59	$36.42	$50.00	$49.76	$36.72	$53.09	$36.66	$60.74	$60.47	$60.21
-10%	$20.33	$32.78	$45.00	$44.78	$33.05	$47.78	$32.99	$54.67	$54.42	$54.19
-5%	$21.46	$34.60	$47.50	$47.27	$34.88	$50.43	$34.83	$57.70	$57.45	$57.20
-1%	$22.37	$36.06	$49.50	$49.26	$36.35	$52.56	$36.29	$60.13	$59.87	$59.61
No Change										
1%	$22.82	$36.79	$50.50	$50.26	$37.09	$53.62	$37.03	$61.35	$61.07	$60.81
5%	$23.72	$38.24	$52.50	$52.25	$38.55	$55.74	$38.49	$63.78	$63.49	$63.22
10%	$24.85	$40.06	$55.00	$54.74	$40.39	$58.40	$40.33	$66.81	$66.52	$66.23

Appendix 9.E.2: **Actual Data and Forecasts – NFG**

	Actual Data						Forecasts			
Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Avg Annual CAP Cost per Non-CAP Residential Customer	$10.45	$9.74	$10.24	$7.86	$6.18	$6.35	$12.29	$12.86	$13.38	$15.88
-10%	$9.40	$8.76	$9.22	$7.07	$5.56	$5.71	$11.06	$11.57	$12.04	$14.29
-5%	$9.92	$9.25	$9.73	$7.47	$5.87	$6.03	$11.68	$12.22	$12.71	$15.09
-1%	$10.34	$9.64	$10.14	$7.78	$6.11	$6.29	$12.17	$12.73	$13.25	$15.72
No Change										
1%	$10.55	$9.83	$10.34	$7.94	$6.24	$6.41	$12.41	$12.99	$13.51	$16.04
5%	$10.97	$10.22	$10.75	$8.25	$6.48	$6.67	$12.90	$13.50	$14.05	$16.67
10%	$11.49	$10.71	$11.26	$8.65	$6.79	$6.98	$13.52	$14.15	$14.72	$17.47

Appendix 9.E.3: **Actual Data and Forecasts – PECO Gas**

	Actual Data						Forecasts			
Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Avg Annual CAP Cost per Non-CAP Residential Customer	$10.58	$12.06	$12.13	$11.13	$6.40	$5.14	$6.72	$5.06	$4.94	$5.07
-10%	$9.52	$10.86	$10.92	$10.02	$5.76	$4.63	$6.05	$4.55	$4.45	$4.56
-5%	$10.05	$11.46	$11.52	$10.58	$6.08	$4.88	$6.38	$4.81	$4.69	$4.82
-1%	$10.47	$11.94	$12.01	$11.02	$6.34	$5.09	$6.65	$5.01	$4.89	$5.02
No Change										
1%	$10.68	$12.19	$12.25	$11.24	$6.47	$5.19	$6.79	$5.11	$4.99	$5.12
5%	$11.11	$12.67	$12.74	$11.69	$6.72	$5.40	$7.06	$5.31	$5.19	$5.32
10%	$11.63	$13.27	$13.34	$12.25	$7.04	$5.65	$7.39	$5.57	$5.43	$5.58

Appendix 9.E.4: **Actual Data and Forecasts – Peoples**

	Actual Data						Forecasts			
Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Avg Annual CAP Cost per Non-CAP Residential Customer	$19.13	$26.37	$36.27	$40.52	$21.18	$25.68	$18.69	$22.36	$22.34	$22.32
-10%	$17.22	$23.74	$32.65	$36.47	$19.06	$23.11	$16.82	$20.12	$20.11	$20.09
-5%	$18.18	$25.06	$34.46	$38.49	$20.12	$24.39	$17.76	$21.24	$21.22	$21.20
-1%	$18.94	$26.11	$35.91	$40.11	$20.96	$25.42	$18.50	$22.14	$22.12	$22.10
No Change										
1%	$19.32	$26.64	$36.64	$40.92	$21.39	$25.93	$18.88	$22.58	$22.56	$22.54
5%	$20.09	$27.69	$38.09	$42.54	$22.23	$26.96	$19.62	$23.48	$23.46	$23.44
10%	$21.04	$29.01	$39.90	$44.57	$23.29	$28.24	$20.56	$24.60	$24.57	$24.55

Appendix 9.E.5: **Actual Data and Forecasts – Peoples EQT**

	Actual Data						Forecasts			
Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Avg Annual CAP Cost per Non-CAP Residential Customer	$26.48	$30.65	$43.37	$37.20	$16.65	$22.68	$16.77	$19.27	$19.31	$19.14
-10%	$23.83	$23.74	$32.65	$36.47	$19.06	$23.11	$16.82	$20.12	$20.11	$20.09
-5%	$25.16	$25.06	$34.46	$38.49	$20.12	$24.39	$17.76	$21.24	$21.22	$21.20
-1%	$26.22	$26.11	$35.91	$40.11	$20.96	$25.42	$18.50	$22.14	$22.12	$22.10
No Change										
1%	$26.75	$26.64	$36.64	$40.92	$21.39	$25.93	$18.88	$22.58	$22.56	$22.54
5%	$27.81	$27.69	$38.09	$42.54	$22.23	$26.96	$19.62	$23.48	$23.46	$23.44
10%	$29.13	$33.71	$47.71	$40.92	$18.32	$24.95	$18.45	$21.20	$21.24	$21.05

Appendix 9.E.6: **Actual Data and Forecasts – PGW**[100]

	Actual Data						Forecasts			
Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Avg Annual CAP Cost per Non-CAP Residential Customer	$137.14	$144.99	$130.90	$101.63	$79.03	$81.12	$90.06	$92.93	$92.93	$86.51
-10%	$123.43	$130.49	$117.81	$91.47	$71.13	$73.01	$81.05	$83.64	$83.64	$77.86
-5%	$130.28	$137.74	$124.36	$96.55	$75.08	$77.06	$85.56	$88.28	$88.28	$82.18
-1%	$135.77	$143.54	$129.59	$100.61	$78.24	$80.31	$89.16	$92.00	$92.00	$85.64
No Change										
1%	$138.51	$146.44	$132.21	$102.65	$79.82	$81.93	$90.96	$93.86	$93.86	$87.38
5%	$144.00	$152.24	$137.45	$106.71	$82.98	$85.18	$94.56	$97.58	$97.58	$90.84
10%	$150.85	$159.49	$143.99	$111.79	$86.93	$89.23	$99.07	$102.22	$102.22	$95.16

Appendix 9.E.7: **Actual Data and Forecasts – UGI Gas**

	Actual Data						Forecasts			
Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Avg Annual CAP Cost per Non-CAP Residential Customer	$8.56	$9.93	$7.64	$12.55	$7.32	$9.25	$11.32	$11.58	$11.94	$12.79
-10%	$7.70	$8.94	$6.88	$11.30	$6.58	$8.33	$10.19	$10.42	$10.75	$11.51
-5%	$8.13	$9.44	$7.26	$11.93	$6.95	$8.79	$10.75	$11.00	$11.34	$12.15
-1%	$8.48	$9.83	$7.56	$12.43	$7.24	$9.16	$11.21	$11.46	$11.82	$12.66
No Change										
1%	$8.65	$10.03	$7.72	$12.68	$7.39	$9.35	$11.43	$11.70	$10.75	$11.51
5%	$8.99	$10.43	$8.02	$13.18	$7.68	$9.72	$11.89	$12.16	$11.34	$12.15
10%	$9.42	$10.93	$8.41	$13.81	$8.05	$10.18	$12.45	$12.74	$11.82	$12.66

[100] Forecasts for PGW are based on 70% residential allocation of CAP costs.

Appendix 9.E.8: **Actual Data and Forecasts – UGI PNG**

	Actual Data						Forecasts			
Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Avg Annual CAP Cost per Non-CAP Residential Customer	$19.48	$19.63	$15.83	$25.86	$14.57	$14.05	$20.34	$21.63	$22.57	$25.52
-10%	$17.53	$17.66	$14.25	$23.27	$13.12	$12.64	$18.31	$19.47	$20.31	$22.97
-5%	$18.51	$18.64	$15.04	$24.56	$13.84	$13.35	$19.32	$20.55	$21.44	$24.24
-1%	$19.29	$19.43	$15.67	$25.60	$14.43	$13.91	$20.14	$21.41	$22.34	$25.26
No Change										
1%	$19.68	$19.82	$15.99	$26.12	$14.72	$14.19	$20.54	$21.85	$22.80	$25.78
5%	$20.46	$20.61	$16.62	$27.15	$15.30	$14.75	$21.36	$22.71	$23.70	$26.80
10%	$21.43	$21.59	$17.42	$28.44	$16.03	$15.45	$22.37	$23.79	$24.83	$28.07

Appendix 9.F: Table 10-6 EDC Annual CAP Costs per Non-CAP Residential Customer 2012-2016, With CAP Enrollment Adjustments and 5-Year Forecasting

Appendix 9.F.1: **Actual Data and Forecasts – Duquesne**

	Actual Data						Forecasts			
Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Avg Annual CAP Cost per Non-CAP Residential Customer	$34.07	$33.76	$32.29	$38.74	$43.57	$46.67	$54.13	$55.67	$60.76	$65.34
-10%	$30.66	$30.38	$29.06	$34.86	$39.22	$42.00	$48.72	$50.10	$54.68	$58.81
-5%	$32.37	$32.07	$30.68	$36.80	$41.39	$44.34	$51.42	$52.89	$57.72	$62.07
-1%	$33.73	$33.42	$31.97	$38.35	$43.14	$46.20	$53.59	$55.11	$60.15	$64.69
No Change										
1%	$34.41	$34.09	$32.61	$39.12	$44.01	$47.14	$54.67	$56.23	$61.37	$65.99
5%	$35.77	$35.44	$33.91	$40.67	$45.75	$49.00	$56.84	$58.45	$63.80	$68.61
10%	$37.48	$37.13	$35.52	$42.61	$47.93	$51.34	$59.54	$61.24	$66.84	$71.87

Appendix 9.F.2: **Actual Data and Forecasts – Met-Ed**

	Actual Data						Forecasts			
Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Avg Annual CAP Cost per Non-CAP Residential Customer	$61.95	$49.42	$37.06	$31.69	$29.76	$30.47	$34.03	$36.04	$35.62	$35.26
-10%	$55.76	$44.48	$33.35	$28.53	$26.79	$27.43	$30.63	$32.44	$32.06	$31.73
-5%	$58.85	$46.95	$35.20	$30.11	$28.27	$28.95	$32.33	$34.24	$33.84	$33.50
-1%	$61.33	$48.93	$36.68	$31.38	$29.46	$30.17	$33.69	$35.68	$35.26	$34.91
No Change										
1%	$62.57	$49.92	$37.43	$32.01	$30.06	$30.78	$34.37	$36.40	$35.98	$35.61
5%	$65.05	$51.89	$38.91	$33.28	$31.25	$32.00	$35.73	$37.84	$37.40	$37.02
10%	$68.15	$54.36	$40.76	$34.86	$32.74	$33.52	$37.43	$39.64	$39.18	$38.79

Appendix 9.F.3: **Actual Data and Forecasts – PECO Electric**

	Actual Data						Forecasts			
Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Avg Annual CAP Cost per Non-CAP Residential Customer	$74.03	$71.31	$73.55	$74.38	$70.29	$52.85	$69.92	$53.42	$52.96	$55.12
-10%	$66.63	$64.17	$66.19	$66.94	$63.26	$47.56	$62.93	$48.08	$47.66	$49.61
-5%	$70.33	$67.74	$69.87	$70.66	$66.78	$50.21	$66.42	$50.75	$50.31	$52.36
-1%	$73.29	$70.59	$72.81	$73.64	$69.59	$52.32	$69.22	$52.89	$52.43	$54.57
No Change										
1%	$74.77	$72.02	$74.28	$75.13	$70.99	$53.38	$70.62	$53.95	$53.49	$55.67
5%	$77.73	$74.87	$77.23	$78.10	$73.81	$55.49	$73.42	$56.09	$55.61	$57.88
10%	$81.43	$78.44	$80.90	$81.82	$77.32	$58.13	$76.91	$58.76	$58.26	$60.63

Appendix 9.F.4: **Actual Data and Forecasts – Penelec**

	Actual Data						Forecasts			
Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Avg Annual CAP Cost per Non-CAP Residential Customer	$64.70	$53.40	$42.15	$37.72	$37.99	$39.24	$46.04	$48.62	$49.05	$49.55
-10%	$58.23	$48.06	$37.93	$33.95	$34.19	$35.32	$41.44	$43.76	$44.15	$44.60
-5%	$61.46	$50.73	$40.04	$35.84	$36.09	$37.28	$43.74	$46.19	$46.60	$47.07
-1%	$64.05	$52.86	$41.72	$37.34	$37.61	$38.85	$45.58	$48.13	$48.56	$49.05
No Change										
1%	$65.34	$53.93	$42.57	$38.10	$38.37	$39.64	$46.50	$49.11	$49.54	$50.05
5%	$67.93	$56.07	$44.25	$39.61	$39.89	$41.21	$48.34	$51.05	$51.50	$52.03
10%	$71.17	$58.74	$46.36	$41.49	$41.79	$43.17	$50.64	$53.48	$53.96	$54.51

Appendix 9.F.5: **Actual Data and Forecasts – Penn Power**

	Actual Data						Forecasts			
Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Avg Annual CAP Cost per Non-CAP Residential Customer	$67.73	$45.69	$31.42	$28.79	$30.77	$31.77	$35.88	$39.76	$39.96	$40.23
-10%	$60.96	$41.12	$28.28	$25.91	$27.69	$28.59	$32.29	$35.78	$35.96	$36.21
-5%	$64.34	$43.40	$29.85	$27.35	$29.23	$30.18	$34.09	$37.77	$37.96	$38.22
-1%	$67.05	$45.23	$31.11	$28.50	$30.46	$31.45	$35.52	$39.36	$39.56	$39.83
No Change										
1%	$68.41	$46.15	$31.73	$29.08	$31.08	$35.88	$39.76	$39.96	$40.23	$35.88
5%	$71.12	$47.97	$32.99	$30.23	$32.31	$32.29	$35.78	$35.96	$36.21	$32.29
10%	$74.50	$50.26	$34.56	$31.67	$33.85	$34.09	$37.77	$37.96	$38.22	$34.09

Appendix 9.F.6: **Actual Data and Forecasts – PPL**

	Actual Data						Forecasts			
Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Avg Annual CAP Cost per Non-CAP Residential Customer	$41.56	$46.66	$60.85	$70.81	$73.43	$69.14	$100.41	$109.99	$133.63	$155.37
-10%	$37.41	$41.99	$54.76	$63.73	$66.09	$62.23	$90.37	$98.99	$120.27	$139.83
-5%	$39.48	$44.33	$57.80	$67.27	$69.76	$65.69	$95.39	$104.49	$126.95	$147.60
-1%	$41.15	$46.19	$60.24	$70.10	$72.70	$68.45	$99.41	$108.89	$132.29	$153.82
No Change										
1%	$41.98	$47.13	$61.45	$71.52	$74.17	$69.84	$101.41	$111.09	$134.97	$156.92
5%	$43.64	$48.99	$63.89	$74.35	$77.11	$72.60	$105.43	$115.49	$140.31	$163.14
10%	$45.72	$51.33	$66.93	$77.89	$80.78	$76.06	$110.45	$120.99	$146.99	$170.91

Appendix 9.F.7: **Actual Data and Forecasts – West Penn**

	Actual Data						Forecasts			
Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Avg Annual CAP Cost per Non-CAP Residential Customer	$14.25	$17.98	$22.34	$27.60	$41.02	$45.52	$53.10	$64.15	$64.78	$65.65
-10%	$12.83	$16.18	$20.10	$24.84	$36.92	$40.96	$47.79	$57.74	$58.30	$59.09
-5%	$13.54	$17.08	$21.22	$26.22	$38.97	$43.24	$50.45	$60.94	$61.54	$62.37
-1%	$14.11	$17.80	$22.11	$27.32	$40.61	$45.06	$52.57	$63.51	$64.13	$64.99
No Change										
1%	$14.39	$18.16	$22.56	$27.87	$41.43	$45.97	$53.63	$64.79	$65.43	$66.31
5%	$14.96	$18.88	$23.46	$28.98	$43.07	$47.79	$55.76	$67.36	$68.02	$68.93
10%	$15.68	$19.78	$24.57	$30.36	$45.12	$50.07	$58.41	$70.57	$71.26	$72.22

Appendix 9.G: Table 10-7 NGDCs Industry Cost per Non-CAP Residential Customer 5-Year Forecasting with Cost Adjustments 2017-2021

Appendix 9.G.1: **NGDC Industry Forecasts: Costs per Non-CAP Residential Customer with Cost Adjustments**

NGDC Industry Forecasts per Non-CAP Residential Customer with CAP Enrollment Adjustments					
Year	**2017***	**2018**	**2019**	**2020**	**2021**
-10%	$24.79	$24.16	$28.07	$28.52	$28.19
-5%	$26.17	$25.50	$29.63	$29.80	$29.76
-1%	$27.27	$26.58	$30.88	$31.05	$31.01
1%	$27.82	$27.11	$31.50	$31.51	$31.46
5%	$28.92	$28.19	$32.75	$32.78	$32.73
10%	$29.89	$29.27	$33.88	$33.92	$33.85

*2017 actual data from USR

Appendix 9.H: Table 10-8 EDCs Industry Cost per Non-CAP Residential Customer 5-Year Forecasting with Cost Adjustments 2017-2021

Appendix 9.H.1: **EDC Industry Forecasts: Costs per Non-CAP Residential Customer with Cost Adjustments**

EDC Industry Forecasts per Non-CAP Residential Customer with CAP Enrollment Adjustment					
Year	**2017***	**2018**	**2019**	**2020**	**2021**
-10%	$40.59	$50.59	$52.44	$56.15	$59.98
-5%	$42.84	$53.40	$55.32	$59.27	$63.31
-1%	$44.64	$55.65	$57.65	$61.77	$65.98
1%	$45.55	$56.78	$58.82	$63.02	$67.31
5%	$47.35	$59.03	$61.15	$65.51	$69.98
10%	$49.60	$61.84	$64.06	$68.63	$73.31

*2017 actual data from USR

Appendix 9.I: Table 10-10 NGDC CAP Heating Model – Additional Discount Needed for 6% NGDC Energy Burden

The example of a 10% energy burden applicable to all heat sources and FPIG levels would equate to a 6% energy burden for NGDC gas heating and 4% for EDC electric non-heating.

Appendix 9.I.1: **NGDC Model for 6% Energy Burden – Components**

NGDC Model for 6% Energy Burden						
Gas Heating	**Average CAP Bill Change Needed**			**Average CAP Gas Heat**		
	Accounts Billed 2012-2016			**Accounts Billed 2012-2016**		
FPIG Level	**50%**	**100%**	**150%**	**50%**	**100%**	**150%**
Columbia	-$250.47	$0.00	$0.00	4,558	9,485	6,253
PECO Gas	-$799.54	-$620.26	-$557.40	1,187	2,346	1,922
Peoples	-$127.08	-$116.75	$0.00	3,799	8,470	5,992
Peoples EQT	-$154.12	-$221.60	-$194.74	4,182	7,090	1,738
PGW	-$56.98	-$330.82	-$696.37	18,795	36,365	10,808
UGI Gas	-$215.49	-$142.69	-$159.33	2,300	3,317	983
UGI PNG	-$264.12	-$209.47	-$176.26	1,289	2,752	1,083

Note: NFG not included in Model because data were not available at specific FPIG levels.

Appendix 9.I.2: **NGDC Model for 6% Energy Burden – Costs**

NGDC Model for 6% Energy Burden					
	AVG Cost to Reach 6% EB			**Incremental Cost to Change CAP Customers Currently Over 6% with Gas Heating, down to a targeted 6% Energy Burden**	
FPIG Level	**50%**	**100%**	**150%**	**Company**	**Amount**
Columbia	-$1,141,671	$0	$0	**Columbia**	-$1,141,671
PECO Gas	-$949,472	-$1,455,171	-$1,071,488	**PECO Gas**	-$3,476,132
Peoples	-$482,898	-$988,893	$0	**Peoples**	-$1,471,791
Peoples EQT	-$644,602	-$1,571,350	-$338,627	**EQT**	-$2,554,578
PGW	-$1,070,907	-$12,030,427	-$7,526,891	**PGW**	-$20,628,225
UGI Gas	-$495,780	-$473,414	-$156,751	**UGI Gas**	-$1,125,945
UGI PNG	-$340,481	-$576,603	-$191,032	**UGI PNG**	-$1,108,115
				NGDC TOTAL	**-$31,506,457**

Note: NFG not included in Model because data were not available at specific FPIG levels.

Appendix 9.J: Table 10-11 EDC CAP Electric Heating Model – Additional Discount Needed for 10% Energy Burden

Appendix 9.J.1*:* **EDC Model for 10% Energy Burden – Components**

EDC Model for 10% Energy Burden						
Electric Heating	Avg CAP Bill Change Needed Accounts Billed 2012-2016			AVG CAP Electric Heat Accounts Billed 2012-2016		
FPIG Level	**50%**	**100%**	**150%**	**50%**	**100%**	**150%**
Duquesne	-$765.72	-$151.78	$0.00	664	2,071	1,086
Met-Ed	-$65.30	$0.00	$0.00	1,440	3,023	1,660
PECO Electric	-$591.82	-$339.58	-$89.68	4,570	8,916	7,591
Penelec	-$160.46	$0.00	$0.00	904	2,444	1,098
Penn Power	-$668.18	-$29.38	$0.00	259	596	368
PPL	-$296.38	$0.00	$0.00	3,141	9,000	6,557
West Penn	-$562.48	-$27.18	$0.00	1,097	2,220	1,306

Appendix 9.J.2: **EDC Model for 10% Energy Burden – Costs**

EDC Model for 10% Energy Burden					
	AVG Cost to Reach 10% EB			Incremental Cost to Change CAP Customers Currently Over 10% with Electric Heating, down to a targeted 10% Energy Burden	
FPIG Level	**50%**	**100%**	**150%**	**Company**	**Amount**
Duquesne	-$508,936	-$314,354	$0	**Duquesne**	-$823,290
Met-Ed	-$94,059	$0	$0	**Met-Ed**	-$94,059
PECO Electric	-$2,704,923	-$3,027,842	-$680,776	**PECO Electric**	-$6,413,541
Penelec	-$145,120	$0	$0	**Penelec**	-$145,120
Penn Power	-$173,337	-$17,530	$0	**Penn Power**	-$190,867
PPL	-$931,182	$0	$0	**PPL**	-$931,182
West Penn	-$617,331	-$60,351	$0	**West Penn**	-$677,682
				EDC TOTAL	**-$9,275,741**

Appendix 9.K: Table 10-12 EDC CAP Electric Non-Heating Model – Additional Discount Needed for 4% Energy Burden

Appendix 9.K.1: **EDC Model for 4% Energy Burden – Components**

EDC Model for 4% Energy Burden						
Electric Non-Heating	Avg CAP Bill Change Needed Accounts Billed 2012-2016			AVG CAP Electric Non-Heat Accounts Billed 2012-2016		
FPIG Level	50%	100%	150%	50%	100%	150%
Duquesne	-$705.14	-$404.33	-$213.85	6,967	16,182	8,755
Met-Ed	-$231.26	-$55.56	$0.00	4,120	7,452	5,457
PECO Electric	-$446.11	-$312.56	-$193.87	24,293	48,334	29,442
Penelec	-$246.94	$0.00	$0.00	5,594	12,179	8,070
Penn Power	-$461.70	-$68.76	-$51.70	1,173	2,725	2,090
PPL	-$703.36	-$414.81	-$49.54	3,804	10,710	8,133
West Penn	-$475.44	-$335.35	-$251.49	4,163	7,247	4,605

Appendix 9.K.2: **EDC Model for 4% Energy Burden – Costs**

EDC Model for 4% Energy Burden					
	AVG Cost to Reach 4% EB			Incremental Cost to Change CAP Customers Currently Over 4% with Electric Non-Heating, down to a targeted 4% Energy Burden	
FPIG Level	50%	100%	150%	Company	Amount
Duquesne	-$4,912,741	-$6,543,038	-$1,872,303	Duquesne	-$13,328,083
Met-Ed	-$952,977	-$414,068	$0	Met-Ed	-$1,367,045
PECO Electric	-$10,837,681	-$15,107,489	-$5,708,105	PECO Electric	-$31,653,275
Penelec	-$1,381,508	$0	$0	Penelec	-$1,381,508
Penn Power	-$542,033	-$187,418	-$108,075	Penn Power	-$837,526
PPL	-$2,676,214	-$4,442,829	-$402,887	PPL	-$7,521,930
West Penn	-$1,979,613	-$2,430,374	-$1,158,215	West Penn	-$5,568,203
				EDC TOTAL	**-$61,657,570**

Appendix 9.L: Table 1-2 NGDC and EDC Energy Usage/Demand Forecasts

Appendix 9.L.1: **Residential Natural Gas Usage Forecasts**

	Retail Residential Gas Usage (Firm Sales) Forecast in Mmcf						2016-2021
Utility:	**2016***	**2017***	***2018***	***2019***	***2020***	***2021***	**Percent Change**
Columbia	24,389	24,984	*23,520*	*23,617*	*23,737*	*23,891*	-2.1%
NFG	15,556	15,602	*17,425*	*17,529*	*17,652*	*17,671*	13.6%
Peoples	40,745	40,873	*41,781*	*41,885*	*41,011*	*41,061*	0.8%
EQT	(Combined with Peoples)						
PGW	30,604	32,668	*35,189*	*35,131*	*35,382*	*35,595*	16.3%
UGI Gas	20,096	20,609	*22,551*	*23,174*	*23,815*	*24,461*	21.7%
UGI PNG	15,160	14,880	*16,844*	*17,003*	*17,138*	*17,319*	14.2%
PECO Gas	35,159	37,918	*41,662*	*41,886*	*42,265*	*42,637*	21.3%

Source: 2018 Annual Resource Planning Reports (ARPR)
*Actual Data

Appendix 9.L.2: **Residential Electric Demand Forecasts**

		Projected Residential Electric Demand in GWh						2016-2021
Utility:		**2016***	**2017***	***2018***	***2019***	***2020***	***2021***	**Percent Change**
Duquesne		4,197	3,876	*3,949*	*3,915*	*3,856*	*3,797*	-9.5%
Met-Ed		5,528	5,351	*5,347*	*5,265*	*5,201*	*5,166*	-6.6%
Penelec		4,328	4,153	*4,238*	*4,157*	*4,090*	*4,056*	-6.3%
Penn Power		1,686	1,591	*1,640*	*1,617*	*1,604*	*1,595*	-5.4%
PECO		13,664	13,024	*13,266*	*13,240*	*13,182*	*13,104*	-4.1%
PPL		13,810	13,650	*13,588*	*13,499*	*13,448*	*13,253*	-4.0%
West Penn		7,186	6,817	*6,931*	*6,906*	*6,819*	*6,756*	-6.0%

Source: 2018 Electric Power Outlook for Pennsylvania -
http://www.puc.pa.gov/General/publications_reports/pdf/EPO_2018.pdf
*Actual Data

Appendix 9.L.3: **Residential National Energy Prices: U.S. EIA**

U.S. Energy Information Administration Historic and Forecast Prices											
Residential	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	***2019***	***2020***	***2021***	**Percent Change**
Units: 2017 $/MMBtu	**Historic**							***Forecast***			**2017-2021**
Energy Prices: Natural Gas	10.60	10.01	10.73	10.25	9.93	10.77	10.39	*10.79*	*11.06*	*11.17*	**3.7%**
Energy Prices: Electricity	35.35	35.64	37.08	37.60	37.46	37.12	37.08	*38.07*	*39.18*	*39.42*	**6.2%**

Appendix 9.M: ***Variance between USECP CAP Cost Projections and Actual CAP Costs***

Appendix 9.M.1: **Variance between USECP CAP Cost Projections and Actual CAP Costs – Energy Industry 2015-2017 (EDC + NGDC)**

	2015	2016	2017	Total	Overall % Spend
CAP Costs from USECPs	$362,091,155	$351,521,805	$367,747,093	$1,081,360,053	
Actual USR CAP Costs	$348,439,656	$327,338,456	$325,596,206	$1,001,374,318	92.6%

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Energy Economics 33 (2011) 870–881

Contents lists available at ScienceDirect

Energy Economics

journal homepage: www.elsevier.com/locate/eneco

Residential consumption of gas and electricity in the U.S.: The role of prices and income

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ARTICLE INFO

Article history:
Received 30 November 2010
Received in revised form 28 January 2011
Accepted 31 January 2011
Available online 10 March 2011

JEL classification:
Q4
Q41
Q48
Q54
Q58

Keywords:
Residential electricity and gas demand
Price elasticity of energy demand
Static model
Dynamic panel data model
Partial adjustment model

ABSTRACT

We study the residential demand for electricity and gas, working with nationwide household-level data that cover recent years, namely 1997–2007. Our dataset is a mixed panel/multi-year cross-sections of dwellings/households in the 50 largest metropolitan areas in the United States as of 2008. We estimate static and dynamic models of electricity and gas demand. We find strong household response to energy prices, both in the short and long term. From the static models, we get estimates of the own price elasticity of electricity demand in the −0.860 to −0.667 range, while the own price elasticity of gas demand is −0.693 to −0.566. These results are robust to a variety of checks. Contrary to earlier literature (Metcalf and Hassett, 1999; Reiss and White, 2005), we find no evidence of significantly different elasticities across households with electric and gas heat. The price elasticity of electricity demand declines with income, but the magnitude of this effect is small. These results are in sharp contrast to much of the literature on residential energy consumption in the United States, and with the figures used in current government agency practice. Our results suggest that there might be greater potential for policies which affect energy price than may have been previously appreciated.

1. Introduction

In the United States and in other developed countries, buildings account for over 40% of total annual energy use. Despite many recent policies that either mandate or promote energy efficiency among residential energy users,[1] U.S. residential energy demand has grown over the last three decades, and projections suggest that it will continue to do so for the foreseeable future (Energy Information Agency, 2010).

Recently, there has been considerable debate in academic and policy circles as to whether retail energy prices, including those charged to the residential sector, will increase or decrease as a result of deregulation (Fabrizio et al., 2007; Showalter, 2007a,b; Carlson and Loomis, 2008), establishment of emissions trading markets (e.g., Frondel et al., 2008; Burtraw et al., 2002; Smale et al., 2006), and imposition of renewable portfolio standards, which is usually done at the state level (Fischer, 2010). More stringent environmental regulations on emissions and pollutants from power plants (e.g., nitrogen and sulfur oxides, and mercury) and tightened ambient air quality standards are also expected to increase the cost of energy to consumers.[2]

For the purpose of forecasting demand and planning for generation, transmission and distribution capacity, and for energy policy purposes, it is important to measure the responsiveness of residential

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[1] The American Recovery and Reinvestment Act (the Stimulus Bill) of 2009, for instance, allocated some $27.2 Billion for energy efficiency and renewable energy R&D. Yet, despite many cost-effective opportunities for energy efficiency improvement, projects often go unpursued. In principle, were homeowners aware of the future energy savings, they would spontaneously undertake energy efficiency investments in their homes. In practice, consumers and homeowners have often been observed to pass up opportunities to make energy-efficiency investments. Possible explanations for the so-called "energy paradox" (Jaffe and Stavins, 1994) include liquidity constraints, limited information, uncertainty about future energy prices (Hassett and Metcalf, 1993), high rates of intertemporal preferences, disbelief in engineering estimates of the cost savings themselves (Metcalf and Hassett, 1999), and institutional disincentives (see Golove and Eto, 1996).

[2] Financing costs from investments to electricity transmission and distribution infrastructure, volatility and rising scarcity in feedstocks such as coal, propane, natural gas, and petroleum, and the establishment of a price on carbon, are all possible mechanisms which would increase the price of energy (Basheda et al., 2006).

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doi:10.1016/j.eneco.2011.01.015

Table 1
Selected empirical studies and price elasticity estimates.

Study	Type of data coverage	Estimate, fuel demand
Dergiades and Tsoulfidis (2008)	Nationwide total, time series, 1965–2006	−0.386 *short-run* (−1.06 *long-run*) electricity
Kamerschen and Porter (2004)	Nationwide total, time series, 1973–1998	Long-run: −0.94 to −0.85 electricity
Alberini and Filippini (2010)	State-level, panel data, 1995–2007	−0.15 to −0.08 (−0.78 to −0.44) electricity
Bernstein and Griffin (2005)	State-level, panel data, 1997–2004	−0.243 (−0.32) electricity
Paul et al. (2009)	State-level, panel data, 1990–2006	−0.13 (−0.36) electricity
Maddala et al. (1997)	State-level, panel data, 1970–1990	−0.19 to −0.21 (−0.56 to −1.03) electricity −0.09 to −0.18 (0.24 to −1.36) gas
Garcia-Cerrutti (2000)	California county-level, panel data, 1983–1997	Long-run: −0.17 electricity; −0.11 gas
Quigley and Rubinfeld (1989)	AHS household-level, cross section, 1980	−0.1 energy
Fell et al. (2010)	CEX and RECS household-level, 2004–2006	−0.82 to −1.02 electricity
Metcalf and Hassett (1999)	RECS household-level, panel data, 1984, 1987 and 1990	−0.78 to −1.11 electricity; −0.48 to −0.71 gas
Reiss and White (2005)	California RECS, household-level, multi-year cross sections, 1993 and 1997	−0.85 to −1.02 electricity
Studies outside the U.S.		
Meier and Rehdanz (2010)	UK, household-level, panel data, 1991–2005	−0.4 to −0.49 oil −0.34 to −0.56 gas
Rehdanz (2007)	Germany household-level panel, 1998 and 2003	−2.03 to−1.68 oil; −0.63 to −0.44 gas
Leth-Petersen and Togeby (2001)	Denmark panel data, 1984–995	−0.08 oil; −0.02 district heating
Bernard et al. (2010)	Quebec household-level, multi-year cross-sections, 1989–2002	−0.51 (−1.32) electricity
Nesbakken (1999)	Norway household level, multi-year cross-sections, 1990–1992, 1994–1995	−0.33 (−0.66) electricity

energy demand to the prices of electricity and gas, the two major sources of residential energy in the U.S. Earlier research has examined household demand for energy and its responsiveness to price, but these analyses i) used old data (Quigley and Rubinfeld, 1989; Metcalf and Hassett, 1999), ii) are restricted to limited geographical areas (e.g., Garcia-Cerrutti, 2000; Reiss and White, 2005), so that it is difficult to extrapolate their results to other areas with different climates, housing stock and electricity suppliers, or iii) were based on cross-sections or extremely short panels of data (with a maximum of two observations per household) (e.g., Metcalf and Hassett, 1999), and did not fully address issues of unobserved heterogeneity and endogeneity. In some cases, responsiveness to price was inferred from supply shocks so severe and geographically circumscribed (e.g., Bushnell and Mansur, 2005; Reiss and White, 2008) as to render them inapplicable for broader areas and more gradual price changes.

For these reasons, in this paper we wish to ask three research questions. First, what *are* the (nationwide) price elasticities of residential electricity and gas demand? Second, is such responsiveness sensitive to equipment and energy choices that are not easily reversed (e.g., using gas or electricity for heating or cooling)? Third, how does household income influence demand and the price elasticities?

We use energy utility data for over 69,000 single-family homes and duplexes (74,000 households) in the 50 largest metropolitan areas in the US for 1997–2007, and estimate static and dynamic models, with and without controls for the current stock of appliances. Unobserved heterogeneity is accounted for using fixed effects at various levels (at the city, dwelling and dwelling-household level). Briefly, we find that electricity use is responsive to the price of electricity (with an elasticity that ranges from −0.67 to −0.86) and increases with the price of gas, indicating that the latter is a substitute for electricity. The demand for gas is only slightly less responsive, with own-price elasticities ranging from −0.565 to −0.693. The elasticities are highest in the models with city-specific effects, and lowest in the models with dwelling-specific effects, but stay within a limited range. (Accounting for unobserved heterogeneity reduces the elasticities by 15% to 32% relative to a model that does not include any effects at all, where the own price elasticity of electricity demand is −1.).

The price elasticities are stable across specifications, and similar for homes with electric and gas heat. Our checks suggest that the effect of mismeasuring energy prices is small. The price elasticities are slightly higher among the poorest households (those that fall in the bottom 25% of the distribution of household income in our sample), and decline monotonically with income, but in practice this effect is not important. Our dynamic models produce short-run own-price elasticities equal to −0.736 and −0.572 for electricity and gas, respectively. Their long-run counterparts are −0.814 and −0.647, respectively. These figures are virtually unchanged whether or not we control for difficult-to-reverse choices of heating/cooling technologies.

The remainder of the paper is organized as follows. We offer a brief literature review in Section 2. We describe the models and econometric issues in Section 3 and the data in Section 4. Section 5 presents the results, and Section 6 offers concluding remarks.

2. Previous literature

Knowing the responsiveness of energy demand to the price allows analysts to predict the effects of price changes or policies that result in price changes—for example, taxes on carbon emissions, or mandates on the share of renewable energy. Earlier research has produced a wide range of estimates of the price elasticity of demand in the residential sector, possibly because of the diverse types of data used (time-series, cross-sections and panel), level of geographical and jurisdictional aggregation (local, state, or national), extent of the observed variation in price, and time periods covered.

We summarize selected studies in Table 1. These include studies based on annual time-series aggregates for the entire US, such as Dergiades and Tsoulfidis (2008), who estimate the short- (long-) run own-price elasticity of residential electricity consumption to be −0.386 (−1.06), and Kamerschen and Porter (2004), where the elasticities range from −0.94 to −0.85. Studies based on recent state-level panel data, such as Bernstein and Griffin (2005), Paul et al. (2009), and Alberini and Filippini (2010), have often found that the demand is relatively insensitive to price, at least in the short term, and that the estimates of the long-run elasticity are very sensitive to the specific estimation procedure.[3] Garcia-Cerrutti (2000) uses county-

[3] For example, Alberini and Filippini (2010) use annual state-level data in the U.S. from 1995 to 2007, and attempt to get consistent estimates of the long-run elasticity by using a bias correct "within" estimator (Kiviet, 1995) and the Blundell and Bond (1998) approach. The short-run own price elasticities of electricity range from −0.15 to −0.08, and their long-run counterparts range from −0.78 to −0.44.

level data from 44 California counties for 1983–1997, estimates the own-price elasticity of electricity demand to be −0.17 in the short run and −0.19 in the long run, and uncovers significant variation between counties.

Most household-level data studies are limited in either time coverage or geographic scale. Quigley and Rubinfeld (1989) use a cross-section from the 1980 American Housing Survey and find evidence of low elasticity of energy demand (−0.1 in the short run). Metcalf and Hassett (1999) use the 1984, 1987 and 1990 waves of the Department of Energy's Residential Energy Consumption Survey (RECS) to examine homeowners' insulation investments, finding price elasticities of electricity ranging from −0.73 to −1.16.

Bernard et al. (2010) have multi-year cross-sections about electricity and gas consumption and prices in Quebec from 1989 to 2002, estimate the short-run and long-run elasticity to be −0.51 and −1.32, respectively, and conclude that electricity and natural gas are substitutes.[4] Reiss and White (2005) focus on the California households in RECS, match each household with the block pricing structure applied by the utility that serves each area, and estimate a model of choice of block and consumption levels using GMM.

One concern when examining the responsiveness of electricity use with respect to price is that the data contain sufficient price variation. Such variation is usually attained by selecting a broad geographic area and/or a sufficient long period of time. In some cases, identification is made possible by abrupt changes in prices due to supply conditions. Reiss and White (2008) and Bushnell and Mansur (2005) exploit the energy crisis and rapidly growing electricity rates in California in 2000 and 2001, and document relatively large reductions in energy usage induced by such price increases. Haas and Schipper (1998) argue that energy-saving investments spurred by raising prices are likely to remain in place even in periods of declining energy prices, but in practice there is reason to question the external validity of findings based on unusual market circumstances at specific locations.

In this paper, we avoid these concerns by following a nationwide sample of dwellings over ten years, and augmenting these data with multi-year cross-sections of households from the same metropolitan areas. To conduct our analyses, we must assign the correct energy price to each household, but doing so is not straightforward.

There is considerable debate in the literature whether household energy demand depends on the marginal or average price, which may differ in the presence of fixed fee and block pricing. Shin (1985) argues that households will respond to average price, which is easily calculated from the electricity bill, rather than to the actual block marginal price, which is costly to determine, and develops an empirical strategy for testing this conjecture. The average price is also used in Metcalf and Hassett (1999),[5] and Borenstein (2008, 2009) and Ito (2010) find no evidence that consumers "bunching up" around the block where the price changes, as one would expect if consumers truly respond to marginal price. If demand is assumed to depend on the marginal block price, then price and consumption are simultaneously determined, and instrumental variable estimation techniques must be used (Burtless and Hausman, 1978; McFadden et al., 1978; Wilder and Willenborg, 1975; Hewitt and Hanemann, 1995; Reiss and White, 2005).

For lack of exact information about the block rates faced by the consumers, however, we are forced to use average price. We impute to each household the average price per unit of electricity or gas charged by the utilities in the area. This measure of price is exogenous to the household, but is affected by measurement error. We discuss this issue in Section 3.3 below. An additional concern is whether usage decisions depend on the price in the current (billing) period, on that of earlier periods, or a moving average of the prices of recent periods (Poyer and Williams, 1993). For good measure, in what follows we experiment with current price, as well as price of the previous period.

3. The models and econometric estimation issues

3.1. Two models of residential energy demand

In this paper, we focus on the demand for gas and electricity, because they are the most important fuels used by households in the U.S. Electricity is used by virtually 100% of the households, and gas serves 60% of the households. Fuel oil (7% of the households), LPG (1.5%) and kerosene (1.5%) are less important.[6]

We estimate two sets of models. In the first set, our regression equations are variants of the static energy demand model:

$$\ln Q_{it}^{(j)} = \beta_0^{(j)} + \beta_1^{(j)} \ln P_{E,it} + \beta_2^{(j)} \ln P_{G,it} + \mathbf{x}_{it}\boldsymbol{\gamma}^{(j)} + \tau_t + \varepsilon_{it}^{(j)} \tag{1}$$

where $j = \text{E, G}$ for electricity and gas, respectively, i denotes the dwelling, and t denotes the time period. Q is consumption, P denotes price, and the coefficients on the log prices are the short-term own- and cross-price elasticities.

Vector $\mathbf{x}$ is comprised of dwelling and household characteristics thought to influence the consumption of energy, such as weather, size and age of the home, heating and cooling equipment dummies, and appliances. For example, a house heated only with an electric heater would have a higher electricity demand than an identical home with gas heat. Household characteristics included in $\mathbf{x}$ are the number and age of occupants, income, the presence of children or elderly persons,[7] and a homeownership dummy. Eq. (1) includes year effects (the τs), and is easily amended to include dwelling or city-specific effects to account for unobserved heterogeneity.[8]

It is of interest to assess how consumption changes if individuals are allowed to adjust their stock of appliances and make energy efficiency and conservation investments. A partial-adjustment model (Houthakker, 1980) lets individuals adjust their stock of appliances and energy-efficiency investments. This model assumes that the change in log actual demand between any two periods ($t-1$ and t) is only some fraction (λ) of the difference between log actual demand in

[4] Studies outside of North America tend to be produce price elasticity ranges similar to those for North America. Nesbakken (1999) focuses on the choice of heating and residential energy consumption in Norway, reporting that short- and long-term price elasticities (in the range of −0.33 to −0.66) are remarkably stable across the 1990–1995 period, with the only exception of 1993. In contrast to other papers, responsiveness to price is more pronounced at higher levels of income. Rehdanz (2007) examines expenditures for residential space heating in Germany, and Meier and Rehdanz (2010) use a 15-year panel of residential heating expenditures in Great Britain. Using a log-linear specification with year and regional effects, they obtain gas price elasticities between −0.4 and −0.49, which fall in the range of −0.2 to −0.57 from the comparable literature. They obtain different elasticities for homeowners and renters. Leth-Petersen and Togeby (2001) find much lower price elasticities in heating fuels (on the order of −0.1) based on a panel dataset from Denmark and a conditional logit fixed-effect model.

[5] When the average price is computed from the consumer's bill divided by quantity, as is the case in Metcalf and Hassett (1999), it is endogenous with quantity.

[6] EIA, http://tonto.eia.doe.gov/energyexplained/index.cfm?page=us_energy_homes (last accessed 28 Sept. 2010).

[7] Earlier literature has examined the effect of age, race and ethnicity on energy demand. Poyer and Williams (1993) find that while the demand is inelastic for all groups, blacks appear to be more sensitive to short-run price variations than Hispanics and whites. Liao and Chang (2002) find that the elderly require more natural gas and fuel oil but less electricity, the demand for space heating increases as the elderly get older, and the demand for energy for heating water decreases with age.

[8] A special case of this situation is when the dwelling-specific effects are suppressed, but the error terms in the demand for electricity and gas equations are correlated within the same dwelling unit in the same period (but uncorrelated in different period and across dwellings). If so, the equations for log $Q^{(E)}$ and log $Q^{(G)}$ are part of a system of seemingly unrelated regression equation. Since the regressors are the same in the equations for log electricity and gas consumption, the most efficient estimation technique (GLS) is simplified to OLS applied separately to each equation.

period $t-1$ and the log of the long-run equilibrium demand in period t, Q_t*. Formally,

$$\ln Q_t - \ln Q_{t-1} = \lambda(\ln Q_t^* - \ln Q_{t-1}), \tag{2}$$

where $0<\lambda<1$. The dwelling subscript i and the electricity or gas equation superscript j are omitted to avoid clutter. This implies that given an optimum, but unobservable, level of energy consumption, demand only gradually converges towards that optimum level between any two time periods.

Assume that desired energy use (for example, desired electricity consumption) can be expressed as $Q_t^* = \alpha \cdot P_E^{\eta} \cdot P_G^{\theta} \cdot \exp(\mathbf{x\gamma})$, where η and θ are the long-term elasticities with respect to the price of the electricity and that of gas, and $\mathbf{x}$ is the vector of variables influencing demand for energy, including income, climate, characteristics of the stock of housing, income, etc. On inserting this expression into Eq. (2), we get

$$\ln Q_t - \ln Q_{t-1} = \lambda \ln \alpha + \lambda\eta \ln P_E + \lambda\theta \ln P_G + \lambda\mathbf{x\gamma} - \lambda \ln Q_{t-1}. \tag{3}$$

On re-arranging and appending an econometric error term, we obtain the regression equation:

$$\ln Q_t = \lambda \ln \alpha + \lambda\eta \ln P_E + \lambda\theta \ln P_G + \mathbf{x}\lambda\boldsymbol{\gamma} + (1-\lambda) \ln Q_{t-1} + \varepsilon \tag{4}$$

Eq. (4) shows that the short-run elasticities are the regression coefficients on the log prices, whereas the long-run elasticities can be computed by dividing these short-run elasticities (i.e., the coefficients on the log prices) by the estimate of λ. In turn, the latter is easily obtained as 1 minus the coefficient on $\ln Q_{t-1}$.

3.2. Estimation of the dynamic model

We wish to estimate the partial adjustment model (Eq. (4)) with fixed, dwelling-specific effects. One concern with this specification is that the lagged dependent variable in the right-hand side may be serially correlated and hence correlated with the error term, which makes the LSDV and GLS estimators biased and inconsistent, since $\left(y_{i,t-1} - \overline{y}_{i,-1}\right)$, where $y_{i,t-1} = \ln Q_{i,t-1}$ and $\overline{y}_{i,-1}$ is the average of the $y_{i,t-1}$s for unit i, is correlated with $\left(\varepsilon_{i,t} - \overline{\varepsilon}_i\right)$ (see Baltagi, 2001). The bias vanishes as T gets large, but the LSDV estimator remains biased and inconsistent for N large and T small, as is the case here, since we have tens of thousands of homes but the maximum length of the longitudinal component of the sample is 6.[9]

Kiviet (1995) derives an approximation for the bias of the LSDV estimator when the errors are serially uncorrelated and the regressors are strongly exogenous, and proposes an estimator that is derived by subtracting a consistent estimate of this bias from the LSDV estimator. An alternative approach is to first-difference the data, thus swiping out the state-specific effects:

$$\Delta y_{it} = \gamma \cdot \Delta y_{i,t-1} + \Delta \mathbf{w}_{it}\boldsymbol{\beta} + \Delta\varepsilon_{it} \tag{5}$$

where $\mathbf{w}$ denotes all exogenous regressors in the right-hand side of Eq. (4), and to use $y_{i,t-2}$ and Δw_{it} as instruments for $\Delta y_{i,t-1}$ (Anderson and Hsiao, 1982).

Arellano and Bond (1991) point out that the latter approach is inefficient and argue that additional instruments can be obtained by exploiting the orthogonality conditions that exist between the lagged values of $y_{i,t}$ and the disturbances. The Arellano–Bond procedure is a generalized method of moments (GMM) estimator that is implemented in two steps. In practice, the Arellano–Bond estimator has been shown to be biased in small samples, and the bias increases with the number of instruments and orthogonality conditions. Moreover, Arellano and Bond (1991) show that the asymptotic approximation of the standard errors of their two-step GMM estimator is biased downwards, and they, as well as Judson and Owen (1999), find that the one-step estimator outperforms the two-step estimator.

Under the additional assumption of the quasi-stationarity of $y_{i,t}$, $\Delta y_{i,t-1}$ is uncorrelated with ε_{it}, and Blundell and Bond (1998) suggest a "system" GMM estimation where one stacks the model in the levels and in the first differences, imposes the cross-equation restriction that the coefficients entering in the two models be the same, and uses the full set of instruments (corresponding to the full set of orthogonality conditions for both models). Blundell and Bond report that in simulation the "system" GMM estimator is more efficient and stable than the Arellano–Bond procedure. This is the approach we adopt for the partial adjustment model.

3.3. Mismeasured prices

As we explain in more detail in Section 4, in this study the price of energy is measured with an error, because we do not know the exact price(s) faced by the household and impute the average price paid by residential customers in that area. The standard econometric theory shows that when a regressor is mismeasured, and the measurement error is classical, the estimated regression coefficient is downward biased (Greene, 2008, page 325–326). In our case, we must keep in mind that the mismeasured price enters in the construction of the dependent variable as well as in the right-hand side of the model as a regressor.

Alberini et al. (2010) discuss the implications of mismeasured prices, assuming for simplicity that only own price in entered in the right-hand side of Eq. (1). Specifically, if the measurement error is approximately constant within a dwelling over time, then it is eliminated by the LSDV procedure, and one obtains consistent estimates of the slopes. If the measurement error is classical (i.e., completely uncorrelated within and between the units in every period), then the price elasticity will be overstated (i.e., the absolute value of the estimated coefficient will be greater than $|\beta_1|$).[10]

How can one get around the mismeasurement problem? One approach is to restrict estimation to areas where mismeasurement is likely to be less severe (e.g., areas with only one utility). Another is to instrument for $\ln p^*$, which we do using state-level electricity and gas prices, or, in alternate runs, lagged electricity prices.

4. The sample and the data

4.1. The Data

In addition to data provided by individual utilities for their service territories (e.g., Borenstein, 2008, 2009) or otherwise geographically circumscribed areas (e.g., Shin, 1985; Garcia-Cerrutti, 2000; Bushnell and Mansur, 2005), earlier research has used the Department of Energy's Residential Energy Consumption Survey (RECS) to examine energy use patterns at the household level (e.g., Metcalf and Hassett, 1999; Reiss and White, 2005). Despite its national coverage, we were dissatisfied with this dataset, because it does not lend itself to panel data modeling (the length of the longitudinal component is at most

[9] We remind the reader that, when attention is restricted to those dwellings that appeared in more than one round of AHS survey, we have an unbalanced panel with T ranging from 2 to 6. A similar argument applies if we use dwelling-household effects instead of dwelling effects.

[10] Alberini et al. (2010) also examine whether it is possible to identify the price elasticity by exploiting the fact that the log real price, which appears in the right-hand side of Eq. (1), is the log of nominal price minus the log of the price index. They show that if only log nominal price and log price index are uncorrelated is it possible to obtain an unbiased estimate of the price elasticity. This is not the case here, since in this dataset log nominal price and log price index are positively correlated.

Table 2
Metropolitan areas selected for the study.

Metro area	Included?[a]	Metro area	Included?[a]
Atlanta–Sandy Springs–Marietta, GA	Yes	Minneapolis–St. Paul–Bloomington, MN–WI	Yes (Minneapolis–St Paul)
Austin–Round Rock, TX	Yes	Nashville–Davidson–Murfreesboro–Franklin, TN	Yes
Baltimore–Towson, MD	Yes	New Orleans–Metairie–Kenner, LA	Yes
Birmingham–Hoover, AL	Yes	New York–Northern New Jersey–Long Island, NY–NJ–PA	Yes (New York, Northern New Jersey)
Boston–Cambridge–Quincy, MA–NH	Yes	Oklahoma City, OK	Yes
Buffalo–Niagara Falls, NY	Yes	Orlando–Kissimmee, FL	Yes
Charlotte–Gastonia–Concord, NC–SC	Yes (Charlotte)	Philadelphia–Camden–Wilmington, PA–NJ–DE–MD	No
Chicago–Naperville–Joliet, IL–IN–WI	Yes (Chicago)	Phoenix–Mesa–Scottsdale, AZ	Yes
Cincinnati–Middletown, OH–KY–IN	No	Pittsburgh, PA	Yes
Cleveland–Elyria–Mentor, OH	Yes	Portland–Vancouver–Beaverton, OR–WA	Yes
Columbus, OH	Yes	Providence–New Bedford–Fall River, RI–MA	Yes (Providence)
Dallas–Fort Worth–Arlington, TX	Yes	Raleigh–Cary, NC	Yes
Denver–Aurora, CO \2	Yes	Richmond, VA	Yes
Detroit–Warren–Livonia, MI	Yes	Riverside–San Bernardino–Ontario, CA	Yes
Hartford–West Hartford–East Hartford, CT	Yes	Sacramento–Arden–Arcade–Roseville, CA	Yes
Houston–Sugar Land–Baytown, TX	Yes	St. Louis, MO–IL \3	No
Indianapolis–Carmel, IN	Yes	Salt Lake City, UT	Yes
Jacksonville, FL	Yes	San Antonio, TX	Yes
Kansas City, MO–KS	No	San Diego–Carlsbad–San Marcos, CA	Yes
Las Vegas–Paradise, NV	Yes	San Francisco–Oakland–Fremont, CA	Yes
Los Angeles–Long Beach–Santa Ana, CA	Yes	San Jose–Sunnyvale–Santa Clara, CA	Yes
Louisville/Jefferson County, KY–IN	Not present in the AHS	Seattle–Tacoma–Bellevue, WA	Yes
Memphis, TN–MS–AR	No	Tampa–St. Petersburg–Clearwater, FL	Yes
Miami–Fort Lauderdale–Pompano Beach, FL	Yes	Virginia Beach–Norfolk–Newport News, VA–NC	No
Milwaukee–Waukesha–West Allis, WI	Yes	Washington–Arlington–Alexandria, DC–VA–MD–WV	No

[a] Eligible because of unambiguous state identification in the AHS.

2), and the geographical identification is at too coarse a level to link each household with the relevant utilities (or to state-level or local policies or incentives).[11]

For these reasons, we assembled a large and comprehensive dataset that merged several sources of data. We use the American Housing Survey (AHS), a longitudinal study conducted by the Department of Housing and Urban Development where the cross-sectional units are dwellings (not households). The AHS contains extensive information about the structural characteristics of the dwelling, renovations and retrofits, home ownership and its financial aspects (mortgages, maintenance costs, etc.), appliances and heating/cooling systems, socio-demographic and economic circumstances of the occupants, and their assessment of the quality of the home and the neighborhood.

We focus on "national" survey AHS data for 1997, 1999, 2001, 2003, 2005, and 2007, which means that we can follow homes for up to $T=6$ periods. We augment this sample with observations from the AHS "metro"[12] surveys, which are conducted in even years in specific areas. We use the 2002, 2004 and 2007 metro surveys. Homes in the metro surveys are surveyed only once, so our sample is a mix of panel data plus multi-year cross-sections.

Because of privacy concerns, the AHS discloses the location of the dwelling only if the area has a population of 100,000 or more. We selected dwellings in the 54 cities corresponding to the 50 largest metropolitan areas in the U.S. as of 2008, unless the AHS SMSA identification makes it impossible to identify unambiguously which state the dwelling is located in. Table 2 lists the "candidate" metro areas (the 50 largest in the U.S. as of 2008) and indicates which are included in our study. These locations should ensure considerable variation in climate, age of the stock of housing and construction materials (which may affect efficiency of space heating and cooling), and utility prices.

Our sample is restricted to single-family homes and duplexes. We further restrict attention to homes that are owner-occupied or occupied by a tenant, and where these persons actually are responsible for paying the utility bills.[13] These criteria yielded a sample size of 120,333 observations. We deleted observations where i) the home was occupied as a residence for only part of the year, ii) the utility bills had been imputed using "hot deck" procedures, iii) the square footage (which should be an important determinant of energy usage) had been imputed using "hot deck" procedures, and/or iv) large and implausible changes in size were observed from one time period to the next.[14] This left us with 98,774 observations, which are further reduced to 98,772 when we further exclude residences where the heating equipment is shared with other units (2 observations).

Table 3 displays the distribution of this final sample by city. Table 4 summarizes information about the longitudinal component of our sample, examining the case where the cross-sectional units are the dwellings, and that where the cross-sectional units are dwelling-families. We have a total of 69,169 homes and 74,697 households (because families may move into and out of any given home during the study period).

4.2. Energy consumption and utilities' rates

The AHS reports the average monthly utility bill (and annual payments on heating oil fuel for those households that use heating oil) in the survey year, but does not report the electricity or gas tariffs, nor the actual energy consumption (in kilowatt-hours [kWh] or thousand cubic feet [MCF]).

[11] RECS provides the Census Region for each household. It provides the state identifier only if the household resides in one of the four most populous states (California, New York, Texas and Florida). HDD and CDD information is provided, but the true figures at the household's location are masked to ensure confidentiality.

[12] The Nationwide AHS sample returns to the same homes for every survey, and adds some newly constructed homes to keep the sample representative of the housing stock in the U.S. The metro surveys are conducted on a representative sample of homes in different cities every two years, but in the metro surveys different homes are selected in different waves for the same city.

[13] In other words, we exclude tenants where the utilities are included in the rent. Incentives to save on utilities may be different in this case.

[14] Specifically, we excluded observations with a change in the amount of energy or gas used that changed by more than 500% from one period to the next, while at the same time no renovation in the home and no square foot change was reported. Homes that experienced a change in square footage of more than 1000% from one period to the next, or with a change in square footage of more than 100% without a reported renovation to the home, were also discarded.

Table 3
Distribution of the sample by city. N = 98,772.

City	Nobs	Percent	City	Nobs	Percent
Anaheim	3618	3.66	Minneapolis	2112	2.14
Atlanta	3335	3.38	Monmouth	339	0.34
Austin	193	0.2	Nashville	275	0.28
Baltimore	1522	1.54	New Orleans	2387	2.42
Bergen-Passaic	428	0.43	New York	2585	2.62
Birmingham	343	0.35	Newark	612	0.62
Boston	1754	1.78	Northern New Jersey	659	0.67
Boulder	91	0.09	Oakland	793	0.8
Buffalo	1739	1.76	Oklahoma City	2752	2.79
Charlotte	2681	2.71	Orlando	434	0.44
Chicago	4306	4.36	Phoenix	3665	3.71
Cleveland	3137	3.18	Pittsburgh	3313	3.35
Columbus	3315	3.36	Providence	271	0.27
Dallas	3488	3.53	Raleigh-Durham	280	0.28
Denver	2415	2.45	Riverside San Bernardino	3883	3.93
Detroit	3467	3.51	Sacramento	2584	2.62
Ft. Worth	2992	3.03	Salt Lake	532	0.54
Hartford	2010	2.03	San Antonio	2781	2.82
Houston	2430	2.46	San Diego	2978	3.02
Indianapolis	2908	2.94	San Francisco	502	0.51
Jacksonville	357	0.36	San Jose	579	0.59
Jersey City	91	0.09	Santa Rosa	90	0.09
Las Vegas	453	0.46	Seattle	2706	2.74
Los Angeles	4870	4.93	Tacoma	224	0.23
Miami	4115	4.17	Tampa	2089	2.11
Middlesex County	300	0.3	Tucson	355	0.36
Milwaukee	2295	2.32	West Palm Beach	339	0.34

We must therefore construct consumption by taking the bills and dividing them by unit price. Unfortunately, the names of the utilities and the rate structure are not identified in the AHS either, so we were forced to impute average tariffs per kWh and cubic foot of gas for each dwelling in a number of ways.

For each metropolitan area, we identified the relevant gas and electric utilities using the listings provided by the state public utility commission, and a variety of on-line city services. We also consulted the list of counties covered by each utility, as documented in the Energy Information Agency (EIA) 861 forms database. We obtained utility-level price information from the EIA 861 forms (for electricity) and EIA 176 forms (for gas), which the utilities are required to file every year with the agency. Next, if the area was supplied by a single utility, we computed the average price per kWh (MCF) as the utility's annual revenue from sales to residential customers divided by the kWh (MCFs) sold to residential customers.[15]

If the area was supplied by more than one utility, we first computed the average price charged by each of them in the aforementioned fashion, and then constructed three alternative measures of price to use in our regressions. One, which we dub “residential price 1,” is a weighted average of each utility's average tariff per kWh, where the weights are proportional to the utility's customer base. The next, which we dub “residential price 2,” is also a weighted average, with weights assigned to represent the utility's dominance of the market.[16] The final constructed price (“residential price 3”) is a simple average of the individual utilities' average tariffs.[17] We followed a similar approach for gas utilities.

We use the prices of electricity and gas in two ways. First, we use them to create the dependent variables in our regressions: consumption of electricity and gas are obtained as the amount on the bill divided by (nominal) price. Second, (real) prices enter in the right-hand side of the demand equations.

[15] We note here that the EIA computes state-level electricity prices and gas prices exactly in this fashion—by taking the revenues of all utilities and dividing by all kWhs (or gas) served to residential households.

[16] If a utility dominates the market completely, despite the nominal existence of other utilities, that utility received a weight of ones and the others weights equal to zero. If two utilities were perceived to share the market in the area in a relatively equitable fashion, we assigned weights of 0.5 to each.

[17] Clearly, if there is a single utility, residential price 1, 2 and 3 are all identical.

Table 4
Distribution of the sample by length of the longitudinal component. N = 98,772.

	Unit: dwelling		Unit: dwelling-family	
T (length of the panel)	Freq.	Percent	Freq.	Percent
1	58,088	58.81	63,916	64.71
2	7094	7.18	9616	9.74
3	5315	5.38	6126	6.2
4	8232	8.33	6236	6.31
5	10,905	11.04	6740	6.82
6	9138	9.25	6138	6.21

We note here that, technically speaking, these average prices are not necessarily equal to the prices faced by the households. The majority of the utilities apply block pricing, but with such a geographically broad sample and such a long study period, it would be unfeasible to obtain the block pricing schemes used by each utility in each period. The only remaining econometric concern is that the price we use in our regression is measured with error. With our model and data construction, as explained in Section 3.3, this would make the household demand appear to be more elastic than it truly is.

We display descriptive statistics about prices and energy use in Table 5. Attention is restricted to the “price 1” variables because the others were very close to them.[18] Every home is served by electricity, and, as shown in Table 5, on average our households use about 930 kWh per month. This is in line with nationwide estimates collected by the Department of Energy using a dedicated survey (RECS). Just over three-quarters of the sample (76.6%) use natural gas as well, and almost 88% of such natural-gas connected households use gas heat. In a typical month, gas usage is 7.27 MCF.

Over the study period, the average price of electricity is about 11 cents per kWh (2007$). We found, however, evidence of considerable variation across states. The state with the lowest prices is Indiana (about 6.8 cents per kWh on average over the study period) and that with the highest prices is New York, where a kWh averaged almost 18 cents over the study period (2007$). The price of natural gas exhibits similar variability across locales. The average price per MCF is $11.41 (2007$), with Georgia exhibiting the lowest prices ($6.10, 2007$, on average) and Florida the highest ($17.83, 2007$).

Since we exploit the longitudinal feature of our data, it is important to check the extent of the variation in prices across and within units. In what follows, the units are the dwellings. We computed the total variation of real electricity prices and of log real electricity prices, and found that in each case the variation within dwellings accounted for only 4% of the total variation.[19] Gas prices are more variable over time: the “within” dwelling variation accounts for about 14% of total variation in real gas prices, and 15% of the total variation for log real gas prices.

4.3. Other key regressors

The weather is an important determinant of energy use. We computed heating and cooling degree-days (HDDs and CDDs) in the year prior to the date of the AHS survey using the T3 Global Summaries of the Day from NOAA's National Climatic Data Center. We matched each metro area with the T3 monitors in that area, computed

[18] The correlation coefficients between the “price 1” variables and the others were generally higher than 0.97.

[19] Our measure of variation is the sum of square deviations from the grand mean.

Table 5
Prices and monthly consumption of electricity and natural gas.

Variable label	Description	Obs	Mean	Std. dev.	Min	Max
kWh 1	Monthly electricity usage (kWh)	97,344	930.39	654.09	11.06	5697.54
gasuse1	Monthly gas usage (MCF)	67,154	7.27	5.50	0.23	71.86
residentialprice1_r	Price of electricity per kWh (2007 dollars)	98,487	0.11	0.03	0.05	0.22
gasprice1_r	Price of natural gas per MCF (2007 dollars)	94,315	11.42	3.10	3.90	22.89
Log kwh1		97,344	6.61	0.70	2.40	8.65
Log gasuse1		67,154	1.75	0.68	−1.49	4.27
Log residentialprice1_r		98,487	−2.23	0.26	−2.92	−1.49
Log gasprice1_r		94,315	2.40	0.26	1.36	3.13

the average of the mean temperatures for each day of the year prior to the date of the survey, created the HDD (CDD) for that day as 65 °F minus the average temperature (average temperature minus 65 °F), and summed over the year prior to the survey. This construction is the same as that used by the U.S. Department of Energy. The average HDDs and CDDs are 3450 and 1658 degree-days, respectively.

Our regressions control for dwelling characteristics, such as the age and size of the home, number of rooms, and number of floors, which come from the AHS. We enter all continuous variables in log form in the regression. Descriptive statistics for these variables are displayed in Table 6. The average size of the home is about 2000 square feet. This figure matches up nicely with the nationwide estimates for single-family homes and homes that are part of a two-unit building from the 1997, 2001, and 2005 RECS.

Despite removing observations with imputed square footage and implausible changes in square footage from one survey wave to the next, our sample does contain some observations with extremely small and extremely large values for size and the number of floors, so in our regressions we further restrict attention to homes no smaller than 400 square feet and no larger than 10,000. We also delete from the usable sample homes with more than 4 floors (single family homes are unlikely to have 5 or more floors).

Descriptive statistics for this cleaned sample are reported in the bottom panel of Table 6. The average square footage, house age and number of rooms are virtually unchanged. We note that a value of zero for the age of the house is correct: it means that the home was built in the same year of the survey. (The AHS does add new dwellings to mirror the stock of housing and new constructions. Homes with age 0 account for less than 1% of the sample.)

We report descriptive statistics about heating and cooling equipment, as well as appliances that use energy, in Table 7. All of this information comes from the AHS. Briefly, in terms of heating, about 67% of the sample has a gas heating system, 26% relies on electricity for heating, and about 5% on heating oil as the main source of heat. Homes with electric heat are located primarily in states with mild or warm climates, such as Arizona (66% of all Arizona homes), Florida (93.80%), Louisiana (43%), Tennessee (59%) and Texas (43.76%), or cheap electricity (e.g., Washington, 29%).

About 84% of the sample has some type of air conditioning, and about 67% has central air conditioning. Window units are used by 20% of the sample, sometimes alongside with central air conditioning. Only 2% of the observations have gas-powered heat pumps. Turning to appliances, virtually all homes have a fridge, almost 72% a dishwasher, 32% use gas-powered clothes dryers, and a little more than half of the sample has an electric stove.

Summary statistics of household characteristics are shown in Table 8. Briefly, we find that the average household income over the study period is about $88,000 (2007$). There are a small number of households (93, or 0.09%) that report negative income. When these persons are removed, the distribution of household income is essentially unchanged: The new sample average is still $88,000 (2007$).[20] The average household size is 2.8, 31% of the sample has small children, 22% has at least one person aged 65 or older living in this house, and almost 84% owns the home.

Table 6
House characteristics.

Variable	Obs	Mean	Std. Dev.	Min	Max
All observations					
Square footage	91,254	2073.96	1615.04	99	18,083
Basement (dummy)	98,772	0.37	0.48	0	1
Floors	98,772	1.83	0.96	1	21
Rooms	98,772	6.42	1.86	1	21
Age of the home	98,772	38.69	23.27	0	88
More than 400 sq ft and less than 10,000 sq ft, no more than 4 floors					
Square footage	88,732	1950.42	1141.95	400	9911
Basement (dummy)	88,732	0.35	0.48	0	1
Floors	88,732	1.77	0.83	1	4
Rooms	88,732	6.47	1.83	1	21
Age of the home	88,732	37.64	22.84	0	88

5. Results

5.1. Static models

Results for several specifications of the static model (see Eq. (1)) are reported in Table 9 for log electricity consumption, and in Table 10 for log gas consumption. The runs differ for the type of effects we include to account for unobserved heterogeneity.

We choose to report results for fixed city-, dwelling- and dwelling-family specific effects. We include city-specific effects because 1) the coefficients on most regressors are similar to those from a random effects model with dwelling-specific effects (estimated using GLS), 2) it stands to reason that homes and residents might share similar unobservable characteristics as other homes and residents in the same metro area, 3) we do not lose the observations with $T=1$, and 4) we are able to assess the impact on consumption of factors that vary widely across locales (e.g., home size, income, etc.) but little within a house over time. Finally, 5) assigning average prices at the metro-area level to each dwelling likely produces errors that are correlated within the metro area, biasing standard error estimates downward (Moulton, 1990). For this reason, we cluster the standard errors at the city level.

Fixed dwelling effects are a natural candidate, since the AHS follows a dwelling over time, while dwelling-family effects allow for unobservable heterogeneity to depend on the household as well as the home.[21] We prefer fixed effects because Hausman tests indicate that if the unobserved heterogeneity is modeled using random effects, these are correlated with the included regressors, which makes the GLS estimates inconsistent. For good measure, the standard errors are clustered at the city level (in specifications with city effects) or at the dwelling level (in specifications with dwelling and dwelling-household effects).

[20] In our regressions, which use log income, we will simply recode log income to zero when income is negative.
[21] The fixed effects also account for any selection of households into cities or homes.

Table 7
Heating and cooling equipment and appliances.

Variable	Obs	Mean	Std. dev.	Min	Max
Gas heat	98,772	0.67	0.47	0	1
Electric heat	98,772	0.26	0.44	0	1
Heating oil heat	98,772	0.05	0.23	0	1
Window A/C units	98,772	0.21	0.40	0	1
Number of rooms with A/C	20,251	1.78	1.02	1	8
Central A/C	98,772	0.67	0.47	0	1
Gas heat pump for A/C	98,772	0.03	0.16	0	1
Any type of A/C present	98,772	0.84	0.37	0	1
Refrigerator	98,772	0.9981	0.04	0	1
Dishwasher	98,772	0.72	0.45	0	1
Gas powered clothes dryer	98,772	0.32	0.47	0	1
Electric stove	98,772	0.53	0.50	0	1

Table 8
Household characteristics.

Variable	Obs	Mean	Std. dev.	Min	Max
Household income in thou. 2007$	98,772	87.92	115.49	−42.33	11,473.2
Number of household members	98,772	2.81	1.52	1	17
Young child (12 or less) lives in this housem (dummy)	98,772	0.31	0.46	0	1
Elderly person (65+) lives in this house	98,772	0.23	0.42	0	1
Owner (dummy)	98,772	0.84	0.37	0	1

Starting with Table 9, most of the coefficients are significant and have the expected sign. Importantly, column (A) – the results of a model with city-specific effects – shows that the elasticity of electricity use with respect to the price of electricity is −0.860, and the cross-elasticity with respect to the price of gas is positive and equal to 0.117, indicating that the two are substitutes.[22]

Consumption of electricity increases by 22% for every 10% increase in the square footage of the home, is 16% higher if the home has air conditioning, and about 15% higher if the home is heated using electricity. Dishwashers and electrical stoves increase usage by 8% and 7%, respectively (not displayed in the table). F tests reject the null hypotheses that heating/cooling systems are jointly equal to zero (F statistic = 37.65, p value less than 0.0001) and that the appliances are not associated with electricity consumption (F statistic = 38.05, p value less than 0.0001).

The income elasticity of electricity consumption is only about 0.02. One reason for such a low elasticity might be the fact that income is highly correlated with characteristics of the home, such as the size, the number of floors, and the presence of certain appliances. Once we removed these from the specification, income elasticity of electricity usage increased to almost 0.05.

Column (B) presents the results of a FE specification where the cross-sectional units are the homes. The own price elasticity is lower (−0.667), as expected, but the cross-price elasticity is slightly stronger. As expected, the coefficients on most other variables are much smaller than their counterparts in the city-specific effects specification, because these variables rarely change within a home over time. In column (C), we present the results of a model with dwelling-household specific effects. They are similar to those in column (B), with slightly stronger own- and cross-price elasticities.

As to the gas equation, columns (A)–(C) of Table 10 show that the own price elasticity ranges from −0.693 (city-specific effects) to −0.565 (dwelling-specific effects). The model with dwelling-household effects produces a price elasticity of −0.577. The cross-price elasticity is positive (0.150) and indicates that gas and electricity are substitutes in the model with city-specific effects (column (A)), but turns insignificant when we use dwelling-specific effects, and negative and insignificant in the model with dwelling-family effects.

The model with city-specific effects indicates that gas usage increases by 19% for every 10 percentage point increase in the square footage of the home, and is about 24% larger in homes with gas heating systems. The impact of these variables is small and statistically insignificant in the variants with dwelling- and dwelling-household effects.

5.2. Robustness checks

Our first order of business is to examine the size of the potential bias due to measurement errors in the prices of electricity and gas. To see if such a bias is severe, we began with regressions where the sample is restricted to metro areas served by one utility. We argue that the measurement error due to our price imputation procedure is smaller in single-utility areas. For electricity usage, the results of these runs are reported in columns (D) and (E) of Table 9 for the models with dwelling-specific effects and dwelling-family effects. Similar models for gas usage are displayed in columns (D) and (E) of Table 10. Clearly, the own-price elasticities are very close (and slightly higher than) to their counterparts in columns (B) and (C).

Next, we estimated a log kWh model with fixed dwelling-specific effects, the regressors as in Table 9, and log electricity price (but no gas price). If we do not instrument for electricity price, the own price elasticity is −0.6794. When we instrument for log electricity price using the log of the state average prices of electricity and gas as the identifying instruments, the coefficient on log price is −.67907.[23] Using log state-level electricity price as the only identifying instrument produces an own price elasticity of electricity demand of −0.6584, while replacing that with the first lag of log price of electricity in the metro area yields an elasticity of −0.6108.

Finally, we estimated a model where the dependent variable is the log electricity bill, the right-hand side includes fixed dwelling-specific effects, all other controls, the log of nominal electricity price and the log of the CPI (but no gas price).[24] The coefficient on log nominal electricity price is 0.3223 and that on log CPI is 0.5981. The corresponding estimates of the elasticity with respect to the price of electricity are −0.6777 and −0.5891 (from the coefficient on log price and log CPI, respectively). Although we argue in Section 3.3 that these are both likely to overstate the true elasticity, they are within 10–15% of the original estimates and of the IV estimates of the price elasticity, suggesting that the impact of measurement error is modest.

Observers sometimes speculate that high price elasticities might be capturing the effect of conservation and energy efficiency installations made possible by the utilities' DSM initiatives.[25] We do have the DSM expenditure per customer by the electrical utilities that serve any given metro area, and, indeed, it is indeed positively correlated with electricity price (correlation coefficient 0.28). However, when we add DSM expenditure per customer (in real terms) in the right-hand side of the log kWh model, the coefficient on log electricity price is virtually unchanged (−0.657).

To check if consumption depends on current or recent prices, we also estimated models similar to the ones shown in Tables 9 and 10, but where we further included lagged prices. We found that i) the

[22] It is useful to compare these figures with their counterparts in an OLS regression that ignores unobserved heterogeneity. The own price elasticity when the city effects are suppressed is −1. Adding state effects (but no city effects) makes it −0.894.

[23] Our instruments are in the spirit of Black and Kniesner (2003), who propose using another mismeasured variable (i.e., state-level annual average prices) to clean out the measurement error in the original mismeasured regressor (here, average price in the metro area).

[24] This model is obtained on recognizing that i) log kWh is equal to log bill minus log nominal price, and ii) in the right-hand side of the demand equation, log real price is equal to log nominal price minus log CPI.

[25] We are grateful to Mark Jacobsen, personal communication, 2010, for raising this issue.

Table 9
Static model: selected regression results. Dependent variable: log of electricity usage (lkWh1).

	(A)	(B)	(C)	(D) only one utility	(E) only one utility	(F) electric heat	(G) gas heat
log elec price	−0.860***	−0.667***	−0.681***	−0.685***	−0.692***	−0.679**	−0.825***
	(−9.37)	(−9.69)	(−8.16)	(−8.26)	(−6.82)	(−3.22)	(−8.12)
log gas price	0.117*	0.122*	0.139*	0.115*	0.107	0.126*	0.102
	(2.02)	(2.45)	(2.36)	(1.97)	(1.58)	(2.04)	(1.63)
log sq. ft.	0.216***	0.0593	0.0522	0.0538	0.0396	0.226***	0.220***
	(11.05)	(1.64)	(1.21)	(1.29)	(0.81)	(7.12)	(9.15)
Age of the home	0.00553***	−0.00477	−0.00195	−0.00164	−0.000416	0.00685***	0.00517***
	(8.38)	(−1.70)	(−0.53)	(−0.48)	(−0.09)	(7.44)	(7.39)
Age of the home squared	−5.4E−5***	4.91E−05	3.07E−05	1.54E−05	4.86E−06	−6.32E−05***	−4.98E−05***
	(−7.56)	(1.69)	(0.81)	(0.43)	(0.10)	(−5.19)	(−6.80)
Owns the home	0.0696***	−0.0558	0.0408	−0.0803	0.0215	0.0899**	0.0518**
	(4.86)	(−1.69)	(0.70)	(−1.79)	(0.26)	(3.33)	(3.25)
No. of rooms	0.0659***	0.0159***	0.0103	0.0202***	0.0130	0.0701***	0.0626***
	(14.74)	(3.42)	(1.94)	(3.39)	(1.91)	(8.14)	(14.07)
No. of floors	−0.0171*	0.0371	0.0297	0.0425	0.0297	−0.0524**	0.00476
	(−2.07)	(1.34)	(0.85)	(1.29)	(0.71)	(−3.35)	(0.59)
log Hhold income	0.0225***	0.00906*	0.00677	0.0107*	0.00804	0.0251***	0.0208***
	(8.83)	(2.30)	(1.49)	(2.12)	(1.38)	(6.10)	(8.08)
Young child dummy	0.0963***	0.0721***	0.0353	0.0614**	0.0335	0.0913***	0.0964***
	(15.06)	(4.24)	(1.48)	(2.82)	(1.09)	(11.36)	(11.93)
Elderly dummy	−0.0390***	−0.0204	−0.00932	−0.0137	−0.00911	−0.0154	−0.0400***
	(−4.20)	(−0.88)	(−0.32)	(−0.49)	(−0.25)	(−0.95)	(−4.22)
Log CDD	0.0727***	0.0299	0.0250	0.0417	0.0272	0.141**	0.0762**
	(3.58)	(1.07)	(0.78)	(1.20)	(0.68)	(3.14)	(3.33)
Log HDD	0.00350	−0.0123	0.00277	−0.0278	−0.0244	0.0393	0.0384
	(0.07)	(−0.39)	(0.07)	(−0.58)	(−0.42)	(0.63)	(0.54)
Gas heat dummy	−0.0990**	−0.0152	−0.0183	−0.00105	−0.0704		
	(−2.79)	(−0.17)	(−0.18)	(−0.01)	(−0.56)		
Electric heat dummy	0.154***	0.106	0.123	0.117	0.0722		
	(4.72)	(1.23)	(1.20)	(1.09)	(0.57)		
Heating oil heat dummy	−0.0971*	0.00475	0.103	0.0230	0.0945		
	(−2.28)	(0.04)	(0.64)	(0.15)	(0.51)		
A/C	0.161***	0.0572*	0.0493	0.0566	0.0445	0.0928*	0.176***
	(8.00)	(2.21)	(1.61)	(1.71)	(1.15)	(2.63)	(8.61)
Constant	1.422**	4.053***	3.861***	4.000***	4.212***	1.510*	1.094
	(2.72)	(7.61)	(6.07)	(5.64)	(4.97)	(2.12)	(1.49)
Effects	City	Dwelling	Dwelling-family	Dwelling	Dwelling-family	City	City
R-squared	0.457	0.0557	0.0491	0.0564	0.0481	0.418	0.407
N. of cases	82,905	82,905	82,905	48,027	48,027	22,003	55,688
Std. errs. clustered	City	Dwelling	Dwelling	Dwelling	Dwelling	City	City

* $p<0.05$, ** $p<0.01$, *** $p<0.001$.
t statistics, not standard errors, are reported in parentheses.

coefficients on contemporaneous price were strongly significant and similar to their counterparts in Tables 9 and 10, and ii) the coefficients on lagged prices were very small in magnitude and insignificant at the conventional levels. This is unsurprising if we recall that the "previous period" is usually two years prior to the current observations. We would expect people to react to changes in recent billing periods, and billing periods are usually one month (see Reiss and White, 2008).

To make that our results are not driven by outliers, we experimented with trimming the sample, e.g., we excluded the observations in the bottom and top 1%, 2.5%, etc. of the distribution of kWh s and MCFs. The elasticities and most other coefficients remained virtually the same as those in Tables 9 and 10.

In columns (F) and (G) of Tables 9 and 10, we report regression results for the subsamples with electric heat and gas heat. We report only the results for the models with city-specific effects for the sake of brevity, but the same qualitative results hold for the models with dwelling- and dwelling-households effects (although the magnitude of the coefficients is slightly smaller). In contrast to earlier literature (Metcalf and Hassett, 1999; Reiss and White, 2005), we find households with electric heating systems are actually *less* responsive to the price of electricity than households that use gas heat. Households with gas heat are slightly *more* sensitive to the price of gas than households that use electric heat.

However, Wald tests of the null that the elasticities are the same across the two groups fail to reject the null. For example, if attention is restricted to the equations in columns (F) and (G) of Table 9, the Wald statistic of the null of identical own price elasticities is only 1.13 (p-value 0.29).

The Wald statistics are even smaller in runs with fixed dwelling (or dwelling-household) effects. One possible explanation for this is that the sample size is rather uneven across the groups of homes served with electric and gas heat. The number of observations with electric heat is 23,542, but drops to 8416 when only true "panels" are used. This is only about 8% of the total sample. The resulting increase in variance may help explain the lack of significant differences across the two subsamples.

Finally, we estimated models where we allow the responsiveness to energy prices to vary with the quartile of the income distribution that the household falls in. We find that the responsiveness to prices is a bit higher in the first quartile, and declines monotonically by quartile. For example, the elasticity of electricity consumption with respect to electricity price is −0.681 among households in the first income quartile, −0.673 among those in the second quartile, −0.663 among those in the third, and −0.645 among those in the fourth. An F test of the null that these elasticities are all identical rejects the null at the 1% level or better (F statistic = 15.96, p-value less than 0.0001).

5.3. Dynamic Models and Models with Investments

Turning to the partial adjustment model, we report results based on the Blundell-Bond estimation procedure in Table 11. Column (A)

Table 10
Static model: selected regression results. Dependent variable: log of gas usage (lgasuse1).

	(A)	(B)	(C)	(D) only one utility	(E) only one utility	(F) electric heat	(G) gas heat
log elec price	0.150*	0.0376	−0.0334	0.0763	0.0192	0.461	0.128*
	(2.15)	(0.48)	(−0.36)	(0.78)	(0.16)	(1.49)	(2.12)
log gas price	−0.693***	−0.565***	−0.577***	−0.583***	−0.587***	−0.634***	−0.693***
	(−6.57)	(−9.51)	(−8.21)	(−8.31)	(−7.24)	(−4.52)	(−6.45)
log sq. ft.	0.189***	0.0524	0.0459	0.0490	0.0439	0.120*	0.201***
	(9.88)	(1.26)	(0.89)	(1.03)	(0.76)	(2.33)	(10.25)
Age of the home	0.00383***	0.0000321	0.000597	−0.0000686	−0.000542	0.00252	0.00384***
	(5.87)	(0.01)	(0.15)	(−0.02)	(−0.12)	(1.06)	(5.85)
Age of the home squared	−9.11 E−06	6.84E−06	1.68E−05	6.19E−06	2.01E−05	−1.07E−05	−7.25E−06
	(−1.30)	(0.22)	(0.42)	(0.16)	(0.42)	(−0.47)	(−1.05)
Owns the Home	0.0322*	−0.0426	−0.00991	−0.0331	−0.00764	0.00436	0.0412**
	(2.56)	(−1.08)	(−0.14)	(−0.61)	(−0.07)	(0.15)	(3.28)
No. of Rooms	0.0549***	0.0149**	0.0125	0.0171*	0.0140	0.0695***	0.0536***
	(18.61)	(2.72)	(1.93)	(2.51)	(1.74)	(7.37)	(17.83)
No. of Floors	0.00974	0.0573	0.0485	0.0645	0.0673	−0.0224	0.00998
	(1.18)	(1.75)	(1.09)	(1.72)	(1.32)	(−0.62)	(1.30)
log Hhold Income	0.00357	0.00285	0.00298	0.00446	0.00313	−0.00950	0.00497*
	(1.61)	(0.60)	(0.55)	(0.74)	(0.47)	(−1.40)	(2.20)
Young child dummy	0.0711***	0.0635**	0.0657*	0.0658*	0.0813*	0.0549***	0.0683***
	(12.01)	(3.05)	(2.25)	(2.44)	(2.18)	(3.73)	(11.12)
Elderly dummy	0.0640***	−0.00246	0.00278	−0.00266	−0.000376	0.0574*	0.0659***
	(7.23)	(−0.10)	(0.08)	(−0.08)	(−0.01)	(2.53)	(7.40)
Log CDD	−0.00384	−0.0262	−0.00987	−0.0189	0.000143	0.105	0.00162
	(−0.13)	(−0.85)	(−0.28)	(−0.49)	(0.00)	(1.24)	(0.06)
Log HDD	0.0991	0.105*	0.114	0.192*	0.198*	−0.0936	0.149**
	(1.67)	(1.99)	(1.93)	(2.20)	(2.15)	(−1.15)	(2.83)
Gas heat dummy	0.215***	−0.0797	−0.0890	−0.0855	−0.108		
	(4.20)	(−0.55)	(−0.48)	(−0.36)	(−0.45)		
Electric heat dummy	0.0211	−0.225	−0.226	−0.237	−0.229		
	(0.47)	(−1.47)	(−1.15)	(−0.95)	(−0.90)		
Heating oil heat dummy	−0.938***	−0.730**	−0.564*	−0.677	−0.506		
	(−11.47)	(−2.82)	(−1.99)	(−1.91)	(−1.36)		
A/C	−0.0147	0.0171	0.00614	−0.000232	−0.0155	−0.0348	−0.0154
	(−0.94)	(0.62)	(0.18)	(−0.01)	(−0.36)	(−1.09)	(−1.01)
Constant	0.214	1.931**	1.587*	1.334	1.050	3.746**	0.206
	(0.35)	(2.76)	(1.97)	(1.29)	(0.95)	(2.79)	(0.33)
Effects	City	Dwelling	Dwelling-family	Dwelling	Dwelling-family	City	City
R-squared	0.438	0.0497	0.0465	0.0556	0.0512	0.250	0.429
N. of cases	59,492	59,492	59,492	34,371	34,371	5,176	53,027
Std. err clustering	City	Dwelling	Dwelling	Dwelling	Dwelling	City	City

* $p<0.05$, ** $p<0.01$, *** $p<0.001$.
t statistics, not standard errors, are reported in parentheses.

shows that the short-run own price elasticity of electricity consumption is −0.736, and the long-run one is −0.814, while the short-run cross-price elasticity (with respect to gas) is 0.265, and the long-run one is 0.293. For gas consumption, shown in column (C), the short-run own price elasticity is −0.572 and the long-run one is −0.647. The price of electricity is not significant in the gas equations. These equations include controls for the heating and cooling system, and we interpret them to imply adjustment when the current heating and cooling technology is considered irreversible.

In specifications (B) and (D) for electricity and gas, respectively, we exclude heating, cooling, and appliance dummies from the regression and interpret the result to apply when the choice of heating and cooling technology is reversible. It has been argued that durable goods and heating and cooling equipment are variable in the long-run, hence these specifications should result in a more pronounced response to energy prices. In fact, we do find slightly elevated price elasticities, but the differences are minor, on the order of 2% for electricity regressions, and 6% for gas regressions.

6. Discussion and Conclusions

The price and income elasticities of residential energy demand are important inputs into assessments of the effects of energy policies, demand forecasts, and greenhouse gas (GHG) emissions and impacts models. Existing estimates based on household-level energy consumption are based on either old data, or on recent, abrupt changes in prices due to supply conditions in geographically limited areas, and so it is unclear whether they are appropriate nationwide.

To address these external validity limitations, we assembled a mixed panel/multi-year cross-sectional dataset of households in the 50 largest metropolitan areas in the United States as of 2008. Our dataset documents utility bills, heating and cooling systems, appliances, and dwelling and household characteristics for over 69,000 dwellings (over 74,000 households) in the American Housing Survey from 1997 to 2007, for a total of over 98,000 observations. We merged these data with utility prices, and heating and cooling degree-days at the metro area level. To our knowledge, this is the most comprehensive set of data for examining household residential energy usage at the national level, containing the broadest geographical coverage, and with the longest longitudinal component (max $T=6$).

We estimate demand functions for electricity and gas. We control for unobserved heterogeneity in three alternate ways: (i) city-specific fixed effects exploit the variation in prices, dwelling characteristics, and state and local policies between observations, while (ii) dwelling-specific and (iii) dwelling-household effects rely on variation of prices, weather, and other local characteristics over time.

We find strong household response to energy prices, both in the short and long term. From the static models, we get estimates of the own price elasticity of electricity demand in the −0.860 to −0.667 range, while the own price elasticity of gas demand is −0.693 to −0.566. The dynamic models produce similar estimates, with short-

Table 11
Blundell–Bond estimates. Dynamic models. (Model based on dwelling-specific effects.)

	Log of energy usage — lkWh		log of energy usage — lMCF	
	(A) dwelling effect	(B) no HVAC	(C) dwelling effect	(D) no HVAC
Lag consumption	0.0958***	0.0939***	0.116***	0.123***
	(6.09)	(5.83)	(6.20)	(6.41)
Log electric price	−0.736***	−0.743***	−0.0716	−0.0821
	(−12.26)	(−12.29)	(−0.91)	(−1.05)
Log gas price	0.265***	0.283***	−0.572***	−0.586***
	(5.15)	(5.56)	(−9.15)	(−9.32)
Log sq. ft	0.142**	0.142**	0.140	0.137
	(2.64)	(2.65)	(1.91)	(1.83)
Age of the home	−0.00624*	−0.00699*	0.00691*	0.00720*
	(−2.04)	(−2.22)	(2.22)	(2.31)
Age of the home squared	0.0000497	0.0000522	−0.0000353	−0.0000365
	(1.63)	(1.68)	(−1.07)	(−1.11)
Owns the home	−0.0261	−0.0310	−0.0168	−0.0101
	(−0.90)	(−1.06)	(−0.45)	(−0.27)
No. rooms	0.0128***	0.0126***	0.0162***	0.0162***
	(3.70)	(3.60)	(3.72)	(3.70)
No. floors	0.00976	−0.00316	0.149***	0.164***
	(0.45)	(−0.14)	(4.98)	(5.40)
Log Hhold income	0.00935**	0.00925**	0.00318	0.00425
	(3.09)	(3.05)	(0.93)	(1.23)
Young child dummy	0.0725***	0.0714***	0.0574**	0.0578**
	(4.89)	(4.80)	(3.01)	(2.99)
Elderly dummy	−0.00728	−0.00829	0.0160	0.0190
	(−0.36)	(−0.41)	(0.69)	(0.81)
log CDD	0.0660**	0.0793***	−0.0297	−0.0304
	(3.01)	(3.56)	(−1.21)	(−1.22)
log HDD	0.0222	0.00478	0.200***	0.202***
	(0.95)	(0.21)	(5.46)	(5.41)
Constant	2.389***	2.422***	−0.661	−0.844
	(4.06)	(4.08)	(−0.91)	(−1.14)
N. of cases	24,487	24,487	17,679	17,679
Long term elasticity	−0.8140	−0.8200	−0.6471	−0.6682

* $p<0.05$, ** $p<0.01$, *** $p<0.001$.
t statistics, not standard errors, are reported in parentheses.

run (long-run) own-price elasticity of demand of −0.736 (−0.814) for electricity and −0.572 (−0.647) for gas.

Our relatively high price elasticity of demand is in sharp contrast with much of the literature on residential energy consumption in the United States, and with the figures used in current government agency practice. In its Annual Energy Outlook, for example, the Energy Information Agency (EIA) historically employed a short-term price elasticity of −0.15 for non-electric energy. In their 2010 report, EIA adopts an electric elasticity of −0.30 in anticipation of improved consumer awareness resulting from recent smart grid projects.[26]

By contrast, our estimate of the income elasticity is low, and only when we remove dwelling characteristics from the right-hand side of the regression equations does it reach 0.05. This figure is consistent with its counterparts in Rehdanz (2007) and Meier and Rehdanz (2010), who examine residential space heating *expenditures* in Germany and the U.K., respectively, using household-level data, but much lower than the income elasticity of energy demand (from all sources and sectors) typically used in many integrated assessment models (see Webster et al., 2008).

Taken together, our findings suggest that when prices increase households tend to substitute other inputs for energy and choose less energy-intensive appliances (or homes), and that as incomes rise, households tend to exhibit preferences for less energy-intensive appliances and homes (Webster et al., 2008). We leave it to future research to explore *which* energy efficiency investments, changes the stock of appliances, or conservation practices people undertake in response to price changes.

[26] The text refers specifically to smart grid projects funded under the American Recovery and Reinvestment Act of 2009 http://www.eia.doe.gov/oiaf/aeo/assumption/residential.html and EIA (2010).

Acknowledgements

We wish to thank Chuck McCormick for his help with the data, and seminar participants at WCERE Montreal and ETH-Zurich, and an anonymous reviewer for their helpful comments. Any errors remain our own.

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Resource and Energy Economics 33 (2011) 315–325

Contents lists available at ScienceDirect

Resource and Energy Economics

journal homepage: www.elsevier.com/locate/ree

A pseudo-panel data model of household electricity demand☆

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ARTICLE INFO

Article history:
Received 13 March 2009
Received in revised form 17 May 2010
Accepted 14 July 2010
Available online 22 July 2010

Keywords:
Household electricity consumption
Pseudo-panel data

JEL classification:
C23
P12
Q4

ABSTRACT

We study the dynamic behaviour of household electricity consumption on the basis of four large independent surveys conducted in the province of Québec from 1989 to 2002. The latter region displays some rather unique features such as the very extensive use of electricity for space heating in a cold climate and the wide range of energy sources used to meet space heating requirements. We adopt Deaton (1985) approach to create 25 cohorts of households that form a pseudo-panel. The cohorts have on average 131 households. The model error terms allow for group heteroskedasticity and serial correlation. Short-run and long-run own and cross-price elasticities are statistically significant. Electricity and natural gas are estimated to be substitutes while electricity and fuel oil are complements, as it may occur in the Quebec context. The estimate of the income elasticity is not significant. Comparisons with related studies are provided.

1. Introduction

There is an ever-lasting interest in the economic analysis of energy demand and it is mainly due to societal concerns with respect to the environment, energy security, and energy price impacts on low income households and on industries. The foremost objective of all econometric studies dealing with energy demand is to shed some light on key parameters such as price and income elasticities and the adjustment process. This type of information is particularly useful in energy demand forecasting and

☆ We thank The Chaire en économique de l'énergie électrique, Université Laval, for financial support and Hydro-Québec for making their residential consumer surveys available to us. We are solely responsible for the results presented in this paper.
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doi:10.1016/j.reseneeco.2010.07.002

in the analysis of energy efficiency programs.[1] In this paper, we deal only with the residential sector. Dahl (1993) and Madlener (1996) provide surveys of econometric models of residential energy demand that rely on data generated over the 1970–1990 period. Dahl (1993) notes that price and income elasticity estimates vary significantly from one study to the next. The same conclusion can be reached if we consider more recent works: Poyer and Williams (1993), Hsing (1994), Maddala et al. (1997), Poyer et al. (1997), Silk and Joutz (1997), Garcia-Cerrutti (2000), Kamerschen and Porter (2004), Dergiades and Tsoulfifis (2008) and Borenstein (2009). The variability of parameters estimates is a reflection of the type of data used to estimate energy demand models, i.e. time series, cross-sections or panels, the sample period, and the extent of geographic aggregation, i.e. counties, states or countries. Model specification and estimation methods contribute also to the wide range of parameter estimates.

The multiplicity of approaches adopted to study energy demand is partly a consequence of the nature of available data. Aggregate time series have desirable features such as reliability and coverage; however they are subject to a major shortcoming with respect to the capacity to bridge a link between energy use and the major complementary appliances required to produce the services desired by users. The seminal work of Dubin and McFadden (1984) has drawn the attention to the estimation biases that may result from neglecting the simultaneous nature of the decisions to acquire a particular space heating system and to use it. Estimation of models as suggested by Dubin and McFadden requires cross-section data that can be very rich in terms of reported socioeconomic variables, however such cross-section data are not free from defects. Two shortcomings are particularly troublesome: one is the lack of energy price variability between consumers who live in the same service territory of a distribution utility and who face more or less the same energy prices by sources, i.e. electricity, natural gas and oil products. The other shortcoming is related to the dynamic nature of the relationship between energy use and the stock of complementary appliances. A single cross-section encompasses users who are at different stages of this evolving process. It is usually assumed that cross-section data portray users who are close to their long-run equilibrium; hence price and income elasticity estimates receive a long-run interpretation in such a context. However the dynamic nature of the adjustment process indicates that reality may not support this assumption in the case of electricity demand.

A way to address this last difficulty is to make use of panel data. However because of the high cost and the attrition that reduces the information obtained from panel samples, this type of statistical information is seldom available; rather what we have at our disposal in a few instances is a set of independent cross-sections that are collected at regular intervals. Following the path-breaking work of Deaton (1985), in this paper we build pseudo-panel data out of four independent cross-sections that come from large residential customer surveys conducted by Hydro-Québec, the electric utility that provides service to most users in the province of Québec. The observation units of pseudo-panel are cohort means. A cohort is a set of households that are grouped together according to specific membership criteria that remain the same for all surveys; the intent is to form a fairly homogeneous group. As it will be seen later on, a pseudo-panel provides a way to address the two aforementioned shortcomings of single cross-sections, i.e. lack of energy price variability and absence of information on the dynamic adjustment process. However aggregation into cohorts causes some information losses and there are trade-offs to be made along key dimensions such as number of households per cohort, number of cohorts, and homogeneity of households within cohorts.

To the best of our knowledge, this is the first application of pseudo-panel techniques in the context of household electricity demand. Furthermore the province of Québec has some distinctive characteristics with respect to household electricity consumption due to the extensive use of electricity for residential space heating in a rather cold climate and the diversity of energy sources that are used for this purpose.

The presentation proceeds as follows: in Section 2, we provide a brief introduction to pseudo-panel models; in Section 3, we specify the cohort electricity demand model and discuss some features of the data set; in Section 4, we describe the estimation method and the results. We also provide

[1] Several governments have introduced or are contemplating using programs or price incentives to curtail energy demand in light of the concerns with respect to global warning caused by greenhouse gas emissions. The impacts of such initiatives depend in part on price elasticities.

comparisons with electricity price and income elasticity estimates which were obtained in previous studies. Section 5 formulates some concluding comments.

Here is a summary of the main findings: the price variables of all the energy sources have statistically significant coefficients at the 1% level and electricity and oil products are complements while electricity and natural gas are substitutes. The income elasticity estimate is not statistically significant. The coefficient estimate of lagged electricity consumption is 0.62; this indicates a fairly slow adjustment process and it induces a large discrepancy between short-run and long-run elasticity estimates. We find that weather variables are not significant factors that influence electricity demand.

2. A brief introduction to pseudo-panel models

Panel data are composed of observations on the same units at different periods and they provide a rich set of information to analyze dynamic and static aspects of economic behaviour.[2] Unfortunately, panel data are expensive and subject to attrition that is likely to increase as the number of periods gets larger. Attrition may introduce a selection bias. Series of independent cross-sections are more readily available. The question then is how to best use independent cross-sections when we do not have access to real panel data? Deaton (1985) proposed to use cohort means as observations.

A cohort is defined as a group of individuals who share a set of characteristics that stay constant from one survey to the next such as age, place of residence, marital status and so on. Cohort means can be organized as a panel and form what is known as a pseudo-panel. Since cohort means are based on a set of individuals and not on the whole population, they can be viewed as approximation of population means and consequently, they are subject to measurement errors.[3] Deaton addressed this problem by applying error-in-variables techniques. When the number of individuals in each cohort is sufficiently large, measurement errors can be ignored. Indeed, most authors ignore measurement errors in empirical applications.[4]

The use of pseudo-panel data does not necessarily imply that estimation results are inferior to those obtained from genuine panel data since the latter are subject to attrition. Pseudo-panels present no such problem since individuals are not the same from one period to the next. Hence, there is a trade-off between more precise information subject to attrition and more complete pseudo-panel data subject to measurement errors.[5]

As with standard panel data, fixed or random individual (cohort) effects must be taken into consideration when use is made of pseudo-panel data. Let us recall that when the regressors are not correlated with individual effects, fixed and random effect estimators are both consistent; however the later is more efficient than the former. If individual effects are correlated with one or more regressors, the random effect estimator is no more consistent, but the fixed effect estimator still is.

Once the type of effects to be included has been determined, it is necessary to select an appropriate estimation method. Several estimators have been suggested in the context of standard panels: within, between, instrumental variables (IV), generalized method of moments (GMM), and maximum likelihood (ML) estimator; they are applied also in the context of pseudo-panels. Here are some instances: Browning et al. (1985) estimate life-cycle models of family consumption and labor supply by using a within estimator; Dargay and Vythoulkas (1998) and Dargay (2002) analyze a dynamic model of household car demand in the United Kingdom and a fixed effect model is estimated by applying the ML method; Gardes and Loisy (1997) estimate demand elasticity based on minimum income relative to declared income and uses the within and the between transformation while correcting for heteroskedasticity that may occur due to the aggregation of households into cohorts.

In the papers published thus far, few authors have taken into consideration the presence of hereroskedasticity and serial correlation with pseudo-panel data. Using real panel data based on California counties, Garcia-Cerrutti (2000) applied generalized least-squares to correct

[2] See Blundell and Meghir (1990) and Baltagi (2005).

[3] Real panels are not free from measurement errors either.

[4] For instances, see Browning et al. (1985), Blundell et al. (1994) and Moffit (1993).

[5] There are estimation methods available to address issues associated with incomplete panels. See Baltagi (2005). However there is still a loss of information caused by attrition.

simultaneously for heteroskedasticity and serial correlation in a dynamic electricity demand model with random effects. In this paper, we extend his work to pseudo-panel data. However we do not borrow his random coefficient specification since we have only access to four cross-sections.

3. Model specification, cohort creation and related data issues

3.1. Model specification

Electricity is an intermediate good used with complementary appliances to produce the desired services. These complementary appliances are durable or semi-durable goods; their life cycles usually span more than one year and are submitted to adjustment costs. This is why there is an interest in the short-run and the long-run responses of energy users to changes of economic conditions. Panel data are particularly useful to study household behaviour conditional on appliance holdings. Such panel data are not available in the province of Québec. However independent cross-sections are produced on a regular basis.

We assume that individual household electricity demand can be represented by the following dynamic model:

$$y_{nt} = \alpha y_{nt-1} + X_{nt}\beta + \theta_n + \varepsilon_{nt} \quad n = 1, 2, \ldots, N_t \text{ and } t = 1, \ldots, T. \tag{1}$$

where y_{nt} is the electricity demand of household n at period t, y_{nt-1} is its lagged value, α is its associated coefficient, X_{nt} is a vector of exogenous explanatory variables, β is a vector of associated parameters, θ_n is an unobservable individual effect, ε_{nt} is an error term, N_t is the number of households in the sample at period t, and T is the number of periods. In repeated independent cross-sections, N_t is not necessarily the same from one period to the next, and the index n is also changing accordingly. Thus it would be more appropriate to write $n(t)$, but to simplify the notation, we keep the index n.

Individual effects are assumed to be fixed; this is a fairly common assumption in the context of pseudo-panels.[6] The price of electricity is of particular concern in econometric studies of electricity demand because the marginal price is the relevant explanatory variable; the latter is not readily available due to the application of tariff schedules.[7] As it will be explained later on, cohort members face the same marginal price in a given year in our sample. When we estimate a model of individual household electricity demand, it is required to take into account the choice of heating system. This gives a non-zero value to the expected error term conditional on the choice of heating system. In our case, this non-zero value is tied to the household and it is incorporated into the fixed effect; we assume that it stays constant for a given cohort from one survey to the next.

When we aggregate individuals into cohorts and compute the mean for each cohort, we get the following model:

$$\bar{y}_{ct} = \alpha \bar{y}_{ct-1} + \bar{X}_{ct}\beta + \bar{\theta}_c + \bar{\varepsilon}_{ct}, \quad c = 1, 2, \ldots, C \text{ and } t = 1, \ldots, T. \tag{2}$$

where $\bar{y}_{ct} = (1/n_c)\sum_{n \in I_c} y_{nt}$, $\bar{X}_{ct} = (1/n_c)\sum_{n \in I_c} y_{nt}, \bar{X}_{nt}$, $\bar{\varepsilon}_{ct} = (1/n_c)\sum_{n \in I_c} \varepsilon_{nt}$, $\bar{\theta}_c = (1/n_c)\sum_{n \in I_c} \theta_n$, I_c is the set of households in cohort c, n_c is the number of households in cohort c, and C is the total number of cohorts.[8] Note that $\bar{y}_{ct-1}$ is the average lagged consumption of cohort c which comes most likely from a different set of households that had the same characteristics at period $t-1$.

Several factors related to cohort size, cohort location, and the nature of regional economic activities can make the error term of model (2) to be heteroskedastic. It is also possible that there is serial correlation between the error terms of two different periods. Therefore, we assume that

$$\begin{aligned} \bar{\varepsilon}_{ct} &= \rho \bar{\varepsilon}_{ct-1} + \bar{u}_{ct}, \\ E(\bar{u}_{ct}) &= 0, \\ \text{and } E(\bar{u}_{ct}^2) &= \sigma_c^2. \end{aligned} \tag{3}$$

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[6] Instances are Deaton (1985), Browning et al. (1985) and Moffit (1993).

[7] As shown by Reiss and White (2005), the non-linearity of the marginal price may introduce a selection bias.

[8] I_c and n_c are not the same from one survey to the next and it would be more appropriate to make them a function of t. This detail is not included to keep the notation simple.

Table 1
Residential relative electricity price in some North American cities, April 1st 2009[a].

Montréal, Qc	100
Vancouver, BC	104
Seattle, WA	121
Edmonton, AB	149
Toronto, On	167
Chicago, IL	219
San Francisco, CA	357
New York, NY	369
Boston, MA	378

Source: Hydro-Québec (2010).
[a] Average monthly bill for 1000 kWh.

ρ is the autocorrelation coefficient that is common to all cohorts and σ_c^2 is the variance that is specific to cohort *c*. In this model, the error terms are subject to group heteroskedasticity and autocorrelation at the same time. However, it is assumed that the error terms of different cohorts are not correlated.

3.2. Cohort creation and data related issues

Our data base comes from four large independent surveys conducted by Hydro-Québec, a government owned utility that distributes more than 95% of the electricity in the province of Québec. In 2009, it sold 62 TWh to 3 649 470 residential users and the average rate was 7.2 Can.¢/kWh.[9] The latter is one of the lowest rates in North America as it can be seen in Table 1 and it is due to the combination of hydroelectric power and public ownership. In 2009, Hydro-Québec had access to 44 192 MW and 91.0% was hydro. The low electricity rates have created conditions favourable to electricity use: in 2000, the average use per capita was 30 687 kWh in Québec, 18 040 kWh in Canada,[10] and 14 684 kWh in USA. Here are the shares of residences in the province of Québec by main energy sources used for space heating in 2002: electricity (68%), oil (17%), wood (9%) and natural gas (6%). Furthermore many residences rely on dual-energy space heating systems such as electricity and fuel oil or electricity and wood. Québec residential households are in the rather unique position to rely heavily on electricity for space heating in cold climate. Furthermore they use a diverse mix of energy sources, either alone or in combination. Hydro-Québec conducted two large mail residential surveys in 1989 and 1994, and some 50 000 questionnaires out of 100 000 were filled.[11] It conducted two smaller phone surveys in 1999 and 2002 and the later have about 10 000 observations each.[12] These surveys provide information on appliance holdings, house characteristics and some socio-economic variables of the households.

In each cross-section, we have chosen only single-family houses: detached, semi-detached or row houses with separate outside entrance. This leads to a more homogenous sample since apartments and trailers are deleted.[13] Because electricity use is larger in single-family houses, this ensures that most users pay at the margin the highest rate of a two-block tariff. Furthermore only houses that were built or converted to another energy source for space heating during the most recent five-year span in each survey are included. This restriction ensures that only households who made a recent decision with respect to a new heating system are included in the sample. This increases further the

[9] Total sales within the province and exports were 165.3 TWh and 23.4 TWh, respectively. See Hydro-Québec (2010).
[10] Including Québec.
[11] The voluntary response to a mail questionnaire may introduce some biases in parameter estimates. Households who are more concerned with energy and the environment are more likely to participate in such surveys. This may create a positive estimation bias in price elasticity and a negative one in income elasticity relative to the overall population.
[12] The response rates to the phone surveys are not known.
[13] However owners of single family houses are usually at the high end of the income distribution. This has implications for the income elasticity estimates.

homogeneity of the sample and focuses on users that are the most likely to respond to energy price changes. Here are the numbers of observations that are drawn from each survey: 2897 in 1989, 4849 in 1994, 3123 in 1999 and 2155 in 2002.

Cohorts must be constructed according to some well-defined rules. In practice, an arbitrage must be performed between the number of cohorts (C) and the number of individuals by cohort (n_c). When C is large, then n_c is small and cohorts means are inaccurate estimates of the true means of cohort population. Verbeek and Nijman (1992) show that n_c must be sufficiently large for the within estimator to be consistent.

The two criteria that we rely upon to identify cohort membership are the region of household residence and her house size. The province is divided into nine administrative regions that vary in terms of population density, economic activity, and weather. Households who live in the same region share some common characteristics and their behaviour concerning energy consumption is related to these region specific characteristics. It should be pointed out that natural gas distribution is not available in low population density areas and it is totally absent east of Québec City. Conversely fire wood is plentiful in rural areas and in small cities, but is not so readily available in large cities.

As the objective is to analyze household electricity demand, an important factor is house size. Houses are partitioned into three groups: small surface (less than 1000 square feet), medium surface (between 1000 and 2000 square feet) and large surface (more than 2000 square feet). Let us recall that more than 60% of electricity used by Québec households is related to water and space heating; both uses are definitely related to house size.

These two criteria (region and heating surface) yield a set of $9 \times 3 = 27$ potential cohorts. Table 2 shows the distribution of cohort sizes by survey. Some cohorts have few observations because the population of these cohorts is small to begin with. Indeed, some regions in the province of Québec have much lower population density than others and this is reflected in the surveys. Two cohorts are merged with another in a neighbouring region and we finally kept 25 cohorts. The average cohort size is 131 households. Cohort sizes are deemed to be large enough to neglect measurement errors of population means.

Hydro-Québec surveys provide information on household income and electricity consumption comes from meter readings. Electricity marginal price is the price of the last block of the two-block tariff. Natural gas price is the average regional residential rate that is specific to each consumer; the province of Québec can be divided into four areas in this respect: two fairly small western regions, the no service area, and the remaining area. Heating oil price is also the average price paid within each of the nine administrative areas. No information is available on fire wood prices. Finally heating and cooling degree days are measured by Environment Canada at the major city of the administrative region. Nominal values are converted to real ones by applying Quebec CPI index.

4. Estimation method and empirical results

Model (2) has the pervasive problem that the lagged dependent variable is correlated with the serially correlated error term. Moffit (1993) extends Deaton's (1985) approach to the estimation of a dynamic model based on independent cross-sections. He interprets the within estimator as an instrumental variables estimator and cohort dummy variables fulfil the role of instruments. Moffit suggests to replace the lagged dependent variable $\bar{y}_{nt-1}$ by its predicted value obtained from data available at time $t-1$.

Verbeek and Vella (2005) examine the estimator proposed by Moffit (1993) and shows that Moffit's estimator is not consistent unless exogenous variables are time invariant or do not have any autocorrelation. They suggest an alternative approach also based on instrumental variables. Their approach makes use of the within estimator with cohorts means. The within estimator together with the augmented instrumental variables is consistent. Consistency requires a large number of cohorts in order to reduce the estimator bias.[14] We also use the instrumental variables (IV) method.

[14] This bias also exists when the within estimator is applied to dynamic models using real panel data and it is even larger than the bias of the within estimator with pseudo-panel data.

Table 2
Cohort size by survey.

Region	Survey															
	1989				1994				1999				2002			
	S	M	L	T	S	M	L	T	S	M	L	T	S	M	L	T
MANICOUAGAN (MAN)	8	26	13	47	11	34	23	68	103	23	9	135	12	53	39	104
SAINT-LAURENT (STL)	52	133	112	297	37	139	86	262	194	67	33	294	14	45	51	110
RICHELIEU (RIC)	97	433	243	773	140	614	468	1222	473	139	56	668	55	153	221	429
MONTMORENCY (MON)	102	286	119	507	120	558	320	998	403	101	38	542	65	153	221	439
LAURENTIDES (LAU)	114	412	194	720	148	598	470	1216	505	209	83	797	78	221	241	540
MAURICIE (MAU)	32	74	44	150	33	199	151	383	131	28	4	163	13	46	77	136
LA GRANDE (LGR)	18	56	29	103	14	73	46	133	100	25	5	130	16	37	40	93
MATAPEDIA (MAT)	27	85	25	137	50	181	96	327	196	36	22	254	28	78	90	196
SAGUENAY (SAG)	36	82	45	163	24	141	75	240	103	29	8	140	10	44	54	108
Total	486	1587	824	2897	577	2537	1735	4849	2208	657	258	3123	291	830	1034	2155

S = small surface, M = medium surface, L = large surface, T = total (i.e. S + M + L).

We assume that $\bar{y}_{ct-1}$ depends on some other variables:

$$\bar{y}_{ct-1} = \bar{W}_{ct-1}a_1 + \bar{Z}_c a_2 + \bar{\nu}_{ct-1},$$

where $\bar{W}_{ct-1}$ is a vector of time variant variables,[15] $\bar{Z}_c$ a vector of time invariant variables that are the cohort fixed effects, a_1 and a_2 are vector of parameters, and $\bar{\nu}_{ct-1}$ is an error term that is assumed to be independent and identically distributed. After instrumenting $\bar{y}_{ct-1}$, we obtain a consistent estimator of ρ, denoted by $\hat{\rho}$.[16]

$$\hat{\rho} = \frac{\Sigma_{c=1}^{C}\Sigma_{t=2}^{T}\bar{e}_{ct}\bar{e}_{ct-1}}{\Sigma_{c=1}^{C}\Sigma_{t=1}^{T}\bar{e}_{ct}^{2}},$$

where $\bar{e}_{ct}$ is the IV estimation residual of (2). $\hat{\rho}$ is then used to carry out the Prais-Winsten transformation in the following way:

$$\bar{y}_{ct}^{*} = \sqrt{1-\hat{\rho}^2}\,\bar{y}_{ct} \text{ and } \bar{X}_{ct}^{*} = \sqrt{1-\hat{\rho}^2}\,\bar{X}_{ct} \quad \text{for } t = 1,$$

$$\bar{y}_{ct}^{*} = \bar{y}_{ct} - \hat{\rho}\bar{y}_{ct-1} \text{ and } \bar{X}_{ct}^{*} = \bar{X}_{ct} - \hat{\rho}\bar{X}_{ct-1} \text{ for } t = 2,\ldots,T.$$

The instrumental variables are transformed in a similar fashion to obtain $\bar{X}_{ct}^{**}$. The transformed data are used in a IV application to obtain consistent estimators of cohort variances:

$$\hat{\sigma}_c^2 = \frac{1}{T}\sum_{t=1}^{T}\bar{e}_{ct}^{*2}$$

where $\bar{e}_{ct}^{*} = \bar{y}_{ct}^{*} - \bar{X}_{ct}^{*}\hat{\beta}$and $\hat{\beta}$ is the estimator obtained by applying OLS to the transformed data.

Note that the cohort effects are included in the $\bar{X}_{ct}$ and β is redefined accordingly. The variance estimators are then used to obtain the feasible generalized least square estimator (FGLS):

$$\hat{\beta}_{\text{FGLS}} = \left[\sum_{t=1}^{T}\sum_{c=1}^{C}\frac{1}{\hat{\sigma}_c^2}\bar{X}_{ct}^{**'}\bar{X}_{ct}^{*}\right]^{-1}\left[\sum_{t=1}^{T}\sum_{c=1}^{C}\frac{1}{\hat{\sigma}_c^2}\bar{X}_{ct}^{**'}\bar{y}_{ct}^{*}\right].$$

The use of pseudo-panel data with fixed effects provides a mixture of a between estimator (cohort means) and a within estimator (cohort fixed effects). The estimation results appear in Table 3.

The lagged dependent variable and the three energy prices are statistically significant at the 1% level. Electricity and natural gas are substitutes while electricity and fuel oil are complements. Complementary of electricity and fuel oil may be related to the fairly widespread use of this type of dual energy for space heating in Québec.[17] The lagged dependent variable captures most of the lethargy present in electricity consumption that is greatly related to house type, heating system and location. This explains why most cohort dummies are also not significant. Only Manicouagan (MAN), a region in the northeast part of the province, has two significant positive effects. It is unexpected to find that heating degree days (hdd) are not statistically significant, a result that is contrary to what was observed in a time series model estimated by Arsenault et al. (1995) and in a single cross-section model estimated by Bernard et al. (1996). Here are the factors that may explain this result in the current context. First, the lagged dependent variable includes the effect of systematic weather differences across regions; second, the cohort dummy variables incorporate also the permanent regional weather differences[18] and finally wood has been left out of the model and wood is more readily available in the northern and colder regions. Wood is mostly used as a supplementary source of heat in conjunction with the main space heating system. Net income is statistically significant only at the 10% level. The weak income effect, which is in line with previous findings, is reduced further here since the sample includes only single-family houses that are occupied by wealthier households.

[15] The variables that vary with time and have been chosen to constitute $\bar{W}_{ct-1}$ are: heating degree days, cooling degree days and the marginal price of electricity.

[16] Regarding the first observation, we suppose that it depends on cohort fixed effects only.

[17] A specific weather related tariff encourages that kind of space heating system.

[18] It turns out that the only two significant dummy coefficients are associated with a northern region.

Table 3
Estimation results.

Variables	Estimates	Standard error	*t*-Student
Lagged consumption	0.616	0.1471	4.19
Net income	0.330	0.236	1.40
Electricity price	−1.962	0.237	−8.29
Natural gas price	0.606	0.128	4.74
Oil price	−1.119	0.292	−3.83
Heating degree days	0.204	0.610	0.33
Cooling degree days	−6.184	3.854	−1.60
Cohort			
MAN-S	1.866	1.760	1.06
MAN-M	3.846	1.545	2.49
MAN-L	4.307	1.396	3.09
STL-S	−1.745	1.686	−1.03
STL-M	−0.256	1.345	−0.19
STL-L	1.149	1.383	0.83
RIC-S	−0.943	1.365	−0.69
RIC-M	−0.366	1.210	−0.30
RIC-L	0.830	1.305	0.64
MON-S	−1.450	1.329	−1.09
MON-M	−0.757	1.147	−0.66
MON-L	−0.182	1.150	−0.16
LAU-S	−0.561	1.302	−0.43
LAU-M	0.281	1.223	0.23
LAU-L	0.960	1.384	0.69
MAU-S	−1.795	1.540	−1.17
MAU-M	−0.816	1.180	−0.69
MAU-L	−0.922	1.417	−0.65
LGR-S	0.199	1.108	0.18
LGR-M	0.721	1.849	0.39
LGR-L	0.680	1.651	0.41
MAT-S	1.524	1.430	1.07
MAT-M	−1.231	1.332	−0.92
MAT-L	−0.392	1.176	−0.33
Intercept including			
SAG-S	21.333	4.623	4.61
ρ	−0.311		

Cooling degree days (cdd) are statistically significant only at the 10% level and furthermore it has a negative sign. Very few houses in Québec have a space cooling system; hence no relationship is expected between cdd and electricity use. However a negative sign is a possibility in Québec since higher cooling degree days may be associated with higher temperature in shoulder months such as April, May, September and October when heating systems are operating. Under these circumstances, higher cdd may simply imply that less heating is required. The variance estimates (σ_c^2) are not shown; they display heterogeneity and they range from 0.15 to 6.57.

Table 4 presents the estimates of income, price and cross-price elasticities of Québec household electricity demand derived from the estimated model; the estimates of the variances are computed using the delta method. All the short-run price elasticities are statistically significant at the 1% level and so are the long-run elasticities, except for natural gas. The short-run income elasticity is significant at the 10% level, but the long-run one is not.

Table 4 provides also the elasticity estimates of the Québec residential electricity demand that were obtained in two previous studies. Building on Dubin and McFadden (1984), Bernard et al. (1996) estimate a joint discrete/continuous model of household heating system choice and electricity demand on the base of the 1989 cross-section sample that is also used in this study. Since no lagged dependent variable appears as explanatory variable and the dependent variable is conditioned on space and water heating system, their estimates receive a short-run interpretation. We can see that the major difference occurs with respect to the oil cross-price elasticity which is positive and much smaller in absolute value in Bernard et al. (1996). Bernard and Genest-Laplante (1995) estimate a

Table 4
Québec residential electricity demand elasticities.

	Electricity price		Natural gas price		Oil price		Income	
	SR	LR	SR	LR	SR	LR	SR	LR
This study	−0.51 (0.06)	−1.32 (0.53)	0.12 (0.03)	0.31 (0.51)	−0.32 (0.08)	−0.89 (0.39)	0.08 (0.05)	0.20 (0.16)
Bernard et al. (1996)	−0.67	–	0.08	–	0.04	–	0.14	–
Bernard and Genest-Laplante (1995)	−0.29	−1.33	−0.02	−0.04	0.02	0.69	0.14	0.35

Note: SR = short-run and LR = long-run.
When available, standard-errors are in parenthesis.

model of Québec residential electricity demand using aggregate time series data from 1962 to 1990.[19] Two significant differences between the two studies are the sign reversals of the two cross-price elasticities and the larger gap between the short-run and the long-run elasticity estimates due to the higher value of the coefficient of the lagged dependent variable.

We now turn briefly to two other studies that present estimates of dynamic household electricity demand models and that make use of a model specification similar to model (2); in particular, the error terms are assumed to be heteroskedastic and serially correlated in the context of panels built from regional data. However both studies allow also for regional dependency of the error terms and different serial correlations by region. Using annual data on 44 California counties from 1983 to 1997, Garcia-Cerrutti (2000) obtains the following estimates of short-run (long-run) income, electricity price and natural gas cross-price elasticities: 0.15 (0.17), −0.17 (−0.19), −0.10 (−0.11).[20] Contrary to this study, he finds that electricity and natural gas are complements. Such a finding is unexpected. Using annual data for five Southern states during the 1981–1990 period, Hsing (1994) gets the following estimates of short-run (long-run) income, electricity price and natural gas cross-price elasticities: 0.40 (0.90), −0.24 (−0.54), and 0.14 (0.32).[21] In comparison to the results presented in this study, he obtains higher income elasticities and lower direct price elasticities; electricity and natural gas are estimated to be substitutes as expected and cross-price elasticity estimates are almost identical in the two studies. Although the model specification of the two USA studies is close to the model specification as in this paper, it should be pointed out that the data have been generated in fairly different contexts and this exemplifies the fact that household electricity demand elasticity estimates depend very much on the data generating process.

5. Conclusion

In this paper, we use four independent surveys on household electricity consumption conducted by Hydro-Québec to build a pseudo-panel of cohort means that is used to estimate a dynamic model of household electricity demand in the province of Québec. Our sample includes only households who inhabit single-family houses built in the last five years before the survey or single-family houses that got a new heating system over the same period. This is a fairly homogenous group of households who are most likely to respond to energy price changes. Furthermore, cohorts allow us to introduce dynamic effects that are difficult to capture in a single cross-section. We find that all price effects are highly statistically significant, that electricity and natural gas are substitutes and that electricity and fuel oil are complements. However the income effect is not significant. The voluntary responses to survey questionnaires and the inclusion of only single-family houses in the sample may explain why

[19] See also Arsenault et al. (1995).
[20] Garcia-Cerrutti (2000) estimates a random coefficient model and a constant coefficient model. We present only the results of the constant coefficient model since this is the specification used in this study. He finds that only the natural gas cross-price electricity is statistically significant at the 5% level.
[21] All parameters estimates are significant at the 1% level.

our price elasticity estimates are at the high end while income elasticity estimates are at the low end relative to other studies.

Our results illustrate the point that electricity demand elasticity estimates are quite specific to the data generating process such as region, time period, and level of aggregation. Hence care should be taken to transfer parameter estimates from one region to another as it is often done in the analysis of energy programs or the use of computable general equilibrium (CGE) models.

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Applied Economics, 1987, **19**, 1471–1482

Estimation of income elasticities from cross-section data

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I. INTRODUCTION

The term 'income elasticity of demand' is a quantitative measure of the relative variation of an individual's (or group of individuals') demand for a certain commodity when his (their) income varies. This measure can be of great interest for many purposes, *inter alia* for applied economic policy:

— the government wants to estimate reactions in consumers' demand when it plans changes in the tax system;
— the government plans to subsidize certain subgroups of the population;
— the government is interested in forecasting long-term changes in the economic structure of the country etc.

Income elasticities can be calculated by estimating Engel curves or demand functions from time-series of consumption data or from cross-section data of household consumption. In the case of cross-section data, usually a certain point, e.g. the mean or the median, of the underlying income distribution is chosen to calculate the income elasticity of demand for a certain commodity. This paper tries to show the necessity and possible ways of integrating the whole income distribution into the calculations of income elasticities.

II. THEORETICAL CONSIDERATIONS

The income elasticity of commodity j of individual i is defined as

$$\varepsilon_j^i(\mathbf{p}, \omega^i) = \frac{\partial f_j^i(\mathbf{p}, \omega^i)}{f_j^i(\mathbf{p}, \omega^i)} \Big/ \frac{\partial \omega^i}{\omega^i}$$
$$= \frac{\partial f_j^i(\mathbf{p}, \omega^i)}{\partial \omega^i} \cdot \frac{\omega^i}{f_j^i(\mathbf{p}, \omega^i)} \qquad (1)$$

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where $f_j^i(p, \omega^i)$ is i's demand function for j; ω^i his budget (income); and $\mathbf{p}$ the price vector. $\varepsilon_j^i(\mathbf{p}, \omega^i)$ shows the relative variation of individual i's demand for commodity j when his income varies.

But it is questionable if this concept can be applied in empirical work where one has household cross-section data and wants to estimate the income elasticity of a commodity of a *group* of households or the income elasticity of the market demand for a commodity.

It has been common practice to compute the value of the elasticity at a certain point of an estimated statistical Engel curve, for example the mean or the median[1] of the income distribution of the group of households, although it is well known that the elasticity values may vary widely along the Engel curve. Therefore, the computed value need not be a good representation for the income elasticity with respect to the *whole* group of households. It may happen that a commodity j is classified as a necessity because at the median income we compute that $0 \leqslant \varepsilon_j \leqslant 1$, but it is inferior for all higher incomes.

Moreover, the method of measuring the income elasticity at only one point of the underlying income distribution leaves aside all considerations about changes in the relative dispersion of the income distribution with varying incomes. These changes, however, are important for the change of the market demand for the commodity whose relative size should be expressed by the income elasticity.

Stone (1954, p. 265) has developed a formula for the income elasticity of market demand for commodity j. Let G be the group of all consumers. Then:

$$\varepsilon_j = \frac{1}{\sum_{i\in G} f_j^i} \cdot \sum_{i\in G} \left\{ f_j^i \left(\frac{\omega^i}{f_j^i} \cdot \frac{\partial f_j^i}{\partial \omega^i} \right) \cdot \left(\frac{\sum_{i\in G} \omega^i}{\omega^i} \cdot \frac{\partial \omega^i}{\partial \left(\sum_{i\in G} \omega^i \right)} \right) \right\} \tag{2}$$

In words, 'the market income elasticity is equal to the weighted average of the products of the individual income elasticities and the elasticities of individual incomes with respect to total income' (Stone, 1954, p. 265).

Let $\bar{F}_j = \bar{F}_j(\mathbf{p}, \omega^1, \omega^2, \ldots, \omega^n) = \frac{1}{\#G} \sum_{i\in G} f_j^i$ ((mean) market demand) and $\bar{\omega} = \frac{1}{\#G} \sum_{i\in G} \omega^i$ (mean income). #G denotes the cardinality of group G. The above formula can easily be simplified:

$$\begin{aligned}
\varepsilon_j &= \frac{1}{\#G \cdot \bar{F}_j} \cdot \sum_{i\in G} \frac{\partial f_j^i}{\partial \omega^i} \cdot \left(\sum_{i\in G} \omega^i \right) \cdot \frac{\partial \omega^i}{\partial \left(\sum_{i\in G} \omega^i \right)} \\
&= \frac{1}{\#G \cdot \bar{F}_j} \cdot \sum_{i\in G} \frac{\partial f_j^i}{\partial \omega^i} \cdot (\#G \cdot \bar{\omega}) \cdot \frac{\partial \omega^i}{\partial \left(\sum_{i\in G} \omega^i \right)} \\
&= \frac{\bar{\omega}}{\bar{F}_j} \sum_{i\in G} \frac{\partial f_j^i}{\partial \omega^i} \cdot \frac{\partial \omega^i}{\partial \left(\sum_{i\in G} \omega^i \right)}
\end{aligned} \tag{3}$$

[1]See among many others Prais and Houthakker (1955, p. 94).

which means that the market income elasticity for commodity j is a function of the sum of the slopes of the individual Engel curves which are weighted by the individual increments in income with respect to the total income of group G.

In general, the value of the elasticity is dependent on the distribution of the increase in total income over the group of households. There is just one exception: all individual Engel curves are linear and have the same slope, i.e. $\partial f_j^i/\partial\omega^i$ is a constant for all i. In all other cases, one has to specify a distribution key in terms of $\partial\omega^i/\partial\left(\sum_{i\in G}\omega^i\right)$ or $\left[\left(\sum_{i\in G}\omega^i\right)/\omega^i\right]\cdot\left[\partial\omega^i/\partial\left(\sum_{i\in G}\omega^i\right)\right]$, according to the formula of the income elasticity, for further investigations.

Hildenbrand (1983b) considers two cases.

Case A: The individual increments are the same for all households. This may, for example, be the appropriate specification if one is interested in the impacts of certain subsidies for subgroups of households.

The distribution key is in this case

$$\frac{\partial\omega^i}{\partial\left(\sum_{i\in G}\omega^i\right)}=\frac{1}{\#G} \tag{4}$$

or, equivalently

$$\frac{\partial\omega^i}{\partial\left(\sum_{i\in G}\omega^i\right)}\cdot\frac{\sum_{i\in G}\omega^i}{\omega^i}=\frac{1}{\#G}\frac{\sum_{i\in G}\omega^i}{\omega^i}=\frac{\bar{\omega}}{\omega^i} \tag{5}$$

The elasticity of individual income with respect to total income is in the case of equal absolute income increments given by the ratio of mean income to individual income. The income elasticity of market demand for commodity j can be written as

$$\varepsilon_j(A)=\sum_{i\in G}\frac{1}{\#G}\frac{\partial f_j^i((\mathbf{p},\omega^i)}{\partial\omega^i}\cdot\frac{\bar{\omega}}{\bar{F}_j}. \tag{6}$$

Case B: The individual increments in income are the same for all households relative to their income. This specification implies that the relative dispersion of the personal income distribution is constant over time.[2] Calculating income elasticities under this assumption could be appropriate if one needs the values for considerations on long-run economic policy.

[2]This assumption is empirically confirmed for example by Schnitzer (1974, p. 39f.) who reports on the stability of the personal income distribution in the USA in the period from 1947 to 1971. This also implies that Case A can only be valid in the short term.

The distribution key is specified as

$$\frac{\partial \omega^i}{\partial\left(\sum_{i \in G} \omega^i\right)} = \frac{\omega^i}{\sum_{i \in G} \omega^i} \tag{7}$$

or, equivalently, as

$$\frac{\partial \omega^i}{\partial\left(\sum_{i \in G} \omega^i\right)} \cdot \frac{\sum_{i \in G} \omega^i}{\omega^i} = 1. \tag{8}$$

In the case of equal relative income increments for all individuals (households), the elasticity of individual income with respect to total income equals unity. The income elasticity of market demand can be written as

$$\varepsilon_j(\mathrm{B}) = \sum_{i \in G} \frac{\omega^i}{\left(\sum_{i \in G} \omega^i\right)} \cdot \frac{\partial f_j^i(\mathbf{p}, \omega^i)}{\partial \omega^i} \cdot \frac{\bar{\omega}}{\bar{F}_j}$$

It should be noted that if all individual incomes are equal, $(\omega^i / \sum_{i \in G} \omega^i = 1/\#G)$ the two elasticity concepts are equivalent.

If the group of households can be considered as homogeneous, i.e. all households have identical preferences and hence a common demand function $f(\mathbf{p}, \omega)$,[3] and the income distribution of this group can be described by a density function $\rho(\omega)$, we can derive formulae which are more convenient for both empirical and theoretical purposes.

We define the market demand function for commodity j as $\bar{F}_j$ and the mean income $\bar{\omega}$ as

$$\bar{F}_j = \bar{F}_j(\mathbf{p}, \rho) = \int_0^\infty f_j(\mathbf{p}, \omega)\rho(\omega)\,\mathrm{d}\omega \tag{9}$$

and

$$\bar{\omega} = \int_0^\infty \omega\rho(\omega)\,\mathrm{d}\omega. \tag{10}$$

The income elasticity can then be written[4] as

$$\varepsilon_j(\mathrm{A}) = \int_0^\infty \frac{\partial f_j(\mathbf{p}, \omega)}{\partial \omega} \rho(\omega)\,\mathrm{d}\omega \cdot \frac{\bar{\omega}}{\bar{F}_j} \tag{11}$$

[3]In empirical work one can try to approximate homogeneity of a group of households by a narrow definition of this group with regard to observable characteristics of households (household size and composition, age, occupation etc.). For a detailed discussion see, for example, Prais and Houthakker (1955, pp. 88–93 and 125–64). For a theoretical concept see Hildenbrand (1985, p. 44).
[4]Proofs are given in Hildenbrand (1983b).

in case A and as

$$\varepsilon_j(\mathrm{B}) = \int_0^\infty \frac{\partial f_j(\mathbf{p}, \omega)}{\partial \omega} \rho(\omega) \omega \mathrm{d}\,\omega \cdot \frac{1}{\bar{F}_j} \tag{12}$$

in case B.

III. FUNCTIONAL SPECIFICATIONS

The empirical application of the above derived income elasticity concepts requires considerations about the functions which should be used for estimation purposes.

Engel curves with income as the only independent variable were chosen. It is obvious that the resulting income elasticities differ from those which stem from Engel curves where other independent variables, for example, family size, asset holding etc. are introduced additionally.[5]

There are quite a lot of properties which a 'good' Engel curve should have.[6] These properties stem from considerations on economic, statistical and practical questions in demand analysis, but, unfortunately, there is no general consent to the above properties in the literature. Therefore, there is no *a priori* reason to trust in and use one certain algebraic formulation of Engel curve only. It is well known that income elasticities for the same commodity and estimated for the same set of household budget data can differ widely when they are derived from different functional types of Engel curves.

To overcome these difficulties ten different functional forms were used. If the fitted curves with respect to a certain commodity are similar, this may serve as a hint on the structure of the *real* Engel curve. On the other hand, the procedure may be regarded as posing the question as to what extent the parametric approach, which means the acceptance of a functional form, is appropriate in demand analysis, seen in contrast to parameter-free procedures (see, for example, Hildenbrand, 1985, pp. 53 ff.).

The functions

The linear function (P1):

$$X_j = a_j + b_j \cdot \omega \tag{A}$$

where X_j denotes the expenditure for commodity j.
The quadratic function (P2):

$$X_j = a_j + b_j \cdot \omega + c_j \cdot \omega^2 \tag{B}$$

The cubic function (P3):

$$X_j = a_j + b_j \cdot \omega + c_j \cdot \omega^2 + d_j \cdot \omega^3 \tag{C}$$

[5]Then the income elasticities are in a certain sense just partial elasticities which are in the case of a positive correlation of income and additional variables lower than those computed here.
[6]See for example Schmucker (1962, pp. 415 ff.), Prais and Houthakker (1955, pp. 82 ff.) or Streissler, E. and M. (1966, p. 83 f.).

The Working function (WO)[7]:

$$X_j = a_j \cdot \omega + b_j \log(\omega) \cdot \omega \tag{D}$$

The Leser function (LE):[8]

$$X_j = a_j + b_j \cdot \omega + c_j \log(\omega) \cdot \omega \tag{E}$$

The hyperbolic function (HY):

$$X_j = a_j + b_j/\omega \tag{F}$$

The log-inverse function (LI):

$$\log(X_j) = a_j + b_j/\omega \Leftrightarrow X_j = 10^{a_j \ b_j/\omega} \tag{G}$$

The semi-logarithmic function (SL):

$$X_j = a_j + b_j \log(\omega) \tag{H}$$

The double-logarithmic function (DL):

$$\log(X_j) = a_j + b_j \log(\omega) \Leftrightarrow X_j = 10^{a_j} \cdot \omega^{b_j} \tag{I}$$

The Goreux-function (GO):[9]

$$\log(X_j) = a_j + b_j/\omega + c_j \log(\omega) \Leftrightarrow X_j = 10^{a_j + b_j/\omega} \cdot \omega^{c_j} \tag{J}$$

For the approximation of an empirical income (or expenditure) distribution the lognormal distribution is usually recommended and used.[10] With the help of some basic properties of the lognormal distribution one can easily derive the theoretical formulae of the income elasticities for the different elasticity concepts and the different Engel curve specifications given above.

Consider the variate X $(0 < x < \infty)$ such that $Y = \ln(X)$ where 'ln' denotes the natural logarithm. If Y is normally distributed with mean μ and variance $\sigma^2 (Y \sim N(\mu, \sigma^2))$, then $X \sim \Lambda(\mu, \sigma^2)$ denotes that X is lognormally distributed and its distribution is completely determined by the two parameters μ and σ^2. The mean $\bar{x}$, median $x_{0.5}$ and mode x_{mod} have the relative positions

$\bar{x} = e^{\mu + \frac{1}{2}\sigma^2}$;

$x_{0.5} = e^{\mu}$; and

$x_{\text{mod}} = e^{\mu - \sigma^2}$.

There exist moments of any order. The jth moment about the origin is given by

$$\lambda_j = \int_0^{\infty} x^j \, d\Lambda(x) = e^{j\mu + \frac{1}{2}j^2 \cdot \sigma^2} \tag{13}$$

[7]Let $\log(z)$ denote the logarithm of z to base 10.
[8]This Engel curve has been proposed by Leser (1963) as a 'logical generalisation' of the Working function.
[9]This function was introduced by Goreux (1960) who called it 'log-log-inverse'.
[10]See for example Prais and Houthakker (1955 p. 13), Thatcher (1976, p. 227 f.) or Hildenbrand (1983a, p. 1001). Also Lydall (1976, p. 17) points out that the 'standard distribution' of earnings is 'approximately lognormal'. For a detailed treatise on the properties of the lognormal distribution see, for example, Aitchison and Brown (1957).

For a homogeneous group of households whose income distribution can be described by the lognormal distribution, we get for example in the case of the hyperbolic function:

$$\varepsilon_j(\mathrm{A}) = \frac{-b_j \cdot \lambda_{-2} \cdot \lambda_1}{a_j + b_j \cdot \lambda_{-1}}$$

$$\varepsilon_j(\mathrm{B}) = \frac{-b_j \cdot \lambda_{-1}}{a_j + b_j \cdot \lambda_{-1}}$$

and

$$\varepsilon_j(\mathrm{C}) = \frac{-b_j/\omega}{a_j + b_j/\omega}$$

where $\varepsilon_j(\mathrm{C})$ denotes the normal elasticity concept ($\varepsilon = \partial f/\partial\omega \cdot (\omega/f)$) and ω is the point of the income distribution (usually the median) where the elasticity will be calculated.

This example already shows that the numerical values of the elasticities, computed for the same commodity and the same functional specification for the Engel curve, will in general differ between the three concepts. The formulae for the other functions, as well as the results of the Engel curve estimations, are given explicitly in Dax (1985).[11]

IV. EMPIRICAL RESULTS

The household data used for the empirical analysis were collected in 1980 for the *Family Expenditure Survey* (FES) in Great Britain (excluding Northern Ireland) which is run by the Social Survey Division of the Office of Population Censuses and Surveys, the Department of Employment and the Central Statistical Office.

On the whole there are data on 6944 households. The recording period for every household was 14 days. The following goods, which had a high recording rate, were chosen for the estimations of the income elasticities: bread, offal, butter, margarine, tea, coffee, beer, wine and newspapers.

It was decided to include the data from *all* households in the calculations so that estimates of *market* income elasticities would be obtained. Values of market income elasticities are, of course, more interesting than values of income elasticities of subgroups of households. The problems of using budget data from non-homogenized households are obvious, but it is an open question how one would aggregate income elasticities correctly from different household groups to get a *market* income elasticity value.[12]

The income distribution[13] of the sample was approximated by a three-parameter lognormal distribution which was fitted by using the method of moments. The threshold parameter, which

[11] The example of the hyperbolic function also shows the dependence of the results from the functional specification of the income distribution and the shape of this distribution.

[12] This would require theoretical and/or empirical evidence on the development of the relative income weights of the household subgroups.

[13] In the empirical work household income was substituted by total expenditures following earlier examples of empirical research. For a discussion on this point refer to Prais and Houthakker (1955, p. 80 f.) and Goreux (1960, pp. 4 ff.). Nevertheless, the term 'income' is used throughout the paper.

defines a lower bound to the range of income values, is 5000 pence/week; λ_1, the first moment of the distribution, amounts to 110 603 pence/week. For the calculation of the elasticities $\varepsilon_j(C)$ the median of the distribution (89 886 pence/week) was used.

Tables 1 to 3 give the values of the income elasticities for the different commodities with respect to the different functional types of Engel curves and with respect to the different concepts of income elasticity. The values were calculated on the basis of estimated Engel curves. For the concepts A and B an integration procedure was run to derive, first, the corresponding market demand for the commodity and the functional specification of the Engel curve and then, in a second step, the elasticity value itself.

These integrations included, of course, the density function of the fitted lognormal income distribution. Values marked with an asterisk in Tables 1 and 2 stem from calculations where the underlying Engel curve was negative over a part of the empirically relevant range of the income distribution. Whereas usually the integrations were made over the range 5481 pence/week up to 1 318 617 pence/week, in the other case just over that range of incomes where the Engel curves were nonnegative was integrated.

A well known empirical result which shows up here once more is that the specific functional form of Engel curve has a strong influence on the value of the income elasticity of a commodity. In Table 3 it is found, for example, that the income elasticity of bread in the case of concept C, $\varepsilon_{\text{bread}}$ (C), ranges from 0.215 for the hyperbolic function to 0.554 for the Working function. Unless there are sound statistical reasons for using a specific function for these calculations explicitly which, however, did not show up in the present analysis, somebody who needs the exact numerical value of an elasticity may have severe problems.

More important for the present purposes, however, are the differences in the elasticity values for the same function with respect to the different elasticity concepts. The values of the hyperbolic function in the case of bread are 0.539, 0.265, 0.215; taking all three concepts and all functional forms the values range from 0.215 to 0.664. The situation is similar for all other commodities and even more extreme examples can easily be found. This clearly shows that the usual method of computing the income elasticity at only one point of the Engel curve may give misleading results.

There does not even seem to be a kind of *ordinal* structure in the elasticity values given in Tables 1 to 3.

(1) A specific functional form of Engel curve does not yield high or low values in *all* three concepts. For example: the log-inverse function on average shows the highest elasticity values in concept A, but only moderate values in concepts B and C; the cubic function which gives low values in concept A shows high values in concept C. This means that it is not possible to find a common ranking for the different functional forms with respect to the values they yield. The same phenomenon can be found for the functions with respect to the commodities: the Working function always yields the highest elasticity values for the 'necessary' goods – bread, offal, tea, margarine – but very low values for the 'luxury' goods – wine and beer – compared to the other functional forms.

(2) Can anything be said about the relations of the different concepts? One would be glad if one knew, for example, that concept X always yields higher elasticity values than concept Y.

To deal with this question it is helpful, first, to develop the explicit formulae for the income elasticities with respect to the different concepts and the different functional forms.

It then shows that concepts A and B are equivalent for the linear function and concepts B and C for the double-logarithmic function. Concepts A and B always differ (with the exception of the case of the linear function) in the numerators of the formulae. Concept A gives products $\lambda_i \cdot \lambda_1$ of moments, whereas Concept B gives the moment λ_{i+1}. Using the properties of the underlying income distribution, one can compare the expressions for concepts A, B and C for arbitrary parameter constellations.

In the empirical calculations $\varepsilon_j(A)$ is always greater than $\varepsilon_j(B)$ except in the case of the linear function, of course, and in the case of the commodity 'wine' for the Working and the double-logarithmic function. The relative difference of the values diminishes as the values rise.

For the hyperbolic and the semi-logarithmic function, the results always show the relation $\varepsilon_j(A) > \varepsilon_j(B) > \varepsilon_j(C)$. For the other functions it is usually found that $\varepsilon_j(A) > \varepsilon_j(C) > \varepsilon_j(B)$ except in the case of wine where $\varepsilon_j(C)$ may yield the highest values.

(3) One could, perhaps, be content to have at least a ranking of the elasticity values for the different commodities, so that statements as 'the income elasticity of good *j* is higher than that of good *i*' could be made. But even this is not possible. The relation may change from one function to the other. Moreover, this relation may change also for the same function when one compares the results of two different concepts. Example: the Goreux function shows the following ranking of elasticity values for concept A: $\varepsilon_{\text{bread}} > \varepsilon_{\text{butter}} > \varepsilon_{\text{margarine}} > \varepsilon_{\text{newspapers}} > \varepsilon_{\text{offal}}$, but for concepts B and C: $\varepsilon_{\text{butter}} > \varepsilon_{\text{newspapers}} > \varepsilon_{\text{bread}} > \varepsilon_{\text{offal}} > \varepsilon_{\text{margarine}}$. The same phenomenon appears for other functional forms.

V. CONCLUSION

In this paper we have repeated theoretical work on the integration of the income distribution of households into the estimation and calculation of *market* income elasticities. The theoretical considerations already show the necessity of this approach. The empirical calculations, which approximate the theoretical work as far as possible, yield results which underline this necessity.

But, the results also show two basic problems in the empirical application of the theoretical concept:

(1) It is absolutely necessary to have an *a priori* hypothesis on the change of the relative dispersion of the income distribution.

(2) The well known fact that different functional specifications of the underlying Engel curve may lead to quite different values of the elasticity. One can just hope that statistical results of the estimations show a superiority of a specific function over the others.

ACKNOWLEDGEMENTS

This article is more or less extracted from a previous paper (Dax, 1985), which was written while the author worked at the University of Bonn, Sonderforschungsbereich 21.

Table 1. *Income elasticities* $\varepsilon_j(A)$

Commodity	Function P1	P2	P3	WO	LE	HY	LI	SL	DL	GO
Bread	0.276	0.412*	0.498	0.664*	0.509*	0.539*	0.625	0.578*	0.436	0.617
Offal	0.281	0.396*	0.446	0.673*	0.472	0.504*	0.578	0.549	0.432	0.528
Butter	0.428	0.538	0.570	0.733	0.591	0.584*	0.781	0.770*	0.623	0.606
Margarine	0.240	0.316	0.439	0.645*	0.423*	0.504*	0.547	0.499	0.387	0.562
Tea	0.181	0.261*	0.320	0.638*	0.434*	0.332*	0.387	0.352	0.305	0.356
Coffee	0.502	0.682*	0.745	0.752	0.787*	0.737*	0.936	0.973*	0.649	0.846
Beer	0.674	0.966*	1.112*	0.766	1.120*	0.899*	1.149	1.283*	0.755	1.214
Wine	1.175*	1.297*	1.307*	1.008	1.348*	0.993*	1.436	1.396*	1.006	1.408
Newspapers	0.319	0.429*	0.472	0.963*	0.500	0.525*	0.623	0.600*	0.471	0.547

An asterisk indicates that the integration procedure did not run over the whole income range due to negativities of the Engel curve.

Table 2. *Income elasticities* $\varepsilon_j(B)$

Commodity	Function P1	P2	P3	WO	LE	HY	LI	SL	DL	GO
Bread	0.276	0.345*	0.360	0.448*	0.354*	0.265*	0.363	0.420*	0.338	0.364
Offal	0.281	0.338*	0.348	0.464*	0.346	0.247*	0.331	0.398	0.334	0.344
Butter	0.428	0.482	0.489	0.564	0.483	0.288*	0.483	0.556*	0.477	0.482
Margarine	0.240	0.278	0.301	0.428*	0.306*	0.246*	0.310	0.363	0.295	0.305
Tea	0.181	0.221*	0.232	0.411*	0.344*	0.168*	0.208	0.257	0.227	0.227
Coffee	0.502	0.592*	0.604	0.587	0.602*	0.376*	0.621	0.709*	0.543	0.605
Beer	0.674	0.821*	0.848*	0.621	0.829*	0.487*	0.862	1.011*	0.662	0.892
Wine	1.176*	1.257*	1.261*	1.013	1.240*	0.560*	1.445	1.320*	1.010	1.405
Newspapers	0.319	0.374*	0.382	0.475*	0.383	0.258*	0.362	0.435*	0.369	0.379

Table 3. *Income elasticities* $\varepsilon_j(C)$

	Function									
Commodity	P1	P2	P3	WO	LE	HY	LI	SL	DL	GO
Bread	0.237	0.373	0.453	0.554	0.428	0.215	0.356	0.369	0.338	0.357
Offal	0.241	0.356	0.404	0.565	0.398	0.200	0.320	0.348	0.334	0.338
Butter	0.378	0.490	0.521	0.634	0.512	0.233	0.498	0.473	0.477	0.482
Margarine	0.204	0.280	0.396	0.540	0.354	0.200	0.297	0.319	0.295	0.290
Tea	0.152	0.232	0.288	0.528	0.269	0.138	0.191	0.234	0.227	0.219
Coffee	0.450	0.637	0.693	0.651	0.682	0.306	0.680	0.578	0.543	0.631
Beer	0.626	0.935	1.057	0.675	0.994	0.407	1.048	0.821	0.662	1.174
Wine	1.227	1.472	1.458	1.013	1.420	0.479	2.273	1.138	1.010	2.064
Newspapers	0.276	0.386	0.428	0.475	0.424	0.209	0.355	0.377	0.367	0.376

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DISCUSSION PAPER

October 2010 ■ RFF DP 10-57

A New Look at Residential Electricity Demand Using Household Expenditure Data

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RESOURCES
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A New Look at Residential Electricity Demand Using Household Expenditure Data

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Abstract

We estimate residential electricity demand for different regions of the country, assuming that consumers respond to average electricity prices. We circumvent the need for individual billing information by developing a novel generalized method of moments approach that allows us to estimate demand based on household electricity expenditure data from the Consumer Expenditure Survey, which does not have quantity and price information. We find that price elasticity estimates vary across the four census regions—the South at –1.02 is the most price-elastic region and the Northeast at –0.82 is the least—and are essentially equivalent across income quartiles. In general, these price elasticity estimates are considerably larger in magnitude than those found in other studies using household-level data that assume that consumers respond to marginal prices. We also apply our elasticity estimates in a U.S. climate policy simulation to determine how these elasticity estimates alter consumption and price outcomes compared to the more conservative elasticity estimates commonly used in policy analysis.

Key Words: residential electricity demand, consumer expenditure survey, generalized method of moments

JEL Classification Numbers: C5, D12, Q4

Contents

A New Look at Residential Electricity Demand Using Household Expenditure Data

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I. Introduction

The recent focus of the U.S. Congress on federal energy policy, which could substantially alter electricity prices, has elevated the importance of characterizing electricity demand behavior. This is particularly true for the burgeoning literature on the incidence of such policies (e.g., Burtraw et al. 2009; Hassett et al. 2009; and Shammin and Bullard 2009). A key parameter in incidence analysis is the household-level price elasticity of demand for electricity. Studies on residential electricity demand have been conducted for many decades, but few of them are based on household data, are national in scope, and allow for regional price elasticity heterogeneity.[1] This paper offers a new technique to estimate residential electricity demand for different regions in the U.S. using household expenditure data, under the assumption that consumers respond to average prices.

Many of the residential electricity demand estimations that use nationwide data are based on panel data, aggregated at the state level (e.g., Houthakker 1980; Maddala et al. 1997; and Bernstein and Griffin 2005). These studies have the advantage of being able to provide regional elasticities, both long-run and short-run, across the nation. However, one should use caution when applying elasticity estimates from these aggregate studies to policy analysis at the household level, as is often done in incidence analyses of climate policy. As Dubin and McFadden (1984) point out, demand estimations using aggregate data may be subject to misspecification bias due to aggregation over electricity usage and price. For example, if the underlying electricity demand at the household level takes nonlinear form (e.g., log–log), demand elasticities estimated using aggregate data (e.g., at the state level) will not represent household-level demand behavior.

* Fell and Li are fellows, and Paul is the Center for Climate and Electricity Policy fellow, at Resources for the Future, Washington, DC. The authors thank Dallas Burtraw for comments and discussions about this work and Josh Blonz for his excellent research assistance. This work was partially funded by a grant from the Center for International Climate and Environmental Research – Norway.

[1] See Taylor (1975) and Bohi (1981) for surveys of early electricity demand studies and Espey and Espey (2004) for a more recent collection of residential electricity demand elasticity estimates.

Several studies employ household-level data (e.g., Barnes et al. 1981; Dubin and McFadden 1984; Herriges and King 1994; and Reiss and White 2005), but these studies are constrained to geographically narrow regions because there is no national data set of electricity rate structures or of household-specific billing information. Given regional household heterogeneity, it may be inappropriate to apply estimates from these area-specific studies to all areas of the country. On a more practical note, getting geographically specific rate structure data for the entire nation and appropriately matching it up to individual households or obtaining household billing information for large geographic areas of the country is quite difficult because of the diversity of rate structures across the country and the proprietary nature of individual billing information.[2]

More importantly, all of the aforementioned studies using household-level data are based on the assumption that households know their marginal rate schedules and optimize accordingly. Although assuming that households respond to marginal prices is theoretically consistent in a utility-maximizing framework, it may not be a realistic representation of consumer behavior in electricity markets. The first reason for this is that many electric utilities, like some other public utilities, offer multitariff pricing where the marginal price for a household depends on the household's consumption. Deciphering an electricity bill to determine the rate structure is often not straightforward, and usually the bill arrives after the period of consumption has concluded. Thus, in many instances consumers may not be aware of their actual rate structure or their marginal price. Second, it may be unrealistic to assume that consumers can monitor and control their consumption at any given point in time during a billing period. If this is the case, then even if consumers know the rate structure, it is difficult for them to optimize consumption based on the marginal price.

Given these attributes of residential electricity consumption, the assumption that consumers respond to marginal price would be unlikely to hold for the average consumer. Indeed, this has been supported by increasing empirical evidence. Using data from seven Ohio utilities with decreasing-block rate schedules, Shin (1985) finds evidence that consumers respond to average prices from the utility bill rather than marginal prices. Based on residential billing data from Southern California Edison, which implements increasing-block pricing, Borenstein

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[2] For example, in Reiss and White (2005), a study using rate structure data from Southern California, electricity rates had to be matched up indirectly with individual household data. Applying such techniques nationwide would quickly become intractable.

(2009) finds no evidence of bunching around the points where the marginal price increases, contrary to what a model of perfectly informed and optimizing consumers would imply.[3] In addition, he shows that the average price is a better indicator of consumer demand response than the marginal price. A recent paper by Ito (2010) using household billing data from two utilities in Southern California obtains the same finding that consumers are more likely to respond to average prices than to marginal prices.

Our study contributes to the literature by addressing the need for nationwide elasticity estimates using household-level data, under the assumption that consumers respond to average prices. Because gathering detailed rate structure data at the national level is impractical, we develop an empirical strategy based on the generalized method of moments (GMM) that allows demand estimation based on publicly available data sets. The main source of data is the Bureau of Labor Statistics' Consumer Expenditure Survey (CEX), which are supplemented with state-level data from the Electric Power Monthly reports produced by the Energy Information Administration (EIA). Though the CEX provides only expenditure data, our empirical approach permits estimations of household-level demand functions without observing household electricity usage or price schedules.

Our results show considerable differences in price elasticities across census regions, with elasticities ranging from –0.82 to –1.02 in the baseline model. These estimates are noticeably larger than other residential demand estimates using household-level data. However, as we demonstrate below, this difference is most likely attributable to the assumption that households respond to average electricity prices as opposed to marginal prices. This result suggests that further research is warranted to understand the prices to which consumers really respond in electricity demand. In addition to price elasticity, we also find small income elasticities, as is common in the electricity demand literature.

The remainder of the paper is organized as follows. In section 2, we present our data. This is followed with a discussion of our empirical method and a Monte Carlo analysis to gauge the effectiveness of the empirical method in section 3. In section 4, we use a simple graphic example to illustrate potential differences that can emerge in demand estimations based on average- or marginal-price responsiveness. Section 5 presents the results of the demand

[3] If consumers were responding to marginal prices, then in a multipart tariff rate structure one would expect to see a concentration of households at consumption levels just below the cut-off points for the rate change. Instead, Borenstein (2009) finds a much smoother distribution of consumption.

estimation, and section 6 illustrates the significance of demand elasticity assumptions in a policy analysis context. In the final section we give concluding remarks.

II. Data

Two data sets on household-level electricity usage are national in scope and publicly available: CEX and EIA's Residential Energy Consumption Survey (RECS). The CEX collects data through quarterly interviews of about 7,500 households.[4] The survey asks respondents to provide detailed expenditure information, including monthly electricity expenditures, but does not address quantity or price information for electricity use. The RECS collects information on residential energy use from fewer than 5,000 households and is conducted about every five years. It provides both electricity consumption (quantity) and expenditure data. Both surveys collect data on housing characteristics, appliances holdings, and household demographics.

We use the CEX data for our analysis for the following reasons. First, the CEX data have a much larger sample, with approximately 90,000 observations (7,500 households for 12 months) each year compared to fewer than 5,000 annual observations from RECS. Second, as mentioned above, the expenditure data from the CEX are available at the month level, the decision period we use in the demand analysis, whereas the data from RECS are at the annual level.[5] Finally, the state information for households is available only for the four most populous states in RECS for the purpose of confidentiality. On the other hand, the CEX data provide location information at the state level for all households. Because they lack state location, use of the RECS data would prevent us from using state-level cost shifters as the instruments for electricity price in the demand analysis and would restrict our ability to get regional price elasticities.

Our empirical analysis is conducted using the CEX data from 2004 to 2006. To reduce sampling errors and avoid instances of no observations in some months, we keep only the states that have at least 2,500 total observations in the survey over the period 2004–2006. This elimination process gives us a final sample of observations spanning 22 different states. The average number of observations in a month for each state ranges from 38 to 537 with a mean of 140. As will be shown in the next section, some of the moment conditions used for estimation

[4] The survey program also conducts a diary survey, in which respondents record all expenditures. However, we only use data from the program's quarterly interview survey. For more information on how the survey is conducted and the data available through the survey see http://www.bls.gov/cex/.

[5] Though the interviews are conducted quarterly, they ask questions about month-specific expenditures.

match average monthly household electricity usage predicted by the model to observed data for each state. Table 1 lists the states used in our analysis and the total number of observations by census region.

Table 2 provides summary statistics for monthly household electricity expenditure, average electricity price, imputed average household usage, and other variables that are treated as demand covariates. Average monthly household electricity expenditure, derived from the CEX, is highest in the South region at an average of $143, whereas it is lowest in the Midwest region at an average of $96. The average electricity price is based on state-level EIA data from Electric Power Monthly (based on EIA Form 826), where it is computed as the total revenue of electricity suppliers divided by the total electricity supplied. The state average price is highest in the Northeast region and lowest in the Midwest region. Based on the EIA average prices and the CEX expenditure data, we impute the naïve electricity usage for each household, shown as the "Quantity" row in the table.[6] The households in the South region use the most, whereas those in the Northeast region use the least.

The other explanatory variables in the demand analysis include house demographics, housing characteristics, and electric appliance holdings from the CEX data. We also obtain monthly heating degree days (HDD) and cooling degree days (CDD) for each state from the National Oceanic and Atmospheric Administration. These two temperature variables are interacted with appliances in the demand equation.

Our empirical method shown below necessitates instrument variables for electricity price. These variables should shift price schedules but do not affect consumption directly. Although local distribution companies, the entities that typically sell electricity to households, have largely regulated price schedules, these schedules often allow for built-in adjustments based on fluctuations in electricity generation costs, especially fuel costs. In addition, utilities often obtain power supply through procurements in advance to meet a larger share of their service obligations. We therefore use, as cost shifters, lagged prices of natural gas and coal (quarterly and yearly moving averages), as well as states' electricity generation profiles and the interaction between generation profiles and generation fuel prices. Coal and natural gas prices come from

[6] We consider this a "naïve" electricity usage measure because dividing household-level expenditures by a state average price neglects the reality that average prices at the household level will depend on a household's usage. Thus, basing a demand estimation on these naïve usage and state average price measures will pose not only standard simultaneity issues, but also measurement error issues. These points are discussed in more detail below.

EIA. Because these price data are often missing at the state level, we use national-level prices. The electricity generation profile data, which give the percentage breakdown of total generation by fuel type in each state, are also available through EIA.[7] We use the lagged values of these variables because electric utilities often procure a large of portion of power to be distributed ahead of schedule. In addition, lagged cost shifters are more likely to be exogenous to current demand shocks.

Figure 1 plots monthly national prices for residential electricity, coal, and natural gas from 2003 to 2006. All three series are trending up, with natural gas prices the most volatile and coal prices the least. Table 3 provides summary statistics of generation fuel profile variables. Across the four census regions, natural gas accounts for the largest share of generation in the West region (36 percent) whereas coal is used most extensively in the Midwest (70 percent). Nuclear and hydropower have the largest share in the West (40 percent) and Northeast regions (39 percent).

III. Empirical Strategy

Utilities frequently use nonlinear price schedules in selling electricity. The nonlinearity could be due to an up-front fixed charge, such as a transmission charge, and/or block pricing. The assumption maintained in most of the literature on electricity demand since Taylor's (1975) survey is that consumers are perfectly informed about the price schedule and are able to perfectly optimize on the margin at every moment: consuming the amount where the marginal value of electricity is equal to the marginal price. Although this assumption is theoretically appealing, it is unlikely to hold in reality. First, it is costly for consumers to obtain their price schedules because they are often not explicitly shown on electricity bills and because electricity bills arrive after consumption choices are made. In addition, price schedules are subject to month-to-month changes. Second, as electricity is billed from month-to-month, the above assumptions require consumers to make perfect predictions about their demand shocks, like a heat wave that raises the value of air-conditioning, for the whole month at the beginning of each month.

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[7] Data for coal prices were downloaded from http://www.eia.doe.gov/cneaf/electricity/page/ferc423.html, and natural gas prices were downloaded from http://tonto.eia.doe.gov/dnav/ng/ng_sum_lsum_a_epg0_peu_dmcf_m.htm. State-specific electricity generation mix data were downloaded from http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html.

In light of increasing empirical evidence that consumers are more likely to respond to average prices rather than marginal prices (e.g., Shin 1985; Borenstein 2009; and Ito 2010), the goal of this paper is to obtain demand estimates under the assumption that consumers respond to average prices. This is a departure from, and in our view an improvement upon, the conventional assumption that consumers respond to marginal prices. At the very least, it offers an alternative demand estimation to the marginal price-response literature.

Method

Our empirical framework is set up based on the CEX data. As discussed above, although CEX provides a national representative sample, it does not have information on electricity price and quantity. Rather, it reports monthly household expenditure on electricity. Some previous studies using CEX data, such as Branch (1993), have used monthly state average prices from EIA as the price variable and constructed the quantity variable by dividing expenditure by the state average price, as we did above for our naïve usage variable. Although this method appears to be straightforward, the estimates could be biased due to at least two sources: measurement error and simultaneity. Measurement error arises because the average price faced by a given household will depend on its quantity consumed and, thus, will not typically be the same as the state average price given by EIA.

To illustrate the simultaneity problem, one can assume that the underlying demand function takes a double-log form commonly used in the literature on electricity demand

$$\ln q_{ist} = \beta \ln p_{ist} + x_{ist}\gamma + e_{ist}, \tag{1}$$

where t is the month index, s the state index, and i the household index. q_{ist} is the quantity of electricity used by household i in state s and month t, and p_{ist} is the average price for that household in month t. Under nonlinear price schedules, the average price depends on the quantity—in other words, p_{ist} is a function of q_{ist}. The simultaneous determination of household electricity usage and the price for that level of usage underlies the traditional simultaneity problem. The vector x_{ist} contains other variables that affect electricity demand, such as household demographics, appliance holdings, and weather conditions. The final variable, e_{ist}, is the demand shock and is assumed to be normally distributed with mean zero and $\text{var}(e_{ist}) = \sigma_e^2$.

Without observing both p_{ist} and q_{ist}, one could apply the naïve method that uses state average price $\overline{p}_{st}$ and imputed quantity $\overline{q}_{ist} = \frac{c_{ist}}{\overline{p}_{st}}$, where c_{ist} is monthly household expenditure, in equation (1), and it would become

$$\begin{aligned}\ln \bar{q}_{ist} &= \beta \ln \bar{p}_{st} + x_{ist}\gamma + (\ln \bar{q}_{ist} - \ln q_{ist}) + \beta(\ln p_{ist} - \ln \bar{p}_{st}) + e_{ist} \\ &= \beta \ln \bar{p}_{st} + x_{ist}\gamma + [\ln(\frac{c_{ist}}{\bar{p}_{st}}) - \ln(\frac{c_{ist}}{p_{ist}})] + \beta(\ln p_{ist} - \ln \bar{p}_{st}) + e_{ist} \\ &= \beta \ln \bar{p}_{st} + x_{ist}\gamma + (1+\beta)(\ln p_{ist} - \ln \bar{p}_{st}) + e_{ist} \\ &= \beta \ln \bar{p}_{st} + x_{ist}\gamma + v_{ist},\end{aligned} \tag{2}$$

where v_{ist} is the composite error term. If one were to estimate (2) taking v_{ist} as the error term, the estimates of both β and γ would be biased for two reasons, as long as β is not equal to –1. First, because the error term v_{ist} includes the state average price variable $\bar{p}_{st}$, $\ln \bar{p}_{st}$ is endogenous. Second, because demand factors x_{ist} affect electricity usage q_{ist}, which in turn would determine the average price paid by the household p_{ist}, x_{ist} is also endogenous as a result of the inclusion of p_{ist} in the error term. Because of the large number of endogenous variables in the equation, it would be impractical to use instrumental variable methods. In addition, the *a priori* direction of bias from the ordinary least squares (OLS) estimate is unknown: both $\bar{p}_{st}$ and x_{ist} are correlated with the error term, and it is unclear what direction the partial correlation between $(\ln p_{ist} - \ln \bar{p}_{st})$ and the explanatory variable takes.

We develop a new empirical strategy using GMM to estimate the demand function with the expenditure data from CEX and some auxiliary data that do not rely on the naïve quantity variable imputed from state average prices. Because we do not observe q_{ist} and p_{ist}, we cannot take equation (1) directly to the data. Instead, we further specify the average-price schedule faced by the household as the following

$$\ln p_{ist} = \alpha_s \ln q_{ist} + z_{ist}\delta + \varepsilon_{ist} \tag{3}$$

where α_s is the state-specific slope for the price schedule, and z_{ist} is a vector of observed variables that shift the price schedule, such as cost shifters, month dummies, and state dummies. This specification allows both the intercept and the slope of the average-price schedule to vary across states. ε_{ist} is the approximation error and is assumed to be normally distributed with mean zero and variance $\text{var}(\varepsilon_{ist}) = \sigma_\varepsilon^2$.

Household electricity usage and average price are determined by the demand equation and the price schedule. Solving for q_{ist} and p_{ist} from (1) and (3), we get

$$\ln q_{ist} = x_{ist}\gamma / (1-\beta\alpha_s) + z_{ist}\delta\beta / (1-\beta\alpha_s) + (e_{ist} + \beta\varepsilon_{ist}) / (1-\beta\alpha_s) \tag{4}$$

$$\ln p_{ist} = x_{ist}\gamma\alpha_s / (1-\beta\alpha_s) + z_{ist}\delta / (1-\beta\alpha_s) + (\alpha_s e_{ist} + \varepsilon_{ist}) / (1-\beta\alpha_s) \tag{5}$$

Given that the total expenditure $c_{ist} = q_{ist} \times q_{ist}$, $\ln c_{ist} = \ln q_{ist} + \ln p_{ist}$. With this, equations (4) and (5) allow us to express the total expenditure in logarithm as the following

$$\begin{aligned} \ln c_{ist} &= x_{ist}\gamma(1+\alpha_s)/(1-\beta\alpha_s) + z_{ist}\delta(1+\beta)/(1-\beta\alpha_s) \\ &\quad + [(1+a_s)e_{ist} + (1+\beta)\varepsilon_{ist}]/(1-\beta\alpha_s) \end{aligned} \tag{6}$$

Because we have data on electricity expenditure, equation (6) provides us with the basis for the first set of moment conditions. We define the predicted value of the log expenditure as

$$\ln \hat{c}_{ist} = x_{ist}\gamma(1+\alpha_s)/(1-\beta\alpha_s) + z_{ist}\delta(1+\beta)/(1-\beta\alpha_s) \tag{7}$$

And the first set of moment conditions is given by

$$E_{i,s,t}([x_{ist} \quad z_{ist}]'(\ln c_{ist} - \ln \hat{c}_{ist})) = 0 \tag{8}$$

Recognizing that some variables, such as month dummies and state dummies, are common in both x_{ist} and z_{ist}, we write the moment conditions this way to save notation. In essence, these moment conditions match the predicted expenditures (in log) with the observed ones. The first set of moment conditions alone does not provide enough restrictions to identify the model parameters. This is intuitive: one cannot separately identify the demand and price functions with only data on expenditure.

Taking advantage of state average prices available from EIA, we construct the second set of moment conditions.[8] Based on the state-level average price, we compute the state-level average quantity of household electricity usage, denoted by $\bar{q}_{st}$. The second set of moment conditions match the average quantity $\bar{q}_{st}$ with the predictions from our model. From equation (4), the expected value of electricity usage for a household, $\hat{q}_{ist}$, is given by

$$\hat{q}_{ist} = E(q_{ist}) = \exp(x_{ist}\gamma/(1-\beta\alpha_s) + z_{ist}\delta\beta/(1-\beta\alpha_s) + 0.5(\sigma_e^2 + \beta^2\sigma_\varepsilon^2)/(1-\beta\alpha_s)^2) \tag{9}$$

where the last term in the parenthesis is half of the variance of the composite error term in equation (4).[9] We define $\hat{\hat{q}}_{st}$ as the average of $\hat{q}_{ist}$ for all households in state s and month t (i.e.,

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[8] EIA's Electric Power Monthly report, available for download at http://www.eia.doe.gov/fuelelectric.html, gives monthly average electricity prices by state.

[9] Given that e_{ist} and ε_{ist} are independent normally distributed random variables, $\ln q_{ist}$ is normally distributed. This implies that q_{ist} is log-normally distributed. Equation (9) is thus the expected value of a log-normally distributed variable.

$\hat{\bar{q}}_{st} = \frac{1}{I}\sum_{i=1}^{I} E(q_{ist})$). Based on $E[q_{ist} - \hat{q}_{ist} \mid x_{ist}, z_{ist}] = 0$, the second set of moment conditions can be constructed as

$$E_{ist}([x_{ist} \quad z_{ist}]'(\bar{q}_{st} - \hat{\bar{q}}_{st})) = 0 \tag{10}$$

Although the number of moment conditions constructed so far is larger than the number of model parameters, the standard errors of the two errors terms, σ_e and σ_ε, cannot be separately identified, given that they both enter moment conditions only through the last term in equation (9). We add another set of moment conditions based on the variance of errors in predicting log expenditure. Following equation (6), we get

$$E_{ist}(\ln c_{ist} - \ln \hat{c}_{ist})^2 - [(1+a_s)^2\sigma_e^2 + (1+\beta)^2\sigma_\varepsilon^2]/(1-\beta\alpha_s)^2 = 0 \tag{11}$$

We stack the three sets of moment conditions and use an iterative GMM procedure to estimate all the model parameters. In obtaining the starting values for the GMM procedure, we first estimate equations (1) and (3) using two-stage least squares, where we take the state-level average prices as the price variable for all households in the corresponding state. We use the identity matrix as the initial weighting matrix and construct the efficient weighting matrix based on parameter estimates from the first iteration.

The underlying model of our analysis assumes that consumers respond to average price in their electricity usage decisions. The interaction between the household demand function and the average-price schedule determines monthly electricity usage and average price at the household level. In addition to the challenge of not observing either household quantity or price data directly, we also face the common simultaneity identification challenge in the empirical demand and supply analysis: quantity and price are determined simultaneously. To deal with the simultaneity problem, our procedure, cast in a system of two equations (i.e., equations (1) and (3)), essentially uses demand-side variables, such as household demographics and appliance holding, to serve as instruments for the quantity variable in the price equation (3), and uses cost shifters, such as shares of fuel types in electricity generation and their interactions with fuel cost, to serve as instruments for the price variable in the demand equation (1).

Notably, although the nature of the CEX gives us some longitudinal information, the relatively short time span analyzed and the lack of detailed product information does not give us sufficient information to estimate the relationship between electricity prices and appliance replacement. We therefore consider our estimates short-run demand estimates.

Monte Carlo Analysis

The empirical strategy outlined above aims to estimate the demand function for residential electricity at the household level for different regions of the country in the absence of household-level price and quantity data. It uses the expenditure data from CEX together with state average electricity prices in a GMM framework. Before showing the estimation results, we present a Monte Carlo analysis to illustrate the effectiveness of the empirical strategy.

The Monte Carlo analysis is based on four states, each of which has more than 2,500 households in the CEX in the Northeast Region (Massachusetts, New Jersey, New York, and Pennsylvania). We first generate price and quantity data for each household, using the demand and price equations (4) and (5) and based on a vector of household characteristics from CEX, cost shifters, and a given set of parameters. The household characteristics, a subset of those listed in Table 2, include household income, number of rooms in the house, and household size. The cost shifters, a subset of those listed in Table 3, include the share of electricity generated using natural gas during the past three months, the share of electricity from coal, and that from nuclear and hydropower. Based on these variables and parameters, we generate monthly expenditure data at the household level and monthly state average electricity price and quantity. We then use both OLS and the GMM approach discussed above to recover the parameters used to generate the data. The OLS approach uses equation (2), where state average electricity prices are used in place of household average prices and quantities are imputed using monthly expenditure divided by state average prices.

Table 4 compares the values of the parameters used to generate the data (the true parameters) to their estimates from OLS and GMM for the different average-price schedules. In all three cases, the GMM method is able to recover the true parameters in the demand equation, whereas the OLS method gives the biased estimates, especially for *log*(*price*), the key variable of interest. To save space, we do not report the results for the 17 dummy variables (4 state dummies, 2 year dummies, and 11 month dummies).

The first panel presents the results for the demand equation where the average-price schedules in all four states are assumed to be upward sloping, with slopes of 0.4, 0.3, 0.2, and 0.1, respectively. The true parameter for *log*(*price*) in the demand equation is –0.8. Whereas the OLS provides an estimate of –0.512 with a standard error of 0.096, the estimate from the GMM approach is –0.837 with a standard error of 0.088. In addition, the OLS estimate on *log*(*household size*) is also statistically different from its true value of 0.4, whereas the GMM estimate is not at any conventional significance level.

The second case is based on simulations where the average-price schedules in all four states are downward sloping, with slopes of –0.4, –0.3, –0.2, and –0.1, respectively. All other parameters are kept the same as in the first panel. The parameter estimates from OLS for the four demand variables shown in the table are all statistically different from their true values, whereas none of the GMM estimates are. The most striking bias from OLS is still in the parameter estimate for *log*(*price*). The estimate from OLS is –1.117 with a standard error of 0.059, compared with the true value of 0.8.

The third panel provides results for simulations that assume positive slopes for the average-price schedule in the first two states but negative slopes in the other two states. In this case, the OLS results are closer to the true values than in the previous cases. Nevertheless, the coefficient estimate on *log*(*price*) is still statistically different from the true parameter at the 10 percent significance level.

The key finding of the simulations is that the GMM approach is effectively able to recover the true parameters, whereas the OLS estimates could result in substantial bias. Although the bias for the coefficient estimate on *log*(*price*) has the same direction as the slopes of the average-price schedules in the first two cases, this finding may not be robust to the addition of more demand-side variables in the regression. As discussed above from equation (2), the direction of bias depends on the *partial* correlation between a particular variable (e.g., *log*(*price*)) and the error term.

IV. Price Elasticities: Average-Price vs. Marginal-Price Response

Assuming that consumers are marginal-price responders in empirical studies if they actually respond to average price could have important implications for price elasticity estimates. In the case of block pricing, a change in average price would imply a larger change in marginal price. Therefore, one would expect demand curves estimated based on average-price responsiveness to be more price elastic than those based on marginal-price responsiveness.

To illustrate the potential for differences in price elasticity estimates based on the two different assumptions, consider the following simple example presented graphically in Figure 2. To understand how the price elasticity is identified, assume that the market consists of three households, A, B, and C, where A and B are on the lower tier of the price schedule and C is on the higher tier. Assume that the quantity demanded, Q_i, is linear and fully determined by income, X_i, and price, P_i, such that $Q_i = \alpha X_i - \beta P_i$, i = (A, B, C). P_i is the price that consumers respond to and it could either be the marginal price or the average price. For concreteness, suppose we observe that ($Q_A = 3$, $X_A = 15$), ($Q_B = 4$, $X_B = 20$), ($Q_C = 6$, $X_C = 40$). We assume that there is no fixed cost, and because A and B pay the same marginal price, they also pay an identical average price, say $P_1 = 0.10$. Household C pays a marginal price on the higher portion of the two-part marginal pricing schedule, and it is assumed to be $P_2 = 0.15$.

We now show how to identify demand parameters under the assumption that consumers respond to marginal prices in their electricity usage decisions. Given that households A and B face the same price, the parameter α can be identified by dividing the difference in quantity consumed between households A and B by the difference in X. In this example, that leads to an estimate of $\alpha = (4 – 3)/(20 – 15) = 0.2$. The effect of a change in marginal price on demand can be determined by adjusting C's income level to that of B's. Given $\alpha = 0.2$, if B and C paid the same price for electricity, then C would consume four more units than B. Thus, if a hypothetical household, B', had the same income level as B but faced the same marginal price as C ($P_2 = 0.15$), it would consume four fewer units than C, resulting in two units of electricity. Connecting points X, corresponding to $P_2 = 0.15$ and $Q'_B = 2$, and Z, corresponding to $P_1 = 0.10$ and $Q_B = 4$, where both have the same income but different marginal prices, we obtain the demand curve for the case where consumers respond to marginal prices. The slope of the demand curve, D^{MP}, is $\beta = (4 – 2)/(0.1 – 0.15) = –40$. This implies a price elasticity, evaluated at Q_B, for the marginal-price demand curve of $\varepsilon^m = \beta/Q_B \times P_1 = –1$. This way of identifying the price elasticity underlies the identification strategy used by Reiss and White (2005), where consumers are assumed to respond to marginal prices.

To identify the demand curve for the case where consumers respond to average prices, note that if the cut-off quantity $Q^* = 4.5$, average prices paid by the three households are $\overline{P}_A = \overline{P}_B = 0.10$ and $\overline{P}_C = 0.1125$. Using the same identification strategy as described above, α would again be 0.2. Again, a hypothetical household, B', with the same income level as B but facing the same average price of 0.1125 as C, would therefore consume two units of electricity (four units less than C). Connecting points Y, corresponding to $P_2 = 0.1125$ and $Q'_B = 2$, and Z, where both have the same income but different *average* prices, we obtain the demand curve under the assumption of average-price response, D^{AP}. This results in a much flatter demand slope of $\beta = –160$ and price elasticity at Q_B of $\varepsilon^a = –4$.

This simple illustration shows that, for the same observations, estimating the demand function under the assumption of average-price responsiveness will result in much more elastic demand than that estimated under the assumption of marginal-price responsiveness.[10] The degree to which the price elasticities will differ is, of course, a function of the data used. Because we do not have individual rate structures for all individuals in our sample, we are not able to estimate the corresponding demand curves under the assumption of marginal-price responsiveness. However, using rate structure data for households served by Southern California Edison, Borenstein (2009) is able to estimate elasticities with respect to both marginal prices and average prices. He finds that the demand function specified over average prices results in an elasticity estimate at least double (in magnitude) that from the demand function specified over marginal prices.

V. Estimation Results

In this section, we first present estimation results for the baseline model, in which price elasticities are assumed to be invariant to income levels. We then present results for models relaxing this assumption. Note that the term *baseline* refers not the method of estimation, but to the set of variables and observations included in the model. The baseline and alternative models are estimated by the GMM procedure described above and by OLS.

Baseline Model

We estimate the empirical model outlined in the sections above separately for each of the four census regions—Midwest, Northeast, South, and West. We do this for two reasons. First, as a result of differences in weather conditions and appliance holdings, for example, demand parameters (e.g., on electricity price and month dummies) differ across regions. Estimation by region allows for region-specific demand parameters. Ideally, we would like to have even more regionally specific demand parameters by estimating the model state by state. However, state-level estimations are infeasible because there is not enough variation in instrumental variables for electricity prices (i.e., cost shifters) to identify the model. Second, the empirical method is data-intensive and computationally intensive because of the larger number of moment conditions and parameters. Estimating the model by region made the problem computationally tractable.

In the baseline model, we drop observations in the upper and lower 2.5 percentiles of electricity expenditure from each region to avoid the effects of outliers (e.g., college

[10] Note also that a similar example using a decreasing-block price schedule would yield the same result with respect to price elasticities as the increasing-block price schedule example described above.

dormitories), possible data entry errors, and households generating a large proportion of electricity by themselves (e.g., through solar panels). For example, the maximum monthly electricity expenditure is \$2,946 by a household with an annual income of \$157,720. Assuming constant monthly income implies the highly unlikely possibility that more than 22 percent of monthly income was spent on electricity. At the other extreme, we have 31 observations with a monthly expenditure of \$10. Among these observations, the household income ranges from \$4,071 to \$440,910 with a mean of \$61,229. We suspect that, if this is not due to data entry error, then some of the observations may come from households that have used self-generated electricity or subsidized electricity through a low-income assistance program. In addition, the use of a linear function to approximate a nonlinear average-price function may not work well at low or high values of consumption in the case of tiered pricing. As mentioned above, we also drop states with fewer than 2,500 observations from the sample to ensure a reasonably large number of observations in each state for each month, which is particularly important for the consistency of the second set of moment conditions. We perform robustness checks with respect to data censoring, and the results are provided below.

Table 5 presents parameter estimates for the baseline model by census region from OLS. The electricity demand also includes state dummies, year dummies, and month dummies, but the parameters associated with these variables were omitted for brevity. Due to the log–log specification used, the parameter on *log*(*price*) in the first row provides price elasticity estimates. The differences in price elasticities across the four regions are substantial and are challenging to explain. According to the OLS results, the West region is the most price elastic with an elasticity of –1.02, whereas the Northeast region is the least price elastic with an elasticity of –0.385. Income elasticities, on the other hand, are very similar across the regions, ranging from 0.061 in the Midwest to 0.072 in the West. Other demand parameters generally have intuitive signs. The appliances in the table, especially electric space heating, increase electricity demand significantly. In the Northeast region, having electric heating increases electricity demand by almost 31 percent at the mean level of HDD (4.55). As discussed above, the OLS estimates could suffer bias as a result of both simultaneity and measurement error issues, and the direction of bias is unknown *a priori*.

Table 6 presents estimation results from GMM. The first row presents price elasticity estimates and their standard errors. Comparing this with the OLS results, two differences are obvious. First, the estimates of price elasticities from GMM in all four regions are noticeably different from their OLS counterparts. The GMM estimates in the first three regions are at least double the OLS results, whereas the elasticity estimate for the West region changes less substantially from –1.02 to –0.88. Second, although significant differences in elasticities remain across regions in the GMM results, the differences are much smaller than those observed from OLS.

Based on the GMM results, the Northeast region is the least price elastic with an elasticity of –0.82, whereas the South region is the most price elastic with an elasticity of –1.02. This result is as expected. Electricity usage is a result of the flow of services from a household's electricity-using appliances. Therefore, a household's ability to respond to a change in electricity price will depend largely on the type and number of appliances for which usage can easily be adjusted. For example, using an end-use demand specification, Reiss and White (2005) show that electricity price changes have the largest demand effects among households with electric space heating and air conditioning, two appliances that often account for a large portion of total household consumption and have easy-to-vary usage. The South region has the highest share of electric space heating at 54 percent compared to only 10 percent in the Northeast. In addition, air conditioning ownership (both central and window air conditioning) is 99 percent in the South compared to only 80 percent in the Northeast region, as shown in Table 2. Altering the use of these appliances is a significant end-use margin on which households can adjust electricity usage. Thus, households with electric space heating and air conditioning are likely to have more price-elastic demands. In the Northeast and Midwest regions, home heating often plays a relatively more significant role than home cooling, but because many homes have natural gas heating, there is not as obvious an end use on which to alter electricity consumption.

The other noticeable feature of our price elasticity estimates is that we find demand to be roughly twice to three times more price elastic than do several other studies using household-level data (e.g., Barnes et al. 1981; Dubin and McFadden 1984; Herriges and King 1994; Reiss and White 2005). All of these studies are based on household-level data matched with actual rate schedules faced by households in specific geographic areas. As pointed out by Dubin and McFadden (1984), household-level data are preferred over aggregate data (e.g., aggregated at the state level) because it could avoid misspecification bias due to date aggregation over electricity usage and price. Using household data in 23 large U.S. metropolitan areas from 1972 to 1973 in the CEX, Barnes et al. (1981) obtain a price elasticity estimate of –0.55. Dubin and McFadden (1984) use a 1975 household survey and estimate a price elasticity of –0.26. Based on data from a controlled experiment in Wisconsin from 1984 to 1985, in which participants were subject to five different rate schedules, Herriges and King (1994) obtain a price elasticity of –0.02 for the summer season and –0.04 for the winter. Reiss and White (2005) use the California subsample of the 1993 and 1997 survey waves of RECS and obtain a price elasticity of –0.39.

The first difference between our study and those four studies is that we are using representative national-level data rather than data from a particular region. More importantly, those studies assume that households respond to marginal prices, whereas we assume that households respond to average prices. As illustrated in the previous section, this difference can lead to drastically different estimated price elasticities. The question of which price consumers respond to in electricity demand is beyond the scope of this study but, as previously mentioned, mounting evidence suggests that consumers respond to average prices, and that result stands to reason. Nevertheless, the importance of this question is underscored by the significant difference between our results and those from studies assuming marginal-price responsiveness.

The second row of Table 6 shows estimates of income elasticities across four regions from the GMM procedure. Differences also exist between these estimates and those from OLS, although the differences are not as large as those in the price elasticity estimates. For example, the largest disparity in estimates comes from the income elasticity estimate for the Midwest region, which is 0.061 from OLS and 0.109 from GMM. The South region has the smallest income elasticity of 0.051 based on GMM results. Unlike the price elasticity estimates, these small income elasticity estimates are within the range found in previous studies. Barnes et al. (1981) obtain an income elasticity estimate of 0.20, whereas Dubin and McFadden (1984) get an estimate of 0.02. Herriges and King (1994) provide an estimate of 0.45, whereas Reiss and White (2005) find no statistically significant income effect.

The remaining parameter estimates in Table 6 correspond to housing characteristics, demographic information, and appliance holding variables. The characteristics of the housing unit we control for include a variable for house size (# of rooms), variables on housing unit age, a dummy if the housing unit is owned (Owned House), and a dummy if the unit is a single-family dwelling (Single House). As expected, we find that electricity consumption increases with increasing house size in all regions. Interpretation of the remaining housing characteristics is not as straightforward.

With respect to the house age characteristics, we control for the age of the house (House Age), a dummy equaling one if the house was built before 1970 (D_{70}), and the interaction between these variables (D_{70}*House Age).[11] The positive parameter estimates on House Age in all regions except the Midwest imply that electricity usage increases with house age for those built after 1970. The interaction between D_{70} and House Age allows the age effect on electricity usage to be different for houses built before 1970 from those built after. Except for the Midwest region, the parameter estimates on the interaction term are all negative, suggesting that the age effect in these regions is smaller for pre-1970 houses than for post-1970 houses. This result could be because much older houses have been renovated and, consequently, have been made more energy efficient.

For the house ownership dummy variable, we find a positive and statistically significant effect of homeownership on electricity consumption. This may seem surprising at first glance. One would expect that homeowners would be more likely to purchase an energy-efficient capital stock because they will accrue the benefits from such stock over a longer period, leading to conditionally lower electricity consumption than renters. Indeed, in a recent study using RECS data, Davis (2010) finds that renters are more likely to have fewer Energy Star appliances than homeowners. However, the ownership of energy-efficient appliances may be counteracted by more time spent in the housing unit and/or a greater frequency of appliance usage. Though we have no specific data on these issues, some evidence from our data appears to be consistent with the notion that homeowners are at home more often and/or use appliances more frequently. For example, if more senior individuals are more likely to spend time in the home than younger individuals, given our positive homeownership effect, we would expect that seniors would occupy a greater percentage of owned homes than rented homes. Indeed, our data show that 40 percent of homeowners, but only 18 percent of renters, are over the age of 64. Similarly, one might also expect that having more children may lead to more hours spent in the home and greater use of energy-intensive appliances such as washers and dryers. Again, our data show that the average number of children under the age of 18 in owned homes for individuals under the age of 64 is 0.9, compared to 0.8 for renters under the age of 64.

With respect to appliance holdings, we find that most of the parameter estimates for appliance holding have statistically significant values and intuitive signs. For instance, our

[11] We use 1970 as a somewhat arbitrary cut-off point between "older" construction and "newer" construction. We have also tried cut-off years above and below 1970 and these do not substantially change our results. Additionally, if this was a totally arbitrary and meaningless cut-off, we would expect to find a statistically insignificant parameter estimate on D_{70}.

demand estimation shows that electricity demand increases when households have electric space heating, air conditioners (window units or central air conditioning), a swimming pool, or an electric cooking appliance. Except for the interaction term between CDD and Swimming Pool in the South region, all of the interaction terms between appliance and weather variables (CDD and HDD) have positive signs, as intuition would suggest.

Although our paper is focused on electricity demand, the identification relies on using cost shifters as instruments, a common strategy in demand estimation. The baseline model uses 10 instruments: quarterly and yearly moving average lagged share of electricity generation from coal, the share from natural gas, that from hydro and nuclear, the interaction between the share from coal with lagged coal price, and the interaction between the share from natural gas with lagged natural gas price. The estimation results show that most of the cost shifters are statistically significant. The yearly moving average variables generally have a larger effect than do the quarterly variables, indicating that electricity prices are often affected by supply conditions even one year prior to production. We conduct a robustness check on the use of instruments in the next section, together with other sensitivity analyses.

Additional Specifications

In considering the distributional impacts of policies that affect electricity prices, like federal energy or climate policy, policymakers are concerned not only with geographical distributions of cost, but also with distributional effects across income groups. That is, households with different income levels may be affected differently by policies that affect electricity price. Our first alternative specification is therefore to examine if there is heterogeneity in price sensitivity across income groups. To that end, we interact *log*(*price*) with income interval dummies that capture four levels of household income: below $25,000, between $25,000 and $45,000, between $45,000 and $80,000, and above 80,000.

Table 7 shows parameter estimates for the four interaction terms between price and income dummies. Parameter estimates for the other variables are very close to those reported in the previous two tables and are omitted from this table. Panel 1 of Table 7 shows the OLS results, and Panel 2 shows the GMM results. Both panels show no economically significant differences in price elasticities across income categories. There could be multiple reasons why we fail to detect significant differences in price elasticities across income groups. First, although lower income groups respond to higher prices by using electricity-consuming products less, higher income groups may respond to higher prices by buying more energy-efficient products but maintaining product use levels. Second, lower-income households may cut back their usage of many commonly found electricity-intensive appliances (e.g., air conditioning) more than higher-income households, but high-income households may also have more nonessential electricity-consuming products (not controlled in the estimation) that can easily be used less when electricity prices are high. If this is the case, elasticity estimates should be relatively constant across income classes.

As stated above, the data exclusion made on the presented results was to remove households with the top and bottom 2.5 percent of electricity expenditure and individuals from states with fewer than 2,500 observations. Additional estimations were conducted in which we also dropped all individuals with household incomes below $10,000, in an attempt to exclude those with potentially subsidized electricity prices (e.g., in subsidized housing) or nondeclared income sources. The results of this estimation, by GMM, are presented in Table 8. The price elasticity estimates are nearly identical to those in Table 6, where there was no censoring based on income. The changes in income elasticities are more noticeable. For example, it increases from 0.071 to 0.102 for the Northeast region. This suggests that households with incomes below $10,000 have smaller income elasticities.

The purpose of dropping observations in the top and bottom 2.5 percent of electricity expenditure is to remove outliers and to obtain a better approximation of the average-price schedule using a linear function. The next specification, in which we drop observations in the top and bottom 1 percent of electricity expenditure, examines the sensitivity of the results with respect to this censoring. The results, presented in Table 9, are close to the results from the baseline model in Table 6. The biggest change in price elasticity estimates is for the West region, where it changes from 0.878 to 0.915.

All previous specifications use 10 cost shifters as instruments for electricity price to form moment conditions. The last alternative specification uses 5 of the 10 lagged cost shifters employed in the baseline model: the average share of electricity generated by coal during the past 12 months, that by natural gas, that by nuclear and hydropower, the interaction between the average coal price during the past 12 months and the coal share of generation, and the interaction between natural gas price and the natural gas share of generation. The other five variables not used in this specification are those measured based on quarterly averages. Table 10 shows the parameter estimates for the demand equations for the four regions. Most of the estimates are very similar to those from the baseline model in Table 6. The noticeable differences are in price elasticity estimates for the Northeast and Midwest regions: they are 0.74 and 1.02 in this specification compared to 0.82 and 0.96 in the baseline model. Nevertheless, demand is still more price elastic in the South and Midwest regions than in the other two regions.

VI. Policy Analysis Simulations

As discussed above, our price elasticity estimates are considerably larger than those based on the assumption of marginal-price responsiveness. The question, however, remains as to how these different estimates will alter analyses of federal policies that affect electricity prices. To examine this issue, we use simulations to study a federal carbon dioxide (CO_2) emissions regulation similar to that proposed in H.R. 2454 (U.S. House of Representatives 2009), the Waxman–Markey climate bill.

The simulations are conducted using Resource for the Future's Haiku electricity market model,[12] a deterministic and highly parameterized simulation model of the electricity sector in the 48 contiguous U.S. states. It calculates information similar to that of the Electricity Market Module of the National Energy Modeling System that is maintained and used by EIA. This analysis hinges on the demand side of the Haiku model, which employs a partial adjustment specification of electricity demand.

We conduct the simulations under three different residential price elasticity of demand parameterizations. In the first parameterization, we use the rather low short-run price elasticity estimates generated by Paul et al. (2009b) that vary by region and season. We denote this the ε_L case to signify the low elasticity estimates.[13] The Paul et al. (2009b) model was based on state-aggregated data and includes both short-run and long-run elasticity estimates. In the second parameterization, we replace the short-run price elasticities of Paul et al. (2009b) with a more moderate estimate of –0.4, the ε_M case. This value is in line with the price elasticity estimated in Reiss and White (2005) which, as stated above, is based on marginal-price responsiveness from household-level data in California.[14] This elasticity is applied to all regions covered under the simulation. In our final parameterization, we use the region-specific price elasticities estimated above as the short-run elasticity in the policy simulation. We denote this the ε_H case to signify our higher elasticity estimates. All other features of the model, such as long-run price elasticities, other residential demand covariates, and all of the coefficients for the industrial and commercial sector demand functions, are those estimated in Paul et al. (2009b).

[12] Complete model documentation is available in Paul et al. (2009a).

[13] The regionally specific residential short-run elasticity estimates in Paul et al. (2009b) range from –0.01 to –0.32, with a national average of –0.13.

[14] Note that Reiss and White (2005) estimate end use-specific elasticities. The value –0.4 is in line with their average elasticity estimate across these end uses and across households in their sample.

The simulation outputs give us, among many other variables, average residential electricity prices and total consumption at the region level and national CO_2 emissions allowance prices. The model is run over the 2010 to 2035 horizon, with the CO_2 emissions control policy beginning in 2012 and holding cumulative economywide CO_2 emissions constant across scenarios.[15] We show the policy simulation results for four years (2012, 2016, 2025, and 2035) for each of the parameterization cases. We also show percentage changes relative to the *Annual Energy Outlook 2010* reference case (U.S. EIA 2010). National results are given in Table 11, and regional results are in Table 12.

The national-level results show that the policy tends to increase electricity prices relative to the reference case and that the price impact tends to grow over time. The details of why this pattern emerges are not important for this analysis, but it hinges on a leftward shift of the electricity supply curves, and we are interested in how the assumption about short-run price elasticities impacts consumption, electricity prices, and allowance prices under this supply-side shift. The simulations show that, especially in the long run, federal climate policy will engender a significantly greater reduction in electricity consumption if consumers are more price elastic. This may have important negative welfare consequences for households, though it will be partly offset by a corresponding reduction in allowance prices. By 2035, the allowance price under the ε_H scenario is 4 percent lower than under the ε_L scenario. This would have a positive welfare impact on households because, under an economywide emissions cap, all goods and services that have any carbon intensity of production will become more expansive as allowance prices rise.

Another factor that mitigates the household welfare impacts of consumption reductions is the electricity price. Table 11 shows an approximate \$3/MWh difference in electricity prices from the ε_L case to the ε_H that holds fairly constant throughout the time span examined. The price difference may seem surprisingly low given the rather large differences in electricity consumption from ε_L to ε_H, however the demand parameters of the other customer classes (commercial and industrial) are held constant across these scenarios, and these residential consumption reductions represent only a part of total electricity demand. Furthermore, the electricity price reductions that emerge under the higher elasticity scenarios result in an increase in consumption by the other customer classes. These factors, along with the observation that the

[15] Haiku includes a marginal abatement cost curve that allows for allowance price-responsive rest-of-economy emissions. It also includes supply curves for domestic and international carbon offsets that are constrained according to the offsets specification of H.R. 2454.

long-run supply curves for electricity production in Haiku are relatively elastic, yield relatively small changes in electricity price.

The region-specific price and consumption patterns largely follow the national patterns, but there are some differences. For instance, in the West region, we find very little difference in electricity prices across elasticity parameterizations, whereas in the Midwest, the price differences from ε_L to ε_H are much more pronounced. This is largely due to the differences between these regions in production technologies. The West region has significant hydroelectric generation and resources for nonemitting renewable electricity production. Thus, the region will incur a relatively small shift in electricity production costs as a result of this cap-and-trade system, and therefore small price increases. Conversely, electricity generation in the Midwest region is predominantly from coal, which will incur the largest shift in production costs with the introduction of an emissions price. The larger shift in the supply curve will, of course, lead to larger price differentials across the elasticity parameterizations. We also find that, unlike the price pattern observed at the national level, electricity prices in the Northeast and Midwest regions are not strictly increasing over time. This is due to the timing of investment in nuclear capacity and the retirement of existing capacity in these regions.

We generally find decreasing regional consumption as we go from the ε_L to ε_H parameterizations, as in the national results. An exception to this is the consumption pattern in the South region in 2012. For that year, we see that consumption under the ε_H setting is actually greater than that under the ε_L parameterization. How can this be? The answer is, in part, due to the complex dynamic investment decisions faced by generation capacity owners. In this particular case, the inclusion of an allowance price leads to greater generation revenues for marginal natural gas electricity generators, particularly in later years of the policy as allowance and electricity prices increase. Electricity prices also include the cost generators incur to have excess reserve capacity that is needed only in the highest demand periods, which we call the reserve cost. Because generators earn larger generation revenues in later periods under a cap-and-trade policy, the equilibrium reserve costs are lower in the near term compared to a case with no emissions control policy. Depending on the price elasticity assumptions, which affect both the emissions allowance price in general and the electricity price, the long-run investment choices may be such that increasing allowance prices lead to a decrease in reserve costs that more than offset the increase in generation costs due to an emissions price. The elasticities under the ε_H setting, combined with the generation technologies of the South region, lead to just such an outcome.

In general, this simulation example yields mostly predictable results, particularly when viewed in aggregate at the national level. However, the results do show some regional differences that highlight how changes in the elasticity assumptions can lead to some particularly interesting and nonintuitive regional pricing and consumption patterns under an electricity price-raising cap-and-trade policy.

VII. Conclusion

Given the recent push to craft a federal energy policy in the U.S., —in which alterations to the portfolio of electricity generators, and therefore to electricity prices and consumption, are likely to be central components—there is a pressing need to obtain accurate electricity demand estimates for all parts of the country. Undertaking such a task poses several challenges, most notably that electricity rate structure data for all parts of the U.S. are not easily obtainable. Hence, most electricity demand models that use household-level data are conducted for very specific regions for which the researchers were able to obtain specific rate structure data.

To avoid the need for specific rate structure data, we develop a novel GMM approach that allows us to recover residential electricity demand parameters and average-price schedule parameters based on electricity expenditure data (along with demand covariates and some other easily obtainable aggregate price and quantity information). We then apply this technique to detailed household-level data in the CEX, which includes monthly household electricity expenditures, but not electricity prices or quantities, over the period 2004–2006. We estimate demand and average-price schedule equations for four census regions separately.

We find that price elasticities vary across the four census regions, with the South region having the most price-elastic demand with an elasticity of –1.02 and the Northeast region having the least price-elastic demand at –0.82. In general, these price elasticity estimates are considerably larger in magnitude than those of other studies of residential electricity demand using household-level data. As we show through a simple example, it is not unreasonable for our estimates to be larger than those derived in studies that assume that households respond to marginal electricity prices because we explicitly assume that households respond to average electricity prices. As noted above, several studies present some empirical evidence, albeit confined to specific geographic regions, to support the notion that average-price responsiveness is a more appropriate assumption than marginal-price responsiveness.

To put these elasticity estimates into a policy-relevant perspective, we conducted a policy study, using a model parameterization based on the estimates derived here, to simulate the recently proposed U.S. climate policy legislation, H.R. 2454 (Waxman–Markey). The outcomes from this policy study, in terms of regional and national electricity prices, consumption, and emissions allowance prices, were then compared to outcomes using more conservative price elasticity parameterizations, typical of marginal price-responsive demand estimation studies. Not surprisingly, we find that, on a national level, simulations using the elasticity estimates derived here compared to more conservative elasticity estimates leads to a greater reduction in electricity consumption as a result of the implementation of the policy and lower emissions allowance prices. From a regional perspective, we find that the decreases in consumption brought about by the policy are not uniform and have considerable heterogeneity depending on the elasticity used. In fact, we find that in the South region, using our larger price elasticities leads to a near-term increase in electricity consumption under the policy relative to the no-policy baseline and relative to the more conservative elasticity parameterizations. This result is due to the complex interaction of dynamic capital investment decisions and price elasticities embedded in our analysis framework. Furthermore, this regional result highlights the important role elasticity assumptions can play in expected policy outcomes.

Though we believe this study provides a novel approach to estimating electricity demand without specific rate structure data and provides valuable regional elasticity estimates, it leaves several issues unexplored. First, because we do not have specific bill information, we cannot validate our average price-responsiveness assumption. This is clearly an important consideration that goes far beyond the current study. In addition, because of the short time frame examined, we do not account for capital adjustment by households. Estimating capital adjustment price responses, and how these responses vary across income groups, would be very valuable in determining the expected outcomes of national energy policies aimed at improving energy efficiency. However, such estimates would require more detailed data than what is available in the CEX.

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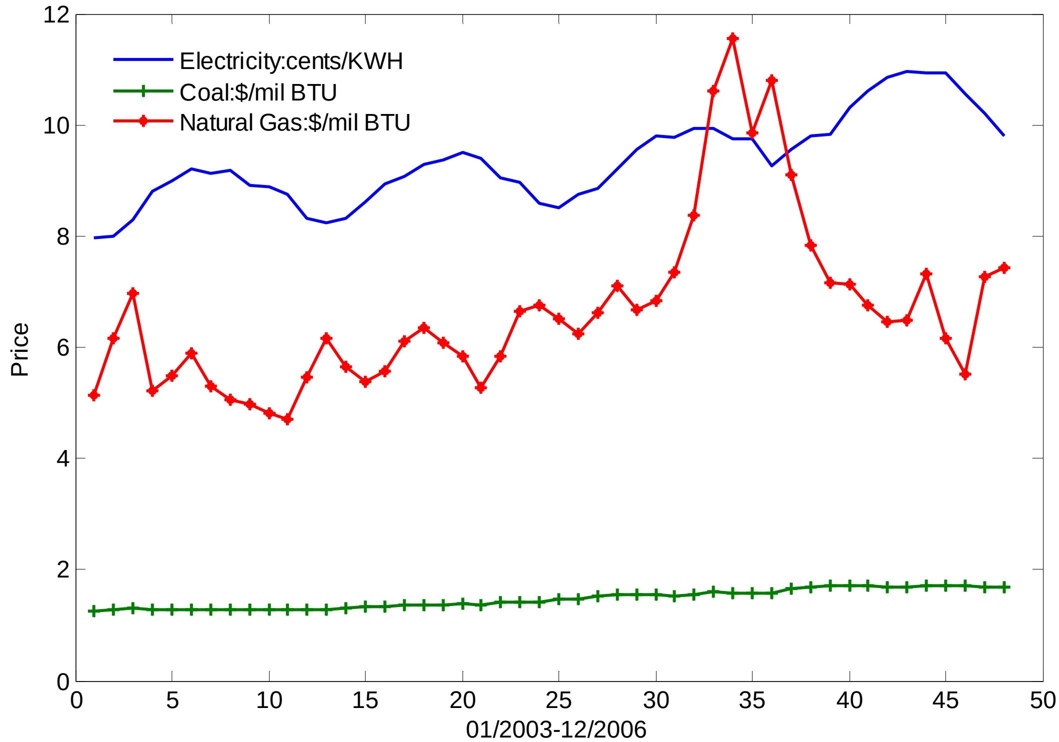
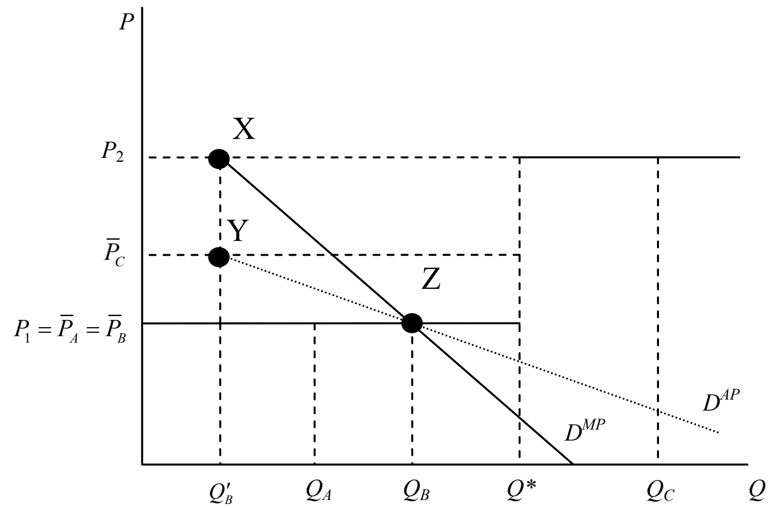
Figures

Figure 1. Monthly Prices of Electricity, Coal, and Natural Gas 2003–2006



Notes: Btu, British thermal unit; kWh, kilowatt-hour.

Figure 2. Marginal-Price versus Average-Price Demand Curves



Notes: D^{AP} denotes the implied demand curve when consumers respond to average price, whereas D^{MP} is the demand curve when consumers respond to marginal price.

Tables

Table 1. States in Analysis by U.S. Census Region

ID	Northeast	South	Midwest	West
1	Massachusetts	Florida	Illinois	Arizona
2	New Jersey	Georgia	Indiana	California
3	New York	Maryland	Michigan	Colorado
4	Pennsylvania	South Carolina	Minnesota	Oregon
5		Texas	Missouri	Washington
6		Virginia	Ohio	
7			Wisconsin	
Obs.	21,862	33,876	28,206	27,234

Notes: Twenty-two states are used for the analysis, each with at least 2,500 (household-month) observations in the CEX data from 2004 to 2006.

Table 2. Summary Statistics of Demand-Side Variables by Census Region

		Northeast		South		Midwest		West	
Variables	**Description**	Mean	S.D.	Mean	S.D.	Mean	S.D.	Mean	S.D.
Expenditure	Monthly expenditure in $	112.7	68.8	142.8	73.8	95.8	52.2	98.0	63.6
State Price	Average price in ¢/kWh	12.87	2.65	9.87	1.46	8.81	0.96	11.07	2.78
Quantity	Imputed quantity in 100 kWh	8.90	5.24	14.54	7.29	10.97	6.05	9.46	6.62
Income	Income in $	7.34	6.01	6.83	5.61	7.07	5.47	7.29	5.73
# of Rooms	Number of rooms in housing unit	6.51	2.12	6.41	1.97	6.65	2.02	6.09	1.89
Household Size	Number living in housing unit	2.60	1.40	2.65	1.40	2.61	1.39	2.81	1.61
House Age	Age of housing unit	5.40	3.77	2.92	2.28	4.18	3.01	3.36	2.30
D_{70}	D_{70} = 1 if unit built before 1970, 0 otherwise	0.68	0.47	0.34	0.47	0.54	0.50	0.42	0.49
Respondent Age	Survey respondent age	52.85	16.03	51.12	15.94	51.88	15.69	50.24	16.17
Electric Heat	Equal to1 if unit has electric heat, 0 otherwise	0.10	0.30	0.54	0.50	0.09	0.28	0.24	0.43
Central AC	Equal to1 if unit has central AC, 0 otherwise	0.43	0.49	0.87	0.34	0.75	0.43	0.50	0.50
Window AC	Equal to1 if unit has window AC, 0 otherwise	0.37	0.48	0.12	0.32	0.17	0.37	0.09	0.29
Swim Pool	Equal to1 if unit has swimming pool, 0 otherwise	0.12	0.33	0.14	0.35	0.09	0.29	0.17	0.37
Electric Cooking	Equal to1 if unit has electric stove, 0 otherwise	0.45	0.50	0.72	0.45	0.53	0.50	0.51	0.50
CDD	65 – pop. weighted mean temp; (°F), if temp < 65	0.67	1.03	1.96	1.93	0.68	1.02	0.90	1.48
HDD	Pop. weighted mean temp; (°F) – 65, if temp > 65	4.55	4.09	1.93	2.50	5.06	4.54	2.78	2.64
Owned House	Equal to 1 if housing unit is owned	0.83	0.37	0.86	0.35	0.89	0.31	0.79	0.41
Single House	Equal to 1 if housing unit is an unattached unit	0.68	0.47	0.75	0.43	0.81	0.39	0.74	0.44

Notes: AC is air conditioning.

Table 3. Summary Statistics of Cost Shifters by Census Region

Variables	Description	Northeast Mean	Northeast S.D.	South Mean	South S.D.	Midwest Mean	Midwest S.D.	West Mean	West S.D.
% Nat. Gas_1	% of generation from natural gas, last 3 months	0.20	0.15	0.25	0.20	0.04	0.04	0.36	0.15
% $Coal_1$	% of generation from coal, last 3 months	0.33	0.18	0.44	0.13	0.70	0.16	0.15	0.23
P_1^{NG}	Average natural gas price, last 3 months	1.36	1.04	1.75	1.42	0.31	0.28	2.51	1.20
P_1^{C}	Average coal price, last 3 months	0.50	0.29	0.66	0.20	1.05	0.25	0.22	0.34
% $(Nuke+Hydro)_1$	% of generation from nuclear+hydro, last 3 months	0.39	0.12	0.24	0.14	0.23	0.15	0.40	0.20
% Nat. Gas_2	% of generation from natural gas, last 12 months	0.19	0.14	0.25	0.19	0.04	0.03	0.36	0.15
% $Coal_2$	% of generation from coal, last 12 months	0.33	0.18	0.44	0.12	0.71	0.16	0.15	0.23
P_2^{NG}	Average natural gas price, last 12 months	1.29	0.97	1.68	1.39	0.29	0.25	2.43	1.08
P_2^{C}	Average coal price, last 12 months	0.48	0.27	0.64	0.19	1.02	0.24	0.22	0.33
% $(Nuke+Hydro)_2$	% of generation from nuclear+hydro, last 12 months	0.39	0.12	0.24	0.14	0.23	0.15	0.40	0.20

Notes: Prices are in \$/million Btu for coal and \$/thousand $feet^3$ for natural gas.

Table 4. Monte Carlo Results for the Demand Equation

Demand equation		OLS results		GMM results	
Dependent variable: Log(quantity)	True	Estimates	S.E.	Estimates	S.E.
Panel 1: Upward sloping price schedule (slopes: 0.4, 0.3, 0.2, 0.1)					
Log(price)	–0.8	–0.512	0.096	–0.837	0.088
Log(income)	0.2	0.199	0.005	0.195	0.006
Log(room number)	0.3	0.306	0.011	0.301	0.012
Log(household size)	0.4	0.420	0.007	0.412	0.011
σ_e^2	0.2			0.211	0.093
Panel 2: Downward sloping price schedule (slopes: –0.4, –0.3, –0.2, –0.1)					
Log(price)	–0.8	–1.117	0.059	–0.860	0.069
Log(income)	0.2	0.182	0.004	0.188	0.009
Log(room number)	0.3	0.280	0.01	0.290	0.016
Log(household size)	0.4	0.384	0.006	0.397	0.018
σ_e^2	0.2			0.188	0.052
Panel 3: Mixed sloping across state (slopes: 0.4, 0.3, –0.2, –0.1)					
Log(price)	–0.8	–0.716	0.051	–0.820	0.045
Log(income)	0.2	0.191	0.004	0.196	0.006
Log(room number)	0.3	0.292	0.010	0.302	0.012
Log(household size)	0.4	0.406	0.006	0.414	0.01
σ_e^2	0.2			0.213	0.058

Notes: Monte Carlo simulations are based on observations from the four states in the Northeast region, each with at least 2,500 observations in the CEX data from 2004 to 2006. Total number of observations: 21,862. Parameters are estimated using both OLS and GMM. Equations include four state dummies, two year dummies, and 11 month dummies.

Table 5. Demand Equation Estimates from OLS: Baseline Model

	Northeast		South		Midwest		West	
	Para.	**S.E.**	**Para.**	**S.E.**	**Para.**	**S.E.**	**Para.**	**S.E.**
Log(price)	**–0.385**	**0.064**	**–0.423**	**0.049**	**–0.472**	**0.068**	**–1.020**	**0.075**
Log(Income)	0.067	0.005	0.066	0.004	0.061	0.005	0.072	0.005
Log(#of rooms)	0.279	0.013	0.310	0.010	0.299	0.012	0.339	0.013
Log(household size)	0.265	0.007	0.212	0.005	0.247	0.006	0.211	0.007
Log(house age)	0.038	0.008	0.043	0.004	0.001	0.006	0.039	0.006
D_{70}*Log(house age)	–0.051	0.013	–0.035	0.015	0.054	0.013	–0.032	0.019
D_{70}	0.010	0.021	0.003	0.024	–0.080	0.020	0.024	0.030
Log(respondent age)	–0.007	0.012	0.031	0.009	0.105	0.010	0.128	0.011
Electric Heat	0.181	0.017	0.167	0.008	0.166	0.015	0.104	0.012
Central AC	0.081	0.011	0.009	0.015	0.023	0.012	0.098	0.009
Window AC	0.023	0.010	0.046	0.016	0.008	0.013	0.042	0.014
Swim Pool	0.089	0.012	0.146	0.011	0.031	0.012	0.150	0.011
Electric Cooking	0.076	0.007	0.030	0.006	0.076	0.006	0.057	0.008
CDD	0.029	0.014	0.037	0.008	0.005	0.012	0.032	0.008
HDD	–0.010	0.004	0.019	0.003	–0.003	0.003	0.010	0.004
CDD*(Central AC)	0.047	0.009	0.023	0.006	0.045	0.010	0.061	0.006
CDD*(Window AC)	0.020	0.009	0.005	0.006	0.005	0.011	0.025	0.009
HDD*(Electric Heat)	0.028	0.003	0.021	0.002	0.017	0.002	0.040	0.003
CDD*(Swim Pool)	0.003	0.010	–0.011	0.004	0.045	0.010	0.001	0.005
Owned House	0.176	0.011	0.077	0.008	0.058	0.011	0.039	0.010
Single House	0.022	0.009	0.045	0.007	0.134	0.010	0.191	0.010
No. of observations	21,862		33,876		28,206		27,234	

Notes: The price variable using OLS is the monthly state average from EIA. The quantity is imputed using the household expenditure divided by this price variable. The demand equations also include state dummies, year dummies, and month dummies.

Table 6. Demand Equation Estimates from GMM: Baseline Model

	Northeast		South		Midwest		West	
	Para.	**S.E.**	**Para.**	**S.E.**	**Para.**	**S.E.**	**Para.**	**S.E.**
Log(price)	**–0.824**	**0.039**	**–1.021**	**0.006**	**–0.964**	**0.006**	**–0.879**	**0.008**
Log(Income)	0.071	0.005	0.051	0.003	0.109	0.005	0.089	0.005
Log(#of rooms)	0.267	0.013	0.249	0.010	0.268	0.013	0.377	0.014
Log(household size)	0.249	0.008	0.202	0.006	0.276	0.009	0.205	0.007
Log(house age)	0.033	0.007	0.052	0.003	0.023	0.005	0.043	0.006
D_{70}*Log(house age)	–0.051	0.012	–0.014	0.014	0.033	0.013	–0.044	0.020
D_{70}	0.016	0.019	–0.031	0.022	–0.033	0.022	0.033	0.032
Log(respondent age)	–0.006	0.011	0.012	0.007	0.126	0.011	0.179	0.012
Electric Heat	0.190	0.014	0.241	0.008	0.313	0.013	0.073	0.012
Central AC	0.051	0.010	0.000	0.009	0.064	0.012	0.083	0.009
Window AC	0.010	0.010	0.069	0.008	0.017	0.014	0.050	0.014
Swim Pool	0.093	0.011	0.090	0.008	0.128	0.010	0.142	0.011
Electric Cooking	0.082	0.007	0.018	0.005	0.094	0.006	0.065	0.008
CDD	0.024	0.008	–0.025	0.003	0.049	0.009	–0.032	0.003
HDD	–0.012	0.001	0.010	0.000	–0.003	0.000	–0.015	0.001
CDD*(Central AC)	0.065	0.006	0.039	0.003	–0.031	0.008	0.074	0.004
CDD*(Window AC)	0.030	0.008	–0.022	0.003	–0.054	0.011	0.019	0.009
HDD*(Electric Heat)	0.020	0.002	–0.014	0.001	0.006	0.000	0.073	0.003
CDD*(Swim Pool)	–0.003	0.008	0.004	0.002	–0.095	0.007	–0.003	0.005
Owned House	0.165	0.011	0.083	0.008	0.068	0.013	0.014	0.011
Single House	0.011	0.009	0.056	0.006	0.125	0.011	0.227	0.011
σ_e^2	0.188	0.051	0.150	0.022	0.245	0.036	0.264	0.032
No. of observations	21,862		33,876		28,206		27,234	

Notes: The equations also include state dummies, year dummies, and month dummies.

Table 7. Income-Specific Price Elasticities by Census Region

	Northeast		South		Midwest		West	
	Para.	**S.E.**	**Para.**	**S.E.**	**Para.**	**S.E.**	**Para.**	**S.E.**
Panel 1: OLS Results								
Log(price)*1(Income<25k)	–0.377	0.064	–0.416	0.050	–0.455	0.069	–1.008	0.075
Log(price)*1(25k≤Income<45k)	–0.397	0.064	–0.426	0.049	–0.473	0.068	–1.037	0.075
Log(price)*1(45k≤Income<80k)	–0.397	0.064	–0.432	0.049	–0.465	0.068	–1.047	0.075
Log(price)*1(Income≥80k)	–0.384	0.064	–0.407	0.049	–0.475	0.068	–1.026	0.075
Panel 2: GMM Results								
Log(price)*1(Income<25k)	–0.816	0.039	–1.023	0.006	–0.962	0.007	–0.876	0.010
Log(price)*1(25k≤Income<45k)	–0.841	0.039	–1.024	0.006	–0.969	0.006	–0.882	0.011
Log(price)*1(45k≤Income<80k)	–0.834	0.039	–1.024	0.007	–0.965	0.007	–0.880	0.011
Log(price)*1(Income≥80k)	–0.824	0.039	–1.006	0.008	–0.968	0.007	–0.866	0.011

Notes: The equations include all of the other explanatory variables as shown in Tables 5 and 6. The coefficient estimates on those variables are omitted here.

Table 8. Demand Equation Estimates from GMM (Household Income ≥ $10,000)

	Northeast		South		Midwest		West	
	Para.	**S.E.**	**Para.**	**S.E.**	**Para.**	**S.E.**	**Para.**	**S.E.**
Log(price)	**–0.834**	**0.039**	**–1.022**	**0.006**	**–0.971**	**0.005**	**–0.881**	**0.008**
Log(Income)	0.102	0.006	0.067	0.004	0.125	0.006	0.113	0.006
Log(#of rooms)	0.244	0.014	0.237	0.011	0.252	0.013	0.369	0.015
Log(household size)	0.246	0.009	0.202	0.007	0.265	0.008	0.202	0.007
Log(house age)	0.035	0.007	0.055	0.004	0.023	0.005	0.043	0.006
D_{70}*Log(house age)	–0.044	0.013	0.000	0.014	0.019	0.013	–0.038	0.020
D_{70}	0.006	0.020	–0.052	0.022	–0.009	0.022	0.025	0.032
Log(respondent age)	0.012	0.011	0.017	0.008	0.138	0.011	0.187	0.013
Electric Heat	0.197	0.014	0.237	0.009	0.310	0.012	0.075	0.012
Central AC	0.042	0.010	–0.006	0.010	0.060	0.012	0.082	0.009
Window AC	0.004	0.010	0.063	0.008	0.018	0.014	0.046	0.015
Swim Pool	0.097	0.011	0.086	0.008	0.127	0.010	0.146	0.011
Electric Cooking	0.082	0.007	0.016	0.006	0.006	0.015	0.066	0.009
CDD	0.018	0.009	–0.032	0.003	0.050	0.008	–0.033	0.003
HDD	–0.014	0.001	0.001	0.093	–0.003	0.000	–0.017	0.001
CDD*(Central AC)	0.070	0.006	0.046	0.003	–0.035	0.008	0.078	0.004
CDD*(Window AC)	0.031	0.008	–0.018	0.003	–0.051	0.011	0.015	0.010
HDD*(Electric Heat)	0.022	0.002	–0.014	0.001	0.005	0.000	0.074	0.003
CDD*(Swim Pool)	0.008	0.009	0.006	0.002	–0.085	0.007	–0.004	0.005
Owned House	0.169	0.011	0.084	0.008	0.081	0.013	0.003	0.011
Single House	0.003	0.009	0.058	0.006	0.123	0.011	0.226	0.011
σ_e^2	0.184	0.051	0.148	0.022	0.234	0.034	0.263	0.032
No. of observations	21,197		32,752		27,497		26,475	

Notes: Observations with income less than $10,000 are dropped. The equations also include state dummies, year dummies, and month dummies.

Table 9. Demand Equation Estimates from GMM (without Lower and Upper 1 Percent of Households)

	Northeast		South		Midwest		West	
	Para.	**S.E.**	**Para.**	**S.E.**	**Para.**	**S.E.**	**Para.**	**S.E.**
Log(price)	**–0.824**	**0.042**	**–1.046**	**0.010**	**–0.975**	**0.005**	**–0.915**	**0.008**
Log(Income)	0.076	0.005	0.055	0.004	0.107	0.005	0.096	0.005
Log(#of rooms)	0.296	0.015	0.257	0.012	0.304	0.013	0.440	0.015
Log(household size)	0.260	0.009	0.215	0.008	0.288	0.008	0.241	0.008
Log(house age)	0.033	0.008	0.047	0.004	0.013	0.005	0.036	0.006
D_{70}*Log(house age)	–0.055	0.013	0.188	0.011	0.035	0.013	–0.070	0.021
D_{70}	0.026	0.020	–0.337	0.019	–0.023	0.022	0.093	0.033
Log(respondent age)	–0.013	0.011	0.026	0.007	0.134	0.011	0.180	0.013
Electric Heat	0.157	0.015	0.187	0.008	0.340	0.011	0.084	0.012
Central AC	0.057	0.010	0.016	0.011	0.061	0.012	0.098	0.009
Window AC	0.000	0.010	0.073	0.011	–0.016	0.014	0.044	0.015
Swim Pool	0.085	0.011	0.119	0.008	0.140	0.010	0.185	0.012
Electric Cooking	0.087	0.007	0.041	0.006	0.085	0.007	0.079	0.009
CDD	0.045	0.011	–0.033	0.004	0.015	0.010	–0.019	0.004
HDD	–0.014	0.001	0.005	0.000	–0.004	0.000	–0.012	0.001
CDD*(Central AC)	0.066	0.006	0.043	0.004	0.004	0.009	0.074	0.005
CDD*(Window AC)	0.032	0.008	0.002	0.003	0.012	0.011	0.001	0.010
HDD*(Electric Heat)	0.032	0.002	–0.002	0.001	0.008	0.000	0.071	0.003
CDD*(Swim Pool)	0.007	0.008	0.013	0.002	–0.090	0.006	–0.012	0.005
Owned House	0.159	0.012	0.088	0.008	0.069	0.013	0.022	0.011
Single House	0.016	0.009	0.042	0.006	0.146	0.011	0.243	0.011
σ_e^2	0.203	0.059	0.149	0.026	0.245	0.032	0.296	0.034
No. of observations	22,532		34,929		29,086		28,112	

Notes: Observations below 1 percentile or above 1 percentile of the monthly expenditure distribution are dropped. The equations also include state dummies, year dummies and month dummies.

Table 10. Demand Equation Estimates from GMM (Five Cost Shifters)

	Northeast		South		Midwest		West	
	Para.	**S.E.**	**Para.**	**S.E.**	**Para.**	**S.E.**	**Para.**	**S.E.**
Log(price)	**–0.742**	**0.044**	**–1.031**	**0.008**	**–1.015**	**0.003**	**–0.868**	**0.009**
Log(Income)	0.065	0.005	0.049	0.003	0.080	0.005	0.074	0.005
Log(#of rooms)	0.245	0.014	0.244	0.011	0.280	0.011	0.342	0.013
Log(household size)	0.229	0.009	0.195	0.007	0.220	0.006	0.188	0.007
Log(house age)	0.029	0.007	0.050	0.004	0.011	0.005	0.041	0.005
D_{70}*Log(house age)	–0.045	0.012	–0.023	0.013	0.024	0.011	–0.032	0.018
D_{70}	0.013	0.018	–0.016	0.021	–0.027	0.018	0.020	0.029
Log(respondent age)	–0.006	0.010	0.011	0.007	0.116	0.009	0.135	0.011
Electric Heat	0.147	0.014	0.240	0.009	0.149	0.011	0.092	0.011
Central AC	0.043	0.009	–0.032	0.010	0.000	0.011	0.024	0.008
Window AC	0.008	0.009	0.059	0.010	–0.034	0.012	0.042	0.013
Swim Pool	0.085	0.010	0.093	0.008	0.164	0.007	0.115	0.010
Electric Cooking	0.076	0.006	0.010	0.005	0.073	0.006	0.059	0.008
CDD	0.039	0.009	–0.043	0.004	–0.019	0.009	–0.078	0.005
HDD	–0.011	0.001	0.010	0.001	–0.004	0.000	–0.007	0.001
CDD*(Central AC)	0.068	0.006	0.055	0.004	0.037	0.009	0.131	0.005
CDD*(Window AC)	0.028	0.008	–0.003	0.003	0.019	0.010	0.013	0.010
HDD*(Electric Heat)	0.025	0.002	–0.014	0.001	0.016	0.001	0.052	0.002
CDD*(Swim Pool)	–0.003	0.008	0.010	0.002	–0.094	0.005	0.011	0.005
Owned House	0.155	0.011	0.088	0.008	0.051	0.011	0.038	0.010
Single House	0.008	0.008	0.055	0.006	0.111	0.009	0.188	0.010
σ_e^2	0.164	0.051	0.145	0.023	0.159	0.020	0.223	0.030
No. of observations	21,862		33,876		28,206		27,234	

Notes: The five instruments for electricity price used here are the five cost shifters measured during the past 12 months. The equations also include state dummies, year dummies, and month dummies.

Table 11. National Policy Simulation Results

ε	2012 P^E	2012 Q	2012 P^A	2016 P^E	2016 Q	2016 P^A	2025 P^E	2025 Q	2025 P^A	2035 P^E	2035 Q	2035 P^A
ε_L	114.2	1,377	11.4	118.8	1,350	15.6	121.6	1,467	31.1	139.5	1,577	67.0
	7.5%	–2.4%		9.9%	–3.9%		10.2%	–4.9%		17.6%	–7.0%	
ε_M	112.8	1,343	11.1	117.4	1,276	15.1	120.3	1,393	30.1	138.3	1,430	65.4
	6.2%	–4.8%		8.6%	–9.2%		9.0%	–9.8%		16.6%	–15.7%	
ε_H	111.4	1,294	10.9	116.7	1,163	14.9	118.7	1,281	29.7	136.7	1,222	64.5
	4.8%	–8.3%		7.9%	–17.3%		7.5%	–17.0%		15.3%	–28.0%	

Notes: P^E and Q are the national average residential electricity price ($/MWh) and national residential quantity consumed (TWh), respectively, for the year given. P^A is the allowance price ($/ton CO_2) in the cap-and-trade system for the given year.

Table 12. Regional Policy Simulation Results

Northeast

ε	2012 P^E	2012 Q	2016 P^E	2016 Q	2025 P^E	2025 Q	2035 P^E	2035 Q
ε_L	153.1	182.1	153.9	177.9	149.0	197.5	173.5	212.4
	8.6%	–2.3%	7.0%	–2.9%	0.4%	–1.1%	8.4%	–2.8%
ε_M	152.3	174.8	152.7	169.1	147.0	201.1	171.8	204.5
	8.0%	–6.2%	6.2%	–7.7%	–1.0%	0.7%	7.3%	–6.4%
ε_H	151.5	166.3	152.0	160.8	144.9	204.8	169.6	196.4
	7.5%	–10.8%	5.8%	–12.2%	–2.4%	2.5%	5.9%	–10.0%

South

ε	2012 P^E	2012 Q	2016 P^E	2016 Q	2025 P^E	2025 Q	2035 P^E	2035 Q
ε_L	105.1	674.9	113.8	664.8	122.0	715.3	138.2	774.7
	4.4%	–1.0%	11.0%	–2.9%	16.4%	–5.2%	21.6%	–6.5%
ε_M	103.4	674.0	112.0	636.4	120.2	662.4	136.5	690.4
	2.6%	–1.2%	9.3%	–7.1%	14.6%	–12.2%	20.1%	–16.7%
ε_H	102.2	675.9	111.2	585.7	118.6	572.4	134.7	559.8
	1.5%	–0.9%	8.5%	–14.5%	13.2%	–24.1%	18.5%	–32.5%

Midwest

ε	2012 P^E	2012 Q	2016 P^E	2016 Q	2025 P^E	2025 Q	2035 P^E	2035 Q
ε_L	111.1	281.9	113.6	272.3	103.6	302.5	124.6	317.1
	17.5%	–5.0%	16.9%	–7.3%	4.7%	–5.2%	21.1%	–9.3%
ε_M	109.7	261.3	112.3	242.1	102.2	293.1	122.4	289.5
	16.1%	–12.0%	15.5%	–17.6%	3.3%	–8.1%	19.0%	–17.2%
ε_H	108.0	224.7	110.7	194.1	99.3	287.7	118.7	256.5
	14.3%	–24.3%	13.8%	–33.9%	0.4%	–9.8%	15.3%	–26.7%

West

ε	2012 P^E	2012 Q	2016 P^E	2016 Q	2025 P^E	2025 Q	2035 P^E	2035 Q
ε_L	114.0	237.6	112.5	235.0	120.8	252.1	134.1	273.2
	3.9%	–3.0%	2.2%	–3.5%	8.7%	–6.8%	11.4%	–8.9%
ε_M	114.2	232.4	111.8	228.7	120.5	236.1	134.1	245.3
	4.0%	–5.2%	1.6%	–6.1%	8.5%	–12.7%	11.4%	–18.2%
ε_H	113.0	227.0	110.7	222.0	119.6	216.4	133.6	209.4
	2.9%	–7.4%	0.6%	–8.9%	7.6%	–20.0%	11.0%	–30.2%

Notes: P^E and Q are the average residential electricity price ($/MWh) and total residential quantity consumed (TWh), respectively, for the year and region given.

Energy Economics 34 (2012) 1693–1699

Contents lists available at SciVerse ScienceDirect

Energy Economics

journal homepage: www.elsevier.com/locate/eneco

Residential electricity consumption in Seattle

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A R T I C L E   I N F O

Article history:
Received 25 May 2011
Received in revised form 22 December 2011
Accepted 9 February 2012
Available online 16 February 2012

JEL classifications:
Q41, energy demand
R15, regional econometrics
M21, business economics

Keywords:
Residential electricity consumption
Seattle metropolitan economy
Applied econometrics

A B S T R A C T

Recent empirical research for different regions of the United States indicates that residential electricity may be an "inferior" good whose consumption is negatively correlated with income. That is a provocative result that runs counter to what many earlier econometric studies indicate. Given that, it makes sense to examine how electricity consumption behaves in different regional service areas. Even if residential electricity is an inferior good whose usage declines as income rises, there is no guarantee that this will be the case across all service areas. This study examines residential electricity consumption for Seattle, Washington, the largest metropolitan economy in the northwestern region of the United States. Results from a dynamic error correction modeling approach indicate that residential electricity consumption reacts in statistically significant manners to changes in real price, real income, and cold weather. In the short-run, residential electricity is a normal good in this metropolitan economy. In the long-run, residential electricity appears to be an inferior good in Seattle. All else equal, whenever real per capita income growth exceeds 1.2%, per capita residential electricity usage declines in Seattle.

1. Introduction

Recent empirical evidence indicates that residential electricity is an inferior good at the state level across the United States (Contreras et al., 2009). This is an interesting possibility that is at odds with a number of prior studies but it overlooks the fact that electricity in the United States tends to be generated, transmitted, distributed, and sold within sub-state regional and municipal service areas. Given the latter, there is no guarantee that econometric results obtained from national data samples of state level electricity usage will also be observed within individual electric utility service areas. Material in this study examines residential electricity consumption for Seattle, Washington, the largest metropolitan economy in the northwestern region of the United States.

Seattle is the economic fulcrum of King County, and is the center of entertainment and employment for citizens located in parts of Snohomish, Pierce and Kitsap Counties. Lying on an isthmus between Puget Sound and Lake Washington, Seattle is an economic hub for trade, tourism and technology. Seattle City Light (SCL) is the public electric utility that provides service to number of sub-regions within the Seattle MSA: Burien, Lake Forest Park, Normandy Park, Renton, SeaTac, Seattle, Shoreline, Tukwila, First Hill and University District. A public monopoly, SCL is the sole provider of electricity in this market and is a department within the Seattle city government.

The King County population estimate for 2007 is 1,861,300 residents. King County nominal per capita personal income in 2007 is $57,710 and has grown at a compound annual growth rate of roughly 5.4% from 1969 forward. The 2007 unemployment rate for King County was 3.8%. The median price for existing houses was $284,996. The number of SCL customers in 2007 was 343,542, an increase of 39% from 1960. This market growth has occasionally resulted in significant off-system power purchases. Total electricity consumption in 2007 reached 3,103,550,000 kilowatt hours (KWH). From 1960 through 2007, the SCL nominal average price per KWH increased from $0.00965 to $0.0632.

Seattle is one of the more unique electricity markets in the United States. SCL distributes electricity generated by hydroelectric plants. Its primary off-system purchases are from electricity generated by dams located on the Columbia River. Federal laws favor the supply of electricity from these generators to public utilities and results in relatively low residential rates for SCL consumers. To date, few empirical analyses of SCL residential electricity consumption have been completed and the manner in which residential usage reacts to income gains has not been documented. Accordingly, one possibility investigated in this effort is whether electricity is an inferior good in the SCL market (Contreras et al., 2009; Roth, 1981).

2. Literature review

Earlier empirical work in residential electricity consumption examined whether the inclusion, or exclusion, of either marginal price or average price in demand equations will generate biased parameter estimates and hamper model simulation capabilities. Marginal rates are determined by negotiations between utility suppliers and regulatory oversight bodies regarding specific quantities of purchased electricity. Taylor (1975) argues that both average price and marginal price

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0140-9883/$ – see front matter © 2012 Elsevier B.V. All rights reserved.
doi:10.1016/j.eneco.2012.02.004

should be included in econometric electricity demand studies to capture income and substitution effects, respectively. It has also been argued that, because of the differing marginal rates among various electricity suppliers, employment of either price metric may be acceptable (Fisher and Kaysen, 1962). Cicchetti and Smith (1975) note that average price measures are often employed as a consequence of data constraints. Empirical results reported in that study indicate that approach may be superior to attempting to create marginal rates from representative customer bills. Fisher and Kaysen (1962) utilize average price for a pooled cross sectional time series study of residential electricity consumption in the 48 contiguous states. Anderson (1973) also models residential usage for California with an average price variable. Both studies indicate that decreases in electricity consumption as a response to increases in average price are less than proportional. Price inelastic residential electricity demand has been confirmed in a very large percentage of subsequent empirical studies (Dergiades and Tsoulfidis, 2008).

Among residential electricity studies employing both price metrics is Roth (1981). Equation estimates in that effort rely on data from an individual southwestern region utility in the United States. Results obtained indicate that electricity is an inferior good for the market in question. This is an intriguing result because it implies that higher income levels will not lead to greater electricity consumption by residential customers. Contreras et al. (2009) report a similar result using national residential electricity consumption data and note that the increased energy efficiencies of higher quality, and higher priced, home appliances may contribute to this finding.

Maddigan et al. (1983) estimate rural residential electricity consumption. That study takes into account one important problem with the employment of an average price variable, endogeneity. A price equation is estimated in an attempt to maintain consistency between total revenue and average price. Empirical results obtained are consistent with prior findings documented in other studies (Anderson, 1973; Fisher and Kaysen, 1962; Wilson, 1971). Out-of-sample forecasting results are also found to compare favorably to than those for a benchmark alternative.

Recent research has pointed to several potential shortcomings associated with marginal price approaches. Among them, a problem arises with the assumption that consumers perfectly optimize utility, or more explicitly stated, respond instantaneously to changes in marginal price. Such a perfectly informed customer is rare and unrealistic. Consumers do not respond directly to a change in marginal price, but rather to the price received at the end of a billing period. Such an assumption does not properly reflect consumer response to a block-rate pricing structure (Borenstein, 2009).

Shin (1985) reports evidence that indicates that average electric rate estimates provide accurate information for the analysis of residential electricity consumption. That study emphasizes that consumers may refer only to average rates when pricing structures make accurate marginal rates costly to obtain or understand. Similar approaches have been utilized in the analysis of municipal water utility consumption trends (Fullerton and Molina, 2010). As with electric utilities, the latter approach is frequently employed when block rate schedule and consumption data are incomplete.

A variety of time series approaches, including error correction models (ECMs), have also been employed in several recent efforts (Dergiades and Tsoulfidis, 2008; Hacioglu, 2007; Zachariadis and Pashourtidou, 2007). ECMs examine long-run equilibrium relationships and also introduce past short-run disequilibria as an explanatory variable of the dynamic behavior of current period variables (Maddala and Kim, 1998). Given the comprehensive allowance for both long-run and short-run behavior, ECMs offer some obviously attractive features for the analysis of electricity consumption patterns.

Among the explanatory variables commonly found to assist in the empirical analysis of residential electricity usage are price, income, and climatic measures. Negative income elasticities reported in Narayan et al. (2007) indicate that residential electricity is an inferior good in those economies. Whether those results are universal among all regions in those countries is not known at this juncture. Own-price elasticities tend to be negative and inelastic in a very high percentage of these efforts (Espey and Espey, 2004). The exact nature of climate impacts on electricity consumption varies substantially.

Similar to many northern hemisphere electric utilities, SCL residential peak usage occurs during the winter months. Commonly employed weather variables for demand equations include heating degree days, cooling degree days, and ambient mean temperature (Lam et al., 2008; Narayan et al., 2007; Wangpattarapong et al., 2008; Zachariadis and Pashourtidou, 2007). Residential consumption equations for utilities located in cooler climates frequently use heating degree days (HDD) as regressors and omit cooling degree days from the specifications (Filippini, 1995). Using a base temperature of 65 °F, HDD is calculated as 65 – DAT, where DAT stands for daily average temperature. For days in which the average temperature exceeds 65 °F, HDD is assigned a value of zero.

3. Data and theoretical model

Annual data for the analysis come from SCL annual reports (SCL, 2010). The data are from 1960 to 2007. Consumption data include total residential consumption in megawatt hours (MWH) and the number of customers. Revenue statistics include total revenue, average revenue per customer, and average revenue per kilowatt hour (KWH). As in a number of other studies, average revenue per KWH is used in this effort as the price variable (Espey and Espey, 2004; Shin, 1985).

Under the SCL current pricing structure, the block rates for residential customers are increasing. The rate schedule varies among different cities within the service area because the cost to provide electricity is not uniform across the service area. Because SCL is a public utility, rates are attempted to be set so that no one area subsidizes another. Beyond that, rates are set to solely cover the cost of producing, transmitting, and distributing electricity. This approach to rate setting differs from that of a private utility service provider where profit maximization within a regulated rate environment applies. Data constraints regarding historical and cross-jurisdictional rate schedules prevent calculating marginal price tariffs (Williams and Suh, 1986). In addition to the lack of detailed rates information, historical records for cross-jurisdictional consumption patterns are also incomplete.

Per capita income is used to account for cyclical economic influences on electricity consumption. Per capita income data for Seattle are reported by SCL using information from the United States Bureau of Economic Analysis and the Washington State Employment Security Department. The Seattle consumer price index from the U.S. Bureau of Labor Statistics (BLS) is used to deflate the price and income data (BLS, 2010).

Residential electricity is consumed through surrogates such as televisions, washers, dryers, stoves, personal computers, and other electricity using durable appliances. Space heaters and air conditioners are used to relieve seasonal weather conditions and can increase the amount of electricity consumption for a given household. Historical stock data for these household appliances are lacking. As a result, proxies must be used to account for stock durables and seasonal fluctuations.

The number of customers will be used to account for the stock of consumer durables. As the number of customer households increases, the need to obtain electrical, and other, appliances for everyday living will rise (Dergiades and Tsoulfidis, 2008). Customers are measured as the average numbers of active meters annually billed by the utility (SCL, 2010).

A northern hemisphere city located near the Pacific Ocean, Seattle observes relatively moderate summer temperatures. Dating back to 1960, the average temperatures during the summer months of June, July and August have consistently remained below 70 °F (WRCC, various issues). Given that, cooling degree days is not included in the model specification below. Heating degree days (HDD) data are reported for Seattle (WRCC, various issues) and are used as a surrogate for climatic conditions influencing heating systems use (Dergiades and Tsoulfidis, 2008; Filippini, 1995).

Aggregate residential electricity demand is assumed to be functionally dependent on price, personal income, the number of customers, and climatic factors during cold weather months. Long-run consumption per customer is specified in Eq. (1). In Eq. (1), KWHC is kilowatt hours per customer and YCAP is real per capita income calculated as nominal per capita income divided by the by the Seattle consumer price index reported by the U.S. Bureau of Labor Statistics. PCPI is the SCL average price per kilowatt hour, also deflated by the Seattle consumer price index, HDD is heating degree days, u is a random disturbance term, and t is an annual time period index. Because natural logarithmic transformations are utilized, the parameters represent elasticities of demand.

$$\mathrm{Ln(KWHCt)} = \alpha 0 + \alpha 1\mathrm{Ln}\underset{(+)}{(\mathrm{YCAPt})} + \alpha 2\mathrm{Ln}\underset{(-)}{(\mathrm{PCPIt})} + \alpha 3\mathrm{Ln}\underset{(+)}{(\mathrm{HDDt})} + \mathrm{ut} \tag{1}$$

Numbers in parentheses under Eq. (1) represent the expected signs of the slope coefficients. Growth in real per capita income will increase consumption per customer if residential electricity is a normal good. The latter occurs if increases in real income lead to greater purchases of and more usage of electricity using household devices (Silk and Joutz, 1997). However, as results in other studies indicate (Contreras et al., 2009; Roth, 1981), residential electricity, in some markets, may be an inferior good.

The price coefficient is expected to be negative as increases in price will typically lead to a reduction in the consumption of a good or service. The latter implicitly assumes that electricity consumption will not be conspicuous in nature (Grinblatt et al., 2008). The parameter sign for HDD is hypothesized as positive sign because ambient temperatures below the baseline mark (65 °F) will increase the need for heating (Dergiades and Tsoulfidis, 2008).

The long-run relationship shown above is known as the cointegrating equation. It represents how equilibrium per customer electricity consumption evolves over time. Deviations away from long-run consumption equilibrium can occur due to a variety of circumstances such as aging household appliance stocks, income shocks, and other factors (Greening and Sanstad, 1996). Those deviations will generally begin to dissipate in the quarter after when they occur, but may not completely be offset for several periods. Any deviation from the long-run equilibrium will, therefore, affect subsequent short-run consumption patterns.

Eq. (2) permits examining short-run characteristics of residential electricity consumption that take into account the potential impact of consumption deviations relative to the long-run. In Eq. (2), d is a difference operator and v_t is a random disturbance term. The error correction term is u_{t-1}, the prior period disturbance from the cointegrating equation. Numbers in parentheses below Eq. (2) indicate the hypothesized for the respective parameters. The coefficient for the error correction term is expected to be less than zero since deviations from equilibrium consumption levels will precipitate offsetting adjustments in the subsequent period. The speed of adjustment to any prior quarter shocks will depend upon the magnitude of b4. Because many electrical appliances are highly durable and expensive, one potential source of residential consumption disequilibria is a relatively slow appliance stock replacement rate.

$$\mathrm{dLn(KWHC_t)} = b_0 + b_1\mathrm{dLn}\underset{(+)}{(\mathrm{YCAP_t})} + b_2\mathrm{dLn}\underset{(-)}{(\mathrm{PCPI_t})} + b_3\mathrm{dLn}\underset{(+)}{(\mathrm{HDD_t})} + \underset{(-)}{b_4 u_{t-1}} + v_t \tag{2}$$

For nearly all public utilities, understanding changes in the numbers of customers from period to period is fairly important. Growth in the number of accounts requires planning for the service expansion as new meters, sub-stations, and distribution lines must be installed for new neighborhoods and residences. Accordingly, an equation is also specified for the number of customers. In many cases, utility customer base increases will be affected by both demographic and economic trends and developments (Fullerton et al., 2007). Such an approach is utilized in the error correction framework shown below for SCL residential accounts. In Eq. (3), POP is defined as the population of the SCL service area and EMP stands for non-agricultural wage and salary employment, also in the SCL service area. Both explanatory variables are expected to be positively correlated with the number of SCL residential customers.

$$\mathrm{LnCSTM_t} = c_0 + c_1\mathrm{Ln}\underset{(+)}{(\mathrm{POP_t})} + c_2\mathrm{Ln}\underset{(+)}{(\mathrm{EMP_{t-1}})} + g_t \tag{3}$$

The short-run error correction specification is shown in Eq. (4). Numbers in parentheses indicate the hypothesized signs for each of the parameters in the equation. Disequilibria in the customer base may result from delays in housing construction and/or problems faced by new migrant in acquiring new residences within the SCL service area. Any prior-period deviation away from the equilibrium number of customers is expected to be partially offset in the subsequent year. The time required to total dissipation will depend upon the magnitude of f_3 in Eq. (4).

$$\mathrm{dLnCSTM_t} = f_0 + f_1\mathrm{dLn}\underset{(+)}{(\mathrm{POP_t})} + f_2\mathrm{dLn}\underset{(+)}{(\mathrm{EMP_{t-1}})} + \underset{(-)}{f_3 g_{t-1}} + h_t \tag{4}$$

4. Estimation results and empirical analysis

Because KWH consumed appears on both sides of Eq. (1), the manner in which the average price variable is calculated raises the specter of potential simultaneity. An artificial regression procedure is used to test this possibility (Davidson and MacKinnon, 1989). The null hypothesis tested is that the average price variable (PCPI) does not have an endogenous relationship with the kilowatt-hour per customer dependent variable (KWHC). If that hypothesis is rejected, it implies that ordinary least squares estimates of Eq. (1) will be inconsistent. This bi-directional relationship could generate a contemporaneous correlation between the endogenous independent price variable and the error-term (Pindyck and Rubinfeld, 1998).

To carry out the endogeneity test, two instrumental variables are utilized. The first is the national fixed asset price deflator for electric power structures (STRUC). That variable is selected because SCL's rates and revenues are based upon operating and capital costs of the federal electric power system. The latter is principally comprised by dams and transmission facilities (Lee et al., 1980). The second instrument is the national electricity price index (ELECP). National electricity prices affect the rate SCL is charged for off-system power purchases, and the rate SCL charges other electricity utility companies. Both of the instrumental variables are obtained from the Bureau of Economic Analysis national income and product account tables (BEA, 2010).

The null hypothesis, H0, that PCPI is not correlated with the error-term in Eq. (1) is rejected at the 1-percent level. That is similar to what has been documented in earlier electricity studies (Henson, 1984; Wilder and Willenborg, 1975). Given the simultaneity outcome, a price equation is estimated to provide fitted price values (PCPIHAT). The specification for the latter is shown in Eq. (5). It utilizes two of the exogenous variables from Eq. (1) plus both of the instrumental variables employed in the artificial regression test. Although SCL is one of the larger public utilities in the United States, it not so large that its rates would influence either of the instruments. Fitted values, PCPIHAT, from the estimated version of Eq. (5) provide

Table 1
Residential electricity consumption in Seattle.

Variable name	Definition
KWHC	Kilowatt hours per customer
YCAPC	Real per capita personal income
PCPIHAT	Fitted values for average electricity price
HDD	Heating degree days
RESIDLR	Residual error term from long-run kilowatt hours per customer equation
POP	Population
EMP	Employment

the average price measure used in the empirical results shown below (estimation results for Eq. (5) are available from the authors).

$$\mathrm{LnPCPIt} = \mathrm{C0} + \mathrm{C1LnYCAPCt} + \mathrm{C2LnHDDt} + \mathrm{C3LnSTRUCt} + \mathrm{C4LnELECPt} + \mathrm{mt} \tag{5}$$

Table 1 lists all of the variable names assigned to the data used for the empirical analysis. Table 2 reports the estimation results for cointegrating demand function in Eq. (1) with the fitted values for the average price variable, PCPIHAT. The modified long-run demand specification is shown in Eq. (6). Each of the coefficient estimates satisfies the 5-percent significance criterion. Overall diagnostics shown in Table 2 are favorable. Although the Durbin–Watson statistic indicates that the residuals are positively correlated, experimentation with a variety of alternative specifications including both autoregressive and moving average coefficients did not yield superior results (Pagan, 1974). A unit root test confirms that a cointegrating relationship exists (Kennedy, 2003).

$$\mathrm{Ln}(\mathrm{KWHC_t}) = \alpha_0 + \alpha_1\mathrm{Ln}(\mathrm{YCAPC_t}) + \alpha_2\mathrm{Ln}(\mathrm{PCPIHAT_t}) + \alpha_3\mathrm{Ln}(\mathrm{HDD_t}) + \mathrm{u_t} \tag{6}$$

Real average price (PCPIHAT) and annual heating degree days (HDD) exhibit the hypothesized signs. An increase in the real price leads to reduced residential electricity use. The magnitude of the price elasticity is somewhat lower, in absolute terms, than some of those reported other in other recent studies (Hacioglu, 2007; Narayan et al., 2007; Zachariadis and Pashourtidou, 2007). It is, however, well within the range of price elasticities that have been historically estimated for residential electricity usage (Espey and Espey, 2004).

Results for the cointegrating equation in Table 2 indicate that cold weather leads Seattle residents to increase electricity consumption. A 1-percent increase in annual heating degree days (HDD) increases residential usage by approximately 0.3%. This elasticity estimate is in line with those reported in similar analyses (Dergiades and Tsoulfidis, 2008). Interestingly, Maddigan et al. (1983) find that rural customers in the northwest region respond more to fluctuations in temperature than to changes in price. To the extent that climate change may lead to more extreme low temperatures during the winter months, the HDD coefficient indicates that SCL residential demand may grow substantially in future years (Zachariadis, 2010).

In Table 2, the negative sign for the real per capita income (YCAPC) parameter indicates that, over the long-run, residential electricity is an inferior good within the SCL service area. That result differs from many studies, but has been documented for other regional electricity markets in the United States (Contreras et al., 2009; Roth, 1981). Over the long-run, a 1% increase in real per capita income is associated with a 0.29% reduction in SCL household electricity consumption. If Seattle metropolitan economy per capita incomes improve in real terms, as they have over the course of four plus decades, SCL residential sales will place less of a burden on the overall system load than otherwise would generally be anticipated.

Results for the short-run parameter estimates are shown in Table 3. All of the computed *t*-statistics for the regressor coefficients satisfy the 5-percent criterion. The statistically significant and negative constant term implies that SCL residential electricity usage has become steadily more efficient over the course of the sample period. The real per capita income (YCAPC) coefficient is positive, indicating that SCL household customers treat electricity as a normal good in the short-run. Because appliance stocks are largely fixed in the short-run, that is a reasonable outcome. The price (PCPIHAT) elasticity in Table 3 is negative and smaller, in absolute magnitude, than its long-run counterpart above (Dergiades and Tsoulfidis, 2008). The climate (HDD) coefficient indicates that SCL residential electricity consumption is fairly sensitive to ambient temperature declines. The latter result potentially reflects the high number of electric heating systems found in the Seattle metropolitan economy.

The residual series from the long-run estimation is used as a proxy for deviations from the long-run consumption equilibrium. As hypothesized, the sign of the error-correction parameter is less than zero. The magnitude of that coefficient indicates that approximately 19.2% of any adjustment toward consumption equilibrium occurs during the first year following a deviation from it. A total of approximately 5.2 years are required for any prior-period consumption deviations away from the equilibrium level to fully dissipate.

To test the stability of the long-run coefficients, cumulative sum (CUSUM) and cumulative sum of squares tests (CUSUMQ) are carried out on the residuals of the error-correction model specified in Eq. (6). A CUSUM stability test measures the systematic movements of the coefficients. The null hypothesis tested is that of coefficient stability. H0 is rejected if the cumulative sum exceeds the specified critical boundaries, demonstrating instability among the coefficients (Maddala and Kim, 1998). A CUSUMQ test measures variance stability. Both tests reveal coefficient and variance stability as the residuals and squared residuals move within their respective 5-percent critical boundaries, failing to reject the respective null hypotheses.

Table 2
Long-run demand equation for kilowatt-hours per capita.

Variable	Coefficient	Standard error	*t*-statistic	Probability
Constant	9.9760	1.4079	7.0852	0.0000
LN(YCAPC)	−0.2947	0.0780	−3.7770	0.0006
LN(PCPIHAT)	−0.3656	0.0884	−4.1327	0.0002
LN(HDD)	0.3030	0.1185	2.5565	0.0151
R-squared	0.8812	Dependent variable mean		9.3248
Adjusted *R*-squared	0.8710	Dep. var. standard dvn.		0.1278
Std. err. of regression	0.0459	Akaike inf. criterion		−3.2276
Sum of squared residuals	0.0737	Schwarz inf. criterion		−3.0570
Log likelihood	66.9398	Hannan–Quinn criterion		−3.1664
F-statistic	86.5514	Durbin–Watson statistic		0.4389
Probability (*F*-statistic)	0.0000			

Method: least squares. Sample (adjusted): 1969, 2007. Included observations: 39 after adjustments.

Table 3
Short-run demand equation for kilowatt-hours per capita.

Variable	Coefficient	Standard error	*t*-statistic	Probability
Constant	−0.0106	0.0043	−2.4366	0.0204
D(LN(YCAPC))	0.2614	0.1291	2.0250	0.0510
D(LN(PCPIHAT))	−0.2442	0.0803	−3.0377	0.0046
D(LN(HDD))	0.3388	0.0464	7.2964	0.0000
RESIDLR(−1)	−0.1923	0.0881	−2.1805	0.0365
R-squared	0.6732	Dependent variable mean		−0.0082
Adjusted *R*-squared	0.6336	Dep. var. standard dvn.		0.0380
Std. err. of regression	0.0230	Akaike inf. criterion		−4.5807
Sum of squared residuals	0.0175	Schwarz inf. criterion		−4.3653
Log likelihood	92.0347	Hannan–Quinn criterion		−4.5041
F-statistic	16.9987	Durbin–Watson statistic		2.4214
Probability (*F*-statistic)	0.0000			

Method: least squares. Sample (adjusted): 1970, 2007. Included observations: 38 after adjustments.

A natural question arises with respect to the seemingly contradictory short-run and long-run income elasticities reported in Tables 2 and 3. At least part of the explanation probably relates to technological advances in energy efficiency (Borg and Kelly, 2011). Income growth is strongly influenced by technological progress (see, for example, Venturini, 2009). Changes in technology and energy efficiency would not, however, be correlated with short-run transitory fluctuations in personal income. Consequently, long-run income gains are likely to be inversely related to household electricity usage, but short-run income variations will be positively correlated with electricity consumption. Based on the estimation results reported in Tables 2 and 3, whenever real per capita income grows by approximately 1.2% or more, residential electricity usage per capita should, all else equal, decline.

The investment requirements associated with capacity development make it important for public utilities to anticipate service growth. To do so requires understanding how the customer base is likely to expand. Population and employment are used as the explanatory variables to account for both economic and demographic factors affecting SCL residential customer growth. The basic specification shown above in Eq. (3) has also been applied to water utility accounts models (Fullerton et al., 2007). Estimation results for Eq. (3) appear in Table 4 and exhibit fairly good statistical traits.

The coefficient of determination, adjusted for degrees of freedom, indicates that approximately 97 percent of the variation in the dependent variable is explained by the equation. The computed *t*-statistics for the regression parameters all satisfy the 5-percent criterion. The slope coefficient magnitudes indicate that 1-percent increases in SCL service area population and/or employment increase the customer base by approximately 0.46%, each. The Durbin–Watson statistic suggests the presence of positive serial correlation. Estimation of an autocorrelation function (ACF) also indicates the presence of serial correlation. In spite of the latter, a variety of autoregressive, moving average, and mixed nonlinear specifications yield coefficients that fail to satisfy the 5-percent criterion (Pagan, 1974). A unit root test conducted with the residuals confirms that a cointegrating relationship exists (Kennedy, 2003). To test for consistency of the long-run multipliers, CUSUM and CSUMSQ tests are run (Maddala and Kim, 1998). Both of those tests indicate coefficient stability for the outcomes reported in Table 4.

A short-run error correction equation is also estimated for SCL residential customers using the specification shown above in Eq. (4). Estimation results are reported for it in Table 5. The statistically significant constant term reflects steady annual increases in the number of SCL residential customers. The parameter estimate for population is not significantly different from zero. The latter is not surprising since many population changes such as births, deaths, household departures, or new arrivals do not necessarily result in either more or fewer SCL residential accounts.

Table 5
Short-run equation for SCL residential customer base.

Variable	Coefficient	Standard Error	*t*-statistic	Probability
Constant	0.0091	0.0014	6.3074	0.0000
D(LN(POP))	0.1000	0.1757	0.5693	0.5731
D(LN(EMP(−1))	0.0974	0.0427	2.2815	0.0293
RESIDCS(−1)	0.0564	0.0592	0.9530	0.3477
R-squared	0.1583	Dependent variable mean		0.0112
Adjusted *R*-squared	0.0794	Dep. var. standard dvn.		0.0073
Std. err. of regression	0.0070	Akaike inf. criterion		−6.9686
Sum of squared residuals	0.0015	Schwarz inf. criterion		−6.7926
Log likelihood	129.4352	Hannan–Quinn criterion		−6.9072
F-statistic	2.0069	Durbin–Watson statistic		2.1264
Probability (*F*-statistic)	0.1327			

Method: least squares. Sample (adjusted): 1972, 2007. Included observations: 36 after adjustments.

The coefficient estimated for lagged employment does satisfy the 5-percent significance criterion. That result also makes practical sense. New employment is more likely to lead to new customer accounts than is population gain. The converse also holds, an important point for a fairly cyclical economy such as Seattle's. The error correction parameter in Table 5 is not significantly different from zero. The overall results for Table 5 indicate that short-run variations in the SCL residential customer base are not easily modeled, but grow steadily and are affected by prior period employment changes.

As an additional step toward examining empirical reliability of the estimation results, a 3-period out-of-sample forecast is simulated for KWHC and CSTM. The forecast period employs the compound annual growth rates (CAGR) from 2004 to 2007 for each of the respective explanatory variables. This follows the Lakhani and Bumb (1978) approach for basic electricity forecasting assessment. HDD is the only variable for which no growth is assumed and the historical mean of 4837 is used (Fullerton and Molina, 2010). It should be noted that the CAGR historical sample occurred before the financial market collapse of 2008 and the simulation is not intended to examine the cyclical extrapolation properties of the residential equations for the SCL service area.

Table 6 reports the estimated CAGRs for each of the explanatory variables. Real per capita income has a CAGR of 1.375%. The CAGR for the fitted price variable, PCPIHAT is −2.339%. The SCL nominal price per KWH decreased by 0.842% from 2004 to 2007. That, in combination with the increases in the Seattle CPI, results in a real price per KWH CAGR decline of 2.339%. Population in the SCL service area increased at a CAGR of 0.413%. Employment rose 1.7854% exceeding the population growth experienced over that same 3-year period.

Table 7 reports the forecasts for the dependent variables and their respective percentage changes between the forecast periods. Because the effects of the real price decline outweigh the impacts of the real income growth, kilowatt-hours per customer are forecast grow from

Table 4
Long-run cointegrating equation for SCL residential customer base.

Variable	Coefficient	Standard error	*t*-statistic	Probability
Constant	6.7348	0.5841	11.5291	0.0000
LN(POP)	0.4601	0.1086	4.2362	0.0002
LN(EMP(−1))	0.4628	0.0275	16.8152	0.0000
R-squared	0.9706	Dependent variable mean		12.5485
Adjusted *R*-squared	0.9688	Dep. var. standard dvn.		0.1255
Std. err. of regression	0.0166	Akaike inf. criterion		−4.7056
Sum of squared residuals	0.0166	Schwarz inf. criterion		−4.5750
Log likelihood	90.0552	Hannan–Quinn criterion		−4.6596
F-statistic	561.7165	Durbin–Watson statistic		0.3853
Probability (*F*-statistic)	0.0000			

Method: least squares. Sample (adjusted): 1971 2007. Included observations: 37 after adjustments.

Table 6
Explanatory variable growth.

	YCAPC	PCPIHAT	HDD	POP	EMP
CAGR (%)	*1.375*	*−2.339*	*0.000*	*0.413*	*1.785*
Year 1	24,942	2.9503	4,837	749.282	592.798
Year 2	25,286	2.8813	4,837	752.376	603.382
Year 3	25,633	2.8139	4,837	755.482	614.154

Notes:
Percentage compound annual growth rates, CAGR%, for 2004 to 2007 for each explanatory variable are italicized.
Per capita income, YCAPC, is shown in real dollars, 1982–84 = 100.
Price per kilowatt hour, PCPIHAT, is shown in real cents per KWH.
HDD stands for annual heating degree days.
Population, POP, and employment, EMP, are measured in thousands for the SCL service area.
Data may not match due to rounding.

Table 7
SCL residential consumption and customer forecasts.

YR	KWHC	%Δ	MWH	%Δ	CSTM	%Δ
1	9579	–	3,227,634	–	336,949	–
2	9623	0.46	3,275,332	1.48	340,365	1.01
3	9668	0.47	3,324,013	1.49	343,816	1.01

Notes:
KWHC is kilowatt-hours per customer.
MWH is megawatt-hours.
CSTM is the number of residential customers.

9,579 in Year 1 to 9,668 in Year 3. SCL residential customers grow by approximately 1.0% per year, reaching 343.8 thousand by the third year of the simulation. Together, the per capita consumption and customer base growth patterns imply that SCL residential MWH usage would expand by approximately 1.5% per year. Those forecasts fall within observable historical norms for the residential rate class of this electric utility, indicating that model simulation performance is at least plausible for recently observed conditions in the Seattle metropolitan economy.

5. Conclusion

To analyze residential electricity demand in the Seattle City Light service area, error-correction models are estimated for per customer consumption and the number of residential customer accounts. Price is approximated using a cent per kilowatt hour average revenue measure. Not surprisingly, artificial regression test outcomes indicate simultaneity exists between the consumption and price variables. Consequently, fitted price values from an instrumental variables equation are utilized for the long-run and short-run per customer consumption equations.

Similar to what has been documented for other regions, SCL residential consumption responds in an inelastic manner to price changes, especially so in the short-run. The cointegrating equation income elasticity is negative and statistically significant, indicating that electricity is an inferior good in Seattle over the long-run. That outcome has also been reported for other residential electricity markets and for the United States as a whole. The error correction equation income elasticity is positive, indicating that SCL residential customers treat electricity as a normal good in the short-run.

Planning for new customers is a major concern for utility companies. Determining the increase in the number of customers is important in planning for the expansion of service, as new meters and distribution lines must be installed for new residencies. The number of customers is modeled as a function of population and lagged employment. The cointegrating equation results indicate that both population and employment affect the SCL customer base over the long-run. The error correction equation attributes short-run customer base changes to employment fluctuations rather than population, potentially reflecting the impacts of migration on the electricity grid.

Out-of-sample simulations indicate that forecasts generated with estimated equations are reasonable. Accordingly, long-run increases in personal income will potentially not translate into greater SCL load demands in the manner that has been reported for other electric utilities. That can help alleviate pressures to augment generation resources. Whether this holds for other metropolitan economies is not known, but recent empirical evidence points to a long-run negative correlation between household incomes and residential electricity usage. That, in combination with careful rate setting, may allow existing generation capacity to accommodate more regional economic expansion than might otherwise be expected.

Acknowledgements

Financial support for this research was provided by El Paso Electric Company, Hunt Companies of El Paso, Hunt Communities, Texas Department of Transportation, JPMorgan Chase Bank of El Paso, a UTEP College of Business Administration Faculty Research Grant, and the James Foundation Scholarship Fund. Helpful comments were provided by Doyle Smith, Joe Guthrie, Richard Tol, and an anonymous referee. Econometric research assistance was provided by Carlos Morales and Francisco Pallares.

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Renewable and Sustainable Energy Reviews 13 (2009) 1819–1835

Contents lists available at ScienceDirect

Renewable and Sustainable Energy Reviews

journal homepage: www.elsevier.com/locate/rser

Modeling of end-use energy consumption in the residential sector: A review of modeling techniques

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ARTICLE INFO

Article history:
Received 9 September 2008
Accepted 30 September 2008

Keywords:
Residential energy model
Residential energy consumption
Housing energy model
Energy model

ABSTRACT

There is a growing interest in reducing energy consumption and the associated greenhouse gas emissions in every sector of the economy. The residential sector is a substantial consumer of energy in every country, and therefore a focus for energy consumption efforts. Since the energy consumption characteristics of the residential sector are complex and inter-related, comprehensive models are needed to assess the technoeconomic impacts of adopting energy efficiency and renewable energy technologies suitable for residential applications.

The aim of this paper is to provide an up-to-date review of the various modeling techniques used for modeling residential sector energy consumption. Two distinct approaches are identified: top-down and bottom-up. The top-down approach treats the residential sector as an energy sink and is not concerned with individual end-uses. It utilizes historic aggregate energy values and regresses the energy consumption of the housing stock as a function of top-level variables such as macroeconomic indicators (e.g. gross domestic product, unemployment, and inflation), energy price, and general climate. The bottom-up approach extrapolates the estimated energy consumption of a representative set of individual houses to regional and national levels, and consists of two distinct methodologies: the statistical method and the engineering method.

Each technique relies on different levels of input information, different calculation or simulation techniques, and provides results with different applicability. A critical review of each technique, focusing on the strengths, shortcomings and purposes, is provided along with a review of models reported in the literature.

Contents

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doi:10.1016/j.rser.2008.09.033

Nomenclature

Acronyms

AEEI	autonomous energy efficiency index
AL	appliances and lighting
ALC	appliances, lighting and cooling
ASHRAE	American Society of Heating, Refrigeration and Air-conditioning Engineers
BEAM	Built Environment Analysis Model
CBECS	Commercial Buildings Energy Consumption Survey
CDA	conditional demand analysis
DHW	domestic hot water
EM	engineering method
EPI	energy performance index
GA	genetic algorithm
GDP	gross domestic product
GIS	geographical information systems
HAP	Hourly Analysis Program
HDD	heating degree days
NEMS	National Energy Modeling System
NN	neural network
SC	space cooling
SH	space heating
SM	statistical method
UEC	unit energy consumption

Symbols

b	constant
B	billing data
c	coefficient
C	appliance ownership (presence or count)
E	energy consumption
HDD	heating degree days
I	income
Pc	price
R	appliance rating
R^2	multiple correlation coefficient
S	housing stock
T	temperature
U	use factor
V	array of interaction variables

Subscripts

an	annual
app	appliance
dis	disposable
e	end-use group
f	fuel type
i	array element location
mo	monthly
ref	reference
t	time or period of time

1. Introduction

Nationally, energy consumption of the residential sector accounts for 16–50% of that consumed by all sectors, and averages approximately 30% worldwide as shown in Fig. 1. This significant consumption level warrants a detailed understanding of the residential sector's consumption characteristics to prepare for and help guide the sector's energy consumption in an increasingly energy conscience world; conscience from standpoints of supply, efficient use, and effects of consumption. In response to climate change, high energy prices, and energy supply/demand, there is interest in understanding the detailed consumption characteristics of the residential sector in an effort to promote conservation, efficiency, technology implementation and energy source switching, such as to on-site renewable energy.

Energy consumption of other major sectors such as commercial, industrial, agriculture and transportation are better understood than the residential sector due to their more centralized ownership, self-interest and expertise in reducing energy consumption, and high levels of regulation and documentation. The residential sector is largely an undefined energy sink due to the following reasons:

- The sector encompasses a wide variety of structure sizes, geometries and thermal envelope materials.
- Occupant behaviour varies widely and can impact energy consumption by as much as 100% for a given dwelling [2].
- Privacy issues limit the successful collection or distribution of energy data related to individual households.
- Detailed sub-metering of household end-uses has prohibitive cost.

The residential sector consumes secondary energy. Secondary energy is that received in suitable form for use by the consuming systems to support the living standards of occupants. The major end-use groups of secondary energy are:

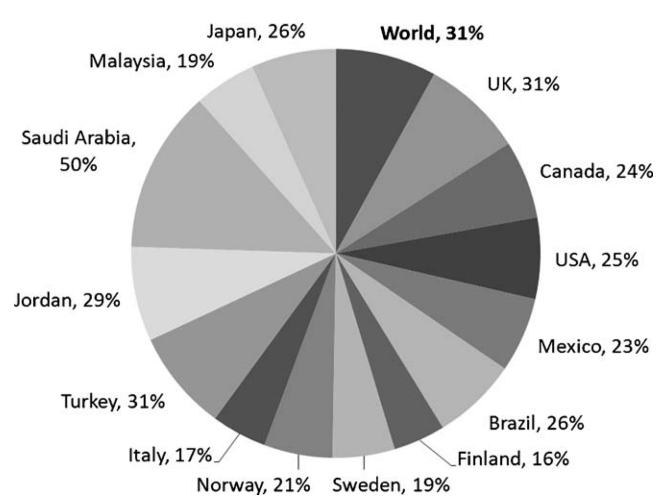

Fig. 1. Residential energy consumption shown as a percentage of national energy consumption and in relative international form [1].

- Space heating (SH) and space cooling (SC)—energy required to support thermal losses incurred across the building envelope due to conduction and radiation, as well as air infiltration/ventilation in an effort to maintain the living space at a comfortable temperature and air quality.
- Domestic hot water (DHW)—energy required to heat water to a comfortable or appropriate temperature for occupant and appliance uses.
- Appliances and lighting (AL)—energy consumed to operate common appliances (e.g. refrigerator and coffee maker) and for the provision of adequate lighting.

The degree to which these groups affect the overall energy consumption is highly dependent on climate, physical dwelling characteristics, appliance and system characteristics, ownership, and occupant behaviour.

The total energy consumption of a dwelling is that required to support all energy consuming end-uses, inclusive of the losses due to appliance and system efficiencies. The end-uses may have complex inter-related effects with regards to energy consumption. For example, the energy consumption of most common appliances results in heating of the conditioned living area. The energy consumption can be supplied by one or more secondary energy sources and includes on-site generation and passive solar gains. The sum of each dwelling's energy consumption for a given area (e.g. city and country) results in a regional or national residential sector energy consumption, the modeling of which is the topic of interest for this review.

Energy consumption modeling of buildings seeks to quantify energy requirements as a function of input parameters. Models may be used for a variety of reasons, the most common being the determination of regional or national energy supply requirements (macro-scale) and the change in energy consumption of a particular dwelling due to an upgrade or addition of technology (micro-scale). Modeling of this nature is useful as it can guide decisions of policy regarding the residential stock, both old and new. By quantifying the consumption and predicting the impact or savings due to retrofits and new materials and technology, decisions can be made to support energy supply, retrofit and technology incentives, new building code, or even demolition and re-construction.

Residential energy models may focus on a thermal zone, building, neighbourhood, city, state or province, region, or nation. The level of detail of input parameters is a function of data availability, model focus and purpose, and assumptions. Increased detail allows for a more comprehensive investigation of particulars, although accurate assumptions may significantly ease the modeling process and provide suitable results.

Emphasis of this review is placed on models that are or could be used to model the residential sector energy consumption. Energy consumption models of this scope involve an approximation of the residential stock and a methodology for estimating the energy consumption of the stock. Such models are useful to formulate policy decisions regarding the residential stock, both old and new. By quantifying the consumption and predicting the impact or savings due to construction/demolition, retrofits and new materials and technology, decisions can be made to support energy supply, retrofit and technology incentives, new building codes, or even demolition and re-construction. This review of residential sector energy consumption models introduces the modeling techniques, reviews the published literature and concludes with an analysis of the strengths and weaknesses of the techniques.

2. Objective

The objective of this paper is to provide an up-to-date review of the various modeling techniques used for modeling residential sector energy consumption. Two distinct approaches are identified: top-down and bottom-up. Each technique relies on different levels of input information, different calculation or simulation techniques, and provides results with different applicability. A critical review of each technique, focusing on the strengths, shortcomings and purposes, is provided along with a review of models reported in the literature.

3. Modeling methodologies

Residential energy models rely on input data from which to calculate or simulate energy consumption. The level of detail of the available input data can vary dramatically, resulting in the use of different modeling techniques which seek to take advantage of the available information. These different modeling techniques have different strengths, weaknesses, capability, and applicability.

3.1. Types and sources of information

Depending on the modeling methodology to be used, the input data required to develop residential energy models includes information on the physical characteristics of the dwellings, occupants and their appliances, historical energy consumption, climatic conditions, and macroeconomic indicators. The information can be collected independently or concurrently, can be national aggregate or individual dwelling values, and vary greatly in level of detail. The basic information collection method is by survey, the results of which are published in raw or analyzed form.

The preliminary estimate of the total residential sector energy consumption is usually published by governments which compile gross energy values submitted by energy providers (examples are Canada [3], USA [4], UK [5], and China [6]). These estimates provide indicators as to sector energy consumption but may be inaccurate as they do not account for unreported energy or on-site generation. A more detailed source of energy consumption data, typically on a monthly basis and for each dwelling, is the billing records of energy suppliers (e.g. monthly dwelling electricity bill). However, with no additional housing information these energy consumption values are difficult to correlate due to the wide variety of dwellings and occupants.

To provide more detailed information than the above aggregate values, housing surveys are conducted. These surveys target a sample of the population to determine building and occupant characteristics and appliance penetration levels (examples are Canada [7], USA [8], and UK [9]). The Tyndall Centre conducted a worldwide review of such surveys [10]. Surveys typically attempt to define the house geometry and thermal envelope, ownership of appliances, occupants and their use of appliances and preferred settings, and demographic characteristics. In addition, surveys may attempt to obtain the energy suppliers' billing data (described above) and alternative energy source information (e.g. unreported wood usage) to correlate the energy consumption of the house with its characteristics identified during the survey. This allows for calibration through reconciliation of a model's predicted energy consumption with actual energy billing data. This level of information is superior to the previously mentioned energy supplier values; however, it is limited due to collection difficulties and cost, and therefore it is imperative that the selected sample be highly representative of the population. Also, occupant descriptions of their appliance use are highly subjective and can be influenced by the season during which the survey takes place [7]. Examples of surveys which have been condensed for the purpose of energy simulation are [11,12].

Elimination of subjective appliance usage estimation is achieved by "sub-metering". This method places energy metering devices on the large energy consuming appliances within the household to determine both their component of the house energy consumption and their usage profile as a function of time (e.g. [13]). This level of information is rare due to its prohibitive cost.

Estimated total sector energy, individual billing data, surveys, and sub-metering have been used to varying degrees in the development of residential energy consumption models. The determination of which information is used depends on availability and model's purpose. The purpose of models ranges widely and may be directed towards determining supply requirements, price and income elasticity, and the energy consumption impacts of upgrades, technologies, or changes to behavioural patterns.

3.2. Techniques to model energy consumption

Techniques used to model residential energy consumption can broadly be grouped into two categories, ''top-down'' and ''bottom-up''. The terminology is with reference to the hierarchal position of data inputs as compared to the housing sector as a whole. Top-down models utilize the estimate of total residential sector energy consumption and other pertinent variables to *attribute* the energy consumption to characteristics of the entire housing sector. In contrast, bottom-up models *calculate* the energy consumption of individual or groups of houses and then extrapolate these results to represent the region or nation.

Groupings of top-down and bottom-up techniques for modeling residential energy consumption are shown in Fig. 2 and are discussed in the following sections.

3.2.1. Overview of the top-down approach

The top-down approach treats the residential sector as an energy sink and does not distinguish energy consumption due to individual end-uses. Top-down models determine the effect on energy consumption due to ongoing long-term changes or transitions within the residential sector, primarily for the purpose of determining supply requirements. Variables which are commonly used by top-down models include macroeconomic indicators (gross domestic product (GDP), employment rates, and price indices), climatic conditions, housing construction/demolition rates, and estimates of appliance ownership and number of units in the residential sector.

Fig. 2 shows two groups of top-down models: *econometric* and *technological*. Econometric models are based primarily on price (of, for example, energy and appliances) and income. Technological models attribute the energy consumption to broad characteristics of the entire housing stock such as appliance ownership trends. In addition there are models which utilize techniques from both groups.

Top-down models operate on an equilibrium framework which balances the historical energy consumption with that estimated based on input variables. The strengths of top-down modeling are the need for only aggregate data which are widely available, simplicity, and reliance on historic residential sector energy values which provide ''inertia'' to the model. As the housing sector rarely undergoes paradigm shifts (e.g. electrification and energy shocks), a weighted model provides good prediction capability for small deviations from the status quo. For example, if housing construction increased the number of units by 2%, an increase in total residential energy consumption of 1.5% might be estimated by the top-down model, as new houses are likely more energy efficient. If this construction was increased to 10% of the units the top-down model could have difficulty in producing an appropriate estimate as the vintage distribution of the housing stock would have changed significantly.

The reliance on historical data is also a drawback as top-down models have no inherent capability to model discontinuous advances in technology. Furthermore, the lack of detail regarding the energy consumption of individual end-uses eliminates the capability of identifying key areas for improvements for the reduction of energy consumption.

3.2.2. Overview of the bottom-up approach

The bottom-up approach encompasses all models which use input data from a hierarchal level less than that of the sector as a whole. Models can account for the energy consumption of individual end-uses, individual houses, or groups of houses and are then extrapolated to represent the region or nation based on the representative weight of the modeled sample. The variety of data inputs results in the groups and sub-groups of the bottom-up approach as shown in Fig. 2.

Statistical methods (SM) rely on historical information and types of regression analysis which are used to attribute dwelling energy consumption to particular end-uses. Once the relationships between end-uses and energy consumption have been established, the model can be used to estimate the energy consumption of dwellings representative of the residential stock. *Engineering* methods (EM) explicitly account for the energy consumption of end-uses based on power ratings and use of equipment and systems and/or heat transfer and thermodynamic relationships.

Common input data to bottom-up models include dwelling properties such as geometry, envelope fabric, equipment and appliances, climate properties, as well as indoor temperatures, occupancy schedules and equipment use. This high level of detail is a strength of bottom-up modeling and gives it the ability to model technological options. Bottom-up models have the capability of determining the energy consumption of each end-use and in doing so can identify areas for improvement. As energy consumption is calculated, the bottom-up approach has the capability of determining the total energy consumption of the residential

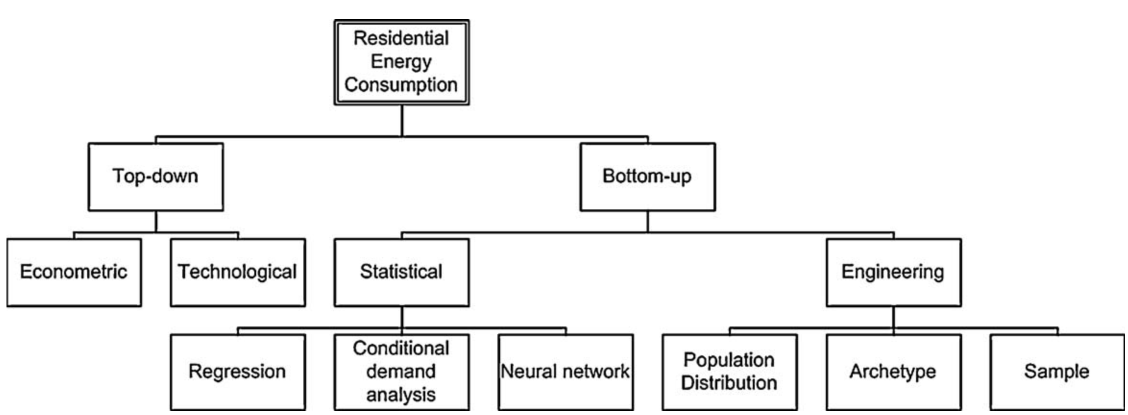

Fig. 2. Top-down and bottom-up modeling techniques for estimating the regional or national residential energy consumption.

sector without relying on historical data. The primary drawback caused by this level of detail is that the input data requirement is greater than that of top-down models and the calculation or simulation techniques of the bottom-up models can be complex.

In all cases the bottom-up models must be extrapolated to represent the housing sector. This is accomplished using a weighting for each modeled house or group of houses based on its representation of the sector.

A notable capability of the bottom-up approach is its ability to explicitly address the effect of occupant behaviour and "free energy" gains such as passive solar gains. Although free energy gains have historically been neglected during residential analysis, they are now a common design point as focus is placed on alternative energy technologies. Statistical methods attribute all of the *measured* energy consumption to end-uses and in doing so incorporate the occupant's behaviour with regards to use and settings of appliances. However, if all energy sources are not accounted for, the end-use energy consumption estimates are derated by this consumption difference. Based in its physical principle roots, the EM has the ability to capture the additional energy consumption level based on requirements, inclusive of free energy. However, occupant behaviour must be estimated which is difficult as behaviour has been shown to vary widely and in unpredictable ways.

The following sections examine the modeling techniques by reviewing published models. The applicability, basic methodology and major conclusions found by the researchers are listed. There is a tendency towards chronological order to facilitate understanding of the modeling technique development stream and contributions by the authors. Certain techniques were found to follow a clear development stream (e.g. conditional demand analysis) while others contain a wide variety of techniques and are discontinuous. Emphasis is placed on modeling technique development and less on the simple application to a new region.

4. Top-down models

The use and development of the top-down modeling approach proliferated with the energy crisis of the late 1970s. In an effort to understand consumer behaviour with changing supply and pricing, broad econometric models were developed for national energy planning. These models require little detail of the actual consumption processes. The models treat the residential sector as an energy sink and regress or apply factors that affect consumption to determine trends. Most top-down models rely on similar statistical data and economic theory.

As the housing stock in most regions is continuously undergoing improvement and increase, simply modeling the energy consumption solely as a function of economic variables is short-termed. Hirst et al. [14] initiated an annual housing energy model of the USA. Their model relied on econometric variables and included a component for growth/contraction of the housing stock. Their work was expanded and improved over the following years resulting in an econometric model which had both housing and technology components [15,16]. The housing component evaluates the number of houses based on census data, housing attrition and new construction. The technology component increases or decreases the energy intensiveness of the appliances as a function of capital cost. The economic component evaluates changes in consumption based on expected behavioural changes and efficiency upgrades made to the technology component. Finally, market penetration is considered a function of income and demand/supply. The simulation model combines the changes in outputs of the components and estimates the energy consumption given historic energy consumption values. The authors felt their model was sensitive to major demographic, economic and technological factors, but recognized the need to continually update all assumed information to improve quality.

Saha and Stephenson [17] developed a similar model for New Zealand although it had a technological focus. Their economic and housing components drive separate analysis of SH, DHW, and cooking, and are added to obtain total consumption. Their basic energy balance, as shown in Eq. (1), determines the annual energy consumption of each fuel used to support each end-use group as a function of stock, ownership, appliance ratings and use. Using historical data, their prediction capability was excellent throughout the 1960s and 1970s although there is significant divergence toward the latter half of the 1970s. This may be due to the model not accounting for shifts in home insulation levels

$$E_{\mathrm{an},e,f} = S \cdot C_{e,f} \cdot R_{e,f} \cdot U_{e,f} \quad (1)$$

where E is the annual energy consumption of end-use group e, corresponding to fuel type, f, S is the level of applicable housing stock, C is the appliance ownership level, R is the rating of all appliances within an end-use group, and U is a use factor.

Haas and Schipper [18] recognized that energy consumption of the housing stock is poorly modeled by only a few econometric indicators. They identified "irreversible improvements in technical efficiency" which are a result of consumer response that not only reduces energy consumption due to rising price, but responds by making upgrades to their dwelling. Consequently a subsequent reduction in price would not cause a perfectly elastic rebound. To quantify this asymmetrical elasticity, they developed econometric models for the USA, Japan, Sweden, West Germany and the UK based on the time periods of: 1970–1993, 1970–1982, and 1982–1983. They found very flat (nearly zero) rebound of energy consumption after periods of increased price, suggesting the typical price elasticity is a diluted average. They also state saturation of appliances can lead to reduced income elasticity and they found limited correlation between increasing technological efficiency leading to increased energy use. When the authors included technological energy intensity in their model (using a bottom up approach based on individual appliance ratings) they found reduced error and that the irreversible share of price elasticity became hidden in the coefficient of intensity.

Two tier econometric models that evaluate choice of system (discrete) and utilization (continuous) are common. Nesbakken [19] developed such a model for Norway, testing sensitivity and stability across a range of income and pricing. The author considered three years of expenditure surveys and energy consumption to determine differences along the time dimension. Their findings were consistent with negative price elasticity and maximization of utility. Different income groups resulted in similar findings although the responses were slightly higher for higher income groups.

Bentzen and Engsted [20] revived simple economic modeling of residential energy consumption. They tested the following three annual energy consumption regression models for Denmark:

$$E_{\mathrm{an},t} = b + c_1 E_{\mathrm{an},t-1} + c_2 I_{\mathrm{disp},t} + c_3 Pc_t \quad (2)$$

$$E_{\mathrm{an},t} = b + c_1 E_{\mathrm{an},t-1} + c_2 I_{\mathrm{disp},t} + c_3 Pc_t + c_4 HDD_t \quad (3)$$

$$E_{\mathrm{an},t} = b + c_1 E_{\mathrm{an},t-1} + c_2 I_{\mathrm{disp},t} + c_3 Pc_t + c_4 HDD_t + c_5 Pc_{t-1} \quad (4)$$

where E is the annual energy consumption for year, t, I is the disposable household income, Pc is the price of energy, HDD is the heating degree days, b is a constant, and c are coefficients.

From 36 years of data they found that, in all three cases, long-term energy consumption was strongly affected by income and lagged energy consumption, and lagged pricing trumped current

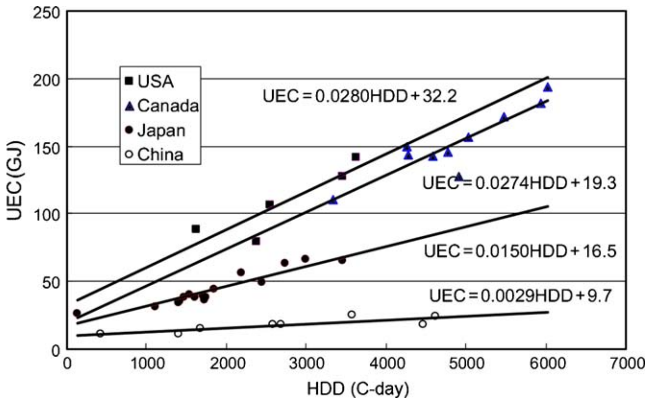

Fig. 3. Comparison of National UEC values [21].

pricing. Their findings indicate that future energy price must increase with income to maintain the current consumption level.

Using aggregate national residential energy values, Zhang [21] compared international values of unit energy consumption (UEC) to determine to potential changes in the sector's energy consumption. The author calculated the UEC for various regions of China based on energy consumption and the number of residences, and compared the Chinese UEC with those of other countries. The results indicate that when normalized for heating requirements based on climate (i.e. heating degree days (HDD)), Japan uses approximately half the UEC of the USA and Canada, as shown in Fig. 3. This may be attributed in part to the high ratio of apartment buildings in Japan (40%). China is closer to one quarter of the North American UEC, owing to limited adoption of space heating devices. The paper also discusses the potential of the Chinese residential sector following the North American or Japanese energy consumption characteristics. Interestingly, the model identified that although China is growing, the secondary energy consumption of the residential sector has remained constant due to switching away from coal as a fuel.

Ozturk et al. [22] and Canyurt et al. [23] proposed the use of genetic algorithms (GA) to determine the relationships between Turkish residential–commercial energy consumption and the following: GDP, population, import/export, house production, cement production and appliance sales. GA models utilize concepts of biology and Darwin's theory of survival of the fittest. Initiated chromosomes (potential solutions) are assessed on the basis of fit (sum of squared errors) to determine their level of participation. Chromosomes are crossed to exchange potential solution characteristics (coefficients of input variables) with the potential of mutations to account for solutions which were not part of the initial population. The authors' GA model estimates the coefficients of the linear model based on the aforementioned variables and their combinations. The resultant model had excellent fit with the calibration information and their projections through the year 2020 were similar to other models. They note the benefits of the GA as requiring limited information and easy development.

The national energy modeling system (NEMS) incorporates a current econometric energy model of the USA housing stock [24]. The model is used for mid-term forecasting and policy analysis. It includes five components: housing stock forecast, technology, appliance stock forecast, building shell integrity, and distributed generation equipment. The appliance stock component places emphasis on appliance lifetime and saturation levels, functions which have been studied in depth for Canada by Young [25]. The distributed generation component indicates that emphasis is being placed on the integration of non-traditional energy sources; it looks at system cost, efficiency, penetration parameters, and solar insolation levels. The calculated energy consumption is then fed back into the NEMS for use with other models and overall energy supply prediction.

Using the entire building register of Goteborg (68,200 buildings) and energy data from the largest energy supplier, Tornber and Thuvander [26] developed an energy model of the building stock. The energy data was measured at metering stations, and was distributed among connected buildings on the basis of building use and age. The model utilizes geographical information systems (GIS) to visually assist the assessment of the consumption rates of different energy sources throughout Goteborg. Although they were unable to directly link the energy consumption to individual buildings, their spatial model clearly identifies energy use within groups of buildings and may be used for identification of high consumption areas.

Labandeira et al. [27] extended a regression model by developing a six equation demand model of Spanish residential energy consumption. Separate equations were developed for energy consumption associated with: electricity, natural gas, propane, automotive fuel, public transport, and food. They found that these products are price inelastic. They regressed the energy consumption of over 27,000 houses as a function of demographic, macroeconomic, and climate variables. They experienced reduced multicollinearity problems as their dataset covered an extended period of time (changing appliances ownership) and this also provided longer-term elasticity assessment.

Siller et al. [28] created a model of the Swiss residential sector to test the impacts of renovations and new construction in an attempt to achieve energy consumption and greenhouse gas emissions targets. Their model is based on the effective reference area which is a measure of the effective heated area and is calculated based on census data. They developed modeling matrices which account for the renovation of buildings and if demand is met, new construction of buildings. In calculating energy consumption they use building type, energy standards, efficiency, and heat demand per area. The update of the housing stock is through new construction and renovation, of which the latter is only occasionally realized. They point out that these estimates have a strong affect on model uncertainty.

Balaras et al. [29] constructed a renovation model of the Hellenic housing stock. Using an assessment of the housing stock and current energy consumption figures, they estimated the impact of fourteen different energy conservation measures that were applied to houses in need of refurbishment. They found the housing stock lacking in insulation and predicted that adding insulation to the stock would save 49% of current space heating energy consumption.

5. Bottom-up models

The bottom-up approach was developed to identify the contribution of each end-use towards the aggregate energy consumption value of the residential stock. This refines the understanding of the details associated with the energy consumption.

There are two distinct categories used in the bottom-up approach to evaluate the energy consumption of particular end-uses. The SM utilizes dwelling energy consumption values from a sample of houses and one of a variety of *techniques* to regress the relationships between the end-uses and the energy consumption. SM models can utilize macroeconomic, energy price and income, and other regional or national indicators, thereby gaining the strengths of the top-down approach. The EM relies on information of the dwelling characteristics and end-uses themselves to calculate the energy consumption based on power ratings and use characteristics and/or heat transfer and thermodynamic principles. Consequently, the engineering technique has strengths such as the ability to model new technologies based solely on their traits. Once developed, the bottom-up models may be used to estimate the energy consumption of houses representative of the residential stock and then these results can be extrapolated to be representative of the regional or national residential sector.

5.1. Statistical techniques

The vast quantity of customer energy billing information stored at the major energy suppliers worldwide is an unprecedented data source for energy modeling. Researchers have applied a variety of SM techniques to utilize this and other information to regress the energy consumption as a function of house characteristics. A capability of the SM techniques is their ability to discern the effect of occupant behaviour. This is of benefit to residential modeling as occupant behaviour has been found to range widely and is poorly represented by simplified estimates [2,30,31].

The three well-documented techniques, all of which use a sample of houses, are:

- Regression—The regression technique uses regression analysis to determine the coefficients of the model corresponding to the input parameters. These models regress the aggregate dwelling energy consumption onto parameters or combinations of parameters which are expected to affect energy consumption. The model is evaluated based on goodness of fit. Input variables which are determined to have a negligible effect are removed for simplicity. Based on the combinations of inputs, the model's coefficients may or may not have physical significance.
- Conditional demand analysis (CDA)—The CDA method performs regression based on the presence of end-use appliances. By regressing total dwelling energy consumption onto the list of owned appliances which are indicated as a binary or count variable, the determined coefficients represent the use level and rating. The primary strength of this technique is the ease of obtaining the required input information: a simple appliance survey from the occupant and energy billing data from the energy supplier. However, it does require a dataset with a variety of appliance ownership throughout the sample. This technique exploits the differences in ownership to determine each appliance's component of the total dwelling energy consumption. In order for the CDA technique to produce reliable results, and depending on the number of variables used, data from hundreds or even thousands of dwellings are required.
- Neural network (NN)—The NN technique utilizes a simplified mathematical model based on the densely interconnected parallel structure of biological neural networks. The technique allows all end-uses to affect one another through a series of parallel "neurons". Each neuron has a bias term and array of coefficients that are multiplied by the value of the preceding layer's neurons. Similar to regression models it seeks to minimize error and may apply scaling and activation functions to account for non-linearity. As it is a parallel model, the coefficients have no physical significance.

5.1.1. Regression

In an effort to identify unusual metering occurrences (e.g. broken meter) and evaluate the level of households with more than one energy source for space heating, Hirst et al. [32] used the Princeton scorekeeping model with monthly or bimonthly energy supplier billing data. They examined the weather and non-weather sensitive elements of the household energy consumption of dwellings by regressing the energy billing data onto a non-weather dependent constant and a weather dependent coefficient based on HDD, as shown in Eq. (5). They left the reference temperature for determination of the HDD as a variable, to be adjusted between 4 °C and 24 °C in an effort to reduce error and increase the multiple correlation coefficient (R^2). The adjustment of T_{ref} was shown to be effective by Jones and Harp [33] who reduced it from the accepted value of 18.0–16.9 °C and achieved more representative results for the space heating requirements of Oklahoma

$$E_{\text{an},t} = b + c\ \text{HDD}_t(T_{\text{ref}}) \tag{5}$$

where E is the annual energy billing data from period, t, HDD is the heating degree days with reference temperature, T_{ref}, b is constant, and c is a coefficient.

The coefficients in the above model were termed "fingerprints" and directed towards determining unusual metering occurrences and identifying the use of alternative space heating fuels when comparing the monthly measured house energy consumption to that predicted by the model. Recently, a similar analysis was conducted by Raffio et al. [34] with the goal of identifying energy conservation potential within a regional area. A similar model with "energy signature" coefficients was developed. These coefficients were compared regionally and also evaluated over the course of the seasons for the identification of patterns which can be used to assess potential energy conserving changes. The authors give examples such as the application of DHW conserving devices to dwellings with high non-weather dependent energy consumption and the application of programmable thermostats to high balance point T_{ref} buildings. While the model cannot determine the impact of these changes, it may identify the potential for application. The primary advantages of this model are simplicity, only requiring billing data, and the capability of normalized comparison across many different residences using a sliding scale which is continuously updated from new billing data. Utilizing larger sets of billing data, the models can become descriptive of a nation.

Tonn and White [35] developed a regression model with four simultaneous equations: separate equations of electricity use associated with SH and AL, wood use, and indoor temperature. Data was sourced from 100 sub-metered homes that utilized wood heat. In an attempt to encompass occupant behaviour they conducted an extensive survey (300 questions) which asked questions related to goals and motivations, and occupants self-defined socioeconomic response. Their desire was to determine the motivation or ethical considerations in energy use. They developed 30 different regression models, consecutively eliminating variables with insignificant impact. Their four regression equations achieved R^2 values ranging from 0.80 to 0.91. While housing characteristics played a distinct role in the models, they found ethical motivations outweigh economic motivations. They found education level and age of the head of household not to affect any of the four equations.Douthitt [36] constructed a model of residential space heating fuel use in Canada by regressing consumption as a function of present and historic fuel price, substitute fuel price, total fuel consumption, and a vector of building structure, climatic, and occupant characteristics. Using 370 records, they achieved R^2 values equal to 0.52 (natural gas), 0.76 (heating oil), 0.37 (electricity with natural gas available), and 0.79 (electricity with no natural gas available). The author found that the sample with energy source alternatives achieve near unity price elasticity, the implication being towards fuel subsidies being ineffective at reducing annual fuel cost per house. Income elasticity was also very unitary, indicating that providing subsidies (in effect income) to low-income families would result in increased usage.

Fung et al. [37] adopted the regression techniques of [36] and others to determine the impact on Canadian residential energy consumption due to energy price, demographics, and weather and equipment characteristics. They found both short and long term fuel price elasticity to be negative, although the long term was larger in magnitude. Income elasticity was found to be insignificant. These results were similar for each end-use group (i.e. SH/SC, DHW, and AL).

5.1.2. Conditional demand analysis

Parti and Parti [38] developed the CDA method given the availability of a detailed survey of appliance and occupants of over 5000 households and their corresponding monthly electrical billing data from the electricity utility in San Diego. They recognized the limitations inherent to an engineering model that approximates occupant behaviour based on theoretical considerations and therefore they attempted to determine the use level of individual appliance based on regression methods. They proposed a *conditional demand regression equation* based on the indication of appliance ownership and expected relations with other house characteristics such as floor area or demographic factors gathered from a survey.

Their regression equation, one for each month of a year of billing data, take the form

$$E_{\text{mo}} = \sum_{i}\sum_{app} c_{app,i}(V_i C_{app}) \tag{6}$$

where E is the monthly electrical energy consumption, C is a variable indicating appliance presence or count for appliances, *app*, V is a set of interaction variables with elements, i, such as the number of occupants, income, and floor area, and c is a coefficient.

The appliance at *app* = 0 is unspecified to account for appliances whose presence were not explicitly surveyed and the interaction variable when $i = 0$ accounts for appliance energy consumption unrelated to interactions with other surveyed information.

The authors specified conditions to limit use of the significant appliances to help in regression coefficient determination. These included disallowing air conditioning from November through March and space heating from July through August. They considered the dominant electrical end-uses: air conditioning, space heating, water heating, and common appliances which include dishwasher, cooking range, dryer, and refrigerators and freezers. The interaction variables corresponding to end-use groups are shown in Table 1.

The final model coefficients were indicative of appliance use and resulted in R^2 values ranging from 0.58 to 0.65. As the regression model included demographic variables, the authors were able to determine econometric effects such as income and energy price elasticity. In comparison with engineering estimates, their CDA model under predicts energy consumption of space heating and over predicts energy consumption of water heating and common appliances. The authors believe they could incorporate solar technologies, but recognize the need for sufficient samples and associated annual dwelling energy consumption data. They see the benefits of the CDA method including the disaggregation of energy consumption by end-use without sub-metering and the inclusion of behavioural aspects within the coefficients.

Using 15 min interval load data from 100 Los Angeles electricity customers, Aigner et al. [39] utilized the CDA method to determine hourly regression equations. Based on constant appliance dummy variables, they found the regression resulted in inadequate coefficients. For example, the magnitude of coefficients (indicating use level) changed throughout the day with load level, but the relationship between different appliances did not, indicating that the coefficients represent an average use level and are not indicative of the daily use profile. To promote differences in the coefficients, the authors imposed restrictive windows of appliance use; specifically, laundry and cooking devices were excluded over the period of 2–5AM. Their results compared to actual occupant load profiles better than conventional CDA.

Caves et al. [40] developed a CDA model of the residential electricity energy consumption of Los Angeles customers by incorporating prior information through the use of Bayesian inference in an effort to reduce unreasonable or negative coefficients estimated by the conventional CDA method. The prior information was developed by using the EM to model appliances and systems and estimate load profiles. These profiles were used to calculate coefficients of use, similar to the CDA coefficients. A typical CDA model, based on a sample of 129 houses with daily energy consumption information (excluding weekends) for the summertime in Los Angeles was constructed using a method similar to [38]. Given the confidence levels of the EM coefficients and the CDA method coefficients, these weighted values are combined using Bayesian techniques to estimate final coefficients of the CDA regression model. This combination approach reduces the multicollinearity effects which can result in negative or unreasonable coefficients; however, it relies on engineering estimates of occupant behaviour.

Bartels and Fiebig propose an alternative method that incorporates sub-metered end-use energy consumption of a subset of the sample into the CDA model [41,42]. This was accomplished by removing the energy consumption and independent variables of the measured appliances within the sub-metered subset of houses. In doing this, they reduced the regression requirements of the subset and weighted the regression of the coefficients of the remaining sample. One advantage of this method is that the elimination of certain end-use consumption of the sub-metered subset increases the resolution and therefore the confidence level of the estimates of non-metered appliances. This is an improvement over using the EM to determine estimates of certain end-uses based on occupant behaviour.

LaFrance and Perron [43] furthered the CDA method by incorporating energy consumption data from three different years over a decade for Quebec. This allowed for the determination of changes in annual energy consumption as a function of changing appliance stock (specifically the addition of electric space heat), and long term pricing response. The database they used was significantly larger than previous efforts, approximately 100,000 samples in total, and contained additional information such as weather relations (heating and cooling degree days), cords of wood (an important energy source for space heating in Quebec), water heater characteristics and certain demographics. These qualities increased the R^2 coefficient to a range of 0.55–0.70.

Their CDA model for each year of available data allowed them to identify changing ownership which evolved to larger, more

Table 1
Interaction variables which have an effect on the energy consumption of particular appliances or equipment [38].

Appliances and equipment	Interaction variables				
	Number of occupants	Electricity price	Household income	Floor area	Heating/cooling per unit area
Common appliances	✓	✓	✓		
Refrigerator	✓				
Hot water	✓	✓	✓		
Space heating and cooling		✓	✓	✓	✓

consuming appliances throughout the period. Strong relationships were identified between incentive activities and appliance penetration. They found the CDA method could estimate the space heating energy consumption associated with wood as an energy source better than engineering estimates. This is due to direct occupant control over wood burning devices (e.g. damper control) and also the wide range of efficiency during operation. The authors identify a multicollinearity issue, the inability to determine which of two or more near linear related independent variables are having an impact on the dependent variable (energy consumption). They found that the nearly ubiquitous presence of the refrigerator and small unspecified appliances made it difficult to determine their impacts. They suggest improving the estimation by further distinguishing certain appliances by their characteristics (e.g. age, size, and number of doors of a refrigerator). Furthermore, they identify that the net energy consumption of the households, as determined by billing data, is not inclusive of passive energy gains and therefore is not representative of the actual consumption of the house, only the net measured consumption. However, this does not impede the relative comparison of two appliances as the passive gains remain identical.

Hsiao et al. [44] combined the work of [40] and [41] by utilizing sub-metered end-use energy consumption as the Bayesian inference prior information. The approach used a small set (49 households) of direct metered end-use data and a larger set which included billing and survey information from Ontario Hydro customers (347 households). The prior information is formed from the mean and variance of the end-use data, thereby providing values which incorporate behavioural aspects better than simple EM estimation.

Bartels and Fiebig [45] further improved upon this modeling technique development stream by increasing "efficiency" of sub-metering by conducting a review of the house appliance survey prior to the sub-metering measurement. They identified houses which would contribute the most to the model by being sub-metered. Based on a preliminary review of 1901 house appliance surveys the authors chose 250 appropriate houses and certain appliances to sub-meter. Sub-metering was also focused on freezers and lighting, areas which posed significant difficulty due to multicollinearity in all previous CDA efforts. Given excellent sub-metered data they attempted to extend their annual model to a half-hour model (48 CDA equations per day); however this resulted in a drop in the R^2 values from 0.66 to 0.34.

Lins et al. [46] developed a national CDA model for Brazil featuring 10,818 dwellings based on monthly energy consumption. As the model covered a wide north-south geographical area with varying climatic conditions, they found it difficult to obtain R^2 greater than 0.5.

Aydinalp-Koksal and Ugursal [47] constructed a national residential CDA model based on over 8000 records from a 1993 Canadian national residential energy consumption survey [48]. To be applicable to the entire energy consumption of the Canadian residential sector, the authors developed three CDA models corresponding to the dominant energy sources in Canada: electricity, natural gas, and oil. As the survey data was highly detailed, new descriptive variables were added to the CDA equations including: programmable thermostats, heat recovery ventilation, heating equipment efficiency, windows and doors, aerators and laundry loads. They mention that the number of independent variables should be limited to facilitate regression and reduce poor approximations of smaller appliances which may be indistinguishable.

The three CDA models achieved R^2 values ranging from 0.79 to 0.89 which may be a result of their annual model that averages the daily and seasonal effects. Certain end-uses were under or overestimated similar to [38]. The authors examined socio-economic effects using the model. The effects were linear, which caused concern as the model was driven to extremity values such as one occupant. Interestingly, the presence of children and adults equivalently affected the electricity consumption of common appliances, lighting, and space cooling. The CDA models were compared to detailed NN and EM models conducted on the same database. The CDA method always under predicted the NN model, and under predicted the EM in the AL, cooling, and SH categories, but not the DHW category. The authors note that the CDA model coefficients are more transparent and their implications better understood in comparison with the NN method.

5.1.3. Neural network

The use of NN methods in modeling residential energy consumption has historically been limited, possibly due to the computational and data requirements or the lack of physical significance of the coefficients relating dwelling characteristics to total energy consumption. Because of their ability to capture non-linear characteristics, NN models have been used to forecast the varying electrical loads seen by utilities. Aydinalp et al. [49] provides a review of the literature and discusses the development of NN models for electrical load forecasting purposes, stating that hundreds of models have been developed. They further report that modeling of energy consumption of individual buildings using NN originated and evolved throughout the 1990s beginning with commercial buildings and progressing in complexity. Specifically noted is an hourly building energy simulation contest reported by Kreider and Haberl [50] in which the top contenders used "connectionist" methods (e.g. NN).

A simplified NN is shown in Fig. 4. Interconnectivity between each characteristic is found at hidden neurons. Coefficients for each input to a hidden or output neuron are included in respective vectors "$\bar{V}$". The neurons are also biased by the term "*b*". For a particular NN arrangement (3:2:1 shown in the figure) and appropriate scaling and activation functions, the coefficient vector and bias are adjusted using a variety of techniques to minimize error of the model. Once the values are determined, the model can be used calculate the energy consumption as a function of different inputs.

Issa et al. [51] introduced the application of NN modeling to the residential energy consumption of a region. They described the development of a NN model that uses energy performance index (EPI) and conditioned floor areas of a group of dwellings with billing data. The EPI is an assigned energy efficiency rating based on housing components. Their NN model bridged the gap between actual energy consumption and the EPI rating. No results were declared.

Mihalakakou et al. [52] created an energy model of a house in Greece using the NN methodology based on atmospheric conditions. Inputs included air temperature and solar radiation and the NN was trained using five years of hourly energy consumption

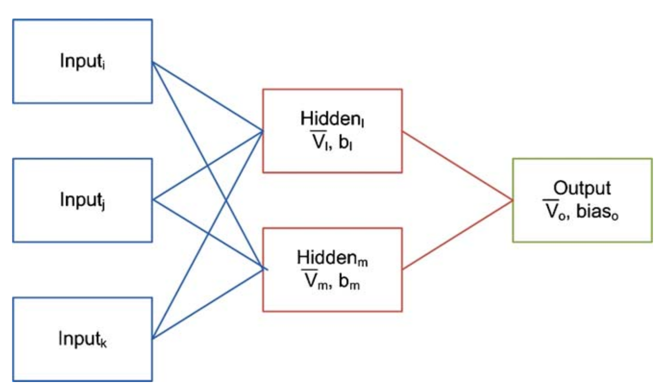

Fig. 4. Simplified NN with three inputs, two hidden neurons with coefficient arrays "$\bar{V}$" and bias "*b*", and one output.

data. Results of predicted energy consumption for the dwelling were excellent on an hourly basis. This can be attributed to the unprecedented amount of hourly "training" data used to calibrate the model. Sadly, while multiyear data was available, dates were not indicated as an input to the NN and therefore annual changes were not accounted for. This method may be extrapolated on a monthly basis using energy supplier billing data to a region of houses. It would therefore become a tool to estimate the variation in energy consumption between cold or warm years.

Aydinalp et al. [49,53] introduced a comprehensive national residential energy consumption model using the NN methodology. They divided it into three separate models: appliances, lighting and cooling (ALC); DHW; and SH. To differentiate the electrical energy consumption for ALC from DHW and SH, only houses which used natural gas or oil for heating loads were used to train the ALC model. The NN models used the 1993 Canadian national residential energy consumption survey [48].

The ALC NN model utilized appliance and heating system information, as well as demographic information for a total of 55 inputs. They trained the model using the annual ALC electricity consumption billing data and inputs from a 741 household "training dataset". The network was optimized by varying properties such as learning algorithm, scaling interval, and hidden layers, which were evaluated by maximizing the R^2 values. Once the network properties were determined it took 182 training cycles to achieve the final nodal coefficients and bias values.

A "testing set" of 247 houses was used to compare the ALC NN model with the EM. Prediction capabilities of the NN surpassed that of the EM, with R^2 values of 0.91 and 0.78, respectively when compared to the metered energy consumption. The authors commented on the ability of the NN to determine an individual appliance's component of the aggregate energy consumption by simply removing its presence from the modeled house. Appliance values compared well with other studies, but were not compared to sub-metered data. Specifically, the refrigerator consumption was not found to be rational, indicating an appliance saturation issue similar to that of the CDA method. As demographic factors were included as inputs, socioeconomic response was analyzed. It was found that ALC energy consumption increased as a second order polynomial as a function of household income.

Aydinalp et al. [54] extended the NN methodology from ALC loads of the Canadian residential sector to loads due to SH and DHW. This was accomplished using similar methods to those described above, using the remaining dataset that contained alternative energy sources. The ALC NN was also used to remove the ALC component when solving for SH and DHW provided by electricity sources. Values of R^2 were again higher than corresponding EM models based on the same data; however, Fig. 5 shows the SH energy consumption predicted by the NN has a biased error. A socioeconomic analysis was conducted and both SH and DHW energy consumption were found to vary linearly with income.

Yang et al. [55] presented a technique for an "adaptive" NN which functions by accumulating additional energy data or using a sliding window of recent energy data. This extends upon the static predictions made by conventional NN, and allows for the coefficients and bias to be updated as new information becomes available. They found that given a previously trained network, the updating of the coefficient and bias values to represent new data takes less time as the initial values are close to the final state. This technique could be applied for continuous update, similar to that of the top-down technique used by the USA EIA [24].

5.2. Engineering method

The EM accounts for energy consumption of the end-uses based on their ratings or characteristics. The EM is the only method that

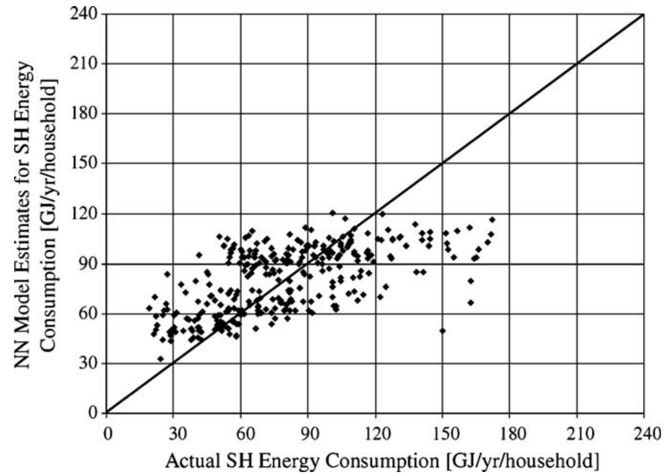

Fig. 5. Comparison of SH energy consumption using the NN technique to actual SH energy consumption [54].

can fully develop the energy consumption of the sector without any historical energy consumption information. Models can be as simple as an estimate of SH based on the climate through the use of HDD or as detailed as a complete thermodynamic and heat transfer analysis on all end-uses within the dwelling. As it functions based on the physics of the end-uses, the EM has the highest degree of flexibility and capability with regard to modeling new technologies which have no historical consumption data. However, occupant behaviour must be assumed. As occupant behaviour varies widely, this is difficult to estimate. Three EM techniques are identified in this review:

- Distributions—This technique utilizes distributions of appliance ownership and use with common appliance ratings to calculate the energy consumption of each end-use. As end-uses are typically calculated separately, this technique does not account for interactions amongst end-uses. The product of appliance ownership, appliance use, appliance rating and the inverse of appliance efficiency results in the energy consumption. By aggregating the appliance consumptions on a regional or national scale the residential energy consumption is estimated.
- Archetypes—This technique is used to broadly classify the housing stock according to vintage, size, house type, etcetera. It is possible to develop archetype definitions for each major class of house and utilize these descriptions as the input data for energy modeling. The energy consumption estimates of modeled archetypes are scaled up to be representative of the regional or national housing stock by multiplying the results by the number of houses which fit the description of each archetype.
- Sample—This technique refers to the use of actual sample house data as the input information to the model. This allows for the capture of the wide variety of houses within the stock and can be used to identify regions with high-energy consumption. If the sample is representative of the regional or national housing stock, the stock energy consumption can be estimated by applying appropriate weightings to the results. As the variety of houses varies widely, this technique requires a large database of representative dwellings.

5.2.1. Distributions

EM models can be constructed by using regional or national distributions of appliance ownership and use, and determining the end-use energy consumption. While they rely on national assessments of appliance penetration and can incorporate historic energy consumption, their level of disaggregation (by end-use) allows them to be considered bottom-up. As the number of houses and appliance penetration distributions are known, the resultant energy consumption is considered to be representative of the region or nation.Capaso et al. [56] developed an appliance use profile of the Italian residential sector based on distributions determined from housing surveys. Demographic and lifestyle data combined with engineering data of a wide range of appliances was used to calculate total house energy consumption. Their model was applied to the region and compared well with load recordings.

Jaccard and Baille [57] developed a model of Canadian provinces using the INSTRUM-R simulation tool. The inputs to the model include historic energy consumption, price, behavioural parameters, distribution levels of technologies, and quantification of appliance unit energy consumption, cost, and availability. The simulation tool then explicitly models the energy consumption of each appliance, the sum of which is considered to be the residential energy consumption. Functions are included to retire old housing stock and also to test the housing stock for retrofit potential. Based on the potential it simulates the purchase of new appliances. The authors detail the advanced life cycle cost assessment features of the model which do not assume perfect knowledge across space and time, thereby limiting a single technology capturing 100% of the market. They consider this to be a strong asset of the model as it more appropriately simulates the regional technology choices.

Using a combination of distributions and micro-level data sources, Kadian et al. [58] developed an energy consumption model of the residential sector of Delhi. They used a simplified end-use consumption equation to incorporate the penetration and use factors of all households, similar to Eq. (1) although extended to individual end-uses. They included end-uses such as lighting, water heating, air conditioning, refrigeration, cooking, washing, and certain subjective loads. The sum of the end-use energy consumption was input into the long range energy alternatives planning (LEAP) system to incorporate variables such as population, income, and increasing number of houses.

Saidur et al. [1] created a non-space heat residential energy model of Malaysia based on different researchers' distribution estimates of appliance ownership, appliance power rating and efficiency, and appliance use (there is no SH requirement in Malaysia). Their estimate of national annual energy consumption is the summation of the product of each appliance's variables and reciprocal of efficiency. Furthermore, they conducted an exergy analysis to complement their efficiency analysis. The exergy analysis allowed for a comparative tool by which to gauge different energy sources and conversion devices based on a reference state. They found an overall energy efficiency of 69% and exergy efficiency of 30% for Malaysia, as shown in Table 2. They state the gap in efficiencies is due to a mismatch of input and output quality levels (i.e. high temperature energy resources were used for low temperature applications). This is dominated by the refrigerator and air conditioner.

Table 2
Overall energy and exergy efficiency of the residential sector [1].

Country	Year	Overall energy eff.	Overall exergy eff.
China	2005	–	10
Canada	1986	50	15
USA	1970	50	14
Brazil	2001	35	23
Italy	1990	–	2
Japan	1985	–	3
Sweden	1994	–	13
Turkey	2004–2005	81	22
Norway	2000	–	12
Saudi Arabia	2004	76	9
Malaysia	2004	70	29

5.2.2. Archetypes

The EM can be applied to a limited set of dwellings that represent classes of houses found in the residential sector, commonly referred to as "archetypes". Depending on the level of detail, modeling of archetypes can capture the interconnectivity of appliances and end-uses within the house which is not possible using models based on distributions. Parekh [59] describes the process of developing archetypes for energy simulation. The author outlines three basic criteria in generating archetypes: geometric characteristics, thermal characteristics, and operating parameters. Using housing surveys and available housing data, geometric and thermal characteristics are correlated to arrive at various groupings found within the housing stock. Data from these archetype groups was examined for minimum, average, and maximum values for use in determining representative characteristics of each archetype for use with building simulation programs.

As the archetype modeling method typically involves a highly detailed integrated simulation of a house, its development progressed with computer and software capabilities. As the number of archetypes is limited, they are the input of choice for EM models as they reduce simulation time as compared with the sample technique which models each house within a database.

MacGregor et al. [60] developed the Nova Scotia residential energy model using three insulation/infiltration levels and nine dwelling types, resulting in 27 archetypes. They used typical values of occupancy, appliances and lights, and evaluated the energy consumption of each archetype using the hourly analysis program (HAP) developed by Carrier Corporation [61]. Energy consumption values were extrapolated to provincial levels based on the estimated number of dwellings represented by each archetype. The results were found to be in agreement with regional top down estimates. The model was used to evaluate the potential for energy savings and economic benefits of introducing small-scale fluidized-bed furnaces for residential space and DHW heating.

Kohler et al. [62] developed a mass, energy, and monetary flow model of the German building sector. They recognized the building stock as the largest economic, physical, and cultural capital of industrialized countries, although the stock is not yet well quantified. To overcome this lack of data, they decomposed survey data into basic elements and classed them. While they state they are "reference" buildings and not "typical", they are associated with "age-use" classifications characteristic of archetypes. Each group was broken down into detailed elements such as window type. Using these elements they developed building specifications which comprise the materials and operations with respect to the building. Included in their model was retirement and replacement of both buildings and appliances. The authors found their bottom-up model was in agreement with other studies and energy surveys.

Huang and Broderick [63] developed an EM model of space heating and cooling loads of the American building stock using 16 multifamily and 45 single-family "prototypical" residential buildings. These archetypes were simulated in 16 different regions; some archetypes were simulated in as many as six regions. The authors utilized DOE-2.1, a building energy simulation program supported by the USA Department of Energy [64]. Building heating and cooling loads were disaggregated to show the contributions from the walls, roof, windows, infiltration, and internal gains by setting the thermal conductivity of each component to zero. They also included plant efficiencies, accounting for part-load efficiency and air-conditioner efficiency; however, only furnace/air-conditioner plants were modeled owing to the source of the archetypes from the Gas Research Institute. The authors utilized building population estimates provided by [8] to scale their results up to a national value. This was accomplished by normalizing the archetypes' energy consumption by heated floor area and multiplying by the national floor area value.

Jones et al. [65] developed an energy and environmental prediction model which utilized GIS techniques. They used a unique technique that augments archetypes with additional information based on a "drive-pass" survey. The model employs the UK Standard Assessment Procedure to simulate a dwelling based on building fabric, glazing, ventilation, water heating, space heating, and fuel costs. To reduce information collection time and effort, residences with similar characteristics were grouped and modeled by an archetype. The augmentation process was accomplished by using GIS to estimate building area, historical sources to estimate age, and the drive-pass (the process of assessing building characteristics from the sidewalk) to determine storeys, chimneys, and the ratio of window to wall area.

Using the developed archetypes (five age groups and twenty built forms) augmented with individual characteristics, the authors simulated the energy consumption of each dwelling in Neath Port Talbot, UK. Using GIS they illustrate the high consumption areas and those dwellings which have high potential for upgrades, as shown in Fig. 6.

Shipley et al. [66] developed archetypes of different Canadian government building types to represent over 3500 buildings. The archetypes were based on categories such as type, floor area, and age. They developed the commercial energy and emissions analysis model which utilizes ASHRAE's modified bin method, which is described by [67]. Archetypes reduced their simulation efforts as the average building accounted for the large group of diverse buildings. They calibrated the model using supplied energy consumption information from a subset of the buildings and used the model to determine the impacts of building envelope improvements.

Carlo et al. [68] took a different approach to the development of archetypes to represent Brazilian commercial buildings. Using previous simulation results of 512 buildings, the authors determined the primary variables of a building energy regression equation to be roof area ratio, façade area ratio, and internal load density. Combinations of these variables were used to develop 12 archetypes which were augmented with additional variables for parametric simulation. This resulted in 695 prototype buildings which were simulated in DOE-2.1 to determine their energy consumption. The results were used in the assessment of potential building code changes.

Shimoda et al. [69] developed a residential end-use energy consumption model on the city scale for Osaka, Japan. They developed 20 dwelling types and 23 household (occupant) types to represent the variety of houses within the city. Each dwelling type (not detailed in the paper) was modeled using conductive heat transfer analysis; however, each dwelling was considered to have identical insulation levels based on 1997 commercial offerings. This identical insulation level is a major drawback. Households were developed based on the number of family members, appliance ownership levels, and appliance ratings. Each archetype was simulated and multiplied by the number of dwellings it represents. The authors found two interesting results from their technique: the total estimated residential energy use is less than historical values because "unreasonable" energy use (e.g. leaving lights on) was not accounted for, and estimated unit energy consumption is larger than statistical values which they attribute to surveys focusing on larger families.

Wan and Yik [70] took an alternate approach to archetypes and focused on solar gains. After conducting a survey of typical housing characteristics in Hong Kong including floor plan, they developed a single archetype of 40 m^2 floor area with a rectangular living and dining room, two bedrooms, kitchen, and a bathroom. They applied typical characteristics including wall thickness, window to wall ratio, glass thickness and wall absorptivity. To introduce variety, they rearranged the floor plan layout and orientation while maintaining the size and room geometries; this resulted in different window areas facing the sun. In addition they specified different family types and use profiles. They utilized HTB2 (heat-transfer) and BECRES (air-conditioning) simulation engines described by [71,72]. They found their estimates of air conditioner energy consumption to be large when compared to historical statistics and they decreased this difference by reducing appliance usage and ownership level within the dwellings. After the modification the predicted energy consumption compared well with statistics.

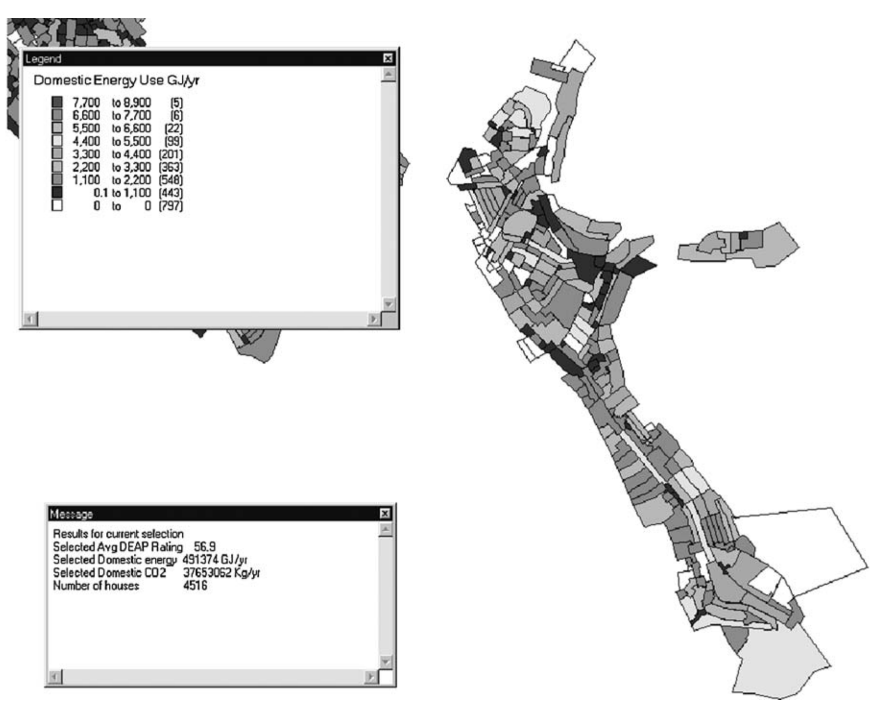

Fig. 6. Domestic energy intensity of individual residences in Neath Port Talbot [65].

Yao and Steemers [73] developed a model based on four typical UK housing topologies: flat, semi-detached, detached, and mid-terraced. Using national appliance ownership distributions, average appliance use, and average appliance rating, the authors generated random daily aggregate appliance energy consumption profiles. They used the thermal resistance method developed by the Martin Centre to calculate heating losses. They generated a regional profile based on 100 generated households and found it to be in agreement with national statistical data.

Palmer et al. [74] developed a model of the UK housing stock using 431 archetypes. They used the BREDEM-8 Building Research Establishment tool which is a monthly heat flux simulation program to model the required SH and DHW heating energy consumption [75]. Occupant and appliance heat gains are calculated based on distributions and DHW consumption is based on typical values. Their model encompasses trends of construction/demolition and demographic changes to estimate the energy consumption of the residential sector through 2050.

Petersdorff et al. [76] modeled the EU-15 building stock by examining five standard buildings with eight insulation standards. They used Ecofys's built environment analysis model (BEAM) to calculate the heating demand for three climatic regions. The three house types included in the model were terrace, small apartment, and large apartment. The eight insulation standards applied to the buildings were determined based on typical values for the climatic conditions and building vintage found in EU countries. The authors modeled different scenarios of retrofit and construction/demolition, and attempted to extend the model to smaller housing types. They found their models corresponded well with statistical data.

To extend the archetype methodology beyond its typical position of limited variety, Nishio and Asano [77] developed an archetype generation tool based on the Monte-Carlo technique. The authors utilized numerous statistics, surveys, and conventional datasets from Japan to define both the distribution and range of housing variables. Their house generator uses the Monte-Carlo technique to define attributes for each archetype based on probability assumptions. It then develops hourly patterns of energy consumption for common activities, and aggregates and applies these on a monthly basis as a function of the proposed family composition. While the number of generated houses is variable, the generator relies on 34 different family types and 47 different climatic regions. In an example, they generate and analyze 10,000 houses.

Clarke et al. [78] focused on the main determinants of energy demand within the Scottish building stock to create representative thermodynamic classes. Using the following determinants and their value or level, they developed 3240 classes: insulation level (6), capacity level (2), capacity position (3), air permeability (3), window size (3), exposure (5), and wall to floor area ratio (2). Each class was modeled using the building performance simulation software ESP-r to determine the thermal energy requirements of the dwelling [79]. System information such as heating/cooling, ventilation, DHW, and lighting was then applied to calculate the total energy consumption of the dwelling. The results were incorporated into a tool for comparative analysis and assessment of the impact of improvement measures upon the stock.

5.2.3. Samples

While archetypes provide a limited representation of the regional or national housing stock due to the limited variety of archetypes that can reasonably be defined, the use of actual house samples with the EM can realistically reflect the high degree of variety found in the actual housing stock, provided that the sample size is sufficiently large. As this form of EM modeling is data intensive, its application has been limited.

Farahbakhsh et al. [80] developed a model of the Canadian housing stock based on 16 archetypes augmented with data from 8767 actual houses. As the house data came from a national housing survey database that is statistically representative of the Canadian housing stock, weights of house representation were provided for the purpose of scaling the consumption up to provincial and national values. An individual house input file was generated for each of the 8767 houses and simulated using Natural Resources Canada's HOT2000 monthly bin type building simulation software [81]. As energy billing data was available for 2524 houses, these were used in the calibration procedure to correct data conversion errors in the input files. The national consumption estimate was found to be in agreement with other studies. Using this national residential energy model, Guler et al. [82,83] studied the impact and economic analysis of energy efficiency upgrades on energy consumption and greenhouse gas emissions. They found energy savings and greenhouse gas reduction potential for upgrades of heating systems to be 8%, basement insulation to be 4%, and programmable thermostats to be 2% (approximate values reported here). Using the energy costs at that time, the major upgrades were not found to be economically feasible. Aydinalp et al. [84] updated the model of [80] by using housing data from 1997 and found that the UEC had increased by 1.8%.

Larsen and Nesbakken [85] developed a model of Norway's housing stock using household information from 2013 dwellings. They describe the simulation engine, ERÅD, and identify its fundamental weakness as the high number of numerical inputs. Significant efforts were required to calibrate the model which is not desirable as the engineering technique should calculate appropriate initial values. They note that while it is possible to account for every end-use in an engineering model, unspecified end-uses must be estimated. Instead, this was accounted for by calibrating the known end-uses, resulting in a slight overestimate of each end-use contribution. The authors found SH and DHW to be approximately 42% and 24% of total consumption, respectively.

Two other sample EM models deal with commercial buildings. Ramirez et al. [86] modeled 2800 commercial premises of California using a modified version of eQuest building simulation software [87]. Combining survey information from all 2800 buildings, their energy billing data, sub-metered data from 500 buildings, and current year weather data from 20 stations, the authors modified predefined footprint templates to represent each building. The model numerically and visually displayed the hourly results of each building simulation. Calibration was conducted on each building model by a simulation specialist and consisted mainly of verifying significant end-uses and their ranges. Final alterations were made by adjusting schedules and operating hours. During the calibration process it was found that occupation, or lack thereof, of the building has unexpected impacts. Specifically, the assumption that AL is turned off at the end of the business day was found to be false.

Griffith and Crawley [88] developed a similar model. They modeled 5430 buildings that comprise the Commercial Buildings Energy Consumption Survey Database (CBECS) and included weighting factors for extrapolation to national results for the USA. However, their focus was the "technical potential" of the sector (i.e. the lowest feasible energy consumption) and thus the 2005 building code requirements were applied to each building. Additional information not included in the CBECS was developed using ASHRAE standards and pseudo-random application of average parameter distributions, such as infiltration. They developed a rule based pre-processor to translate the parameters into "shoebox" building input files for simulation by the USA Department of Energy's EnergyPlus software [89]. Simulations were conducted on a computer cluster. They determined that the high number of building records was a disadvantage as it required significant computing capability. They recommend this technique only when results must reflect national implications on a limited number of scenarios. They recommend a smaller database size for high numbers of parametric simulations.

Swan et al. [90] is developing a national residential energy model of Canada using a detailed database of nearly 17,000 houses. The housing database, described by [12], is a selected subset from a national home energy audit program database that characterised the thermal envelope of each dwelling, including an air tightness test. The database of houses descriptions is presently being converted to detailed house models for building energy simulation using the software ESP-r [79]. The detailed house descriptions and high-resolution simulation (one hour time-step) allow for an assessment of the impact on energy consumption due to the application of new technologies to appropriate houses.

6. Critical analysis of top-down and bottom-up approaches

The top-down and bottom-up approaches each have distinct similarities and differences, as well as advantages and disadvantages. Two of the most critical issues that characterize these approaches are the required input information and the desired range of modeled scenarios.

6.1. Strengths and weaknesses of the top-down approach

Top-down approaches are relatively easy to develop based on the limited information provided by macroeconomic indicators such as price and income, technology development pace, and climate. Top-down models heavily weigh the historical energy consumption which is indicative of the expected pace of change with regards to energy consumption. This weighting may be seen in Eq. (4). Models that evaluate from a regional or national scope are useful for estimating the required energy supply and the implications of a changing economy. They falter when discontinuity is encountered. Examples of such situations include technological breakthroughs or severe supply shocks, the latter being most pronounced due to the slow turnover rate of the housing stock. Contrary to other studies and with respect to a practical sense given today's energy environment, Haas and Schipper [18] clearly identified non-elastic response due to "irreversible improvements in technical efficiency". This exemplifies the importance of including a representative technological component in top-down models. Jaccard and Bailie [57] discussed the notable dichotomy that top-down models estimate high abatement costs for reducing carbon dioxide emissions whereas bottom-up models' estimates are notably lower. They attribute this to economists' over-reliance on the autonomous energy efficiency index (AEEI) and the elasticity of substitution (ESUB). The NEMS has included both a *technology* and *distributed-generation* component [24]. This indicates that top-down modeling systems are now attempting to account for the uptake of new technologies. While these techniques may account for future technology penetration based on historic rates of change, they do not provide an indication of the *potential* impacts of such technologies and are therefore not helpful in the development of policy or incentive to encourage them.

6.2. Strengths and weaknesses of the bottom-up approach

Bottom-up statistical techniques bridge the gap between detailed bottom-up end-use energy consumption models and regional or national econometric indicators. These techniques are capable of encompassing the affects of regional or national economic changes while indicating the energy intensity of particular end-uses. The primary information source of the bottom-up SM is energy supplier billing data. While this is private information, the sheer quantity and quality of this information warrants further compilation and use. By disaggregating measured energy consumption among end-uses, occupant behaviour can be accounted for. This is a distinct advantage of the SM over the EM. Of the three bottom-up SM techniques, common regression is the least favoured as the utilized inputs vary widely among models, limiting their comparison. In contrast, CDA is focused on simplifications of end-uses and is therefore easily ported to other locations and its predictions are comparable among different studies. As appliances currently on the market vary widely in size and less in technology, the addition of such information could be beneficial for future CDA studies. Although the NN technique allows for the most variation and integration between end-uses, resulting in the highest prediction capabilities (Aydinalp et al. [91]), its coefficients have no physical significance. This is a severe drawback. Estimation of individual end-uses was demonstrated by removing their presence in the NN model. However, due to the interconnectivity between each end-use, the removal of many end-uses, individually or simultaneously, reduces the level of confidence in the resulting predictions. Furthermore, bias of the energy estimation error was found when using the NN technique. Aydinalp-Koksal and Ugursal [47] provide a detailed review and comparison of specific CDA, NN, and EM models.

Bottom-up EM techniques rely on more detailed housing information. These models explicitly calculate or simulate the energy consumption and do not rely on historical values, although historical data can be used for calibration. Larsen and Nesbakken [85] developed both engineering (samples) and statistical (CDA) models to compare their results. They noted that the engineering technique requires many more inputs and has difficulty estimating the unspecified loads, but while the statistical technique reduces both of these issues it is hampered by multicollinearity resulting in poor prediction of certain end-uses.

If the objective is to evaluate the impact of new technologies, the only option is to use bottom-up EM techniques. This is a point of emphasis because compared to taxation and pricing policies, technological solutions are more likely to gain public acceptance to reduce energy consumption and the associated greenhouse gas emissions. The EM is capable of modeling on-site energy collection or generation such as active or passive solar and co-generation technologies.

The most apparent drawback of the EM is the assumption of occupant behaviour. Because the effect of occupant behaviour can significantly impact energy consumption, the assumption of occupants' activities is not trivial. Statistical techniques based on monthly data are capable of incorporating the effects of occupant behaviour, although they may be inappropriately applied to end-uses. Also, the high level of expertise required in the development and use of the EM may be considered a drawback. The computational limitations discussed by Griffith and Crawley [88] regarding large numbers of simulations are no longer critical as the data processing capability of computers is continuing to increase rapidly.

To address the shortcomings of both the EM and the statistical based models, research is currently being conducted by Swan et al. [90] to develop a "hybrid" EM and NN model for the Canadian housing sector that will incorporate a NN model to predict the highly occupant sensitive DHW and AL energy consumption, while using the EM to predict the SH and SC energy consumption.

6.3. Attributes and applicability of the modeling approaches

The important attributes of the three major residential energy modeling approaches, namely the top-down, bottom-up statistical and bottom-up engineering, are shown in Table 3. Each approach

Table 3
Positive and negative attributes of the three major residential energy modeling approaches.

	Top-down	Bottom-up statistical	Bottom-up engineering
Positive attributes	• Long term forecasting in the absence of any discontinuity	• Encompasses occupant behaviour	• Model new technologies
	• Inclusion of macroeconomic and socioeconomic effects	• Determination of typical end-use energy contribution	• “Ground-up” energy estimation
	• Simple input information	• Inclusion of macroeconomic and socioeconomic effects	• Determination of each end-use energy consumption by type, rating, etc.
	• Encompasses trends	• Uses billing data and simple survey information	• Determination of end-use qualities based on simulation
Negative attributes	• Reliance on historical consumption information	• Multicollinearity	• Assumption of occupant behaviour and unspecified end-uses
	• No explicit representation of end-uses	• Reliance on historical consumption information	• Detailed input information
	• Coarse analysis	• Large survey sample to exploit variety	• Computationally intensive
			• No economic factors

meets a specific need for energy modeling which corresponds to its strongest attribute:

- Top-down approaches are used for supply analysis based on long-term projections of energy demand by accounting for historic response.
- Bottom-up statistical techniques are used to determine the energy demand contribution of end-uses inclusive of behavioural aspects based on data obtained from energy bills and simple surveys.
- Bottom-up engineering techniques are used to explicitly calculate energy consumption of end-uses based on detailed descriptions of a representative set of houses, and these techniques have the capability of determining the impact of new technologies.

Given today’s energy considerations that encompass supply, efficient use, and effects of energy consumption leading to the promotion of conservation, efficiency, and technology implementation, all three modeling approaches are useful. Top-down models are the clear winner in supply considerations as they are heavily weighted by historical energy consumption which places their estimates of supply within reason. Bottom-up statistical models can account for occupant behaviour and use of major appliances, which leads to the identification of behaviours and end-uses which cause consumption of unwarranted quantities of energy. Lastly, bottom-up engineering models may identify the impact of new technologies based on their characteristics and account for the wide degree of variety within the housing stock.

As the effects and limitations of conventional energy sources (i.e. fossil fuels) are widely acknowledged, alternative energy sources and technologies are continuously being investigated and developed. To determine the impacts of such new developments requires a bottom-up model. This is further exemplified by the focus being placed on efficiency and on-site energy collection and generation at individual houses. During this period of rapid technological development and implementation, the bottom-up techniques will likely provide much utility as policy and strategy development tools.

Acknowledgements

The authors gratefully acknowledge the financial support provided to this project through the Solar Buildings Research Network primarily funded by the Natural Sciences and Engineering Research Council of Canada (NSERC), as well as through the Discovery Grant provided to V.I. Ugursal by NSERC.

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Review of Economic Studies (2005) **72**, 853–883
0034-6527/05/00340853$02.00

Household Electricity Demand, Revisited

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First version received June 2002; *final version accepted October* 2004 (*Eds.*)

Recent efforts to restructure electricity markets have renewed interest in assessing how consumers respond to price changes. This paper develops a model for evaluating the effects of alternative tariff designs on electricity use. The model concurrently addresses several interrelated difficulties posed by nonlinear pricing, heterogeneity in consumer price sensitivity, and consumption aggregation over appliances and time. We estimate the model using extensive data for a representative sample of 1300 California households. The results imply a strikingly skewed distribution of household electricity price elasticities in the population, with a small fraction of households accounting for most aggregate demand response. We then estimate the aggregate and distributional consequences of recent tariff structure changes in California, the consumption effects of which have been the subject of considerable debate.

1. INTRODUCTION

Recent efforts to restructure electricity markets have renewed interest in electricity demand and pricing. This interest reflects a broad desire to improve the efficiency of electricity markets, and policy-makers' concerns over the impact of price changes on consumers. How new pricing mechanisms would affect households' consumption and expenditures is a matter of considerable uncertainty, however. This uncertainty has provoked controversy and debate in the regulatory policy arena, hampering market reforms.

Using econometric methods to assess the effects of electricity price changes presents several challenges. These include the nonlinear structure of tariff schedules, aggregation of metered consumption behaviour over time and appliances, and the interdependence of energy use with longer-term household decisions over appliance ownership and dwelling characteristics. The first two issues introduce complex simultaneity problems between marginal prices and consumption. The third issue imposes high data requirements (information on household-specific appliance holdings and residence features), and creates heterogeneity in consumption responses related to the characteristics of these durable goods. When the researcher's objective is to develop a model for simulating the effects of prospective tariff changes, ignoring these issues will provide an incomplete assessment of demand responses and potentially misleading predictions of a new tariff's consumption and revenue consequences.

In this paper, we estimate a model of household electricity demand that can be used to evaluate alternative tariff designs. The model focuses on the heterogeneity in households' demand elasticities, their relation to appliance holdings and other household characteristics, and how they inform household consumption responses to complex (nonlinear) price schedule changes. Although these issues have received attention in the literature, few (if any) studies have addressed them in an integrated way.[1] This shortcoming is notable in that theory suggests that the effects of an alternative tariff design on a diverse population will depend on the heterogeneity in consumers' price elasticities as well as their consumption levels. We address these features using a model of endogenous sorting along a nonlinear price schedule, and a group-wise specification of price-sensitivity heterogeneity based on household appliance ownership. This model reveals a rich, highly asymmetric shape to the population distribution of households' price elasticities. It also indicates a larger aggregate price elasticity of residential electricity demand than prior studies that ignore these issues.

We estimate the model using data for a representative probability sample of California households from the *Residential Energy Consumption Survey* of the U.S. Department of Energy. The rich detail on appliance holdings and dwelling characteristics in these data allow us to model the considerable variation in households' electricity use and sensitivity. We have supplemented the *Survey* by matching each sample household with its complete, seasonally varying electric rate schedule. The use of precise rate schedule information is a central feature of the analysis, both to minimize specification error in estimation and to evaluate individual behavioural responses to alternative rate structures. To lend credence to the specifications and results, we conduct out-of-sample tests of the model that show how well it predicts consumption responses to new price changes.

We then use the model to study the effects of a controversial new tariff design in California. Following an electricity supply crisis in 2000–2001, regulatory authorities approved a novel, five-part tariff structure for residential electricity consumption. This design was intended to induce energy conservation, raise additional revenue for utilities, and minimize expenditure changes for lower-income households. Due to its unprecedented form, however, little was known about how well the new system would achieve these objectives prior to its adoption. We show how such uncertainties can be evaluated prospectively using the sample data, and contrast our estimates with methods employed by public agencies in California and elsewhere.

The next section lays the econometric groundwork for our empirical methods, and highlights how our approach differs from prior studies. Our treatment of the endogenous sorting problem that occurs with nonlinear prices builds upon Hanemann's (1984) and Hausman's (1985) choice models given nonlinear budget constraints. Our approach also handles two important aggregation-related problems common to electricity demand research. Section 3 then develops the empirical specification. Following prior work, this model explains heterogeneity in households' electricity price elasticities in terms of appliance holdings and use. Section 4 discusses estimation via an exact nonlinear method of moments, and Section 5 summarizes the data. Sections 6 and 7 present estimation results and elasticities, including out-of-sample validation tests of the model. In Section 8 we then illustrate how the model and methods lend themselves to analysing prospective tariff design changes, such as California's complex new tariff structures.

2. MODELLING DEMAND WITH NONLINEAR PRICES

Although economic theory offers considerable guidance on how consumers will respond to nonlinear prices, econometric treatments of estimation and identification in this setting remain

1. Taylor (1975) contains an early treatment of nonlinear tariffs in empirical work. More sophisticated methods followed Burtless and Hausman's (1978) work on closely related issues in the analysis of labour supply under nonlinear income taxation. Surprisingly little of these econometric techniques have permeated the (considerable) literature on electricity demand; notable exceptions are Maddock, Castano and Vella (1992) and Herriges and King (1994). A greater consensus has emerged on the importance of incorporating household-level appliance stock information into electricity demand analyses, as well as empirical methods for doing so; see Parti and Parti (1980), Dubin and McFadden (1984), Dubin (1985), and EPRI (1989).

incomplete. This section summarizes the problems inherent in prior estimation strategies, motivates and describes our econometric approach, and connects it to related econometric literatures.

2.1. *Specification and identification*

Most nonlinear price schedules take the form of multi-part tariffs. Since Gabor (1955), economists have realized that multi-part tariffs imply that the consumer faces a nonlinear (*i.e.* a kinked) budget constraint. The demand behaviour of a utility-maximizing consumer thus depends not on the average price, nor any single marginal price, but on the entire price schedule. The standard econometric approach to demand analysis in this setting, which traces to Hall (1973), is to "linearize" the budget constraint. This amounts to using the plane tangent to the consumer's nonlinear budget constraint at the optimal consumption bundle as its linear approximation. By doing so, one can express demand under nonlinear pricing in terms of the ordinary demand function of classical consumer theory, which assumes a linear budget constraint.

To be specific, let $x(p, y)$ be the ordinary demand function that indicates the consumer's desired quantity facing a constant (marginal and average) price p and income y. Suppose, however, that the consumer faces an increasing price schedule $s(p)$ of the form depicted in Figure 1. Here the consumer pays a low price p_1 for each unit up to the quantity $\bar{x}$, and a higher price p_2 thereafter. Then the optimal consumption level x^* satisfies

$$x^* = x(p^*, y^*) \tag{1}$$

where p^* is the slope of the approximating linear budget constraint and $y^* = y + \bar{x} \cdot (p^* - p_1)$. In economic terms, p^* is the consumer's equilibrium marginal willingness-to-pay and y^* is the income level that would induce consumption x^* at this (constant) price. With (1), the demand specification problem under nonlinear pricing can be recast in terms of the ordinary demand function familiar to applied work. Note that both p^* and x^* are endogenously determined, according to the three-equation system consisting of (1), the expression for y^*, and the nonlinear price schedule $s(p^*)$.[2]

Nearly all previous studies of household electricity demand have based estimation—either implicitly or explicitly—on a single-equation analogue of equation (1). Because the marginal price is simultaneously determined by a supply equation and a demand equation, standard econometric arguments imply that ordinary least squares estimation using p^* will yield biased and inconsistent estimates of demand parameters. Recognizing as much, most previous studies have used either an exogenous proxy for the marginal price or instrumental variables (IV) procedures in estimation. While either method can alleviate the endogeneity problem, both introduce biases of their own: the former due to mis-specification of the appropriate marginal price, and the latter because of the difficulty in finding good instruments (that do not *a priori* belong in the demand equation) in this setting.

To elaborate on the latter point, the natural set of instruments in this context are the components of the price schedule itself. This idea appears in early work by McFadden, Puig and Kirshner (1977) and others. An important shortcoming of this approach, however, is that there may be little or no price schedule variation in the data. This is a common situation in nonlinear pricing applications, as the data are often provided by a single firm that charges either one tariff,

2. The analysis with a decreasing price schedule is slightly more complex, because of the possibility that demand may have multiple crossings of the price (supply) schedule. In that event, these three equations have multiple solutions and a fourth equation (involving the indirect utility function) is needed to determine consumption. This analysis is feasible if the econometric demand specification admits a known indirect utility function; see, *e.g.* Hausman (1985).

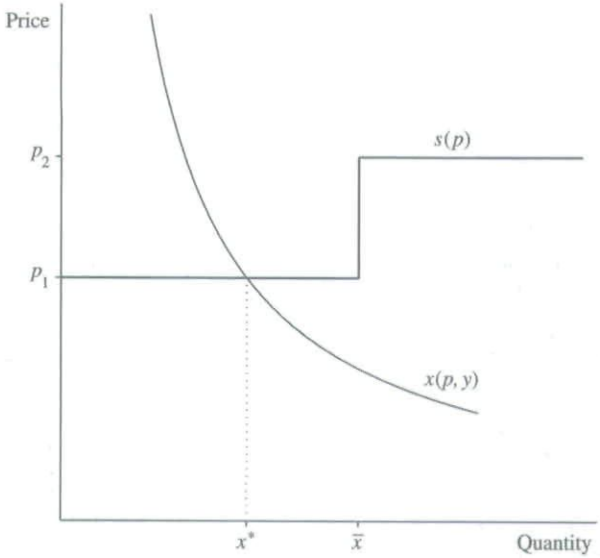


FIGURE 1
An increasing two-tier price schedule

or a few very similar ones, to all consumers. Researchers thus face a canonical weak instruments problem that can result in imprecise and misleading price-elasticity estimates.[3]

A second, and more general, concern arises when consumption decisions are aggregated over time or over distinct services. In the presence of nonlinear pricing, such aggregation often makes IV procedures infeasible.[4] For example, when the consumption data are aggregated over billing periods, the consumer's actual marginal prices are typically not observed. Thus there is no way to construct a proper IV estimator: the endogenous (sequence of) marginal prices are not available to project onto any instrument. Similar difficulties arise if consumption outcomes are aggregated over nonlinearly priced goods or services, rather than over time.[5]

Data aggregation problems of this sort are nearly universal in electricity demand studies. They occur both because a household's electricity meter aggregates consumption of numerous distinct appliance "services" (addressed further in Section 3), and because publicly available data often record consumption over annual (or other) intervals covering multiple billing periods. The predominant treatment of this latter issue in the literature has simply been to ignore it, proceeding as if the household faced a constant (marginal) price over the course of the year. This not only mis-specifies the prices consumers face, it assumes away the economic effects of interest.

In this paper we handle these difficulties in an integrated way. The starting point is the true reduced form of the "supply equals demand" equilibrium condition in (1); that is, solving the three-equation system above for x^* as a function of the price schedule. We do so here assuming the consumer's ordinary demand function (demand at a constant price p) takes the

3. Dubin (1985) shows that ignoring simultaneity problems can produce substantially biased electricity demand elasticities. Maddock *et al.* (1992) show that one common IV approach fails to correct well for the simultaneity bias, resulting in estimated price elasticities that are biased toward the slope of the supply curve.

4. We thank an anonymous referee for emphasizing this point.

5. This problem also arises in other econometric applications. An example is the analysis of aggregated retail scanner data for consumption goods, which are often sold using nonlinear forms of pricing (volume discounts, limited-quantity coupons, 2-for-1 offers, etc.). Policy-makers that use such data are now evidently aware of these aggregation biases; see FTC (2002).

econometric form

$$x(p, y, z, \varepsilon; \beta) \tag{2}$$

where z represents observed consumer characteristics, ε unobserved consumer characteristics, and β a set of parameters to be estimated. To avoid unnecessary technicalities, assume demand is strictly increasing in ε and strictly decreasing in p.

Facing an increasing two-tier price schedule, the reduced form for the household's consumption level x^* as a function of the price schedule is

$$x^* = \begin{cases} x(p_1, y, z, \varepsilon; \beta) & \text{if } \varepsilon < c_1 \\ \bar{x} & \text{if } c_1 < \varepsilon < c_2 \\ x(p_2, y_2, z, \varepsilon; \beta) & \text{if } \varepsilon > c_2 \end{cases} \tag{3}$$

where $y_2 = y + \bar{x} \cdot (p_2 - p_1)$ and c_j is the solution to $x(p_j, y_j, z, c_j; \beta) = \bar{x}$ with $y_1 = y$ (that is, c_j is the maximum (for $j = 1$) or minimum (for $j = 2$) value of ε for which consumption occurs on tier j). Equation (3) states that consumption is given by demand at the low price if the first tier is on the margin, by demand at the high price plus an income effect if the second tier is on the margin, and by the quantity $\bar{x}$ when demand crosses supply in the "gap" between the two tiers of the price schedule.[6] The lower and upper cut-off values c_1 and c_2 satisfy $c_1 < c_2$ for any downward-sloping demand function, provided that income effects are not too large.[7]

It is useful to be clear about why estimating the single reduced-form equation (3) can separately identify the effect of price on demand and supply (*e.g.* β in (2)). Intuition from classical supply-and-demand simultaneity in linear econometric models suggests that additional exclusion restrictions are necessary—tantamount to assuming that viable instruments are available. With nonlinear pricing problems, however, this is not the case. Demand is identifiable here because (i) the supply schedule has constant-price segments, and (ii) the conditional distribution of ε (given the marginal price) is computable. Intuitively, one can use the variation in consumption among all households on the *same* tariff segment to identify the non-price components of demand.[8] Given that, the effect of price can be determined from the remaining difference in average consumption between households on *different* tariff segments, less the average difference in their unobserved characteristics. The latter is computable from the marginal distribution of ε and the price schedule. Researchers can therefore estimate demand without price schedule variation, provided one is willing to place some distributional restrictions on ε. Of course, when there is price schedule variation in the data, this will provide a second "source of identification" for the demand specification (2).

In sum, by solving-out the marginal price to obtain (3), the simultaneity problems arising in econometric analyses using (1) can be avoided. In addition, if one proceeds from an empirical specification of the ordinary demand function that is consistent with (or perhaps derived from) a utility specification, then (3) indicates precisely how the individual terms of a nonlinear price

6. The term $\bar{x} \cdot (p_2 - p_1)$ that is added to income in the third case in (3) is the infra-marginal price discount: the difference between the expenditure necessary to purchase the higher quantities $x^* > \bar{x}$ under nonlinear pricing, and that necessary to purchase x^* at a constant price of p_2.

7. Technically, the case conditions in (3) are correct only if certain restrictions on preferences hold. For a normal good (one whose consumption rises with income), these amount to assuming that the income effect is not "too large"; or, more specifically, that the income effect of the infra-marginal discount does not dominate the substitution effect of the higher marginal price. If this fails, the conditioning-event inequalities on the R.H.S. of (3) are more complex.

8. This argument ignores income effects (cf. note 7) and confounding due to aggregation over time (more about which further below).

schedule enter the demand decision. This provides a framework for predicting how consumption would change under an entirely different price schedule.

2.2. *Estimation issues*

From an econometric perspective, equation (3) is a nonlinear censored regression model in which the censoring occurs in the interior of the distribution of outcomes rather than the tails. Such models are generally estimated by maximum likelihood methods, using the discrete structure in (3) to derive the change-of-variables from an (assumed) marginal distribution of ε to the distribution of x^*. Burtless and Hausman (1978), with later extensions by Hausman (1985), Moffitt (1986), and others, develop likelihood functions for models with this structure. Unfortunately, maximum likelihood estimation quickly becomes computationally intractable when the consumption outcomes from a mixed discrete/continuous model are aggregated over time. This problem renders likelihood methods infeasible for our application.[9] Consequently, we pursue a moment-based approach to estimation.

Conditional on the observables, (3) can be integrated piecewise to obtain

$$E(x^* \mid \cdot) = E_\varepsilon[x(p_2, y_2, z, \varepsilon; \beta)] + h(p_1, p_2, \bar{x}, y, z; \beta) \tag{4}$$

where $h(\cdot) \equiv \tau_2 - \tau_1$ is a sorting correction function defined by the truncated moments

$$\tau_j = \int_{-\infty}^{c_j(\beta)} [\bar{x} - x(p_j, y_j, z, \varepsilon; \beta)]\, dF_\varepsilon, \qquad j = 1, 2, \tag{5}$$

with c_1, c_2 defined in (3) and $y_1 = y$. These expressions do not place restrictions on $x(\cdot)$ or how ε enters it (beyond integrability of demand and monotonicity in ε). Although complex in the general form, the moments in (5) that correct for the nonlinearity of the price schedule are straightforward to evaluate for most error specifications in applied work. For example, if F_ε is $N(0, \sigma^2)$ and ε enters demand (2) additively, then expected consumption simplifies to

$$\begin{aligned} E(x^* \mid \cdot) = {} & [x(p_1, y, z; \beta) - \sigma\lambda_1]\Phi_1 + \bar{x} \cdot (\Phi_2 - \Phi_1) \\ & + [x(p_2, y_2, z; \beta) + \sigma\lambda_2]\,(1 - \Phi_2) \end{aligned} \tag{6}$$

where Φ_j is the standard normal distribution evaluated at $c_j(\beta)/\sigma$, ϕ_j the normal density at $c_j(\beta)/\sigma$, $\lambda_1 = \phi_1/\Phi_1$, and $\lambda_2 = \phi_2/(1 - \Phi_2)$.

Equation (6) highlights a useful parallel to more familiar econometric selection models. The terms in square brackets in (6) correct for the fact that, given the observables, consumers that sort onto the lower marginal price are different in their unobservable characteristics from those who choose the higher-tier price. This parallels conventional sample-selectivity problems inasmuch as the econometric complications in both settings stem from endogenous sorting along a budget constraint. Unlike traditional models of labour supply (such as Heckman, 1974), however, here the sorting occurs between segments of a nonlinear budget constraint. This situation generates greater information about the distribution of consumer preferences than sorting between interior and boundary solutions along a linear constraint, which makes (4) more complex than standard selection–correction models.[10]

9. To illustrate, the likelihood function for a single (monthly) consumption outcome x^* of the model (3) is a mixed continuous/discrete function with three discrete segments (one for each case in (3)). The likelihood function for the sum of 12 months' consumption outcomes therefore involves 3^{12}, or 531,441 distinct segments. While there is some redundancy involved, the task of evaluating such a likelihood function (for use in either direct or simulated likelihood methods) appears quite burdensome.

10. At the risk of confusing matters, there is one other difference between the present analysis and traditional models of labour market supply. The analysis here is more complicated because the supply and demand system is non-

The moment expressions in equations (4) and (5), and its interpretation as a selection problem, suggest that it might be possible to take a semi-parametric approach to estimating this model (following Ichimura (1993) or Das, Newey and Vella (2003)). Such methods are not designed to handle situations, such as ours, where there is no ancillary selection information about which segment of the budget constraint is marginal. That is, there are no covariates that predict a household's tariff tier that can be *a priori* excluded from the demand specification. One paper that appears to have made progress in this area is Blomquist and Newey (2002), in the context of modelling labour supply decisions subject to nonlinear income taxation. Their non-parametric approach does not appear adaptable to the present setting, unfortunately, for two reasons. First, identification appears to require considerable cross-sectional variation in price schedules across sample observations. While not a problem for the labour supply context (due to wide wage dispersion), this is a significant limitation in nonlinear pricing applications. The second, and more subtle, issue is that the non-parametric literature cannot yet handle cases where the observed outcome is the aggregation of several distinct consumption decisions that are interdependent. Demand is then implicitly defined by an equilibrium relation for which the marginal effects (of price schedule changes) may not be non-parametrically identified. Such a structure is inherent in electricity demand analyses, due to the aggregation of consumption across appliances.[11]

These considerations necessitate a parametric approach to modelling F_ε in nonlinear pricing problems, at least in our context. In estimation we use (6), which fits our data well. In general, restrictions on F_ε sufficient to evaluate the truncated moments in (5) are necessary to estimate demand elasticities and other quantities dependent on (2), in the absence of considerable (and exogenous) variation in price schedules. This, of course, raises the issue of whether such restrictions are valid for the particular application at hand. We take a formal approach to validating our model using out-of-sample testing in Section 7.

2.3. *Aggregation over time*

A method of moments framework also allows us to handle complications posed by data aggregation over time. In practice, electricity tariffs apply to households' consumption on a monthly basis. In contrast, the data available to us provide only *annual* household electricity consumption. This temporal mismatch is a potential source of bias, as the effects of prices and other time-varying covariates will tend to be confounded in the data. For example, a decrease in a household's cumulative demand over a period of several cooler-than-usual summer months could be due solely to the effect of weather, or due to an increase in seasonal electricity tariffs during the summer, or due to a composition of these two simultaneous effects. With only annual data, it is difficult to disentangle and separately identify the direct effect of marginal price changes. Yet estimating this effect is precisely what is required if we are to measure the effects of changing (monthly) tariff schedules.[12]

recursive. That is, in traditional labour supply models, the individual's labour supply function depends on the market wage, but the market wage is constant irrespective of the labour hours supplied. The slope of the budget constraint is therefore exogenous. In the present analysis, the quantity demanded depends on the marginal price (through substitution behaviour) and the marginal price depends on the quantity consumed (through the price schedule). This feature eliminates triangular-system approaches to estimation (*e.g.* Newey, Powell and Vella, 1999).

11. To elaborate, aggregation across appliances implies that a household's electricity demand x^* takes the implicit form $x^* = \sum_k f_k(p(x^*), z)$, where $p(x^*) \in \{p_1, p_2\}$ is the marginal price (which depends on total consumption) and f_k is the demand for the k-th appliance's services. Projecting observed values of x^* onto $\{p_1, p_2, z\}$ non-parametrically describes the equilibrium relation between these variables, not the marginal effect of changing the price schedule on demand. The latter is the effect of empirical interest.

12. Similar temporal aggregation problems occur in other contexts, such as when workers' wages are determined weekly (including overtime), but only monthly or annual data are available.

Addressing this problem constructively requires modelling each monthly consumption outcome, in order to avoid mis-specifying the prices consumers actually face. It also requires information on how demand conditions changed during the year. To be precise, let w_t denote the observable variables affecting consumption in month t, including the applicable price schedule and that month's weather conditions. Let x_t^* denote the household's electricity consumption in month t, and $x^a = \sum_{t=1}^{12} x_t^*$ the household's annual electricity consumption. The value of x_t^* for month t is determined by (3), using the R.H.S. covariates for that month.

To estimate the model we require an expression for the expected value of annual demand, $E[x^a \mid w_1, w_2, \ldots, w_{12}]$. Exploiting linearity of expectations, we assume

$$E[x^a \mid w_1, w_2, \ldots, w_{12}] = \sum_{t=1}^{12} E[x_t^* \mid w_t], \tag{7}$$

where $E[x_t^* \mid w_t]$ is as defined in (6).[13] That is, we evaluate the (conditional) expectation of annual demand by evaluating the monthly consumption equation 12 times, using the appropriate covariates for each month. There is no simple form for otherwise calculating the expected value of annual demand.

In the empirical analysis of demand behaviour, the expected consumption equations (6) and (7) serve two roles. They can be used to estimate a model of demand that avoids aggregation biases when consumers face nonlinear tariffs of the form in Figure 1; and, given the estimated demand model, they can be used to predict how consumption would differ under an alternative tariff structure. Proceeding to the first of these objectives next, we now consider the specification of a household electricity demand function, $x(p, y, z, \varepsilon; \beta)$.

3. HOUSEHOLD ELECTRICITY DEMAND

Like many household services, electricity is not consumed directly. Rather, electricity demand is derived from the flow of services provided by a household's energy-using appliances. The durability of these appliances creates a distinction between short-run and long-run demand elasticities. The "short-run" refers to demand behaviour taking a household's existing appliance stock as given. For example, in response to an increase in the price of electricity, a household might tolerate a warmer air conditioner setting or reduce the number of hours a pool filter operates. In contrast, long-run elasticities incorporate both changes in utilization behaviour and any adjustments to the stock of appliances owned by the household.

This distinction has important consequences for modelling demand behaviour. The long-run effects of electricity price changes are an equilibrium outcome of households' appliance replacement decisions (on the demand side) and appliance manufacturers' choices of technological characteristics and prices for new appliances (on the supply side). Like most prior studies, however, our (cross-sectional survey) data do not contain the longitudinal information necessary to estimate how these replacement decisions are prompted by changing energy prices. Thus, we focus on analysing short-run demand elasticities, and leave appliance replacement decisions for subsequent research. Our results therefore describe changes in demand

13. Equation (7) makes a subtle separability assumption about the conditioning sets, which affects household substitution behaviour over time. If we assume that households consume electricity out of permanent rather than contemporaneous (*i.e.* monthly) income, the only time-varying elements in w_t are the monthly weather-related covariates and the price schedules (being seasonal). Equation (7) makes the implicit assumption that, conditional on a household's existing appliance stock, knowledge of the electricity price schedules and weather patterns for past and future months this year has no effect on the current month's consumption. While untestable directly, this is a plausible assumption since households cannot store electricity.

due to changes in appliance utilization behaviour, rather than equilibrium appliance stock adjustments.[14]

This approach to modelling electricity demand amounts to conditioning on households' existing appliance stocks. Since households vary markedly in the set of appliances they own, however, the factors influencing electricity demand in one household may differ significantly from those in the next. We address such heterogeneity by specifying electricity demand functions at the level of the individual appliance.[15] Because we do not observe the electricity consumption of individual appliances, but rather total household electricity consumption, we treat the electricity used by each of a household's individual appliances as a latent outcome. We then aggregate these appliance-level demand specifications to model household electricity demand.

Specifically, we treat total household demand as the sum of electricity used by K distinct appliance categories. These categories include space heating, water heating, air conditioning, refrigeration, pools, and the like. If a household owns an appliance of type $k = 1, 2, \ldots, K$, we assume that electricity consumption (per billing period) for the category, x_k, takes the linear form

$$x_k = \alpha_k p + \gamma_k y + z_k' \delta_k + \varepsilon_k \tag{8}$$

where p is the price of electricity, y household income, z_k a vector of observable household characteristics, and ε_k unobservable household characteristics. The unknown demand parameters α_k, γ_k, and δ_k are assumed constant across households. Depending on the appliance, the category-specific vector z_k may include household demographic information, dwelling structure characteristics, appliance attributes, and (contemporaneous billing-period) weather data. We interpret equation (8) as household demand when it faces a constant (marginal and average) price, p.

Since a household's total electricity demand is the sum of its appliances', we can aggregate (8) to obtain

$$x = \sum_k d_k \alpha_k p + \sum_k d_k \gamma_k y + \sum_k d_k z_k' \delta_k + \sum_k d_k \varepsilon_k, \tag{9}$$

where x is total household electricity consumption, $d_k = 1$ if the household owns appliance type k, and $d_k = 0$ if otherwise. This is conveniently rewritten as

$$x = \alpha p + \gamma y + z' \delta + \varepsilon \tag{10}$$

by setting $\alpha = \sum_k d_k \alpha_k$, $\gamma = \sum_k d_k \gamma_k$, and so on. Although equation (10) looks like a conventional linear demand function, the price, income, and other slope coefficients depend upon the household's appliance portfolio. Notice that we are not estimating α directly, but rather the parameters $\alpha_1, \alpha_2, \ldots, \alpha_K$ that characterize the price-sensitivity of each appliance category (and similarly for γ, δ). Thus, this specification allows households with numerous electricity-intensive appliances, such as air conditioners, swimming pools, or electric space heating systems, to exhibit different price and income elasticities than households without such appliances.[16]

14. The element of technological change in appliance manufacturers' choices makes estimating the long-run effects of electricity price changes particularly complex. One effort to do so is the EPRI Residential End-Use Energy Planning System (REEPS) micro-simulation models; see Goett and McFadden (1984). These models build on Dubin and McFadden's (1984) model of contemporaneous appliance choice and utilization decisions.

15. This latent-variables approach to modelling electricity consumption is implicit in Fisher and Kaysen's (1962) pioneering work on aggregate electricity demand. Later studies using related approaches include Parti and Parti (1980), Barnes, Gillingham and Hagemann (1981), and Dubin (1985). The present approach is sometimes termed "conditional demand analysis" in the literature (see especially EPRI, 1989 and references therein); we avoid this usage because it conflicts with similar terminology in econometric multi-level budgeting models.

16. A separate issue not examined here is that the choice of major appliances in a residence is ultimately endogenous, and may be statistically endogenous to a model of utilization behaviour. Dubin and McFadden (1984)

Equation (10) corresponds to the conventional demand function $x(p, y)$ of classical consumer theory. That is, it specifies the amount of electricity the household would consume *if* it faced income level y and a constant price p for electricity. Since the sample households face nonlinear price schedules, the optimal consumption level is given by evaluating demand using equation (3). The expected value of demand is similarly determined, by appropriately inserting the demand specification (10) into the expected consumption equation (6).

Variances. An important aspect of this model is that the household-level demand error, ε, is heteroscedastic. This occurs because the stochastic term in the household-level demand specification is the sum of the stochastic terms associated with the K appliance utilization equations (8). Specifically, from equations (8) to (10), the variance of the household-level stochastic term is a function of the appliances owned:

$$\begin{aligned} \operatorname{var}(\varepsilon) &= \sum_{j=1}^{K} \sum_{k=1}^{K} d_j d_k \operatorname{cov}(\varepsilon_j, \varepsilon_k) \\ &\equiv \sigma(d_1, d_2, \ldots, d_K)^2. \end{aligned} \tag{11}$$

We think of the appliance-level stochastic terms as reflecting households' idiosyncratic tastes for utilizing appliances. A variety of behavioural considerations then suggest that the covariance terms entering (11) will tend to be positive, so that the variance of the household-level stochastic term will increase with the number of appliances owned.

From an econometric perspective, equation (11) is a simple model of group-wise heteroscedasticity in which the "group" is a specific portfolio of household appliances. Normally, this would not be a major concern for estimating the parameters of a linear demand specification such as (10). When consumers face nonlinear prices, however, the variance of the household-level stochastic term affects the likelihood that a consumer will fall on one tariff segment or another. This can be seen immediately from equation (6), where (the root of) the variance term, σ, enters the conditional expectation function and the tariff segment probabilities. The heteroscedastic variance of unobserved tastes thus affects expected consumption calculations and estimation of all the demand parameters.

4. ESTIMATION DETAILS

The foregoing discussion suggests a straightforward, albeit nonlinear, least-squares procedure for estimation. This is to choose as estimates the values of the unknown parameters that minimize the difference between the observed and expected annual consumption outcomes. Unfortunately, for some realizations of the data (including ours), the conditional expectation function (6) may be nearly flat with respect to σ near its true value. In essence, the first moments of the sample may contain too little information to estimate the variance components in (11) accurately. To resolve this problem, it is necessary to incorporate additional information into estimation.

We employ a generalized method of moments (GMM) procedure based on first- and second-moment differences between observed and expected annual consumption:

$$\begin{aligned} u_1 &= x^a - h_1(\mathcal{W}, \theta) \\ u_2 &= (x^a)^2 - h_2(\mathcal{W}, \theta) - 2h_1(\mathcal{W}, \theta)\,(x^a - h_1(\mathcal{W}, \theta)), \end{aligned}$$

present some evidence on this issue for gas vs. electric home heating systems. In earlier work we attempted to account for this possible endogeneity in a homoscedastic model (where the household-level error did not depend on the appliances owned; cf. equation (11)). For appliance instruments we used 30-year averages of local weather data. The results from this model did not differ noticeably from an un-instrumented homoscedastic model.

where $h_r(\mathcal{W}, \theta) = E[(x^a)^r | \mathcal{W}]$ denotes the r-th conditional moment of annual consumption, θ the unknown parameters to be estimated, and $\mathcal{W}$ all observable variables influencing the household's annual consumption. The second equation bases inference on the centred second moment of annual consumption.[17] Let β denote the demand parameters from (10) and ξ a vector of variance terms from (11), so $\theta = (\beta, \xi)$. Since optimal instruments in this setting involve (covariance-weighted) derivatives of the conditional moments h_1 and h_2, we set

$$z_1(\mathcal{W}, \theta)' = \nabla_\beta\, h_1(\mathcal{W}, \theta) \qquad \text{and} \qquad z_2(\mathcal{W}, \theta)' = \begin{bmatrix} \nabla_\beta\, h_2(\mathcal{W}, \theta) \\ \nabla_\xi\, h_2(\mathcal{W}, \theta) \end{bmatrix},$$

and base estimation on the orthogonality conditions $E[z_r' u_r] = 0$, $r = 1, 2$.[18] Note that the gradient of h_1 with respect to the variance parameters is excluded from the instruments, for the sample analogue contains no useful information (it is essentially singular—this is the reason the variance parameters are not identified by (6) alone).[19]

The functional form of $h_1(\mathcal{W}, \theta)$ is given by (6) and (7). The functional form of $h_2(\mathcal{W}, \theta)$ is derived similarly, and involves the second moment of the truncated normal distribution. In doing so, an additional complication arises due to temporal aggregation of consumption. While computing h_1 involves only the mean and variance of the stochastic term ε in the underlying monthly demand specification, evaluating h_2 requires an assumption about the correlation of ε over time. We assume that the value of ε in the household's demand specification (10) is independent from month to month. Jointly estimating an autocorrelation structure for the 12 monthly unobservables appears impractical with annual consumption data.

Estimation sequentially minimizes the metric $||A\, u(\theta)||^2$, where A is a weighting matrix held fixed during each minimization, and $u(\theta)' = [u_1(\theta)'\ u_2(\theta)']$ is the $2n$-vector of "stacked" first and second conditional moment differences for all n households. The matrix $A = \tilde{R}\, \tilde{Z}' D$, where D is a diagonal matrix containing the survey sampling weight for each observation, $\tilde{Z}$ the matrix of instruments evaluated at an initial (consistent) estimate of θ, and $\tilde{R}$ the (Cholesky) root such that $\tilde{R}'\tilde{R} = [D\tilde{Z}'\tilde{\Omega}\tilde{Z}D]^{-1}$. Here $\tilde{\Omega}$ is the true covariance function matrix $E[u(\theta)u(\theta)' | \mathcal{W}]$, evaluated at the initial estimate of θ. These covariance functions are directly computable (the non-zero elements being the second through fourth conditional moments of annual consumption), and we use their analytic expressions in estimation.

To obtain final parameter estimates, we iterated minimization of the GMM distance metric six times using successive updates of the matrix A. Full optimization required approximately three minutes on a 2·0 GHz computer, with 270 moment equations and 212 estimated parameters. Numerical optimization was performed using an efficient trust-region subspace minimization algorithm (Nocedal and Wright, 1999) and implemented in Matlab.

5. DATA AND EMPIRICAL SPECIFICATIONS

We estimate the model using data from the *Residential Energy Consumption Survey* (RECS). The RECS is conducted every three to four years by the U.S. Department of Energy to collect information on household appliances and energy use. The survey is a nationally representative

17. Centring (via the cross-product term $-2h_1(x^a - h_1)$) considerably improves sampling precision: if $(x^a)^2 > h_2$ then the cross-product term tends to be negative, and conversely if $(x^a)^2 < h_2$, which reduces the sampling variance of u_2.

18. It may be verified by direct analysis that these instruments preserve a unique solution for θ to equations $E[z_r' u_r] = 0$, $r = 1, 2$, provided that the variance function $\sigma(d_1, d_2, \ldots, d_K)^2$ is bounded away from zero.

19. In estimation we use a re-parameterization of the variance function (11) that facilitates estimation but at the cost of increasing the number of parameters. Estimation is easier because the re-parameterized GMM objective function is orthogonal in each of the 154 variance parameters. This re-parameterization imposes positive definiteness but otherwise places no restrictions on the covariance matrix in (11).

probability sample of households, with representative subsamples for several large states. We use the California subsamples of the 1993 and 1997 survey waves. Together they provide information on 1307 California households.

The survey is conducted through in-home interviews. Interviewers inventory the household's appliances, assess physical characteristics of the residence, and collect demographic information. The survey also includes weather data (heating and cooling degree-days) for each household, which are obtained from the nearest National Weather Service (NWS) station during the survey year. Each household's metered energy consumption data are collected by the survey directly from its electric utility. Further details about the RECS data and survey design are available in EIA (1994, 1996).

The appliance information, representativeness, and quality of the consumption data make the RECS particularly valuable for analysing household electricity demand. There are, however, two noteworthy shortcomings of the RECS data. The first is that the RECS public-use files only provide *annual* household electricity consumption and expenditures, as noted in Section 2. The second shortcoming pertains to the limited electricity tariff information available in the survey. Inadequate pricing data are a first-order problem for many previous studies of electricity demand and for other researchers using the RECS. Our considerable efforts to rectify this problem merit a brief digression here.

5.1. Prices

During the sample period most California households faced an increasing two-tier electricity price schedule each month, such as the one depicted in Figure 1. These schedules vary by service provider, climate zone, household heating system, household income, and season. For example, the state's largest utility, Pacific Gas and Electric (PG&E), had 72 variants of its standard residential rate schedule in effect during 1993 and 1997. A similar structure applies to the state's other major utilities.

The RECS data provide two summary price measures for each household. The first is the household's annual average electricity price, in cents per kilowatt-hour. The second is the local electric utility's annual average revenue per kilowatt-hour sold to all its residential customers. Either of these price measures unfortunately presents problems for modelling electricity demand at a disaggregate (household) level. As noted in Section 2, the first of these two price measures is endogenous (it rises with consumption) and bears a complex relation to the household's monthly use. The second, utility-level average price, while putatively exogenous, will typically mis-measure the actual marginal price faced by a household. Either summary price measure could therefore be expected to provide poor information regarding the marginal price facing the household each month, and thus biased price elasticity estimates.

To address these shortcomings, we developed a procedure for matching each observation in the RECS with the complete rate schedule facing the household. The data this requires that are not provided in the RECS are each household's utility and its utility-designated climate zone. To determine these, we exploit three types of information in the RECS about the household: the local utility's average electricity price, the availability and price of natural gas, and the weather information. The weather data provide considerable information regarding where in California's diverse climate zones each household is located. The utility-level electricity and natural gas price data then help pinpoint the household's service provider.

To match each RECS household to its utility and climate zone, we first used maps of utility service areas to assign each of the approximately 240 NWS stations in California to one (or two adjacent) utility service territories. We then collected the local average electricity and gas prices for each service territory in the state. These weather and price data are the same primary data series used by the RECS and included with each household in the survey. We then determine each household's utility and climate zone by matching the household's information in the RECS with the known average price and weather data for each utility and NWS station in California.

The remaining information necessary to determine a household's specific rate schedule (namely, the household's income and its home heating system) are directly available in the survey. We also used the RECS's electricity expenditure data to determine which eligible low-income households are actually participating in their utilities' low-income electricity tariff programmes. To complete the procedure, we manually compiled the complete 1993 and 1997 electricity tariff books for each California utility, from filings archived at the California Public Utilities Commission public records library and direct contact with municipal utilities' tariff departments. In the end, the 1307 California households in the RECS sample were matched to 189 distinct rate schedules.

Table 1 provides some information on how well this matching procedure performs. As the survey is a stratified probability sample of California households, we expect (and find) reasonable agreement between what the utilities report as their number of residential accounts and the number of households implied by the survey. For the five largest utilities (which serve 93% of California households), the implied geographic distribution of RECS households by utility is quite close to that reported in the utilities' regulatory accounting data. The most notable deviations occur for the two smallest investor-owned utilities, Sierra Pacific and PacifiCorp, which serve sparsely populated mountainous northern and eastern areas of the state. We believe that the stratification design and a special segment of the RECS that oversamples low-income households may account for their overrepresentation.[20]

5.2. *Appliance demand specifications*

Our monthly appliance demand specifications are based on prior empirical research that has studied households' appliance use decisions. Principal sources are the EPRI/REEPS model described in LBL (1995) and the EIA Residential End-Use Model, EIA (1995). We model end-use electricity demand using eight distinct appliance categories: (1) baseline electricity use; (2) electric space heating; (3) central air conditioning; (4) room air conditioning; (5) electric water heating; (6) swimming pools; (7) additional refrigerators and freezers; and (8) other appliances. The baseline category accounts for the electricity consumption of appliances that are universally owned, such as the (first) refrigerator and lights. This category also implicitly includes consumption attributable to any unspecified electrical appliances below the resolution of the RECS survey (such as electric clocks, irons, hair dryers, and the like). Appliance categories two through six are energy-intensive end uses that previous research indicates exhibit some utilization price elasticity (EPRI, 1989). The final category includes less energy-intensive household appliances. A description of all appliances entering the model is provided in Table A1.

Different factors influence appliance-level electricity demand in each category. In particular, we estimate separate price and income effects for each of the first six categories. The remaining appliances are assumed to have a common price effect, as previous studies indicate most of these (refrigeration, cooking, clothes dryers, etc.) exhibit no significant electricity price elasticity. Demographic and other explanatory variables entering the model are defined in Table A2. Demographic characteristics of households are assumed constant during the survey year; the

20. We are grateful to U.S. Energy Information Administration analysts for lengthy discussions on these RECS sampling issues. One unresolved issue is the RECS sampling weights imply 350,000 more California households with electricity service than comparable figures in California utilities' regulatory accounting data (this is evident in the bottom line of Table 1). In addition, the survey's cluster sampling procedure will generally yield uneven coverage of smaller utility service areas.

TABLE 1

Average price and number of households for California electric utilities

	Average residential rate in 1993[a] (cents per kWh)	*Number of households*		*Per cent of households*	
		Actual[a]	Estimate[b]	Actual[a]	Estimate[b]
Investor-owned utilities					
Pacific Gas & Elec.	12·25	3,748,831	4,069,268	34·8	36·6
Southern Calif. Edison	12·10	3,636,295	3,655,184	33·8	32·9
San Diego Gas & Elec.	10·81	1,005,257	1,020,010	9·3	9·2
PacifiCorp (Calif.)	6·94	31,872	351,053	0·3	3·2
Sierra Pacific Pwr. (Calif.)	8·79	36,581	169,317	0·3	1·5
Investor-owned subtotal		8,458,836	9,264,832	78·5	83·3
Municipal/public utilities					
Los Angeles	9·85	1,168,229	1,169,431	10·8	10·5
Sacramento	7·65	416,364	377,054	3·9	3·4
Riverside	10·57	80,828	35,510	0·8	0·3
Imperial	8·36	67,021	7592	0·6	0·1
Santa Clara	7·30	38,129	126,735	0·4	1·1
Lompoc	9·21	12,729	61,569	0·1	0·6
Plumas-Sierra	7·70	4674	82,557	0·0	0·7
Subtotal		1,787,974	1,860,448	16·6	16·7
Other municipal/public utilities[c]		526,480	0	4·9	0·0
State total		10,773,290	11,125,280	100·0	100·0

[a]Sources: U.S. Dept. of Energy Form EIA-861 (1993), FERC Form 1 (1993).
[b]Estimate based on the 1993 RECS survey data (see text).
[c]Households served by other small municipalities, rural electric cooperatives, and public power districts.

monthly varying covariates in our specifications are the price schedules and the weather data.[21] All monetary variables are normalized to real (June 1993) prices, using the CPI-U series for California's three consolidated metropolitan statistical areas.

6. RESULTS AND IMPLICATIONS

6.1. Estimates and marginal effects

Table 2 presents the model's estimated marginal effects for the principal variables of interest. Table entries show the effect of a one unit increase in each explanatory factor on monthly kilowatt-hour consumption of each specified appliance. We compute marginal effects separately for each household (using the gradient of its conditional expectation function (6)), and then average across households using the RECS sampling weights. These are interpretable as the mean marginal effects in the population, conditional on ownership of the indicated appliance. Raw demand parameter estimates are reported in Table A3. The fitted model has a mean square error of (2352 kWh/year)^2, which is approximately one-third of the sample variance of consumption.[22]

21. In addition to the specifications evident in Table A3, we imposed a constraint that electricity consumption for space heating and cooling is zero during the summer and winter months, respectively. To accommodate the varied heating and cooling season lengths for different regions and elevations in California, this was implemented via a minimum (one per day) degree-day threshold for the use of these appliances.

22. Hansen's over-identification test statistic is 76·9, which under simple random sampling has $p = 0{\cdot}05$ (df $= 58$) asymptotically. The RECS is not based on simple random sampling, however. Its multi-stage sampling design implies the actual critical value of this test statistic will be larger (possibly much larger) than its nominal counterpart. We take an alternative formal approach to testing model fit in Section 7, using standard errors adjusted by the survey's design

TABLE 2

Estimated marginal effects (asymptotic standard errors in parentheses)

Explanatory variable	*Effect on kWh consumed per month for:* [a] Baseline use	Elec. space heating [b]	Central air cond. [c]	Room air cond. [c]	Elec. water heating	Swimming pool
Price (cents/kWh)	0·4 (3·7)	−37·8 (14·8)	−22·5 (21·3)	−63·4 (31·1)	−34·0 (9·5)	−27·5 (18·4)
Income ('000 $)	0·4 (2·3)	16·2 (13·0)	9·1 (10·6)	21·6 (20·8)	−32·8 (7·5)	6·3 (9·8)
No. of members	18·0 (3·3)	−7·9 (20·3)	−38·6 (16·3)	−52·1 (19·9)	47·5 (10·6)	
No. of rooms	12·9 (4·5)	20·4 (22·0)	9·8 (17·4)	29·2 (23·4)	−35·3 (15·2)	
No. of bathrooms	27·0 (9·8)				119·0 (40·1)	
Heating deg.-days ('00 °F, base 60)	−10·6 (6·3)	43·3 (21·9)				
Cooling deg.-days ('00 °F, base 70)	−59·5 (22·5)		233·0 (57·0)	45·1 (123·0)		
Dummy variables						
Apt. building	−48·4 (14·1)					
Housing project	−78·9 (24·6)					
At home during day	15·8 (10·0)					
Urban location	−35·5 (11·9)					
Rural location	31·4 (25·1)					

(Effects of additional appliances are shown in Table A4)

[a] Estimated change in monthly appliance electricity consumption associated with a unit increase in the explanatory variable, *ceteris paribus*. The marginal effects shown are estimated population means, conditional on appliance ownership.
[b] Heating-season months only.
[c] Cooling-season months only.

The signs and magnitudes of the estimates in Table 2 generally agree with prior studies, although there are a few exceptions.[23] The estimated price effects vary substantially across appliances. The smallest effect is associated with baseline use, and is effectively zero. All other appliance price sensitivities are of considerable practical significance. For example, the −27·5 estimate for price and swimming pools in Table 2 implies that a one cent per kilowatt-hour (kWh) increase in the marginal price would reduce a household's annual utilization of pool pumps and motors by approximately 330 kWh per year, which is 15% of a pool's typical electricity use. The

efficiency ratios to account for its complex sampling design.

23. For example, the negative coefficients on income and on the number of rooms in the water heating specification. We suspect this may be due to confounding from unobserved variation in water heater energy efficiency, which is likely to be considerably higher in newer (larger) homes in California. The negative coefficients on the number of household members and space cooling are also of unexpected sign, and may be attributable to an omitted (positive) influence of householder age on space cooling demand.

TABLE 3

Price and income elasticities for California households

Mean elasticities of electricity demand[a]	Price: GMM method	Price: OLS method	Income: GMM method	Income: OLS method
All households	−0·39	+0·16	−0·00	+0·00
Households with:				
Electric space heating	−1·02	−0·46	−0·00	+0·01
No electric space heating	−0·20	+0·35	−0·00	−0·00
Central or room air conditioning	−0·64	+0·05	+0·02	+0·02
No air conditioning	−0·20	+0·24	−0·01	−0·01
No electric space heating nor air conditioning	−0·08	+0·39	−0·01	−0·01

[a] Annual elasticities (see text and Appendix B).

price effects for major appliances providing space heating, cooling, and water heating services differ from one another considerably, both in absolute terms and relative to typical consumption for each appliance (see Table A4).

By contrast, the income effects are mostly statistically insignificant and negligible as a practical matter. This is not entirely surprising, given that our analysis is conditional on households' appliance stocks. To the extent that income affects electricity consumption, it is evidently manifest through households' choices of appliances rather than through utilization behaviour. These results are consistent with prior studies' findings of low-to-negligible appliance utilization income elasticities at the household level (*e.g.* Parti and Parti (1980) and Dubin and McFadden (1984)).

Details on specific appliance-level consumption estimates are provided in Appendix A and Table A4.

6.2. Price elasticities

Table 3 presents estimated average annual household price and income elasticities. These elasticity estimates correspond to the percentage change in a household's annual electricity consumption resulting from a 1% increase in the marginal price (or household income) in each month of the year, holding the appliance stock fixed. We calculate demand elasticities separately for each of the 1307 households in the sample, and then average using the survey sampling weights. The elasticities shown in Table 3 are estimated population means for California households.

Before interpreting these numbers, it is important to note that with nonlinear tariffs there is more than one "price" involved in measuring the elasticity of demand. For example, one can calculate the elasticity of demand with respect to an increase in the intercept of the price schedule, with respect to the price of a specific tariff tier, or with respect to the consumer's marginal price. We present elasticity estimates based on the third of these interpretations, so as to reflect households' demand sensitivity on the margin. In doing so we recognize the fact that with multi-part tariffs, changing a consumer's marginal price may alter consumption within the current tariff segment or induce a discrete jump to a different price tier. Our elasticity calculations explicitly account for this possibility, using methods described in Appendix B.

We estimate the mean annual electricity price elasticity for California households to be −0·39. Previous studies of residential electricity demand data have estimated widely varying utilization price elasticities, ranging from nearly zero to about −0·6. These estimates reflect differences in the geographic regions examined, as well as considerable variation in data quality and statistical techniques. Studies conducted by electric utilities, which often have higher-quality data, tend to obtain price elasticities within a narrower range of −0·15 to −0·35 (EPRI, 1989). Our results with the California RECS data fall at this set's upper end, but are close to the −0·35 estimate contained in a much earlier Rand Corporation study of Los Angeles-area households by Acton, Mitchell and Mowill (1976).

It is useful to compare our estimates to those using more traditional estimation methods. The second column in Table 3 shows the elasticities obtained if we ignore the simultaneity of price and quantity under nonlinear pricing and simply perform OLS using the household's average price. The resulting mean price elasticity estimate is +0·16, which has the wrong sign. Such large biases are typical when simultaneity is ignored in electricity demand studies, for the simple reason that there is wide (cross-sectional) variation in demand but relatively limited variation in the price schedules. OLS techniques using the consumer's average or marginal price therefore tend (in essence) to fit the average slope of the price schedule. Similar biases are noted in Dubin (1985) and Maddock *et al.* (1992).

Additional regressions that use other summary price measures appearing in the literature (*e.g.* the midpoint of the two tiers or utility-level average prices) yield elasticity estimates of the correct sign, but much smaller in magnitude than the GMM results using the complete rate schedule. For example, estimates obtained using OLS with the (statistically exogenous) utility-level average price measure in the RECS yield a mean household price elasticity of −0·28.[24] This estimate is consistent with the bias toward zero that one would expect due to this proxy's mis-measurement of the consumer's actual marginal price. It also suggests an explanation for why our GMM estimates imply somewhat more price-elastic behaviour than many earlier studies' (particularly the utility-conducted studies noted above), in that most prior work treats tariff structure information in either an *ad hoc* manner or not at all.

Heterogeneity in price sensitivity. The disaggregate data also reveal considerable and meaningful heterogeneity in households' price and income elasticities. As noted previously, the model permits households' price and income elasticities to vary across households not just with their consumption level, but also with their appliance holdings. Table 3 illustrates the marked differences in demand elasticities for households with different heating and cooling systems. Households with electric space heating or air conditioning exhibit a much higher electricity price elasticity than households without such systems. Households that do not use electricity for either of these purposes have an estimated mean price elasticity very close to zero. This heterogeneity is consistent with the limited prior evidence on electricity price elasticity variation across households (*e.g.* Dubin, 1985). As a practical matter, it suggests that there are effectively two "types" of households with respect to electricity demand behaviour: those who use electricity for space heating or air conditioning and exhibit some electricity price elasticity, and those who do not and are price insensitive.

Further information about the heterogeneity in households' demand elasticities is provided in Figure 2. This histogram of the sample households' price elasticities is constructed (using the survey weights) to represent the distribution for the California population. The point-mass at zero

24. Price elasticity differences of seemingly small amounts (*e.g.* −0·28 vs. −0·39) are economically quite important in electricity markets. Assuming residential demand is too inelastic by this difference of −0·1 when increasing the marginal rate by (say) three cents per kWh would overestimate annual revenue for California's larger utilities by approximately 75 million dollars.

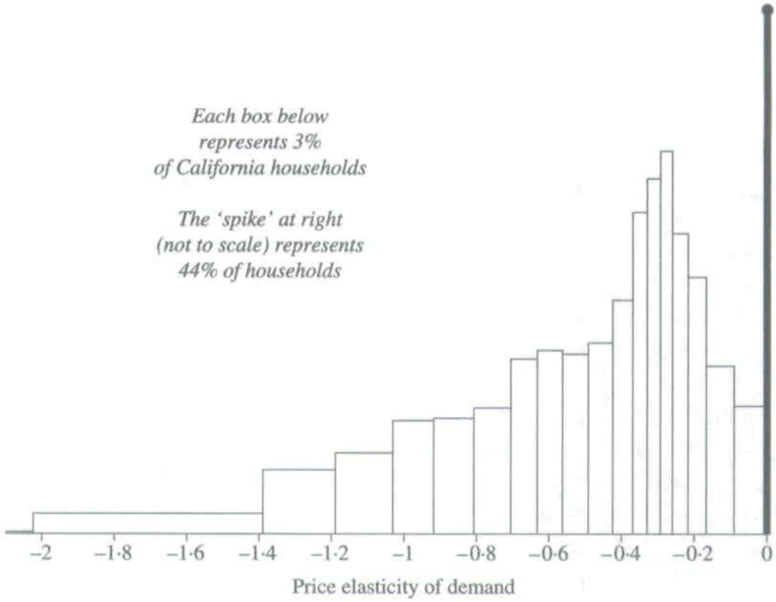


FIGURE 2
Estimated distribution of California households' electricity price elasticities

indicates that 44% of California households exhibit no short-run demand sensitivity to changes in the marginal price of electricity. This segment of the population is primarily households that own no major electric appliances other than a refrigerator, and whose minor appliances fall within the inelastic "baseline use" category of the model. The expected fraction of households whose demand curves cross their price schedules in the "gap" between the two price tiers is 1–2% each month. Thus, very few households have a locally zero estimated price elasticity due only to the discontinuity in the price schedule.

The striking feature of Figure 2 is its highly asymmetric, negatively skewed shape. This pattern indicates that most households will alter their electricity consumption very little in response to a price change. A small fraction of households, however, are actually elastic demanders (roughly 1 in every 8 families) and would react with large changes in their electricity use. This has noteworthy implications for the welfare effects of electricity price changes, inasmuch as most of the dead-weight welfare losses from a price increase would evidently be borne by a fairly small share of the consumer population.

Where a household is located in this distribution is related to its income and other demographic characteristics. Table 4 summarizes household electricity price elasticities by income and consumption levels. How price elasticities vary with household income (in the cross section) is of interest because regulatory commissions provide subsidized tariffs to low-income households, and are at times concerned with the consumption incentives of these subsidies. The conventional wisdom is that households with lower incomes are more sensitive to energy prices than households with medium-to-high incomes. The results in the top half of Table 4 are consistent with this view, although the magnitudes of these differences are not dramatic.

The lower half of Table 4 indicates how household price elasticities vary with the amount of electricity the household consumes. This relationship is of interest because the aggregate consumption and revenue effects of a tariff change depend upon how elasticities vary across the different tiers of the price schedule. Somewhat surprisingly, we find that elasticities are lower

TABLE 4

Price elasticities by household income and electricity consumption

Quartile	Quartile range	Price elasticity[a] GMM method	Price elasticity[a] OLS method
By household annual income level:[b]			
1-st	Less than $18,000	−0·49	+0·15
2-nd	$18,000 to $37,000	−0·34	+0·17
3-rd	$37,000 to $60,000	−0·37	+0·14
4-th	More than $60,000	−0·29	+0·17
By household annual electricity consumption:			
1-st	Less than 4450 kWh	−0·46	+0·37
2-nd	4450 to 6580 kWh	−0·35	+0·04
3-rd	6580 to 9700 kWh	−0·32	−0·00
4-th	More than 9700 kWh	−0·33	−0·08

[a] Mean annual electricity price elasticity for households within each quartile.
[b] Approximate California household income quartiles, in 1998 dollars.

for households that use high amounts of electricity, despite the fact that households with energy-intensive electric space heating/cooling systems have much greater electricity price sensitivity *ceteris paribus*. This inverse relationship reflects both a weak correlation between household income and ownership of electric space heating/cooling systems, and the fact that households tend to substitute toward more price-inelastic electricity uses as income rises. Thus, from an economic efficiency standpoint, the welfare cost of raising a given amount of revenue will be minimized if the marginal price changes are disproportionately larger for the highest-demand consumers.

Further results along these lines using different data are examined in Reiss and White (2003).

7. VALIDATION: THE 1998 PRICE CHANGES

Our empirical results rest in part on the appliance demand specifications and error distribution assumptions of the model. Because we must aggregate over appliances and over time to match the consumption level of the data, these appliance demand specifications are not testable directly. In this section we examine the model's validity using both within- and out-of-sample tests.

7.1. Within-sample fit

For purposes of interpreting the out-of-sample test below, it is useful to first examine the representativeness of the RECS consumption data and in-sample model predictions. Because electric utilities are subject to extensive regulatory reporting requirements, there exist comprehensive aggregate data on utilities' actual sales and number of customers. In principle, averages from these data will differ from their counterparts for the RECS households by amounts attributable to the survey's sampling error.

Some evidence on this issue is provided in Table 5. The first numerical column in Table 5 presents actual electricity consumption per household for California and its four largest utilities. The second column presents the corresponding mean electricity consumption for the RECS

TABLE 5

Within-sample predicted and actual consumption

Electricity consumption per household, in kWh	Actual[a]	Sample data: Sample mean	Sample data: Standard error[b]	Sample data: Actual error	Estimated model: Predicted mean	Estimated model: Average within-sample error
Pacific Gas & Elec.	6531	5796	258	+735	5899	+103
Southern Calif. Edison	6238	6063	291	+175	5961	−102
San Diego Gas & Elec.	5706	4627	514	+1079	4775	+148
Los Angeles Wtr. & Power	5261	5113	454	+148	4867	−246
All California	6355	6007	157	+348	6010	+3

[a] Weighted average of the total residential sales (in kWh) divided by the number of residential accounts in each of 1993 and 1997, as reported by each utility. Source: U.S. Dept. of Energy Form EIA-861 (1993, 1997).

[b] Standards errors shown account for the multi-stage sample design of the RECS (see EIA, 1994).

sample households along with the standard error of the survey. For the state as a whole, Table 5 implies that the RECS sample under-represents actual household electricity consumption by slightly more than two standard errors. We also find that the RECS data understate average household consumption for each of the state's four largest utilities, although by sometimes less than two standard errors.[25]

The final columns compare the model's predictions to these actual and sample consumption averages. Since the model is fitted to the RECS data, the difference between the observed and predicted averages represents within-sample error. Although our model is nonlinear, the average within-sample error for the full sample is essentially zero. As with the raw sample data, however, the estimated model under-predicts actual consumption for each utility and the state overall. This is not entirely surprising, given that the model can at best capture the behaviour of the sample to which it is fitted. We conclude that while the RECS sample appears to understate actual household consumption in California, the model does reasonably well (*i.e.* within a few per cent) at fitting the sample data for each utility.

7.2. *Out-of-sample tests*

In January 1998, shortly after the end of our sample data, California's three largest investor-owned utilities reduced the price of residential electric service by 10%. This price change, by virtue of its magnitude and exogeneity to the household, provides a unique opportunity to evaluate the model's out-of-sample accuracy. We also account for the El Niño Pacific weather disturbance that occurred in 1998 and 1999, which changed California's weather patterns substantially.

Ideally, we would prefer to evaluate the model using within-household differences in predicted and actual consumption between 1997 and 1998 (*i.e.* a matched-pair test). Unfortunately, due to the triennial (and non-longitudinal) nature of the RECS, we do not have data on actual consumption after 1997 for the sample households. Instead, we base inference on

25. There are other reasons why the *utility-specific* averages might differ between the RECS and the actual (regulatory accounting) data. First, while the RECS is designed to generate a representative sample of households at the state level, the sampling scheme is not designed to produce representative samples within each utility's service territory. Second, the household-utility matching procedure we use to obtain rate schedules (in Section 5) introduces potential misclassification error. The difference in state-level average consumption between the RECS and the regulatory accounting data is not subject to these caveats, however.

TABLE 6

Out-of-sample prediction tests for 1998 and 1999

Utility electricity sales per household, in kWh	Actual[a]	Predicted	Difference	Std. error	Prob.[b]
		Panel A: 1998			
Pacific Gas & Elec.	6775	6198	+578	252	0·02
Southern Calif. Edison	6455	6233	+223	280	0·43
San Diego Gas & Elec.	5935	5005	+930	580	0·11
Los Angeles Wtr. & Power	5438	4885	+554	498	0·27
		Panel B: 1999			
Pacific Gas & Elec.	6905	6187	+718	267	0·01
Southern Calif. Edison	6423	6257	+136	292	0·64
San Diego Gas & Elec.	5964	5078	+886	647	0·17
Los Angeles Wtr. & Power	4866	4826	+40	496	0·94

[a] Total residential sales (in kWh) divided by the number of residential accounts, as reported by each utility. Source: U.S. Dept. of Energy Form EIA-861 (1998, 1999).

[b] Approximate probability of a difference between actual and predicted at least as large (in magnitude) as observed, under the model.

comparisons to the average household consumption reported in California utilities' regulatory accounting data for 1998 and 1999.

To implement a formal test we first extended the actual weather series used in the model through 1998 and 1999. We also collected the exact form of the tariff changes implemented in 1998 and 1999 for each RECS household.[26] We then use the model to predict what the RECS households would have done in 1998 and 1999, given the price change and weather conditions that occurred, and aggregate these responses to the utility level.

Table 6 compares these out-of-sample predictions to actual residential electricity consumption for California's four largest utilities in 1998 and 1999. The second-to-last column provides estimated standard errors for the difference between the actual and predicted consumption averages. These standard errors account for both the non-sampling variance in future consumption outcomes under the model, and the sampling error associated with the RECS multi-stage design.[27] The final column reports the (two-sided) probability of observing a difference at least as large as that shown, under the maintained assumptions of the model. Small p-values constitute evidence against the validity of the model.

As the within-sample results foreshadowed, the model continues to under-predict average consumption in 1998 and 1999. For three of the four utilities in each panel, however, the observed differences from the model's predictions are within the bounds of what may be ascribed to chance by conventional standards of statistical significance. The smallest p-values, for Pacific Gas and Electric in 1998 and 1999, are attributable to the particularly acute under-representativeness (relative to sampling error) of the RECS households' consumption data for

26. The January 1998 price decrease amounted to lowering each tier of the household's price schedule by 10%. The actual marginal price change thus depends upon the household's particular rate schedule. There was also a separate price increase for households served by the Los Angeles Department of Water and Power in 1999, which shows up as a notable decline in consumption for Los Angeles households between 1998 and 1999.

27. Since we have a nonlinear model and the RECS uses a multi-stage sampling design, the standard errors for this test are approximate. We use a linear approximation (delta) method to estimate the variance of average predicted consumption under simple $(1/n)$ random sampling, and then inflate the result by the design efficiency ratio of the RECS consumption series (about 1·4) to get the standard errors in Table 6. This method and related techniques are discussed in Skinner, Holt and Smith (1989).

this utility. Interestingly, for three of the four utilities in each panel, the model's average error (relative to actual) is smaller for the out-of-sample years of 1998 and 1999 than it is for the within-sample years reported in Table 5. On that basis, the model appears to deliver reasonable predictions for how California households respond to electricity price changes.

8. ANALYSING PROSPECTIVE TARIFF DESIGNS

An important feature of the model developed above is that it can be used to evaluate, on a prospective basis, the effects of complex price schedule changes. For a variety of practical reasons, regulatory agencies are often reluctant to authorize randomized-assignment pricing experiments as a means to evaluate major tariff changes. Thus, counter-factual simulations based on econometric models become the analytic method of choice. The accuracy of these simulations is a matter of considerable practical interest, inasmuch as tariff changes for electricity can affect billions of dollars in consumer expenditures.

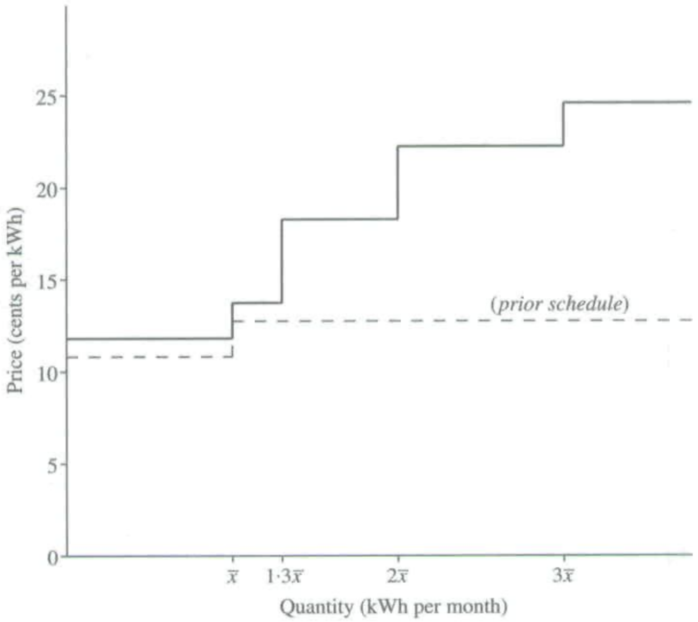
In this section, we provide consumption and expenditure estimates for a complex tariff design being implemented in California. Following a financial crisis facing that state's utilities in the spring of 2001, the California Public Utilities Commission approved new tariff structures for the state's two largest utilities. The new multi-part tariff structure for residential electric service is shown graphically in Figure 3. Under this five-tier design, the household inherits from its prior (two-tier) tariff a monthly reference quantity, $\bar{x}$. The first $\bar{x}$ kilowatt-hours of monthly electricity consumption are then billed at one price per kilowatt-hour, the next $30\% \times \bar{x}$ are billed at a higher price, and so forth as indicated in Figure 3. The reference quantity $\bar{x}$ and the specific tier prices vary based on the utility, the season, the household's climate zone and home heating system, and other factors.

This novel pricing system is intended to achieve several objectives. First and foremost is to raise additional revenue for the state's utilities. Second, the new tariff is intended to promote energy conservation, particularly among higher-demand consumers. Third, there is a distributive objective underlying this tariff design. Electricity is a necessary good (in the sense that its budget share declines as household income rises), so a uniform increase in the price of electricity can be quite regressive. By raising marginal prices more for higher levels of consumption, regulatory authorities hope to attenuate this regressivity and minimize expenditure changes for lower-income households.

Because the five-part tariff is unprecedented in historical consumption data, there is no way to extrapolate how well this new system would achieve these objectives using descriptive (*i.e.* reduced-form) econometric methods. Rather, predicting aggregate demand requires explicitly modelling consumer choice behaviour under the new tariffs. To do so, suppose j indexes the five tiers in Figure 3, p_j is the marginal price on tier j, and $\bar{x}_j$ is the j-th-tier upper boundary. Set $x_j = x(p_j, y_j, z, \varepsilon; \beta)$, where y_j denotes the household's income plus the cumulative infra-marginal price discount applicable in tier j. Conditional on observable household characteristics, the expected value of monthly household consumption is then

$$E(x^* \mid \cdot) = \sum\nolimits_{j=1}^{5} P_\varepsilon(\bar{x}_{j-1} < x_j < \bar{x}_j) \cdot E_\varepsilon(x_j \mid \bar{x}_{j-1} < x_j < \bar{x}_j) + \sum\nolimits_{j=1}^{4} P(x_{j+1} < \bar{x}_j < x_j) \cdot \bar{x}_j \tag{12}$$

using the conventions $\bar{x}_0 = 0$, $\bar{x}_5 = \infty$, and P_ε the distribution of ε given the observables. The first sum is the contribution to expected consumption conditional on demand crossing the price schedule on one of the five steps, and the second sum is the contribution conditional on demand crossing the price schedule in one of the "gaps" between the steps. As before, this



Notes: The reference quantity, $\bar{x}$, varies across households and seasons. The rates depicted above are for the most common residential tariff schedule for this utility. The prior schedule shown applied from 1998 through 2000.

Source: Southern California Edison PUC Advice Letter 1545E, Schedule D, Tariff Sheet 29197E (2001).

FIGURE 3

A five-tier price schedule Southern California Edison, Residential Electric Service

amounts to a probability-weighted average of expected demand within each segment of the new tariff schedule. Stated in behavioural terms, the consumer sorting-on-the-unobservables problem that occurs with multi-part tariffs must be addressed not only in demand estimation, but also when predicting consumption at new prices.[28] Such nonlinearities are why the aggregate impacts of a new tariff design depend, sometimes delicately, upon the heterogeneity in consumers' price elasticities across the population.

We use equation (12) and the estimated demand model to evaluate a five-tier tariff system adopted by the California Public Utilities Commission in May 2001. With little prior analysis, this system was implemented the following month for approximately 7·8 million households served by the Pacific Gas and Electric Company and the Southern California Edison Company. We use these utilities' tariff books to identify the terms of the new tariff applicable to each household in the RECS sample. We also evaluate these tariff changes for "normal" weather conditions, using 30-year average degree-days from the NWS station located nearest each household. The tier selection probabilities in (12), which depend upon both the household and its particular tariff schedule, are evaluated using the normality assumption and household-specific variance estimate from the econometric model. We evaluate the expected consumption equation

28. In particular, equation (12) differs from what one obtains by simply intersecting the household's estimated demand curve (assuming ε to be zero) and the new price schedule. That technique implicitly treats the tariff segment selection probabilities in (12) as either zero or one, and ignores the conditional expectation adjustment for ε in each tariff segment. Unless the variance in the household's future consumption (given the observables) is in fact zero—a highly unlikely circumstance—such a technique will systematically misestimate consumption under a new price schedule.

TABLE 7

Household consumption and expenditure changes with five-tier tariff schedules (all monetary amounts in constant 1998 dollars)

Means per household[a]	All households	By income quartile[b] 1-st	2-nd	3-rd	4-th
Consumption (kWh/year)					
With 2 tiers (1998)	6196	5524	6299	6330	7455
With 5 tiers	5578	4987	5677	5519	6637
Change (%)	−10·0	−9·7	−9·9	−9·7	−11·0
Expenditures ($/year)					
With 2 tiers (1998)	718	633	734	734	873
With 5 tiers	897	770	921	925	1120
Change (%)	24·8	21·6	25·4	25·9	28·3

[a] Estimated population means for the 7·8 million California households served by the Pacific Gas and Electric Corporation or the Southern California Edison Company. For calculation methods, see text.
[b] For income quartile breakpoints, see Table 4.

separately for each of the 1307 households in the RECS sample, and average these predictions using the survey sampling weights. A similar formula and procedure is used to estimate each household's (expected) expenditures under the new tariff.[29]

Table 7 provides estimates of average household electricity consumption and expenditures under the new five-tier tariffs. For comparison, we also show the values obtained using the prior two-tier tariff schedules in effect from 1998 through 2000. The first numerical column presents estimated population means for all the 7·8 million affected households. The results indicate their average (and aggregate) annual electricity consumption would be approximately 10% lower under the new five-tier tariff system than under the preceding tariffs over a normal weather year. The corresponding increase in annual household electricity expenditures is approximately 25%, or $179 per household (in 1998 dollars). To put this in some perspective, $179 is 8% of the average 1998 state personal income tax liability per household in California.

Our expenditure results are considerably lower than the official estimates of the California Public Utilities Commission. That agency predicted the increase in the two affected utilities' total residential electric revenues would be approximately $1·8 billion annually, or $228 per household. The difference between these two estimates can be explained largely by differences in the treatment of demand elasticities. In particular, the Commission uses a "static scoring" method for predicting the revenue change associated with a new rate schedule design. This amounts to assuming that each consumer's annual demand is completely price-inelastic, so that expenditure changes can be predicted by applying the old and new tariff schedules to the same consumption data. Inasmuch as consumers do exhibit some demand elasticity, this method overestimates revenue associated with the higher tariff structure.

Since the model we employ is estimated with survey data, we have information on individual households' income levels that can be used to examine the distributional consequences of tariff changes. This issue has not been examined quantitatively in the state regulatory agency's tariff

29. Note that approximately 10% of households participate in a low-income tariff programme that is exempt from the new tariff designs. These households appear in our sample, and our predictions for them use their (unchanged) tariffs. The predictions do not account for changes in an eligible non-participating household's incentive to apply for this programme, however.

models, as their analyses rely upon utilities' billing data that do not include income information. The additional columns in Table 7 report the model's predictions for average consumption and expenditures by household income quartile. Not surprisingly, under either tariff electricity consumption and electricity expenditures increase with household income. What is interesting to note, however, is that in percentage terms the change in household electricity consumption between the new and old tariff systems is nearly constant across income quartiles. That is, the larger marginal price increases paid by households consuming higher quantities more or less exactly offsets the increasingly inelastic demand behaviour of households with higher incomes (see again Table 4).

A similar phenomenon is evident in the estimated expenditures. In absolute terms, however, the increase in expenditures across income quantiles does not rise nearly as fast as income. This implies, and can be verified directly in the unsummarized data, that the new tariff is (slightly) more regressive than the system it replaces. It is, however, considerably less regressive than a revenue-equivalent traditional uniform rate increase, whose distributional impacts California policy-makers have sought to avoid.

9. CONCLUDING REMARKS

The practical motivation for this paper arose from an acrimonious—and, we believe, poorly informed—debate over the consequences of major electricity price changes in California. Our objective is not to impugn the decisions ultimately made and examined here, however; rather, it is to show how more sophisticated empirical methods, in conjunction with detailed micro-survey data now available, can be productively harnessed to resolve *ex ante* the policy-making uncertainties that fuel such debates.

It is worth noting that substantively similar methodological issues arise in a variety of other markets. Regulatory pricing of local telephone service (a perennially controversial matter) and residential water use are leading examples. In those markets nonlinear pricing is quite common, and formal demand analysis is a largely accepted part of the price-setting process. The econometric issues addressed in this paper would appear particularly germane to those contexts. In a substantively different setting, there are close parallels between the analytic methods used here and the micro-simulation procedures commonly used to evaluate tax code changes. Specifically, the methodological aspects of implementing "dynamic" vs. "static" scoring techniques for tax revenue changes are precisely analogous to the modelling of consumers' demand elasticities in the tariff design analysis presented here.

Last, an interesting and useful extension of this research is the normative empirical analysis of nonlinear tariff designs. The methods employed above would appear to lend themselves readily to development of more economically efficient tariffs. For example, if the new five-part tariffs in California are efficient (by almost any criterion), it is by fortuity rather than by design. Despite a great deal of work in the theoretical literature on efficient nonlinear pricing schemes, there are as yet few (if any) detailed empirical studies. We leave this interesting issue a matter for future research.

APPENDIX A. APPLIANCE-LEVEL SPECIFICATIONS

A.1. Specification and parameters

A complete list of the variables entering the demand model is shown in Tables A1 and A2. The complete set of coefficient estimates are listed in Table A3. This table is organized so that each column contains the parameter estimates associated with an appliance category's electricity demand. These raw parameters are used to obtain the marginal effects in Table 2, as described in Section 6.

TABLE A1

Appliances entering electricity demand model

Mnemonic	*Appliance*	*Description*
	Primary electric space heating	1 if household has permanently installed electric space heating (electric furnace, heat pump(s), or wall resistance units)
	Central air cond.	1 if household has a central air conditioning unit
	Room air cond.	1 if household has room window/wall air conditioning units
	Electric water heat.	1 if household has an electric water heater
ELECCOOK	Electric cooking	1 if household has an electric oven and/or stove
ELECDRYR	Electric dryer	1 if household has an electric clothes dryer
FREEZER1	Separate freezer	1 if household has a separate (stand-alone) freezer
FREEZER2	Second freezer	1 if household has two (stand-alone) freezers
FRIDGE2	Second refrigerator	1 if household has a second refrigerator
CLTHWASH	Clothes washer	1 if household has an automatic clothes washer
DISHWASH	Dishwasher	1 if household has an automatic dishwasher
PORTHEAT	Portable space heat	1 if household has one or more portable electric space heaters
HOTTUB	Hot tub	1 if household has a hot tub with electric heating
POOL	Swimming pool	1 if household has a swimming pool
H2OBEDHT	Waterbed heating	1 if household has a waterbed with electric heating
MICROWV	Microwave	1 if household has a microwave oven
NTV	Number of TVs	Number of televisions in household

TABLE A2

Additional explanatory variables entering demand model

Mnemonic	*Variable*	*Description*
PRICE	Electricity price	Monthly electricity price, in 1993 cents per kilowatt-hour
INCOME	Household income	Average monthly household income, in thousand 1993 dollars
HDD	Heating degree-days	Monthly heating degree-days base 60 °F, in hundreds
CDD	Cooling degree-days	Monthly cooling degree-days base 70 °F, in hundreds
NROOMS	Number of rooms	Number of rooms in home (excluding bathrooms)
NBATHRMS	Number of bathrooms	Number of bathrooms in home
NMEMBERS	Number of members	Number of people in household
FRSIZE	Fridge/freezer size	Size of appliance, in cubic feet
ATHOME	At home	1 if someone is normally at home during the day
HUPROJ	Housing project	1 if household resides in a public housing project
APTBLDG	Apartment building	1 if household resides in an apartment building
RURAL	Rural location	1 if household resides in a rural location
URBAN	Urban location	1 if household resides in an urban location
YEAR97	Survey year 1997	1 if household data from 1997 survey wave

The model also includes 154 variance and covariance parameters (from equation (11)) not reported here. These indicate that the variance of household-level unobservable characteristics increases with appliance holdings, although it depends (in a complicated fashion) on the types of appliances owned by the household. Overall, the heteroscedasticity patterns sensibly reflect the enormous differences in potential energy consumption associated with different appliance portfolios.

A.2. Appliance consumption estimates

A useful feature of the fitted model is that it provides estimates of electricity use for each appliance. These are reported in Table A4. In addition to being of direct interest to energy analysts, these appliance-level consumption estimates provide a useful check on the model since they can be compared to independent estimates.

The first numerical column is the estimated proportion of California households that own particular appliances, based on a weighted average of 1993 and 1997 sample ownership frequencies in the RECS. The second column reports the model's prediction for the average annual electricity consumption of each appliance. These estimates are obtained

TABLE A3

Electricity demand model coefficient estimates—GMM method (asymptotic standard errors in parentheses)

Explanatory variable[a]	Baseline use[b]	Elec. space heating	Central air cond.	Room air cond.	Elec. water heating	Swimming pool	Second refrig.	Separate freezer
CONST	−24·6 (49·9)	379·0 (216·0)	312·0 (276·0)	814·0 (369·0)	467·0 (107·0)	514·0 (229·0)	−23·5 (61·6)	−108·0 (57·9)
PRICE	0·4 (3·8)	−38·2 (15·0)	−23·2 (22·1)	−65·3 (32·5)	−35·3 (9·6)	−28·2 (19·3)		
INCOME	0·4 (2·4)	16·3 (13·1)	9·3 (11·0)	22·3 (21·5)	−34·0 (7·7)	6·4 (10·1)		
NMEMBERS	18·1 (3·4)	−8·0 (20·5)	−39·8 (16·8)	−53·7 (20·5)	49·3 (11·1)			
NROOMS	13·0 (4·5)	20·6 (22·3)	10·1 (17·9)	30·1 (24·1)	−36·6 (15·8)			
NBATHRMS	27·3 (9·9)				123·0 (41·8)			
HDD	−10·7 (6·3)	43·8 (22·1)						
CDD	−60·0 (22·7)		240·0 (58·8)	46·5 (128·)				
FRSIZE	6·5 (1·7)						7·8 (3·7)	9·3 (3·3)
DISHWASH	20·4 (11·5)				11·3 (37·3)			
CLTHWASH	18·8 (14·0)				71·3 (40·9)			
ELECDRYR	66·2 (13·1)							
FREEZER2	178·0 (55·7)							
ELECCOOK	21·5 (11·7)							
MICROWV	32·8 (12·1)							
HOTTUB	109·0 (32·2)							
PORTHEAT	108·0 (21·1)							
H20BEDHT	51·2 (23·7)							
NTVS	40·7 (5·8)							
ATHOME	16·0 (10·1)							
APTBLDG	−48·8 (14·2)							
HUPROJ	−79·6 (24·8)							
RURAL	31·7 (25·3)							
URBAN	−35·8 (12·0)							

Table continues on next page

TABLE A3

Continued

Explanatory variable[a]	*Baseline use*[b]	*Elec. space heating*	*Central air cond.*	*Room air cond.*	*Elec. water heating*	*Swimming pool*	*Second refrig.*	*Separate freezer*
YEAR97	2·0 (10·3)							
Model RMSE (kWh/year)	2352·0							

[a]Estimated on 1307 California households in the 1993 and 1997 Residential Energy Consumption Surveys. The dependent variable is electricity consumption, in kWh; parameter estimates are monthly demand coefficients from equation (8).

[b]This category includes all miscellaneous electrical appliances not explicitly modelled such as lights, household electronics, fans, and so forth. The first refrigerator is included in this category because ownership is nearly universal and its effect not separately identifiable from other universally owned appliances such as lights.

TABLE A4

Estimated electricity consumption by household appliance

	Present study		*Prior estimates*[a]	
			Average annual use, in kWh:	
Appliance type	Households with appliance, in per cent[b]	Avg. annual electricity use, in kWh[b]	EIA (1995)[c]	LBL (1997)[c]
Elec. space heating	23·2	1131	1185[b]	2609–3481[d]
Central air cond.	30·3	1270	1283[b]	1306–1446[d]
Room air cond.[e]	13·7	619	n.a.	476[d]
Elec. water heating	15·6	2389	2835	3658
Refrigerator	99·8	1231[f]	1141	1144
Electric cooking	46·0	258	451	822
Separate freezer	16·7	582	1013	1026
Elec. clothes dryer	32·2	795	1090	1000
Clothes washer[g]	64·1	223	n.a.	100
Dishwasher[g]	48·3	241	n.a.	250
Swimming pool	5·6	2227	n.a.	1500[h]
Hot tub	3·5	1288	n.a.	2300
Waterbed heater	5·1	606	n.a.	900
Microwave	83·4	388	n.a.	132
Televisions[e]	98·3	482	n.a.	513

Notes:

[a]Sources: U.S. Energy Information Administration (1995), Table 3.1, and public-use micro files.

Lawrence Berkeley Laboratory (1997), Tables A6 and A7.

[b]Estimates for California households.

[c]Estimates for all U.S. households, except as indicated.

[d]Range of estimates for households in southwestern U.S. states (Calif., Nev., and Ariz.).

[e]Estimates are for all units in household combined.

[f]Estimate based on second refrigerator only.

[g]Excludes energy used to heat water entering washer.

[h]Estimate for pool pump motor only.

n.a. indicates an estimate is not available.

from the fitted appliance demand equations (8), then averaged across households (using the RECS sampling weights) so as to reflect typical values in the population of appliance owners.

The third column in Table A4 contains appliance energy consumption predictions from a model developed by the U.S. Energy Information Administration (EIA, 1995). The final column is from a Lawrence Berkeley Laboratory (LBL, 1997) meta-analysis of numerous residential appliance energy consumption estimates. These estimates are derived from a wide range of direct metering, engineering, and statistical studies of energy use in different areas of the U.S. Overall, there is general agreement between these prior studies and the model's results—perhaps surprisingly so, since the present model is not fit to utilization data for individual appliances. The principal difference occurs with heating, where the LBL survey reports a significantly higher number than we or the EIA do. This can in part be explained by the broader geographic coverage of the LBL analysis and the high sensitivity of heating energy use to climate differences.

APPENDIX B. ELASTICITY CALCULATIONS

This Appendix describes the method used to calculate the elasticity estimates reported in Tables 3 and 4. There are two complications that make calculating elasticity estimates more involved here than in conventional settings. The first is the temporal issue of how to calculate an annual elasticity of demand when the consumer may face varying (and unobserved) marginal prices over the course of the year. The second is the discontinuity problem—because the price schedule is discrete, a change in the consumer's marginal price can move consumption smoothly within a single tariff segment, shift the consumer off or onto the discontinuity between tariff segments, or yield no change in consumption at all.

Addressing the discontinuity problem first, write the optimal consumption for household i in month t using the equilibrium relation from equation (1):

$$x^*_{it} = x(p^*_{it}, y^*_{it}, z_{it}, \varepsilon_{it}),$$

where $y^*_{it} = y_{it} + \bar{x}_{it} \cdot (p^*_{it} - p_{1,it})$. In this equation, p^*_{it} is the household's marginal willingness to pay for the last unit consumed (which may differ from the marginal price, if consumption occurs at the step-point $\bar{x}$ where the price rises from p_1 to p_2). To account for this discontinuous feature when calculating elasticities, we use the following decomposition. Consider an increase in the price of the specific tariff segment in which the household initially consumes. Denoting this initial marginal price as mp, and the consumer's initial marginal willingness to pay as $mwtp$, the total change in consumption can be written as

$$\frac{dx^*}{d(mp)} = \left[\underbrace{\frac{\partial x^*}{\partial(mwtp)}}_{\substack{\text{slope of}\\ \text{demand}}} + \underbrace{\frac{\partial x^*}{\partial y}}_{\substack{\text{marginal}\\ \text{income}\\ \text{effect}}} \cdot \underbrace{\frac{d\,\Delta y}{d(mwtp)}}_{\substack{\text{change in}\\ \text{infra-marginal}\\ \text{expenditure}}} \right] \underbrace{\frac{d(mwtp)}{d(mp)}}_{\substack{0 \text{ if at } \bar{x},\\ 1 \text{ if not}}}$$

where $\Delta y = \bar{x}_{it} \cdot (p^*_{it} - p_{1,it})$ (cf. (3)). The first term in the square brackets is standard. The remaining terms in the bracketed expression yield the (income) effect of changing the infra-marginal price discount. For an optimizing consumer, the term outside the brackets will be zero if consumption occurs at the step-point, $\bar{x}$, and one otherwise.

For the demand specification and two-tier tariff we analyse, this expression takes the simple form:

$$\frac{dx^*_{it}}{d(mp)} = \alpha \cdot \mathbf{1}(x^*_{it} \neq \bar{x}_{it}) + \beta\, \bar{x}_{it} \cdot \mathbf{1}(x^*_{it} > \bar{x}_{it}) \tag{B.1}$$

where $\mathbf{1}(\cdot)$ is the indicator function, and α, β are the price and income coefficients from equation (10). We define a household's monthly price elasticity, η_{it}, in terms of the effect of price on the margin:

$$\eta_{it} = \frac{(mp)_{it}}{x^*_{it}} \cdot \frac{dx^*_{it}}{d(mp)}.$$

A wrinkle arises in computing η_{it}. Since our consumption data are aggregated to an annual level, we do not observe the household's monthly consumption, x^*_{it}, nor its monthly marginal price. Instead, we estimate x^*_{it} with the "plug-in" estimator

$$\hat{x}^*_{it} \equiv E[x^*_{it} \mid w_{it}; \hat{\theta}]$$

using the conditional moment equation derived in (6) evaluated at the estimated parameter values. We then obtain the marginal price estimate, $\widehat{mp}_{it}$, from the household's rate schedule in month t for the quantity $\hat{x}^*_{it}$. Finally, we can compute each household's monthly price elasticity using equation (B.1) as

$$\hat{\eta}_{it} = \frac{\widehat{mp}_{it}}{\hat{x}^*_{it}} \cdot \left[\hat{\alpha}_i \cdot \mathbf{1}(\hat{x}^*_{it} \neq \bar{x}_{it}) + \hat{\beta}_i\, \bar{x}_{it} \cdot \mathbf{1}(\hat{x}^*_{it} > \bar{x}_{it}) \right]$$

where the "hats" indicate estimated quantities.

To obtain the annual price elasticities reported in Tables 3 and 4, we calculate (pointwise) the percentage change in annual electricity consumption for a per cent change in the household's marginal price in *each month* of the year. That is, for each household in the sample we compute

$$\hat{\eta}_i = \frac{1}{x_i} \sum_{t=1}^{12} \hat{\eta}_{it} \cdot \hat{x}^*_{it}$$

where x_i is the household's actual annual electricity consumption. The tables report estimated population means obtained by averaging these household-level annual elasticity estimates using the RECS survey weights.

Income elasticities are obtained similarly, after observing that

$$\frac{dx^*_{it}}{dy} = \beta \cdot \mathbf{1}(x^*_{it} \neq \bar{x}_{it}).$$

Acknowledgements. We thank Jerry Royer of the California Public Utilities Commission for valuable help in accessing and interpreting Commission records, Brent Goldfarb for research assistance, and two anonymous referees for helpful suggestions. White gratefully acknowledges the support of the University of Pennsylvania Research Foundation and the George J. Stigler Center for the Study of the Economy and the State at the University of Chicago.

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Pepco Response to OPC Data Request 3-34

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 3

QUESTION NO. 34
Low-Income Households.

a. Please identify the metric or metrics the Company uses to define low-income households in the Company's service area.

b. Please provide the number and percentage of households in your service area that the Company considers low-income for each of the years 2013-2022.

c. Please provide the requested documents in electronic form with all spreadsheet links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

RESPONSE:

a. The Company uses the enrollment in energy assistance programs to classify customers as a low or moderate-income (LMI) customers. Apart from this, the Company is unable to identify LMI customers since the administering program agencies qualify customers, based on income, and then notifies the Company regarding customer eligibility.

b. Based on the number of active customers enrolled in energy assistance programs (see 3.34a) the number and percentage of households considered LMI for 2013-2022 is as follows:

# Unique Households Considered LMI [1]			
Year	# Unique Customers with Active Enrollment LMI [2]	# Residential Customers (December)	% LMI
2013-2016	Data is not available		
2017	26,029	269,947	9.6%
2018	31,327	279,010	11.2%
2019	32,550	285,498	11.4%
2020	28,280	294,511	9.6%
2021	34,130	301,185	11.3%
2022	37,850	310,172	12.2%

[1] Includes Residential Aid Discount (RAD), Low Income Home Energy Assistance Program (LIHEAP) and DC Arrearage Management Program (AMP) enrollments. A customer can be enrolled in one, two or all three programs but will only be counted once in the data provided.

[2] Enrollments vary in length. RAD enrollments are 18 months, LIHEAP enrollments are 12 months and AMP enrollments are 15 months. Enrollments can span multiple years depending on the enrollment start date. Customers are considered LMI as long as the enrollment is active.

Pepco Response to OPC Data Request 3-34

c. Please see FC 1176 OPC DR 3-34 Attachment.

SPONSOR: Morlon Bell-Izzard

Pepco Response to OPC Data Request 3-45

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 3

QUESTION NO. 45
Please describe how the Company collaborates with community organizations and government agencies to address energy affordability issues, and what partnerships have been successful in the past. Provide sources used and explain all assumptions and calculations used.

RESPONSE:

Pepco has long-term relationships with many local community organizations and government agencies who engage with the low-to-moderate-income population who may need energy assistance to promote the Low-Income Home Energy Assistance Program (LIHEAP). The Company's partnership with United Way of the National Capital Area's partnership spans decades. These partnerships provide equitable access to resources to improve the lives of low-income neighbors who may have affordability issues. In addition, the Company has partnerships with other local organizations in the community which include Mary's Center, Interfaith Works, and others.

Locally, Pepco has partnered with the District of Columbia at a plethora of community events to include the weekly summer program called "Beat the Streets" in collaboration with the local Metropolitan Police who canvass the neighborhood providing safety information. During these events, the Company provides energy assistance information. In addition, the Company provides monthly opportunities for customers to enroll in energy assistance during outreach events at apartment complexes, senior facilities, and local food banks. The Company also partners with other utilities by sponsoring energy assistance sign up days.

Please see FC 1176 OPC DR 3-45 Attachment for the number of outreach events held from 2022-2023.

The Company also partners with government agencies to include the Department of Energy and Environment (DOEE) to assist customers with resolving balances on customer's accounts, technical and bill related issues for vulnerable customers, and those needing other extra support. Pepco has increased customer awareness and application intake through effective community outreach and marketing initiatives to raise public awareness of energy assistance programs.
In 2013, the average RAD enrollment was at 17,757 participants. In 2022, participation increased to an average of 25,814 which resulted in a 45% surge in part due to the effective community outreach activities implemented last year (see table below) combined with the expansion of the eligibility requirements.

Pepco Response to OPC Data Request 3-45

Year	Average RAD Enrollment
2013	17,757
2014	16,997
2015	17,513
2016	15,500
2017	17,129
2018	17,947
2019	18,229
2020	17,637
2021	16,904
2022	25,814

SPONSOR: Morlon Bell-Izzard

-

IV. MULTIYEAR RATE PLAN

Q10. How does the changing energy policy in the District of Columbia impact the Company?

A10. The Company must make significant long-term investments to meet the policy goals of the District of Columbia and the changing needs of our customers. As the Company evaluates investments to improve reliability and modernize the grid, it is paramount for the Company's investments plans to align with the District of Columbia's policy goals and customer expectations. The current regulatory process in which investments are made and subsequently reviewed in a base rate case does not provide the proper alignment of the Company's investments and performance with the policy goals of the District of Columbia and customer expectations.

Q11. How does the Company's MRP proposal address these concerns?

A11. The Company's MRP proposal, as further explained by Company Witness McGowan and Company Witness Wolverton, is a three-year MRP with forecasted years 2020-2022. The MRP also includes Performance Incentive Mechanisms (PIMs), developed with input from stakeholders, that further drive operational performance and policy objectives. The Company's proposal increases transparency into the Company's future capital investment spending plans and allows stakeholders to evaluate the Company's plans and how these investments align with the District of Columbia's policy goals and customer expectations. The MRP improves the timing of cost recovery by the utility without the need to file annual rate cases. This is important as the Company invests in grid modernization and the infrastructure required to facilitate the

Formal Case No. 1156, Direct Testimony of David M. Velazquez (Exhibit PEPCO (A)), Pages 8-9

District of Columbia's goals of climate action, transportation electrification, and increased resilience.

While many of the investments needed to allow widespread adoption of the technologies discussed above are not in the current capital plan through 2022, we believe it is time to evaluate and adopt an MRP so that parties may start the process of aligning the Company's planned investments with the goals of the District of Columbia and expectations of customers. Adoption of the MRP now will set the framework, so as the Company continues to plan for future investments and evaluates with stakeholders future PIMs around grid modernization, a structure will be well established that facilitates a transparent discussion of investment plans with stakeholders before those investments are made.

The transition from the traditional ratemaking process, which is retrospective, to a prospective MRP will streamline the regulatory process, allow greater transparency into the Company's investments to all stakeholders, reduce the number of rate case proceedings and associated costs, and provide more rate predictability to our customers. The Company is an enthusiastic and essential partner in delivering the District of Columbia and the Commission's goals of addressing climate change. It is timely to move toward a forward-looking mechanism that aligns the Company's investment plans and performance targets with the District of Columbia's policy goals and evolving customer needs. The MRP will allow more timely recovery of the Company's investments and enable the Company to make the investments required to modernize the grid and achieve the District of Columbia and the Commission's progressive energy policy goals.

Exhibit OPC (A)-29
Formal Case No. 1176

Company's Response to the Joint Motion filed on April 20, 2020, Pepco believes this proceeding should move forward. The Company is very much aware of the impact that the pandemic has had on the District of Columbia and the region as a whole and has been working to continue to provide safe and reliable service to our customers throughout this public health emergency. Disregarding all the time and effort expended by the parties and the Commission over this past year is not prudent and would not solve the immediate issues at hand.

In response to Order No. 20349, the Company has crafted the MRP Enhanced Proposal, which incorporates a number of recommendations other parties have made regarding the Original MRP Proposal and on which there is the potential for alignment. Pepco married those recommendations with a number of innovative options to craft the MRP Enhanced Proposal, which results in no overall distribution rate increase until January 1, 2022 for any customer and substantial mitigation of the overall distribution rate increase to customers during 2022. Additional details regarding the MRP Enhanced Proposal are also set forth in the Surrebuttal Testimonies of Company Witnesses Wolverton and Blazunas.

Q19. Are the elements of the MRP Enhanced Proposal severable such that some can be adopted but not others?

A19. No. To be clear, the Company's MRP Enhanced Proposal is an integrated package with interdependent elements designed to operate as a whole in order that this proceeding be resolved expeditiously. The individual elements are not severable as they all need to operate in unison if the MRP Enhanced Proposal is to work. For example, although the Company believes that it has established through the testimonies of Company Witness Hevert that a return on equity of 10.30% is warranted, in order to allow for the customer

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 4

QUESTION NO. 1
Referencing the testimony presented by Witness Cantler at page 5, lines 20-23 and the statement that "[t]he Company's investments during this MYP period are implemented to advance and support various Company objectives such as driving solutions to address climate change, enhancing grid performance, improving social equity and affordability, and looking for new opportunities to enhance customer experience."

a. For each of the identified objectives, explain how the Company intends to measure the Company's performance relative to the stated objective. Provide any objective criteria that the Company proposes to use to measure the success of the MYP period projects in achieving the stated objectives.

b. Provide a breakdown to the MYP projects sorted by the Company objectives that they are intended to advance and support.

c. Provide any cost-benefit analyses performed with respect to the cost of the MYP period projects and the benefits to ratepayers.

RESPONSE:

a. The Company does not have internal metrics in place for measuring the status of the identified objective. The Company's objectives, as noted on pg. 5, lines 17-23 of Company Witness Cantler's Direct Testimony are features of its capital investment strategy throughout this MYP and support a pathway to a Climate Ready Grid. As such, please see the Company's response provided for AOBA DR 1-2. The Company is committed to supporting solutions to address climate change, enhancing our grid's performance, improving social equity and affordability and looking to enhance our customers' experience.

b. The requested breakdown has not been performed. There are too many direct, indirect and tertiary benefits to certain projects to accurately ascertain and/or categorize which singular Company objective a project supports or does not support.

   However, projects, like the implementation of Advanced Distribution Management System, as referenced Pepco (H)-2 on pg. 174, are indicative of enhancing grid performance, and if granted IIJA funding would also, in turn, support affordability for our customer base through subsidization offered by a federal grant. Additionally, there are components of the Company's IT investments referenced in Pepco (H)-2 that will contribute to making energy more affordable by increasing customer participation in

Pepco Response to OPC Data Request 4-1

energy assistance and energy efficiency programs. For a full list of every project and the justification for that project work please refer to Pepco (H)-2 in its entirety.

c. The Company does not generally conduct cost-benefit analysis (CBA), though as mentioned previously, does conduct robust alternative analyses. The Company has conducted cost-benefit analysis in a few areas including: evaluating technologies or initiatives that have not previously been proposed, an initiative that has a societal benefit, or when required by the Commission or regulatory body.

That being stated, and in an effort to be responsive to this request, the Company is currently in the process of compiling relevant information pertinent to CBAs that exist for project work specific to this MYP for a similar request related to AOBA DR 7-25. Once that information has been compiled it will be shared and made available in response.

SPONSOR: Jaclyn Cantler

Pepco Response to OPC Data Request 6-20

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 6

QUESTION NO. 20
Reference Direct Testimony of Cantler at p.22 "The goal of the ADMS Project is to deploy foundational Distributed Energy Resource Management System (DERMS) capabilities - including DER Visualization, DER Estimation, DER Forecasting, and DER Monitoring & Control."

a) Please describe all the functionalities and benefits that will be enabled by the ADMS deployment.
b) Please provide an implementation timeline for when the ADMS and DERMS functionalities will be deployed and available for use.
c) Does the Company intend to procure "digital twin" functionality as part of its ADMS procurement?
d) Where on the system does the Company expect DERMS control functionality to be deployed and how is this determined?

RESPONSE:

a. Please see the Company's Attachment NN that was provided in response to AOBA DR 7-25 for a description of ADMS functionalities and benefits the project will enable.

b. The estimated date that ADMS and DERMS functionalities will be deployed and available for use is 2029.

c. The term "digital twin" is not a term that the ADMS project, or the software vendor is using to describe ADMS capabilities. The term "digital twin" can have various meanings so further clarification would be needed to provide a more specific answer about the functionality in question. However, ADMS does plan to include "Study Mode" models and analysis, as well as unbalanced load flow analysis both of which could be considered "Digital Twin" functionality. ADMS does not plan to include 3D geo-spatial modeling of assets if that is what is implied with "Digital Twin" functionality.

d. Given DERMS is scheduled for a future phase of ADMS implementation, the detailed functionality and capabilities have yet to be fully scoped or defined. As such, an evaluation of where DERMS functionality would reside in the organization has yet to be determined.

SPONSOR: Jaclyn Cantler

Exhibit OPC (A)-32
Formal Case No. 1176

component that can under-collect or over-collect the Company's costs and can make cost recovery unpredictable.

I also noted that in the absence of the BSA, utilities have a strong financial incentive to sell as much electricity or gas as possible. As I explained in my testimony in that case, the BSA is beneficial because it:

- Stabilizes customer bills and improves Pepco's ability to recover its costs;
- Provides Pepco with a more stable stream of revenues and prevents over-collection and under-collection of costs as actual sales vary from test year sales due to weather conditions and/or energy efficiency;
- Eliminates the Company's financial disincentive to promote energy efficiency; and
- Helps ensure fixed-cost recovery.

It is important to note that at the time of the Commission's decision in Formal Case No. 1053, there was uncertainty regarding the impact of revenue decoupling mechanisms, like the BSA, on a utility's overall level of risk. In that proceeding, the Commission held that the Company's authorized return on equity should be reduced in light of the BSA. Since that time, however, as explained by Company Witness Hevert, it has become clear that no such reduction is appropriate.

Q16. Have you changed your position on the BSA?

A16. No, I have not. In fact, as discussed below, I think there are additional reasons to support the BSA beyond those discussed in my prior testimony, including the growth of DER installations.

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POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1156
RESPONSE TO OPC DATA REQUEST NO. 61

QUESTION NO. 7

Source of Errata. Please identify with specificity the date that Pepco was first informed or realized that there was a data error that impacted the calculations of the billing determinants for commercial classes with demand charges.

RESPONSE:

For the actual demand billing determinant error corrected in Rebuttal Testimony: Company Witness Blazunas was notified of the potential issue with the demand billing determinants in February 2020 by the Manager of Rate Administration for Atlantic City Electric and Delmarva Power.

For the forecasted demand billing determinant error corrected in the Company's July 28, 2020 Errata and July 30, 2020 Supplemental Testimony: Staff DR 24-24 was received on July 15, 2020. The Company first became aware of the need for the corrections to its forecasted demand billing determinants in review and preparation of the Company's response to Staff DR 24-24.
In preparation of the Company's response to FC 1156 Staff DR 24-24, Company Witness Blazunas determined that the following statement made in his Rebuttal Testimony was incorrect:

> "As discussed later in my testimony, to address this issue, the Company is incorporating updated demand billing determinants into its proposed rate design for the commercial classes with demand rate components for the TTPCF. With respect to the MRP, this issue is avoided as a result of the use of forecasted billing determinants as well as the use of the Company's proposed Annual Billing Determinant Update in the ultimate design of the MRP rates."

The need for the correction is due to the fact that the corrected actual demand (kW) billing determinants should also have been used to calculate corrected load factors with which to derive corrected forecasted demand (kW) billing determinants for each of the three years in the Original MRP Proposal and the MRP Enhanced Proposal.

SPONSOR: Peter R. Blazunas

Exhibit OPC (A)-34
Formal Case No. 1176

Formal Case No. 1156, Pepco Response to OPC Data Request 61-3

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1156
RESPONSE TO OPC DATA REQUEST NO. 61

QUESTION NO. 3

Source of Errata. Please confirm that the only source of the data error(s) that impacted the calculations of the billing determinants for commercial classes with demand charges was a report that double counted demand in the months with a rate change.

A. If so confirmed:
   1. Please provide the name and purpose of the report.
   2. When did Pepco start using this report to calculate its billing determinants for commercial classes with demand charges?
   3. Please identify each previous rate cases in which Pepco relied on data from this report.

B. If not so confirmed, please:
   1. Identify in detail each and every source of the data error;
   2. Explain the reason why that source provided incorrect data; and
   3. Provide responses the requests in subsections A.1-3 above.

RESPONSE:

A. The Company confirms that the source of the error is a demand billing determinant report that double counted demand in the months with a "time slice" (such as a month with a rate change). A "time slice" occurs when there are multiple price values within a bill period, and that price is set-up to be prorated within that period.

1. The name of the variant of the Active Billed Report used to provide the actual demand billing determinants for commercial classes with demand rate components in its Application is "Sum of Demand."

2. The "Sum of Demand" variant was in use starting in 2015.

3. Formal Case No. 1150 and Formal Case No. 1139.

B. N/A

SPONSOR: Peter R. Blazunas

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1156
RESPONSE TO STAFF DATA REQUEST NO. 19

QUESTION NO. 6

The implicit under-recovery of rates from the FC 1150 rates going into effect through March 2020 is listed as $20.77 million. What is the projected under-recovery of rates for the period of April 2020 through December 2020? Said another way, what is the projected under-recovery expected to be collected through the BSA due to the use of incorrect demand charges in calculating the FC 1150 rates?

RESPONSE:

The estimated incremental under-recovery for the period April 2020 through December 2020 is $9.57 million ($20.77 million for August 2018 to March 2020 plus $9.57 million for April 2020 to December 2020 equals $30.33 million for the period August 2018 through December 2020). This estimate was obtained using the workpaper provided as FC 1156 AOBA DR 2-10 Attachment and changing the "Current Date" value shown on tab "4. Years Calculation" from 3/31/2020 to 12/31/2020.

SPONSOR: Peter R. Blazunas

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1156
RESPONSE TO OPC DATA REQUEST NO. 61

QUESTION NO. 17

Outstanding BSA Balances. Is Pepco proposing to take any financial responsibility over the large outstanding BSA balances? If yes, please explain how Pepco is proposing to do so. If no, please state so.

RESPONSE:

The Bill Stabilization Adjustment (BSA) works as designed in that it allows the Company to collect the difference between its authorized level of revenue and its billed distribution revenue. In every rate case, rates are designed such that they recover the Company's authorized level of revenue. To the extent that billing determinants change, the BSA allows the Company to continue to collect its authorized level of revenue. Assuming that there is not a large disconnect between the billing determinants during the rate-effective period and the billing determinants used to design rates (as happened with the issue surrounding the demand billing determinants), sufficient space under the BSA cap should be created at the time new rates are put in place to unwind deferral balances over time. Nonetheless, the BSA deferral balances appropriately represent amounts approved for collection by the Company but not yet billed. Once new rates are effective, remediation of the billing determinant issue going forward will, all else equal, help to reduce the size of existing deferral balances and the accumulation of future monthly deferrals.

SPONSOR: Peter R. Blazunas

Pepco Response to OPC Data Request 10-6

Exhibit OPC (A)-37
Formal Case No. 1176
David E. Dismukes

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 10

QUESTION NO. 6
Please provide all documents and analyses prepared by or on behalf of Pepco discussing or relating in any way to the prudence of its (i) administration of the BSA, (ii) incurrence of the BSA deferral balances relating to the erroneous billing determinants, or (iii) recovery of BSA deferral balances relating to the erroneous billing determinants.

RESPONSE:

As directed in Formal Case No. 1156, Order No. 20755, a series of technical conferences were convened to, among other things, examine the design of the BSA and discuss the impact of the billing determinants error identified in Formal Case No. 1156 on the BSA deferral balance. At the December 9, 2021 BSA Technical Conference, the Company presented the results of its Estimated BSA Drivers Analysis which identified several key drivers of the BSA deferral balance, including the billing determinants error, and estimated the magnitude of revenue under- and over-collections associated with each driver. The Company's December 9, 2021 presentation is provided as FC1176 OPC DR 10-6 Attachment. The results of the Company's analysis are presented on slides 21 through 23 and show that the billing determinant error resulted in an estimated $15.3 million revenue under-collection, approximately $7.4 million of which remained uncollected in the BSA deferral balance as of October 2021.

Order No. 20755 further directed an external audit of the BSA mechanism, including among other things an evaluation of the design of the BSA, a comprehensive evaluation of all Pepco BSA internal controls, and an evaluation of Pepco's BSA Driver Analysis presented at the December 9, 2021 BSA Technical Conference. See FC 1176 OPC DR 5-18 Attachment A for a copy of the final BSA audit report produced by Atrium Economics, the independent auditor selected by the Commission. Specifically, the results of Atrium's BSA deferral drivers analysis are presented in Table 2-11 on page 50 in Atrium Economics final report and estimate that the billing determinant error resulted in approximately $15.1 million in revenue under-collections. As shown in Table 2-16 on page 52, Atrium estimated that as of December 31, 2022, approximately $2.0 million of the Company's BSA deferral balance remained attributable to the billing determinant error, indicating that $13.1 million in under-recoveries related to the billing determinant error had already been reconciled through BSA surcharges.

SPONSOR: Matthew J. Bonikowski

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In the Matter of	§	
	§	
The Application of Potomac Electric Power Company for Authority to Implement a Multiyear Rate Plan for Electric Distribution Service in the District of Columbia	§ § § §	**Formal Case No. 1176**

DIRECT TESTIMONY
AND SUPPORTING EXHIBITS OF
MICHAEL P. GORMAN

Exhibit OPC (B)

On Behalf of the
Office of the People's Counsel
for the District of Columbia

January 12, 2024

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Exhibit OPC (B)-4	Referenced Data Responses

I. INTRODUCTION

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017. I am a consultant in the field of public utility regulation and a Managing Principal of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q. HAVE YOU PREPARED AN ATTACHMENT SUMMARIZING YOUR QUALIFICATIONS AND REGULATORY EXPERIENCE?

A. Yes. I have attached Exhibit OPC (B)-1, which is a summary of my regulatory experience and qualifications.

Q. FOR WHOM ARE YOU APPEARING?

A. I am testifying on behalf of the Office of the People's Counsel of the District of Columbia ("OPC" or "Office").

Q. WAS YOUR TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes.

II. SCOPE OF TESTIMONY

Q. WHAT IS THE SCOPE AND PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony addresses the Potomac Electric Power Company's ("Pepco" or the "Company") proposed revenue requirements for both its Multi-Year Plan ("MYP") and

Traditional Test Year ("TTY"). I recommend a number of adjustments to the Company's revenue requirements which will be detailed later in my testimony. Finally, I support the revenue requirement impact of adjustments proposed by other OPC witnesses including:

- Christopher C. Walters (Return on Equity)
- Brian C. Andrews (Depreciation)
- Kevin J. Mara (Construction Budget)

Q. DOES THE FACT THAT YOU DID NOT ADDRESS EVERY ISSUE RAISED IN PEPCO'S MYP OR TTY TESTIMONIES MEAN THAT YOU AGREE WITH PEPCO ON THOSE ISSUES?

A. No. The fact that I do not comment on every specific issue raised by Pepco should not be construed as an endorsement of, agreement with, or, acquiescence to the Company's position on such issues. Likewise, OPC Witness Dismukes sponsors testimony recommending rejection of the MYP. The fact that I sponsor testimony on the revenue requirements for the duration of the MYP should not be construed as being contrary to Dr. Dismukes' recommendation. Instead, I am addressing the MYP revenue requirements in the event the Public Service Commission ("Commission") does not accept Dr. Dismukes' recommendation.

III. <u>SUMMARY OF TESTIMONY</u>

Q. PLEASE SUMMARIZE YOUR TESTIMONY AS IT PERTAINS TO PEPCO'S OVERALL REVENUE REQUIREMENTS FOR BOTH ITS MYP AND TTY.

A. In my testimony, I will summarize adjustments to Pepco's claimed revenue requirements offered by witnesses sponsored by OPC for both the MYP and the traditional revenue requirement.

MYP Revenue Requirement Adjustments.

As shown in Table 1, based on revenue requirement adjustments sponsored by the OPC in this case, Pepco's MYP revenue deficiency is overstated by $56.4 million in 2024, $63.9 million in 2025, and $71.7 million in 2026 (Table 1).

TABLE 1

Multi-Year Plan
Revenue Requirement Adjustments
($ Millions)

Line	Description	MYP Year 1 12ME Dec 2024 (1)	MYP Year 2 12ME Dec 2025 (2)	MYP Year 3 12ME Dec 2026 (3)
1	Claimed Revenue Deficiency	$ 116.4	$ 153.4	$ 190.7
	Adjustments:			
2	Return on Equity	$ 25.0	$ 26.8	$ 28.3
3	Depreciation	25.2	24.6	23.7
4	MYP Capital Projects	1.9	5.5	9.8
5	Sales Forecast	0.7	2.1	4.3
6	Service Company Cost Escalation	1.6	2.8	3.7
7	Deficient Deferred Income Taxes	1.5	1.4	1.4
8	Regulatory Asset Amortization	0.6	0.6	0.7
9	Total Adjustments	$ 56.4	$ 63.9	$ 71.7
10	Adjusted Revenue Deficiency	$ 60.1	$ 89.5	$ 119.0

Traditional Year Revenue Requirements Adjustments

Similarly, Pepco's TTY revenue deficiency is also overstated by $60.4 million (Table 2).

TABLE 2

Traditional Test Year
Revenue Requirement Adjustments
($ Millions)

Line	Description	12ME Dec 2023 (1)
1	Claimed Revenue Deficiency	$ 108.2
	Adjustments:	
2	Return on Equity	$ 20.0
3	Depreciation	23.4
4	TTY Capital Projects	3.2
5	Annualized Revenues	1.1
6	Deficient Deferred Income Taxes	1.5
7	Regulatory Asset Amortization	0.5
8	Inflation	0.4
9	BSA Deferral	10.3
10	Total Adjustments	$ 60.4
11	Adjusted Revenue Deficiency	$ 47.8

The rate of return adjustment in the tables above is supported by my colleague, Mr. Christopher C. Walters. Mr. Walters demonstrates the unreasonableness of Pepco's recommended 10.5% return on equity ("ROE"). Adjusting the ROE to a reasonable level—i.e., to 9.30% from 10.5%--reduces Pepco's revenue requirements during the MYP by the amounts shown above. Adjusting the ROE to 9.55% from 10.5% to reflect different risk associated with a TTY as opposed to an MYP reduces Pepco's TTY revenue requirement by the amount shown above. My adjustment to reflect Mr. Walters' ROE is included as part of my Exhibit OPC (B)-2 (MYP) and Exhibit OPC (B)-3 (TTY) which are summaries of my revenue requirement adjustments.

The depreciation adjustment in the tables above is supported by my colleague, Mr. Brian C. Andrews. Mr. Andrews supports OPC's proposed depreciation rates. The tables above include the test year depreciation expense adjustments reflecting the test year plant balances and Mr. Andrews' proposed depreciation rates.

OPC witness Kevin J. Mara, Exhibit OPC (E), recommends several adjustments to the construction and capital investment costs included in Pepco's MYP. Mr. Mara recommends a number of projects be canceled or delayed due to a reduction in load, he takes issue with the allocation of sub-transmission costs to the District, and he recommends some costs be disallowed due to changes in the Downtown Resupply Project. Mr. Mara also recommends several projects be removed from the TTY because they may not be completed and provide benefits to ratepayers during the rate-effective period. I have included the revenue requirement impact of Mr. Mara's adjustments on my summary exhibits.

Q. PLEASE SUMMARIZE WHY THERE IS BOTH A MYP AND A TTY IN THIS PROCEEDING.

A. On April 13, 2023, Pepco filed its application to implement a second MYP for 2024 to 2026. The MYP proposed revenue requirement increases of $116.4 million in 2024, $36.9 million in 2025, and $37.3 million in 2026. These revenue requirements are shown on the Company's Exhibit PEPCO (B)-1. Ms. O'Donnell in her April 2023 direct testimony argues Pepco is seeking approval of a "Climate Ready Pathway that provides the Commission, customers and stakeholders with a forward-looking plan and a detailed view of the investments the Company intends to make from 2024 through 2026."[1] Pepco's MYP application also included investments from 2023 that were placed in service but were not yet reflected in rates due to the "stay-out provision" approved in Formal Case No. 1156 ("FC 1156").

On July 28, 2023 in Order No. 21886 the Commission directed Pepco to make two additional filings in response to comments filed by OPC, the Apartment and Office Building Association of Metropolitan Washington ("AOBA"), and the District of Columbia Government ("DCG"). The Commission directed Pepco to file supplemental direct testimony that 1) addressed the benefits of, problems identified, and lessons learned from the MYP pilot the Commission approved in FC 1156 and 2) supported a traditional one-year rate case for a calendar year 2023 test year. Pepco filed its supplemental testimony regarding the first MYP on August 31, 2023 and its supplemental testimony with the TTY on October 16, 2023.

Pepco's TTY is based on a calendar year 2023 test year and includes six months of actual data (January 2023 to July 2023) and six months of forecasted data (July 2023 to December 2023). The TTY supports a $108.2 million revenue requirement. This revenue requirement is shown on the Company's Exhibit PEPCO (2B)-1.

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[1] Exhibit PEPCO (A), O'Donnell Direct at 5.

Q. HOW WILL THE REMAINDER OF YOUR TESTIMONY BE ORGANIZED?

A. In Section IV, I will discuss my recommended revenue requirement adjustments to Pepco's MYP. In Section V, I will discuss my recommended revenue requirement adjustments to Pepco's TTY. Several of my revenue requirement adjustments are applicable to both the MYP and TTY. For those adjustments I will use the MYP section to discuss my reasoning rather than duplicate my testimony in both the MYP and TTY sections. In Section VI, I will respond to Pepco's proposal to earn a return on its Bill Stabilization Adjustment ("BSA") deferral balance in the TTY. I note that OPC Witness Dismukes also sponsors testimony addressing the BSA.

IV. <u>MULTI-YEAR PLAN REVENUE REQUIREMENT ADJUSTMENTS</u>

Q. PLEASE BRIEFLY SUMMARIZE YOUR PROPOSED ADJUSTMENTS TO PEPCO'S MYP REVENUE REQUIREMENTS?

A. I recommend several adjustments to Pepco's MYP revenue requirements, as shown above in Table 1.

- Pepco's sales forecast is understated because it is based on unbalanced projections for expected use per residential customer. The sales projections at current rates needed to be adjusted to reflect symmetrical and balanced outlooks of changes in use per customer.

  Specifically, Pepco's residential sales forecast reflects the Company's energy efficiency forecast, which will lower sales during the forecast period, but does not reflect residential load growth from increased electrification. Pepco's cost of service projections do include projected capital expenditures needed to accommodate expected electrification conversion during the forecast period. This imbalance in assumptions made to produce the projected cost of service in the MYP is unreasonable and should be corrected. I recommend the residential sales forecast be based on the Company's 2023 use per customer forecast rather than the Company's MYP forecast which assumes electricity use per residential customer will decrease each year during the forecast period. A flat projection of use per customer accommodates the outlook of both reduction in use per customer due to conservation, and the increase in use per customer for electrification. These are important factual matters the Commission should resolve in setting Pepco's cost of service.

- Pepco's O&M forecasting process diverges from the Commission-approved methodology used in the previous MYP and as a result offers less transparency into the cost drivers of Pepco's distribution operations in the DC jurisdiction. Pepco forecasts its O&M will escalate during the MYP based on a projection of total company and affiliate service company costs, and a projection of the jurisdictional allocation of these costs to the DC jurisdiction. In the last MYP, O&M expenses were projected using the Company's actual O&M costs and then applying an inflation escalator.

  A primary contributor to the 2023 O&M escalation is an increase in the affiliate service company charges which are allocated to Pepco's DC jurisdiction. Also, total distribution allocated labor costs increased by 39% in 2023 relative to 2022. This material cost escalation has not been fully explained or justified. I recommend these projected costs escalations be reduced to a reasonable level based on jurisdiction historical costs to Pepco's actual cost forecasted 2023 level for the MYP. At a minimum, the bases for and reasonableness of Pepco's proposals are material issues of fact that the Commission must resolve.

- Pepco is requesting authority to recover its deficient deferred income taxes just as it did in its previous proceeding, FC 1156. In this previous proceeding, the Commission denied Pepco's request to recover these deferred costs from jurisdictional customers. Pepco has not offered new evidence in support of the recovery of these deferred costs. Therefore, I recommend that the Commission again deny recovery of these deferred costs for setting prospective rates.

- Pepco is requesting to recover several of its regulatory assets, including deferred COVID-19 costs, over five years. I recommend Pepco recover these costs over six years, or approximately two rate case cycles, as a more balanced and fair recovery period. Failure to align the recovery period with an expected rate cycle period will allow Pepco to over recover these regulatory assets costs.

A. MYP Sales Forecast

Q. PLEASE PROVIDE AN OVERVIEW OF HOW PEPCO FORECASTS ITS REVENUES DURING THE MYP PERIOD.

A. Pepco provides a forecast of its billing determinants during the MYP as Exhibit PEPCO (K), Ekaterina (Kate) Efimova's direct testimony and exhibits. The billing determinants forecast includes estimates for Pepco's number of customers, the amount of kWh sales, and kW demand during the MYP period. The forecasted billing determinants are then applied to Pepco's present and proposed rates for the various rate classes to calculate the MYP revenues. Ms. Efimova sponsors Pepco's billing determinants forecast and she writes regarding the forecast:

> The goal of billing determinants forecasting is to produce a reasonable outlook incorporating all of the most relevant information available to a forecaster. The forecast of billing determinants is specifically based on historical data collected from customer bills or meters, i.e., billed sales (kWh), customers (count of contracts), and billed demand (kW). Additional information about major factors impacting billing determinants, such as weather and economics, is typically used to explain historical trends. Forecasted future changes in these major factors are then used to forecast billing determinants.[2]

Ms. Efimova lists the number of households and overall economic activity as the most important drivers for the number of customers forecast. She lists weather, economic activity, and energy efficiency/demand side management programs as the most important drivers for the energy sales forecast. Finally, she states the billed demand forecast is closely related to and has the same drivers as the energy sales forecast.

[2] Exhibit PEPCO (K), Efimova Direct at 4.

Pepco uses an econometric regression analysis to determine the relationship between the drivers above and Pepco's historical billing determinants. Exhibit PEPCO (K)-1 provides more details on the Company's forecast and forecasting process. The results of the forecast are provided in the subsequent (K) exhibits. Pepco relies on historical data up through September 2022 in its analysis. Ms. Efimova outlines the overall trends in the forecast drivers on pages 20-21 of her direct testimony.

Q. WHAT ARE THE RESULTS OF PEPCO'S FORECAST?

A. Ms. Efimova estimates that Pepco's electric sales will decline by 1.3% per year over the MYP period. She writes regarding forecasted sales for each rate class:

> Residential class sales will grow 0.1% which is slower than the 1.2% pre-COVID-19 growth due to slower economic growth and growing impacts of EE. Small Commercial class sales will decline (2.5%) which is lower than the (1.8%) pre-COVID-19 growth due to stronger EE. Large Commercial class sales will decline (1.8%) annually over the MYP period after declining (1.1%) during the pre-COVID-19 period of 2017-2019 due to growing impacts of EE.[3]

"EE" in the quote above refers to energy efficiency. EE is driving the decrease in sales per customer in the Company's forecast. Ms. Efimova writes regarding customer growth:

> Pepco's total electric customers are expected to grow by 1.6% per year over the MYP period, driven by Residential class growth of 1.8%. The Residential MYP growth is slower than pre-COVID-19 period due to slower economic growth. The Small Commercial customers are expected to decline (0.3%) driven by slower expected economic growth. The Large Commercial customers will grow 0.5% per year over the MYP period which is slower than pre-COVID-19 growth driven by economic weakness and the continuing impact of COVID-19.[4]

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[3] Exhibit PEPCO (K), Efimova Direct at 21.

[4] Exhibit PEPCO (K), Efimova Direct at 22-23.

Ms. Efimova concludes by arguing Pepco's forecast is reasonable.[5]

Q. DO YOU HAVE ANY CONCERNS WITH PEPCO'S MYP REVENUES FORECAST?

A. Yes. I recommend that the Commission find that the Company's projected energy use per customer over the forecast period understates a reasonable estimate of residential sales at current rates throughout the MYP period. Understating electricity use per customer results in less forecasted sales and, therefore, underestimates revenues at present rates and overstates the claimed revenue deficiency.

My primary concern with Pepco's forecast is that the Company includes factors that decrease use per customer sales, such as energy efficiency, but excludes factors that may increase use per customer, such as conversion to electrification in the forecasted period. Ms. Efimova acknowledges the Company's sales forecast assumptions did not include an offset to conservation sales impacts at pages 15-16 of her direct testimony.

> The Company did not make an explicit assumption regarding building electrification impacts on the billing determinants forecast. However, changes in appliance and building standards used by customers are implicitly captured through the historical sales data that runs through the models. Existing trends in appliances and building standards will thus drive similar impacts in the MYP forecast. No additional assumptions regarding future standards or potential changes to related policies are assumed in the forecast.[6]

I am concerned that Pepco's assumptions are underestimating sales in the MYP period.

5 Exhibit PEPCO (K), Efimova Direct at 25-26.

6 Exhibit PEPCO (K), Efimova Direct at 15-16.

Q. DID YOU REVIEW PEPCO'S ENERGY EFFICIENCY FORECAST?

A. Yes. Pepco includes its energy efficiency forecast as Exhibit PEPCO (K)-6. Ms. Efimova's Exhibit PEPCO (K)-1 discusses the impact of energy efficiency on the forecast.

> The EE data are entered into the residential average use sales model on a per customer basis by dividing the Residential EE forecast by the residential customers. The cumulative monthly EE data are directly entered into other Residential and Commercial econometric sales models as an independent variable. Please see Attachment 'Pepco DC (K)-6.xlsx' for the underlying EE data and the calculations used to get the data into a monthly cumulative series used in the sales models. The MMA model uses Residential EE and the GSLV and MGTLV & GTLV use Commercial EE. EE is expected to reduce Company sales; in the models the sign of the coefficient is expected to be negative. EE is one of the largest impacts that decreases sales.[7]

The Company, however, acknowledges that the results of the EE programs to reduce sales is uncertain and in some cases untested. Exhibit PEPCO (K)-6 includes forecasted energy savings for energy efficiency programs that have not yet been evaluated or commenced. Pepco provided more detail on PEPCO (K)-6 in discovery:

> **QUESTION NO. 39c:** Please provide the most recent program evaluation for each of the programs listed in PEPCO (K)-6.
>
> **RESPONSE:** Evaluations for the Company run programs listed in Pepco (K)-6 are not available as Pepco administered programs through FC1160 have yet to be approved and commence. For DC Sustainable Energy Utility please refer to the DCSEU for any evaluations done on their behalf.
>
> **QUESTION NO. 39d:** Please describe the Company's process for forecasting the energy efficiency savings for programs that do not show any actual savings (or savings before 2023).
>
> **RESPONSE:** Savings forecasts for energy efficiency programs that had no actual savings prior 2023 were based off the forecasted savings that were presented in Pepco's FC1160 filing. The Company only included savings

[7] Exhibit PEPCO (K)-1 at 27.

> from programs that were initially approved with modifications by the Commission in Order 21417.
>
> **QUESTION NO. 39e:** Please describe the Company's process for forecasting the energy efficiency savings for the behavior based program
>
> **RESPONSE:** The Company's forecast for the behavior-based program was taken from its FC1160 filing. The FC1160 forecast was derived from previously evaluated savings of the behavior-based programs the Company administers in nearby Maryland jurisdictions rescaled to the District's population.[8]

Q. DID YOU REVIEW PEPCO'S ELECTRIFICATION ASSUMPTIONS?

A. Yes. As mentioned above, Ms. Efimova states the Company's forecast did not include an assumption regarding electrification in forming its sales forecast over the MYP. This was confirmed in discovery in response to AOBA Data Request 1-11.

> Currently, the Company does not directly include electrification into its 10-year capacity/load forecasts. While identified and specific near-term usage and planned capacity additions have been incorporated, electrification has not been projected.[9]

Despite excluding the increase to sales due to electrification in its MYP projections, Pepco did include costs in the MYP period associated with its outlook for electrification initiatives. Pepco Witness Ms. O'Donnell argues on page 5 of her direct testimony that, "more interactive grid is necessary to accommodate increasing deployment of distributed energy resources and manage increased electrification load."[10] She continues, "Pepco's Climate Ready Grid investments create a platform to support the proliferation of beneficial

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8 Pepco's response to Data Request OPC 13-39, provided in Exhibit OPC (B)-4.

9 Pepco's response to Data Request AOBA 1-11, provided in Exhibit OPC (B)-4.

10 Exhibit PEPCO (A), O'Donnell Direct at 5.

electrification measures in the District's transportation, buildings, and commercial sectors."[11]

Pepco was asked about this statement and its relationship to Pepco's load forecast in discovery in DCG Data Request 1-4.

> **QUESTION NO. 4 -** Refer to Pepco Response to AOBA Data Request No. 11-1(a). If Pepco does not directly include electrification into its 10-year capacity/load forecasts, explain why "proposed investments in this MYP are fundamental to preparing the grid for customer adoption of electrification in the near-term" as stated in the Direct Testimony of Witness O'Donnell at page 10.
>
> **RESPONSE -** The Company assumes that the question meant to reference Pepco's response to AOBA 1-11(a). The Company does not forecast electrification separately from other load, at this time, as noted in the response to 1-11(a). However, the Company does incorporate near term usage when available.
>
> The proposed investments in this MYP are fundamental to preparing the distribution system because the distribution system needs to operate efficiently and effectively, especially with the growth in electrification that will be required to advance the District's decarbonization and clean energy goals. As noted in Witness O'Donnell's testimony (page 10, line 17-20) as customers increase their use of electricity at homes and businesses across the District, it will be even more vital that the grid function smoothly and provide consistent, reliable service.[12]

The evidence demonstrates that Pepco's MYP test year forecast is imbalanced because Pepco includes the costs related to electrification but ignores the increased sales that will be produced by electrification.

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11 Exhibit PEPCO (A), O'Donnell Direct at 5.

12 Pepco's response to Data Request DCG 1-4, provided in Exhibit OPC (B)-4.

Q. DOES PEPCO EXPECT AN INCREASE IN SALES DUE TO THE CONVERSION TO ELECTRIFICATION?

A. Yes. Pepco witness Jaclyn Cantler supports the Company's distribution capital investments being made in the MYP. She also supports Exhibit PEPCO (H)-1, which includes the Company's peak load forecast. Ms. Cantler's direct testimony states that Pepco is preparing for increased load from electrification.

> **Q11. How does the Company's capital investment strategy support the Climate Ready Grid discussed in Company Witness O'Donnell's Direct Testimony?**
>
> A11. The Climate Ready Grid is a series of investments into, among other things, the reliability and resiliency of Pepco's distribution system in the face of the energy transformation. This transformation has been established in District policy and requires a significant shift to electrification. Pepco's climate ready grid addresses the operational readiness to reliably accommodate these shifts and prepare the system for current and future climate impacts. The construction report, which I will discuss later in my testimony, contains investments that are needed to support reliability and resiliency which is increasingly important as customers rely on electrification for their everyday needs – including transportation, heating and cooling.[13]

Despite the capital expenditures included to address electrification, Pepco's load forecast included as Exhibit PEPCO (H)-1 states, "the forecasted loads do not include prospective electrification projects driven by legislative actions that have not been finalized."[14]

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[13] Exhibit PEPCO (H) Cantler Direct at 6.

[14] Exhibit PEPCO (H)-1 at 21.

Q. DOES PEPCO'S LOAD FORECAST RESULT IN A DECREASE TO RESIDENTIAL USE PER CUSTOMER SALES OVER THE FORECAST PERIOD?

A. Yes. Pepco assumes an energy use per residential customer of 625 kWh per month in 2024. Pepco assumes this will decrease to 615 kWh in 2025 and to 605 kWh in 2026. This projection is well below the five-year average weather normalized use per customer of 646 kWh per month as shown below. Table 3 is supported by my Exhibit OPC (B)-5.

TABLE 3

Weather Normalized Use Per Customer

Line	Description	Monthly Avg. kWh Use per Customer (1)	Percent Change (2)
1	2018	666	
2	2019	654	-1.9%
3	2020	651	-0.4%
4	2021	642	-1.4%
5	2022	618	-3.9%
6	5-Year Avg.	646	-1.9%
	Forecast		
7	2023	636	
8	2024	625	-1.6%
9	2025	615	-1.6%
10	2026	605	-1.7%

Sources:
Exhibit OPC (B)-5.

Pepco has not proven that its use per customer assumptions are reasonable and reflect all potential drivers of electricity use in the district during the MYP period.

Q. ARE YOU PROPOSING AN ADJUSTMENT TO PEPCO'S SALES FORECAST?

A. Yes. I recommend the Commission base the MYP sales forecast on Pepco's normalized use per customer for 2023, or a 636 kWh per month per residential customer. Changes in the actual use per customer during the MYP period will be based on, among other drivers, energy efficiency and electrification impacts on households' electric use. Pepco has not provided evidence or analysis that reliably indicates if a use per customer projection based on a balanced forecast will result in an increase, decrease or similar level of electricity sales. Assuming no change in use per customer is the most conservative assumption for the MYP period.

To the extent Pepco's sales forecast used to set rates differs from actual sales while the rates are in effect, the Company has the protection of the MYP reconciliation process to ensure it recovers its cost of service. Consequently, my proposal is more reasonable and balanced than Pepco's projection.

Q. CAN YOU BRIEFLY DESCRIBE THE MYP'S PROPOSED ANNUAL RECONCILIATION PROCESS?

A. Pepco Witness Leming discusses the MYP's annual reconciliation process. The process includes an Annual Informational Filing that compares projected data to actual data, a consolidated reconciliation and prudency review in a subsequent rate case, and a final reconciliation and prudency review after the conclusion of the MYP. Mr. Leming states this comparison aligns with the process the Commission previously approved for the MYP pilot in Formal Case No. 1156. The annual information filing will be submitted by Pepco within 90 days of the end of 2024 and 2025. Mr. Leming writes regarding the annual information filing:

> If the Company is over-earning, parties to the proceeding could petition (or the Commission on its own accord could initiate) for a review of whether rates should be decreased if a significant disparity between revenues and expenses to the detriment of customers is demonstrated. If the Company is under-earning, it will not have an opportunity for rates to be increased as a part of the annual informational filing. This process is meant to serve as an information review with any rate adjustment to occur within a reconciliation and prudency review, such that the MYP does not result in individual reconciliations and rate updates each year, absent a significant disparity between revenues and expenses.[15]

While the MYP process aims to avoid annual reconciliations, the MYP process does allow a party, including Pepco, to petition the Commission to reopen the MYP.

Q. WHAT IS THE IMPACT OF YOUR ADJUSTMENT TO RESIDENTIAL SALES ON THE MYP REVENUE DEFICIENCY?

A. My adjustment is included as Exhibit OPC (B)-6. As shown on my exhibit, forecasting Pepco's revenues at present rates using a more reasonable use per customer assumption lowers the Company's claimed revenue deficiency by $678,429 in 2024, $2,077,428 in 2025, and $4,299,154 in 2026.

My exhibit uses the same forecasting process as Pepco. I used the same number of customers forecast, electric vehicles forecast, and solar forecast as Pepco. Once Pepco calculated a monthly use per customer using its regression analysis, the Company then applied a small adjustment for electric vehicles and solar adoption. Pepco then multiples this adjusted monthly use per customer by its forecasted number of customers to calculate

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[15] Exhibit PEPCO (B), Robert Leming Direct at 14.

its kWh sales forecast. The forecasted sales then flow into the PEPCO (E) exhibits which calculates the MYP revenues at present rates. My exhibit only changes the use per customer assumption and does not adjust Pepco's number of customers forecast or other assumptions.

B. MYP Cost Escalation

Q. PLEASE DESCRIBE HOW PEPCO FORECASTED ITS OPERATION AND MAINTENANCE ("O&M") EXPENSE FOR THE MYP PERIOD.

A. Pepco's MYP forecasts the expected O&M (and capital investments) for the three-year period using the Long Range Plan ("LRP") developed by Pepco Holdings LLC ("PHI"). Pepco's application also outlines the 2022 historical test year and 2023 bridge year. Exhibit PEPCO (B)-1 is a summary of the historical test year, 2023 bridge year, and MYP period revenue requirements. The Commission requires the Company to identify baseline revenues and cost information and to explain how the Company forecasts its cost of service as part of its alternate forms of regulation ("AFOR").[16]

Table 4, below, highlights the Company's forecasted O&M expense from 2023 to 2026. While Pepco limited its projected escalation of O&M expense during the MYP to 1.93%,[17] its projected O&M escalation was 9.2% in the 2023 bridge year over the 2022

[16] Exhibit PEPCO (B), Leming Direct at 27.

[17] Exhibit PEPCO (A), O'Donnell Direct at 32.

historical year. The overall O&M annual growth rate included in the MYP forecast (2022 to 2026) is 3.7%.[18]

TABLE 4

Pepco's MYP O&M Expense Forecast
($000)

Line	Year	O&M Expense (1)	Percent Increase (2)
1	2022 HTY	$ 164,178	
2	2023 Bridge	179,338	9.23%
3	2024 MYP	185,235	3.29%
4	2025 MYP	186,125	0.48%
5	2026 MYP	189,910	2.03%
6	5-Year Annual Growth Rate		3.71%
7	MYP Annual Growth Rate		1.93%

Source:
Exhibit PEPCO (B)-1.

As explained above, the MYP O&M forecasts were developed within the PHI LRP process. The following Company witnesses sponsored certain components of these O&M cost projections:

- Phillip S. Barnett forecasts O&M at Pepco and the PHI Service Company ("PHISCO") for non-operational departments
- Phillip Vavala forecasts O&M for Operations
- Morlon D. Bell-Izzard forecasts O&M for Customer Operations

18 Exhibit PEPCO (B), Leming Direct at 5-6.

Pepco witnesses Barnett, Vavala, and Bell-Izzard describe PHI's LRP noting that O&M budgets are completed at a "Management View" and include total Pepco direct O&M and total PHISCO O&M before an allocation is made to the Pepco DC jurisdiction. Hence, the forecast process includes affiliate and Pepco jurisdictional combined cost flowed by an allocation of combined costs to respective jurisdictions. Mr. Barnett presents the Pepco Adjusted O&M costs on a Consolidated Pepco Reporting Basis which includes Pepco's allocation of total PHISCO affiliate service company costs. Witness Leming discusses how these O&M costs are allocated to the Pepco DC distribution jurisdiction.

Mr. Leming presents Pepco's O&M costs in his Table 6 which I have replicated below as my Table 5. Mr. Leming provided his jurisdictional cost of service study as Exhibit PEPCO (B)-3.

TABLE 5

Allocation of Pepco's MYP O&M Expense Forecast
($000)

Line	Description	HTY 2022 (1)	Bridge Year 2023 (2)	MYP Year 1 2024 (3)	MYP Year 2 2025 (4)	MYP Year 3 2026 (5)
1	O&M - Management View	$ 635,974	$ 663,036	$ 684,897	$ 700,145	$ 717,738
2	Less: Non-Pepco PHISCO Allocated Costs	(146,687)	(163,006)	(172,960)	(180,379)	(184,217)
3	O&M - Consolidated Pepco Reporting	$ 489,287	$ 500,030	$ 511,937	$ 519,766	$ 533,521
4	Plus: Regulatory Programs Recovered Via Riders & Exclusions	17,223	19,137	40,711	68,990	95,874
5	GAAP O&M	$ 506,510	$ 519,167	$ 552,648	$ 588,756	$ 629,395
6	Less: Non-Distribution Lines of Business O&M	(83,843)	(80,763)	(105,102)	(135,511)	(164,430)
7	Less: Below the Line O&M	(14,515)	(13,854)	(10,281)	(10,244)	(14,146)
8	Plus: Regulatory Asset Amortization	2,888	5,675	4,713	3,474	1,398
9	Total Distribution O&M	$ 411,040	$ 430,225	$ 441,978	$ 446,475	$ 452,217
10	Less: Maryland Distribution O&M	(237,125)	(245,854)	(252,295)	(255,714)	(257,571)
11	DC Distribution O&M	$ 173,915	$ 184,371	$ 189,683	$ 190,761	$ 194,646
12	Less: Ratemaking Adjustments	(9,737)	(5,033)	(4,447)	(4,635)	(4,737)
13	**Adjusted DC Distribution O&M (Revenue Requirement View)**	**$ 164,178**	**$ 179,338**	**$ 185,236**	**$ 186,126**	**$ 189,909**

Source:
Leming Direct Testimony at 39.

Q. IS PEPCO USING A DIFFERENT METHODOLOGY FOR ITS O&M FORECAST THAN WHAT WAS APPROVED IN FC 1156?

A. Yes. In FC 1156, Pepco submitted two MYP proposals. The first used the Company's LRP to forecast revenues and expenses and the second was based on a historic period with annual additions to plant in-service and O&M expense tied to an escalation factor. The Commission accepted Pepco's second proposal with modifications, which is referred to as the Modified Enhanced Multiyear Rate Plan ("Modified EMRP") pilot. The modifications included a reduced return on equity (9.275% instead of 9.70%) and a reduction in the inflation escalator, among other modifications. The Commission used an inflation escalator of 2.17% instead of Pepco's proposed 2.5%. The Commission concluded:

> Specifically, the Modified EMRP uses an escalation factor independent from actual cost changes. The escalator incentivizes Pepco to control costs over the course of the EMRP and benefits ratepayers since Pepco is prevented from escalated costs in a manner that equals its desired revenue requirements.[19]

Mr. Leming states the Company developed the O&M expenses in this application based on PHI's LRP (rather than the index approached used in the Modified EMRP pilot), and he believes this methodology is more reasonable and appropriate. He states:

> Leveraging the Company's LRP for the projection of revenues and expenses provides all parties in the case and customers with transparency into the Company's plans and ensures that there is a basis for the revenue requirements rooted in plans that support the District's goals and policies, while ensuring that customers continue to receive reliable service.[20]

* * *

[19] FC1156 Order and Opinion No. 20755, June 8, 2021, page 63.

[20] Exhibit PEPCO (B), Leming Direct at 9.

> The LRP reflects the Company's best current estimates regarding the specific distribution programs and initiatives Pepco will undertake in the District and considers impacts of inflation and supply chain issues during the 3-year term of the MYP.[21]

Table 3 of his direct testimony compares the Company's proposed MYP in this case with the Modified EMRP pilot. His table shows that the proposed approach for forecasting O&M costs in the second MYP is the forecast from the Long Range Plans while the Modified EMRP pilot used an index.

Ms. O'Donnell explains in her direct testimony why the Company did not use an escalation factor similar to the Modified EMRP pilot. She argues that the LRP is forward-looking and reflects cost projections that take into account the specific distribution programs and initiatives Pepco intends to implement. Ms. O'Donnell also argues that the LRP reflects the Company's best current estimates regarding inflation and supply chain issues that may be experienced during the MYP period. Ms. O'Donnell also argues the reconciliation process ensures customers eventually pay for the actual cost of service.

Pepco further explained its decision to not use an index or escalator approach for this MYP in response to DCG Data Request 4-3.

> **QUESTION NO. 4-3**
>
> C. Explain how the LRP approach improves the Company's incentive to achieve cost-efficiencies compared to the index approach.
>
> **RESPONSE**
>
> C. The LRP approach improves the Company's incentive to achieve cost efficiencies by aligning the baseline from which to seek efficiencies to the

[21] Exhibit PEPCO, Leming Direct at 9.

> work it expects to perform, rather than a general inflation factor which may or may not correlate with the planned work in a given year.[22]

Q. DID PEPCO SUMMARIZE THE PRIMARY DRIVERS OF ITS FORECASTED O&M COST PROJECTIONS?

A. Yes. Witness Barnett states the primary drivers of the O&M cost increase in his areas are merit increases, higher pension and Other Post-Employment Benefits ("OPEB") costs, and higher Business Services Company ("BSC") and Information Technology ("IT") costs.[23] Witness Vavala states the primary drivers of the O&M cost increase in his areas are merit increases, higher pension and OPEB costs, contracting costs, technical services, and transmission and substation (distribution) costs.[24] Witness Bell-Izzard states the primary drivers of the O&M cost increase in his areas is payroll / merit increases.[25]

Q. DOES THE COMPANY'S REVISED METHOD OF FORECASTING ITS MYP O&M EXPENSE PROVIDE SUFFICIENT TRANSPARENCY TO ENSURE THAT CUSTOMERS' INTERESTS ARE PROTECTED?

A. No. The Company's updated method of forecasting O&M expense under an MYP is largely tied to consolidated Company operations, including service company fees rather than tracking estimates for jurisdictional Pepco operating expenses, and explaining changes to these costs based on expected inflationary escalation factors, weights changes

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22 Pepco's response to Data Request DCG 4-3, provided in Exhibit OPC (B)-4.

23 Exhibit PEPCO (G), Barnett Direct at 17.

24 Exhibit PEPCO (I), Vavala Direct at 6-7.

25 Exhibit PEPCO (J), Bell-Izzard Direct at 36-37.

or other methods that can be used to gauge the reasonableness of projected prospective changes relative to historical actual costs in forecasting cost of service in an MYP. Customers should be protected by maintaining as much transparency as possible in forecasting cost of service in the MYP. The Commission achieved this objection when it previously approved method of forecasting O&M expenses regarding the Modified EMRP pilot. Pepco has not identified any deficiency with the Commission's prior approach or provided evidence to support factual determination that its proposal is superior to the prior approach. I believe the new approach is less transparent and reduces customer rate setting protections relative to the prior approach. .

Q. PLEASE EXPLAIN WHY THE NEW LRP APPROACH OF BUDGETING O&M EXPENSE IS LESS TRANSPARENT THAN THE BUDGETING PRIOR APPROACH PREVIOUSLY APPROVED BY THE COMMISSION?

A. As noted above, Ms. O'Donnell argues in her direct testimony that the MYP reflects the Company's best current estimates regarding inflation and supply chain issues. Mr. Leming makes the same argument in his direct testimony. Importantly, however, Pepco does not detail its inflation outlook during the MYP in its new approach of forecasting O&M. Witness Barnett describes the LRP process in his direct testimony:

> PHI's operational plans are updated annually for current operating conditions and safety and reliability goals and the PHI LRP process begins with a kick-off meeting that is led by Finance to provide key instructions to the responsibility areas on the timing of deliverables, key planning assumptions, and guidance on responsibilities for milestones in the development of the LRP. Responsibilities areas are provided with targets and O&M planning assumptions including such things as inflation, merit increases, fringe benefits and pension/OPEB. Any significant changes in

> operational goals and regulatory requirements are taken into consideration in the LRP process.[26]

LRPs for the three O&M areas were provided as Exhibits PEPCO (G)-1 and (G)-2 (non-operations functions), PEPCO (I)-1 and (I)-2 (operations), and PEPCO (J)-1 and (J)-2 (customer service). Nothing in Pepco's testimony or the plans themselves provides the Company's O&M planning assumptions, e.g., an inflation estimate for the MYP. Instead, Pepco cites the average Consumer Price Indices for 2021 and 2022 of 6.7% as evidence that purportedly shows its O&M cost increases during the MYP are reasonable.[27] Pepco also describes 6.7% as the current inflation rate.[28] This is an issue of fact for the forecasted costs in the MYP because inflation has declined significantly in 2023 relative to 2021 and 2022 and consensus economists' forecasts for future inflation are lower than current rates of inflation. The current inflation rate is often described as a ceiling for the LRP, therefore it is important to ensure Pepco's forecasted costs reflect up to date inflation estimates.

> In terms of the financial plan, spending targets are set in order to achieve operational goals, to comply with regulatory requirements, and to ensure that overall O&M increases are lower than the rate of inflation, which helps mitigate customer bill impact.[29]

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[26] Exhibit PEPCO (G), Barnett Direct at 11-12.

[27] Exhibit PEPCO (A), O'Donnell Direct at 32.

[28] Exhibit PEPCO, Leming Direct at 6.

[29] Exhibit PEPCO (G), Barnett Direct at 11.

Q. DID YOU ASK ABOUT PEPCO ABOUT THE BASIS FOR ITS INFLATION ASSUMPTIONS IN DISCOVERY?

A. Yes. Pepco stated in discovery that, "when developing estimates of growth and inflation, Pepco leveraged the IHS Macro 10-year Baseline Consumer Price Index ('CPI') annual percent change from 2023-2026 as well as factored in recent inflation levels, which were in excess of this average."[30] Figure 1 shows Pepco's inflation estimates.

FIGURE 1[31]

Inflation Assumptions

	Assumption *(annual %)*	2023 LRP	2024 LRP	2025 LRP	2026 LRP
1	Default Inflation Rate (1)	3.9%	2.2%	2.1%	2.2%

Labor Rate Assumptions

	Labor Rate Assumption *(annual %)*	2023 LRP	2024 LRP	2025 LRP	2026 LRP
2	Salary Inflation Rate (average)	4.00%	3.00%	3.00%	3.00%
3	Hourly Non-Represented Inflation Rate (average)	4.00%	3.00%	3.00%	3.00%

NOTES
1. IHS U.S. Macro 10-Year Baseline Consumer Price Index [2022 September Vintage/Release]. Annual percent change

Pepco states it "factored in recent inflation levels" in its MYP forecast. However, it is important to note that inflation has decreased significantly since the Company developed its LRP. According to the *Blue Chip Financial Forecasts*, inflation was 3.2% in Q3 2023

30 Pepco's response to Data Request OPC 13-16, provided in Exhibit OPC (B)-4.

31 *Id.*

and expected to be 3.1% in Q4 2023.[32] However, inflation is forecasted to decline to about 2.4% through 2024.[33] This is a significant decrease from the 6.7% inflation Pepco cites in its testimony and Pepco has not demonstrated that its proposal is reasonable in light of this material change.

Importantly, Pepco's 2023 inflation forecast exceeded actual inflation in 2023. As discussed below, I believe this inflation estimate is one of the reasons for the significant 9.23% O&M increases Pepco assumes for 2023 and that inflates subsequent years in the MYP.

Q. DID PEPCO FORECAST A SIGNIFICANT INCREASE IN O&M COSTS IN THE MYP'S 2023 "BRIDGE" YEAR?

A. Yes. I provide an overview of Pepco's O&M expenses from 2018 through 2026 by account as my Exhibit OPC (B)-7. I also provide the labor and non-labor breakout of Pepco's O&M costs from 2018 to 2026 as Exhibit OPC (B)-8. The data is provided at the total distribution level rather than the DC distribution level because Pepco responded in discovery that it did not have the labor and non-labor O&M expenses at the DC jurisdictional level.

Table 6 summarizes the total distribution O&M expenses shown on Exhibit OPC (B)-8.

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32 *Blue Chip Financial Forecasts*, October 2, 2023, at 2.

33 *Blue Chip Financial Forecasts*, October 2, 2023, at 2.

TABLE 6

Total Distribution O&M Expense
($ Millions)

		Labor O&M		Non-Labor O&M		Total O&M	
Line	**Description**	**Amount (1)**	**% Change (2)**	**Amount (3)**	**% Change (4)**	**Amount (5)**	**% Change (6)**
1	2018	$ 111.0		$ 293.9		$ 404.9	
2	2019	113.3	2.1%	299.7	2.0%	413.0	2.0%
3	2020	110.8	-2.2%	290.1	-3.2%	400.9	-2.9%
4	2021	111.8	0.9%	274.4	-5.4%	386.1	-3.7%
5	2022	110.8	-0.8%	300.2	9.4%	411.0	6.4%
6	2023	135.5	22.3%	294.7	-1.8%	430.2	4.7%
7	2024	140.9	4.0%	301.1	2.2%	442.0	2.7%
8	2025	147.3	4.5%	299.2	-0.6%	446.5	1.0%
9	2026	151.6	2.9%	300.6	0.5%	452.2	1.3%

Source:
Exhibit OPC (B)-8.

As shown above, Pepco's total distribution O&M expenses are expected to increase by $41.2 million between the end of the 2022 historical test year and the end of the MYP. This cost increase can be attributed entirely to outside services, which is expected to increase by $41.0 million over the same time period, as shown on line 34 of Exhibit OPC (B)-7. This is by far the single biggest cost increase. No other account is forecasted to increase by over $10 million over this same time period.

A significant driver of Pepco's forecasted O&M increases is the PHISCO and Exelon Business Services Company ("BSC") costs allocated to Pepco. Pepco estimates that the PHISCO allocated labor costs will increase by $10.6 million between 2022 and the end of the MYP, and the BSC allocated labor costs will increase by $17.4 million in that same period. These service company labor costs are shown in Table 7, below.

TABLE 7

Total Distribution Service Company Labor Costs
($ Millions)

		PHISCO Allocated to Pepco		BSC Allocated to Pepco		Total Allocated to Pepco	
Line	**Description**	**Amount (1)**	**% Change (2)**	**Amount (3)**	**% Change (4)**	**Amount (5)**	**% Change (6)**
1	2018	$ 29.1		$ 17.4		$ 46.5	
2	2019	30.2	4.0%	18.7	7.2%	48.9	5.2%
3	2020	28.3	-6.3%	19.7	5.5%	48.0	-1.8%
4	2021	29.6	4.7%	19.0	-3.7%	48.6	1.2%
5	2022	29.4	-0.9%	21.1	11.0%	50.4	3.8%
6	2023	35.9	22.2%	34.2	62.4%	70.1	39.0%
7	2024	37.4	4.2%	36.3	6.2%	73.7	5.2%
8	2025	38.9	4.2%	37.6	3.4%	76.5	3.8%
9	2026	39.9	2.6%	38.4	2.3%	78.4	2.5%

Source:
Exhibit OPC (B)-8.

Both Table 6 and Table 7 show that Pepco assumes a significant increase in costs during the 2023 bridge year. Again, part of this increase may be attributable to Pepco's excessive and unreasonable inflation assumption for 2023.

Q. PLEASE DESCRIBE PHISCO AND BSC.

A. Pepco Witness Barnett summarizes the relationship between the various companies on pages 3-4 of his direct testimony:

> Exelon and PHI merged in 2016 with the District of Columbia Public Service Commission's authorization in Order No. 18148. PHI is a limited liability company and an indirect, wholly owned subsidiary of Exelon. PHI is comprised of PHISCO and three regulated utilities: Pepco, ACE, and DPL. PHISCO is a subsidiary of PHI. PHISCO provides a variety of shared services pursuant to service agreements with PHI's three regulated subsidiaries, Pepco, ACE, and DPL. Exelon also operates the Business Services Company (BSC), a separate shared service company. Similar to

> PHISCO, BSC provides services to PHISCO, Pepco, ACE, and DPL pursuant to service agreements. BSC is a subsidiary of Exelon. Both PHISCO and BSC are also responsible for delivering specific, unique shared services to Pepco.[34]

Mr. Barnett explains on pages 5-6 of his direct testimony how the services provided by PHISCO and BSC differ. CONFIDENTIAL Exhibit PEPCO (B)-9 includes the Cost Accounting Manual ("CAM") and General Services Agreement ("GSA") which cover the allocation of the service company costs to Pepco.

My Exhibit OPC (B)-9 provides the historical charges for PHISCO and BSC to each of their affiliates as reported on the FERC Form 60. As shown on my exhibit, the BSC costs allocated to Pepco in particular saw a large increase in 2022 despite total charges across all affiliates decreasing by 17% that year. The decrease was largely due to Exelon completing the spin-off of its generation business on February 1, 2022.

It is necessary to take a fresh look at the affiliate allocation factors as the BSC client companies change to ensure that the costs being allocated to the DC jurisdiction are being fairly calculated. Pepco's MYP testimony has not provided this level of transparency into its allocation factors. Pepco has not developed the factual support necessary to prove the reasonableness of its projections.

Q. DID PEPCO JUSTIFY THE SIGNIFICANT INCREASE IN ALLOCATED SERVICE COMPANY FEES SHOWN IN TABLE 6 AND TABLE 7, ABOVE?

A. No. Pepco Witnesses Barnett, Vavala, and Bell-Izzard support O&M costs at the management view, or line 1 on my Table 5. They do not adequately describe what

34 Exhibit PEPCO (G), Barnett Direct at 3-4.

additional services Pepco's DC operations are expected to receive from PHISCO and BSC that justify the significant cost increases, nor do they argue the service company charges are being correctly allocated to Pepco. Mr. Barnett does note when discussing the 2023 non-IT increases in BSC costs that the increase includes, "higher inflation costs, annual merit increases, insurance premiums, and cybersecurity costs as well as higher staffing and recruitment costs…"[35] However, Mr. Barnett does not state what inflation estimate he is using for 2023 nor what additional services the additional staff will be providing Pepco. Pepco's failure to provide these key details undermines the reliability of its projections.

Mr. Leming supports the allocation of service company fees to Pepco but he does not provide workpapers supporting the allocation of PHISCO and BSC costs to Pepco relative to other affiliates. Mr. Leming provides CONFIDENTIAL Exhibit PEPCO (B)-9 but this exhibit only describes the allocation process and does not support the actual allocation factors used to allocate costs to Pepco.

Q. WHAT DO YOU RECOMMEND?

A. Given Pepco's failure to provide factual or analytical support for the significant increase in service company charges, I recommend the Commission limit the amount of these charges in the MYP pending justification from Pepco that includes a full accounting of the allocated costs, reasons for the increase, support for each allocation factor used to allocate costs from PHISCO and BSC, how that allocation compares to other PHISCO and BSC affiliates, and evidence that the service company charges paid by Pepco are no more than

[35] Exhibit PEPCO (G), Barnett Direct at 36.

those that would be charged by an independent third party. I recommend the Commission cap the service company charges at the 2023 bridge year level. As shown in my Table 8, below, this still reflects a significant increase over Pepco's actual 2022 expenses. Capping these costs at the forecasted 2023 level will lower the total distribution O&M expense during the MYP by $3.6 million in 2024, $6.4 million in 2025 and $8.3 million in 2026. The DC distribution impact is $1.6 million in 2024, $2.8 million in 2025, and $3.7 million in 2026. My adjustment is included as Exhibit OPC (B)-10.

TABLE 8

Service Company Charges Adjustment
($000)

Line	Year	PHISCO Allocated to Pepco (1)	BSC Allocated to Pepco (2)	Total Charges (3)	Adjustment (4)	Revised Total Charges (5)
1	2022	$ 29,361	$ 21,053	$ 50,414		$ 50,414
2	2023	35,871	34,197	70,069		70,069
3	2024	37,367	36,312	73,679	(3,611)	70,069
4	2025	38,921	37,562	76,483	(6,414)	70,069
5	2026	39,928	38,435	78,363	(8,294)	70,069

Source:
Exhibit OPC (B)-10.

Q. IS THERE ADDITIONAL EVIDENCE THAT CAPPING THESE COSTS AT THE MYP'S 2023 BRIDGE YEAR AMOUNT IS A REASONABLE ADJUSTMENT?

A. Yes. Pepco's TTY compliance filing shows that the 2023 service company labor costs are expected to be $64.9 million compared to the $70.1 million shown above in Table 8.[36] Assuming the updated cost estimate of $64.9 million for these allocated labor costs was escalated at a 2.5% inflation rate each year then the costs during the MYP would still be below my proposed cap of $70.1 million.

C. Deficient Deferred Income Taxes

Q. PLEASE DESCRIBE PEPCO'S PROPOSAL REGARDING ITS DEFICIENT DEFERRED INCOME TAXES ("DDIT").

A. Pepco Witness Leming discusses the Company's DDIT proposal in his direct testimony. He also includes a DDIT adjustment as Ratemaking Adjustment ("RMA") 15. Pepco re-measured its accumulated deferred income tax ("ADIT") balance as a result of the 2017 Tax Cuts and Jobs Act ("TCJA"). The presence of Excess deferred income taxes ("EDIT") or DDIT is the result of differences between deferred taxes at the old federal income tax rate and the new rate. EDIT represents an over-collection of deferred tax payments from customers that will not be remitted to government taxing authorities due to the TCJA. DDIT are an under-collection.

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[36] Pepco's response to Data Request OPC 13-4, provided in Exhibit OPC (B)-4.

Mr. Leming explains that property-related deferred tax differences are typically the result of accelerated tax depreciation versus straight-line depreciation timing differences.[37] The TCJA created EDIT for Pepco's property-related deferred tax liabilities. Mr. Leming goes on to explain that non-property related deferred income tax differences are typically the result of payroll related timing differences.[38] The TCJA created DDIT for Pepco's non-property related deferred tax assets because the value of the deferred tax assets was re-measured downward. The DDIT balance is for PHISCO. A portion of the DDIT balance was allocated to Pepco consistent with the Company's cost allocation methodologies.

Pepco proposes to amortize the non-property related DDIT over five years in its MYP application. This adjustment is included as RMA-15. The adjustment increases Pepco's revenue deficiency by $1.579 million in 2024, $1.489 million in 2025, and $1.398 million in 2026.

Q. HAS THE COMMISSION RULED ON RECOVERY OF THIS DDIT FROM CUSTOMERS?

A. Yes. In FC 1156, the Commission approved the amortization of Pepco's EDIT but denied an amortization of Pepco's share of PHISCO's DDIT. The Commission concluded in Order No. 20755:

> The Commission agrees with OPC's position that while the PHISCO plant assets and property related ADIT balances are authorized in rate base, the PHISCO non-property related ADIT balances are not. Pepco contended that the test should be whether the underlying basis is included in customer rates as a recoverable operating expense since there are underlying tax basis accounts that are not included in Pepco's ADIT in rate base but were

[37] Exhibit PEPCO (B), Leming Direct at 57.

[38] Exhibit PEPCO, Leming Direct at 57.

> included in Pepco's non-property EDIT agreed to in Formal Case No. 1150. However, the Commission denies the Company's revised proposal to include the NPNP DDIT asset of $5.853 million on a gross basis. The Company's reference to the EDIT Settlement agreement is misplaced. The NP EDIT agreed to in Formal Case No. 1150 did not address the PHISCO deferred income tax balances; it only addressed the Pepco balances. PHISCO non-property ADIT is not a component of rate base.[39]

Q. WHY DOES MR. LEMING BELIEVE THE COMMISSION SHOULD REVERSE ITS DECISION FROM FC 1156?

A. Mr. Leming offers two reasons why the Commission should reverse its decision. However, his reasoning does not justify a change from the Commission finding in FC1156.

Q. PLEASE EXPLAIN.

A. First, Mr. Leming notes that the DDIT was approved for recovery in Maryland Public Service Commission Case No. 9602 in Order No. 89227[40] issued on August 12, 2019. This Maryland decision was before the DC Commission's decision in FC1156 that was issued on June 8, 2021. The Maryland Order was available at the time the FC 1156 decision was entered and does not constitute new information.

Second, Mr. Leming argues that because the underlying costs giving rise to PHISCO's non-property related DDIT is included in customer rates, the corresponding DDIT should also be included cost of service.[41] Again, this is not new information. More importantly, the Commission considered and rejected this argument from Pepco in FC 1156: "Pepco contended that the test should be whether the underlying basis is included

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[39] FC1156 Order and Opinion No. 20755, June 8, 2021, page 136.

[40] Pepco (B), Leming Direct at 59.

[41] Pepco (B), Leming Direct at 59.

in customer rates as a recoverable operating expense..."[42] Pepco provides no basis for reversing this rationale and reaching a different conclusion in this proceeding.

Q. WHAT IS YOUR RECOMMENDATION?

A. Consistent with prior findings, I recommend Pepco's proposed RMA-15 pro forma adjustment be removed from the MYP projected cost of service. As shown on my summary exhibit, removing. Pepco's RMA-15 reduces the Company's revenue deficiency by $1.579 million in 2024, $1.489 million in 2025, and $1.398 million in 2026.

D. COVID-19 Cost Recovery

Q. PLEASE DESCRIBE PEPCO'S PROPOSAL REGARDING THE RECOVERY OF ITS COVID-19 RELATED INCREMENTAL COSTS DURING THE MYP.

A. In Order No. 20329 the Commission directed Pepco to create a regulatory asset for incremental costs related to COVID-19 that could be considered for recovery in a future base rate case. Pepco states it deferred prudently incurred incremental costs related to COVID-19 between March 11, 2020 and August 8, 2021. The deferred costs include incremental lost late payment revenues, incremental lost connection and reconnection fees, and pandemic-related incremental equipment, cleaning, and other costs. The COVID-19 costs also includes the incremental increase in bad debt expense. Pepco also recorded cost offsets such as reduced meals, travel and other costs.

[42] FC1156 Order and Opinion No. 20755, June 8, 2021, page 136.

Pepco proposes to recover the COVID-19 over five years. This regulatory asset increases Pepco's revenue requirement by $3.441 million in 2024, $3.244 million in 2025, and $3.046 million in 2026.

Q. DO YOU HAVE ANY CONCERNS WITH PEPCO'S PROPOSAL?

A. Yes. I believe the Commission should consider approving a longer amortization period given the extraordinary and non-recurring nature of this cost. The pandemic is not expected to be repeated and is therefore a once in a lifetime non-recurring event. The rate impact of this COVID event should be mitigated as much as possible in this case. I recommend a six-year amortization period be used for either the MYP or TTY cost of service. A typical rate case cycle is two or three years. A six-year recovery period will align recovery of the COVID-19 costs with two to three traditional rate case cycles if Pepco files a rate case every two to three years. I believe a six-year recovery is more appropriate than a five-year recovery because extending the recovery period will mitigate the rate increase proposed by Pepco without harming the Company's ability to recover these costs while still allowing the Company to recovery these costs over the same two to three traditional rate case cycles. Pepco stated in discovery the Commission has approved various regulatory asset amortization periods ranging from 3 years to 15 years.[43]

The adjustment to reflect a six-year recovery of the pandemic-related costs is included in my Exhibit OPC (B)-11. Recovering the COVID-19 costs over the Company's

[43] Pepco's response to Data Request OPC 13-33, provided in Exhibit OPC (B)-4.

next two MYPs will lower the Company's revenue requirement by approximately $408,000 in 2024, $375,000 in 2025, and $342,000 in 2026.

Q. DO YOU RECOMMEND OTHER REGULATORY ASSETS BE RECOVERED OVER SIX YEARS?

A. Yes. Pepco has four other MYP RMAs that propose a five-year amortization. Aligning these amortization periods with two to three traditional rate case cycles helps alleviate some of the revenue deficiency in this case while limiting cost recovery to the same two or three rate case cycles. My adjustment is included in Exhibit OPC (B)-11. Combined with my COVID-19 adjustment, the longer amortization periods lower Pepco's claimed revenue deficiency by approximately $553,000 in 2024, $510,000 in 2025, and $471,000 in 2026.

V. <u>TRADITIONAL TEST YEAR REVENUE REQUIREMENT ADJUSTMENTS</u>

Q. PLEASE BRIEFLY SUMMARIZE YOUR PROPOSED ADJUSTMENTS TO PEPCO'S TTY REVENUE REQUIREMENTS?

A. I recommend several adjustments to Pepco's TTY revenue requirement, as shown on Table 2 above.

- Pepco's TTY Compliance filing includes several adjustments to annualize expenses for the end of the test year but the Company does not annualize revenues to account for customer growth during the test year. I recommend Pepco's TTY revenues be adjusted to reflect the number of customers at the end of 2023.

- Pepco is requesting authority from the Commission to recover its deficient deferred income taxes just as the Company did in FC 1156. Given Pepco has offered no new evidence that would suggest the Commission reverse its decision from the prior case, I recommend these costs be removed from cost of service.

- Pepco is requesting to recover several of its regulatory assets, including the deferred COVID-19 costs, over five years. Given the extraordinary nature of the pandemic, I recommend the COVID-19 costs be recovered over a longer period of time, or six years.

- Pepco's TTY Compliance filing includes an inflation adjustment to non-labor O&M expense. However, Pepco's adjustment uses an inflation rate that is excessive compared to actual inflation in 2023. Therefore, I recommend Pepco's adjustment be adjusted to reflect actual inflation in the second half of 2023.

A. 2023 Sales Revenues

Q. HOW DOES PEPCO FORECAST ITS REVENUES FOR THE TTY?

A. Pepco assumes $671,304,428 of electricity sales in its 2023 TTY. As shown on Pepco's Voluntary DR 1-01, Attachment A14 (provided in Exhibit OPC (B)-4) this assumption includes six months of actual sales and six months of forecasted sales. Pepco makes one ratemaking adjustment to its TTY revenues. RMA 13 removes from the TTY revenues the five-year EDIT credits that will sunset during the test period.

Q. DID PEPCO PROJECT TTY REVENUE SALES FOR ITS TRADITIONAL COST OF SERVICE IN A SIMILAR WAY THAT IT PROJECTED RATE BASE AND O&M EXPENSES?

A. No. In projecting test year sales, the Company relied on actual sales within the test year. However, for projecting rate base and O&M expenses, the Company adjusted these items for end-of-year growth in plant investment and operating expenses. Hence, there is a mismatch in the way the Company developed its revenue projections for the historical test year and the manner in which it is projecting rate base and O&M expenses for the same time period. For example, Pepco uses a year end rate base. Mr. Leming argues using a year-end rate base is more appropriate in his October 2023 supplemental direct testimony.

> RMA 4 annualizes the difference in rate base that results from using a 13-month average balance for the cost of service rather than the year-end balance. The year-end balance provides a better picture of the used and useful investments that serve customers during the rate effective period. The 13-month average balance understates the Company's true cost of service for these investments, which in turn, limits the Company from earning a reasonable authorized return on these investments.[44]

Pepco elaborated on its position in discovery:

> When setting rates based on a traditional test period, the year end balances for that test period would be used and useful in providing service to customers in each month of the rate effective period. Said another way, an asset placed in-service in December 2023 would be used and useful in every month in 2024 when rates in this proceeding are anticipated to go into effect. If that asset were to be treated on a 13-month average basis, that asset would only be reflected in 1-month of the 13-month average from December 2022 through December 2023. This means that customers' rates would only reflect a small fraction of the annual cost of service related to this asset, while it is used and useful in providing service in each month of the rate effective period. This has the effect of drastically understating the true cost of service for this asset.[45]

This same principle also applies to Pepco's revenues. Pepco not making an adjustment to annualize revenues to account for the increase in customers during the TTY results in the Company understating revenue and inflating the claimed revenue deficiency. Further, Pepco adjusted operating expenses including depreciation expense for end-of-year items.[46] Adjusting operating expenses to year end, decreases operating income and increases the

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[44] Exhibit PEPCO (2B), Leming October 2023 Supplemental Direct at 11.

[45] Pepco's response to Data Request OPC 13-14, provided in Exhibit OPC (B)-4.

[46] Exhibit PEPCO (2B), Leming October 2023 Supplemental Direct at 10.

estimated revenue deficiency. Conversely, adjusting customers to year end, increases operating, and reduces the revenue deficiency. If yearend adjustments are allowed, all adjustment to historical year data are needed to properly match historical revenue and expenses based on historical year-end data. This produces the most accurate and reliable estimated of the ability of current rates to recover Pepco's cost of service in the rate effective period.

Pepco explained why it did not make a year-end adjustment to revenues in discovery:

> Calculating test year base distribution revenues based on year-end customer counts would improperly over- or under-state the revenues for each rate class that the Company is allowed during the test year and would be inconsistent with prior traditional test year rate cases.[47]

Pepco is incorrect for the reasons I stated above.

Q. HOW SHOULD REVENUES FOR THE TEST YEAR BE ADJUSTED TO REFLECT END-OF-YEAR RATE BASE AND OPERATING EXPENSES?

A. Test year revenues should be adjusted to reflect end-of-year growth in number of customers that occurred throughout the test year. This will result in an increased level of annual sales due to an increased level of number of customers taking service at year-end, compared to the average number of customers throughout the year.

Pepco forecasts it will have 395,386 customers in December 2023, or an increase of 4,989 customers, or 1.3%.[48] The increase in sales revenues associated with customers

[47] Pepco's response to Data Request OPC 14-4, provided in Exhibit OPC (B)-4.

[48] Exhibit PEPCO 2(E)-1.

growth will provide Pepco increased revenue to pay for its projected increase to year-end rate base and O&M expense in the test year.

Q. WHAT DO YOU RECOMMEND?

A. I recommend the TTY revenues be annualized to reflect the year end number of customers. My adjustment is included as Exhibit OPC (B)-12. My adjustment increases the TTY revenues by approximately $1.1 million. My adjustment relied on the monthly BSA revenue per customer targets and the December 2023 number of customer provided as part of Exhibit PEPCO 2(E).

B. Deficient Deferred Income Taxes

Q. ARE YOU PROPOSING AN ADJUSTMENT TO PEPCO'S DDIT IN THE TTY?

A. Yes. I recommend the DDIT be excluded from cost of service for the same reasons I discussed above. This adjustment lowers the TTY revenue requirement by $1.5 million.

C. COVID-19 Cost Recovery

Q. ARE YOU PROPOSING A SIMILAR COVID-19 ADJUSTMENT TO THE COMPANY'S TTY COMPLIANCE FILING?

A. Yes. Given the extraordinary nature of the pandemic I believe a longer recovery period is appropriate. As discussed above, rate cases are typically filed every two to three years. A six-year amortization period is preferable to a five-year amortization period because it mitigates the rate increase proposed in this proceeding while limiting cost recovery to the same two to three traditional rate cycles that would be applicable to a five-year amortization. My adjustment to the compliance filing is included as Exhibit OPC (B)-13 and reflects a six-year amortization. This adjustment reduces the TTY revenue deficiency by approximately $412,000. Adjusting the other two RMA regulatory assets in the TTY that Pepco proposes to recover over five years to six years increases the total adjustment to approximately $500,000.

D. Inflation Adjustment

Q. DOES PEPCO INCLUDE AN INFLATION ADJUSTMENT TO ITS O&M IN ITS TTY COST OF SERVICE?

A. Yes. Pepco's TTY Compliance filing includes an inflation adjustment to non-labor O&M expense (RMA 34). Pepco uses a 3.63% annual inflation rate based on a five-year historical average inflation rate. This inflation rate is overstated compared to the actual inflation rate in the second half of 2023 and an independent economist forecasted inflation rate for 2024.

Pepco's TTY uses a test year ending December 31, 2023 that includes six months of actual data and six months of forecasted data. According to the *Blue Chip Financial Forecasts,* inflation was 3.2% in Q3 2023 and expected to be 3.1% in Q4 2023. Inflation is forecasted to be about 2.4% in 2024. Pepco's inflation estimate in the TTY of 3.63% (see RMA 34) should be revised to reflect the consensus analysts' estimate of 3.2%, and to be in effect for the six-month projection period. This adjustment lowers Pepco's TTY revenue requirement by approximately $384,000. My adjustment is included as Exhibit OPC (B)-14.

VI. BILL STABILIZATION ADJUSTMENT ("BSA")

Q. DOES PEPCO INCLUDE THE BSA REGULATORY ASSET DEFERRAL IN ITS TTY COST OF SERVICE?

A. Yes. As part of its TTY compliance filing the Company is requesting a return on its BSA deferral balance. The current balance of the deferral is $113.781 million. Pepco's proposal stems from a finding in an independent audit requested by the Commission in Order No. 20755. The Atrium Economics final audit report was issued in July 2023, or after the Company's MYP filing in April 2023. Among other findings, the report recommended the Commission consider credit-supportive measures due to the deferral.

> In response to the financial concerns addressed in F-2.3 (7), Atrium recommends that the Commission continue to monitor Pepco's credit quality for signs of deterioration and consider implementing credit support measures such as allowing a return on the BSA deferral balance or increasing ROE to account for under-earnings associated with the BSA balance, should circumstances warrant such support. [R-2.3(2)][49]

Ms. O'Donnell agreed with Atrium Economics' recommendation in her October 2023 direct testimony.

> **Q. Does the Company agree that a return on the BSA 1 deferral balance is warranted and is it included in the TTYCF?**
>
> A10. Yes, as discussed in my Direct Testimony (page 40), a large deferral balance and the associated unrecovered carrying costs put additional cash flow burden on the Company and negatively impacts Pepco's Generally Accepted Accounting Principles (GAAP) earned ROE. The approval of the Company's proposed MYP, and an update to the Company's billing determinants, will improve the overall financial health of the Company and its credit metrics, reducing borrowing costs, which leads to lower customer rates. The Company has included a ratemaking adjustment (RMA) to reflect

[49] Atrium Economics Final Audit Report, July 7, 2023.

the BSA regulatory asset deferral balance in rate base for the TTYCF.

Mr. Leming supports the Company's RMA 12 which adds the BSA deferral balance as a regulatory asset in rate base.

Q. DO YOU BELIEVE PEPCO IS ENTITLED TO EARN A RETURN ON ITS BSA DEFERRAL BALANCE?

A. No. Pepco acknowledged in its April 2023 MYP filing that the Company is not currently authorized to earn a return on the BSA deferral balances.[50] Furthermore, Pepco has not shown a need to earn a return on the BSA deferral balance as part of its TTY and a reason to reverse the current policy regarding a return. Ms. O'Donnell argues in her October 2023 supplemental direct testimony that, "the approval of the Company's proposed MYP, and an update to the Company's billing determinants, will improve the overall financial health of the Company and its credit metrics..."[51] The same is true for the TTY. While Pepco has argued the BSA is one of the reasons it has not previously earned its authorized ROE[52], the updated rates and billing determinants approved in this proceeding will give Pepco the opportunity to earn its authorized ROE even without a return on the BSA deferral balances.

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[50] O'Donnell Direct at 40.

[51] O'Donnell October 2023 Supplemental Direct at 5.

[52] Barnett Direct at 56. Mr. Barnett argues, "Approximately $9 million (pre-tax) in unrecoverable carrying costs reduces Pepco's earned GAAP ROE reported to investors. For perspective, had the BSA deferral balance been included in rate base, it would have reduced Pepco DC's ratemaking ROE by approximately 55 basis points (bps) in 2022."

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF REMOVING THE BSA REGULATORY ASSET FROM THE TTY RATE BASE?

A. I include this adjustment as my Exhibit OPC (B)-15. Removing the BSA regulatory asset from rate base lowers the Company's TTY revenue deficiency by approximately $10.3 million.

Q. ASSUMING THE COMMISSION ALLOWS THE COMPANY TO EARN A RETURN ON THE BSA REGULATORY ASSET, HAS PEPCO ACCURATELY ESTIMATED THE IMPACT ON THE TTY RATE BASE?

A. No. Pepco did not adjust the BSA regulatory asset to remove income taxes included in the uncollected revenue that is recorded in the BSA regulatory asset. The income tax expense associated with uncollected revenue will not become taxable income until the Company recovers the BSA revenue from customers. Hence, the BSA regulatory asset should be reduced by the income tax included in the uncollected BSA revenue, and a carrying charge should only apply to the after-tax balance of the BSA regulatory asset. The full value of the BSA asset should be collected as the asset is amortized.

Q. DOES THIS COMPLETE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, it does.

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In the Matter of the	)	
	)	
Application of Potomac Electric Power Company	)	**Formal Case No. 1176**
for Authority to Implement a Multiyear Rate	)	
Plan for Electric Distribution Service	)	
in the District of Columbia	)	

AFFIDAVIT

I declare under penalty of perjury that the foregoing testimony was prepared by me or under my direction and is true and correct to the best of my knowledge, information, and belief.

Signature

Date: January 10, 2024

MARIA E. DECKER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis City
My Commission Expires: May 5, 2025
Commission # 13706793

Maria E. Decker

<u>Qualifications of Michael P. Gorman</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. PLEASE STATE YOUR OCCUPATION.

A. I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. In 1983 I received a Bachelor of Science Degree in Electrical Engineering from Southern Illinois University, and in 1986, I received a Master's Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield. I have also completed several graduate level economics courses.

In August of 1983, I accepted an analyst position with the Illinois Commerce Commission ("ICC"). In this position, I performed a variety of analyses for both formal and informal investigations before the ICC, including: marginal cost of energy, central dispatch, avoided cost of energy, annual system production costs, and working capital. In October of 1986, I was promoted to the position of Senior Analyst. In this position, I assumed the additional responsibilities of technical leader on projects, and my areas of responsibility were expanded to include utility financial modeling and financial analyses.

In 1987, I was promoted to Director of the Financial Analysis Department. In this position, I was responsible for all financial analyses conducted by the Staff. Among other things, I conducted analyses and sponsored testimony before the ICC on rate of return, financial integrity, financial modeling and related issues. I also supervised the development of all Staff analyses and testimony on these same issues. In addition, I supervised the Staff's review and recommendations to the Commission concerning utility plans to issue debt and equity securities.

In August of 1989, I accepted a position with Merrill-Lynch as a financial consultant. After receiving all required securities licenses, I worked with individual investors and small businesses in evaluating and selecting investments suitable to their requirements.

In September of 1990, I accepted a position with Drazen-Brubaker & Associates, Inc. ("DBA"). In April 1995, the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and Staff. Since 1990, I have performed various analyses and sponsored testimony on cost of capital, cost/benefits of utility mergers and acquisitions, utility reorganizations, level of operating expenses and rate base, cost of service studies, and analyses relating to industrial jobs and economic development. I also participated in a study used to revise the financial policy for the municipal utility in Kansas City, Kansas.

At BAI, I also have extensive experience working with large energy users to distribute and critically evaluate responses to requests for proposals ("RFPs") for electric, steam, and gas energy supply from competitive energy suppliers. These analyses include the evaluation of gas supply and delivery charges, cogeneration and/or combined cycle unit feasibility studies, and the evaluation of third-party asset/supply management agreements. I have participated in rate cases on rate design and class cost of service for electric, natural gas, water and wastewater utilities. I have also analyzed commodity pricing indices and forward pricing methods for third party supply agreements, and have also conducted regional electric market price forecasts.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Detroit, Michigan; Louisville, Kentucky and Phoenix, Arizona.

Q. HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the Federal Energy Regulatory Commission and numerous state regulatory commissions including: Alaska, Arkansas, Arizona, California, Colorado, Delaware, the District of Columbia, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oklahoma, Oregon, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, Wyoming, and before the provincial regulatory boards in Alberta, Nova Scotia, and Quebec, Canada. I have also sponsored testimony before the Board of Public Utilities in Kansas City, Kansas; presented rate setting position reports to the regulatory board of the municipal utility in Austin, Texas, and Salt River Project, Arizona, on behalf of industrial customers;

and negotiated rate disputes for industrial customers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

Q. PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A. I earned the designation of Chartered Financial Analyst ("CFA") from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting, economics, fixed income and equity valuation and professional and ethical conduct. I am a member of the CFA Institute's Financial Analyst Society.

Potomac Electric Power Company

Summary of Traditional Test Year
Revenue Requirement Adjustments
($000)

Line	Description	Rate Base (1)	Operating Income (2)	MYP Year 1 Revenue Requirement (3)
1	Proposed Rate of Return			7.17%
2	Proposed Pre-Tax Rate of Return[1]			8.95%
	Revenue Requirement Adjustments			
3	Lower Return on Equity			(24,955)
4	Depreciation[2]	13,075	19,115	(25,202)
5	Capital Projects[3]	(20,751)	-	(1,858)
6	Revised Residential Sales Forecast	-	491	(678)
7	Service Company Cost Escalation	-	1,140	(1,573)
8	Deficient Deferred Income Taxes	(3,818)	848	(1,512)
9	Longer Regulatory Asset Amortization	(209)	412	(587)
10	**Total Revenue Requirement Adjustments**			**$ (56,365)**
11	**Adjusted Revenue Requirement**			**$ 60,083**

Notes:
[1] Revenue requirement impacts calculated using Mr. Walters's proposed rate of return, grossed up for income taxes.
[2] Exhibit OPC (D)-5.
[3] List of capital projects taken from Exhibit OPC (E).

Potomac Electric Power Company

Summary of Traditional Test Year
Revenue Requirement Adjustments
($000)

Line	Description	Rate Base (1)	Operating Income (2)	MYP Year 2 Revenue Requirement (3)
1	Proposed Rate of Return			7.18%
2	Proposed Pre-Tax Rate of Return[1]			8.96%
	Revenue Requirement Adjustments			
3	Lower Return on Equity			(26,792)
4	Depreciation[2]	40,362	20,478	(24,638)
5	Capital Projects[3]	(61,507)	-	(5,514)
6	Revised Residential Sales Forecast	-	1,506	(2,077)
7	Service Company Cost Escalation	-	2,022	(2,790)
8	Deficient Deferred Income Taxes	(2,970)	848	(1,436)
9	Longer Regulatory Asset Amortization	(619)	412	(624)
10	**Total Revenue Requirement Adjustments**			**$ (63,872)**
11	**Adjusted Revenue Requirement**			**$ 89,503**

Notes:
[1] Revenue requirement impacts calculated using Mr. Walters's proposed rate of return, grossed up for income taxes.
[2] Exhibit OPC (D)-5.
[3] List of capital projects taken from Exhibit OPC (E).

Potomac Electric Power Company

Summary of Traditional Test Year
Revenue Requirement Adjustments
($000)

Line	Description	Rate Base (1)	Operating Income (2)	MYP Year 3 Revenue Requirement (3)
1	Proposed Rate of Return			7.19%
2	Proposed Pre-Tax Rate of Return[1]			8.97%
	Revenue Requirement Adjustments			
3	Lower Return on Equity			(28,279)
4	Depreciation[2]	69,469	21,654	(23,654)
5	Capital Projects[3]	(108,774)	-	(9,762)
6	Revised Residential Sales Forecast	-	3,116	(4,299)
7	Service Company Cost Escalation	-	2,651	(3,658)
8	Deficient Deferred Income Taxes	(2,121)	848	(1,360)
9	Longer Regulatory Asset Amortization	(1,032)	412	(661)
10	**Total Revenue Requirement Adjustments**			**$ (71,674)**
11	**Adjusted Revenue Requirement**			**$ 119,041**

Notes:
[1] Revenue requirement impacts calculated using Mr. Walters's proposed rate of return, grossed up for income taxes.
[2] Exhibit OPC (D)-5.
[3] List of capital projects taken from Exhibit OPC (E).

Potomac Electric Power Company

Summary of Traditional Test Year
Revenue Requirement Adjustments
($000)

Line	Description	Rate Base (1)	Operating Income (2)	Revenue Requirement (3)
1	Proposed Rate of Return			7.18%
2	Proposed Pre-Tax Rate of Return[1]			9.01%
	Revenue Requirement Adjustments			
3	Lower Return on Equity			(20,022)
4	Depreciation[2]	12,259	17,771	(23,414)
5	Capital Projects[3]	(35,108)	-	(3,163)
6	Annualized Sales Adjustment	-	799	(1,103)
7	Deficient Deferred Income Taxes	(3,818)	848	(1,514)
8	Longer Regulatory Asset Amortization	188	376	(502)
9	Corrected Inflation Escalator	-	277	(382)
10	No Return on BSA Deferral Balance	(113,781)	-	(10,252)
11	**Total Revenue Requirement Adjustments**			**$ (60,351)**
12	**Adjusted Revenue Requirement**			**$ 47,845**

Notes:

[1] Revenue requirement impacts calculated using Mr. Walters's proposed rate of return, grossed up for income taxes.

[2] Exhibit OPC (D)-5.

[3] List of capital projects taken from Exhibit OPC (E).

Formal Case No. 1176
Pepco's Responses to Data Requests
Referenced in the Direct Testimony
<u>of OPC Witness Michael P. Gorman</u>

<u>Pepco's Responses to Data Requests</u>: **<u>Page</u>**

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO AOBA DATA REQUEST NO. 1

QUESTION NO. 11
Re: Exhibit Pepco (A), page 10, lines 15-17. Please:

a. Provide the Company's forecasts of the "growth in electrification" it antici-pates within each year of its current planning horizon, as well as the workpapers, analyses, data, studies, and other documents relied upon to make such forecasts for its District of Columbia distribution system.
b. Detail the impacts of the referenced "growth in electrification" on the Company's forecasted units of service (i.e., customers, kWh deliveries, and kW demands by rate class) for each year of the Company's proposed multi-year rate plan.
c. Provide the Company's forecasts by year of the numbers of current users of gas heating customers heating systems that the Company expects to convert from gas service to electric service.

RESPONSE:

a. Currently, the Company does not directly include electrification into its 10-year capacity/load forecasts. While identified and specific near-term usage and planned capacity additions have been incorporated, electrification has not been projected at levels that would be required to meet the District's anticipated goals for electrification.

   For a detailed explanation of the Company's capacity planning forecasting and methodology, please see PEPCO (H)-1, Chapter 1 entitled "Load Growth."

b. Please see Pepco's response to part (a) and note that, for distribution system planning purposes, as identified in the question, Pepco does not perform detailed analyses down to the rate class level regarding forecasted units of service.

c. Pepco has not included conversions of gas heat to electrical heating sources in its most recent Ten-Year Forecast.

SPONSOR: Jaclyn Cantler

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO DCG DATA REQUEST NO. 1

QUESTION NO. 4
Refer to Pepco Response to AOBA Data Request No. 11-1(a). If Pepco does not directly include electrification into its 10-year capacity/load forecasts, explain why "proposed investments in this MYP are fundamental to preparing the grid for customer adoption of electrification in the near-term" as stated in the Direct Testimony of Witness O'Donnell at page 10.

RESPONSE:

The Company assumes that the question meant to reference Pepco's response to AOBA 1-11(a). The Company does not forecast electrification separately from other load, at this time, as noted in the response to 1-11(a). However, the Company does incorporate near term usage when available.

The proposed investments in this MYP are fundamental to preparing the distribution system because the distribution system needs to operate efficiently and effectively, especially with the growth in electrification that will be required to advance the District's decarbonization and clean energy goals. As noted in Witness O'Donnell's testimony (page 10, line 17-20) As customers increase their use of electricity at homes and businesses across the District, it will be even more vital that the grid function smoothly and provide consistent, reliable service.

SPONSOR: Elizabeth M. D. O'Donnell and Jaclyn Cantler

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO DCG DATA REQUEST NO. 4

QUESTION NO. 3
Answer the following related to Pepco's decision to use the Company's Long-Range Plan (LRP) for the projection of revenues and expenses instead of the index approach as approved in FC 1156 as described on pages 8-9 of the Direct Testimony of Witness Leming.

A. Have any of the parties to FC 1156 raised concerns with the level of transparency over the course of the Modified EMRP? If yes, explain the number of parties that raised concerns and the specific concerns.

B. Is it the Company's opinion that the use of an escalation factor approach is the reason it did not earn its authorized rate of return during the EMRP period? If no, explain all other contributing factors.

C. Explain how the LRP approach improves the Company's incentive to achieve cost-efficiencies compared to the index approach.

RESPONSE:

A. FC 1156 is an open docket and any concerns raised by parties in that proceeding are available for review on the Commission's website.

B. No. Please refer to the Company's response to DCG DR 3-11.

C. The LRP approach improves the Company's incentive to achieve cost efficiencies by aligning the baseline from which to seek efficiencies to the work it expects to perform, rather than a general inflation factor which may or may not correlate with the planned work in a given year.

SPONSOR: Robert T. Leming

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 3

QUESTION NO. 9
Provide normalized (weather-adjusted) electricity usage data by month for each current and proposed rate class for each of the years 2018 – 2022 and each month of 2023. Provide the source documents containing the usage data supplied in response to this request. Provide the requested documents in electronic form with all spreadsheet links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested. Please also provide the data used and estimation of weather normalized electricity usage for each rate class and for each year.

RESPONSE:

Please see FC 1176 OPC DR 3-9 Attachment.

SPONSOR: Matthew J. Bonikowski and Ekaterina Efimova

PHI SERVICE COMPANY
DISTRICT 12 MONTH ENDING DECEMBER 31, 2023 BILLING MONTH WEATHER CORRECTED SALES, KWH

Weather Corrected Sales

MONTH	DCRES*	DCR	DCAE	DCRAD	DCRADR	DCRADAE	DCRTM	DCMMA	DCGSND	DCGSLV	GS3A	TEMP	DCTN	DCGTLV	DCMGTLV	DCGT3A	DCGT3B	DCMET**	DCSL	DCTS	DC TOTAL
January '23	196,242,656	139,443,683	56,798,973	27,071,091	16,207,718	10,863,373	1,121,475	19,071,683	23,208,539	45,073,460	68,910	1,432,401	228,278	149,398,858	257,343,632	151,945,573	15,036,536	26,061,258	8,244,283	890,442	922,439,075
February '23	189,664,347	133,028,165	56,636,182	25,067,635	14,812,067	10,255,568	1,144,481	16,879,734	21,140,807	42,063,418	56,509	1,372,040	228,283	135,264,489	229,324,750	151,643,455	14,572,586	23,631,833	8,058,942	890,442	861,003,751
March '23	163,033,184	117,284,464	45,748,720	22,564,493	13,796,084	8,768,409	826,393	16,407,033	19,522,312	38,512,993	62,918	1,487,034	206,188	130,790,865	219,167,537	167,831,166	14,048,844	21,662,354	6,782,720	804,271	823,710,305
April '23	144,276,278	106,548,035	37,728,243	15,568,196	9,748,936	5,819,260	839,397	15,045,792	17,466,168	36,426,682	65,760	550,466	228,277	120,055,012	208,472,519	147,319,863	14,920,129	22,248,247	6,665,181	890,442	751,038,409
May '23	130,502,785	98,584,569	31,918,216	13,787,880	9,323,510	4,464,370	706,280	17,186,861	17,010,294	35,493,203	61,558	1,030,316	220,911	119,717,988	199,377,060	157,557,830	13,902,641	25,228,284	5,740,378	861,719	738,385,988
June '23																					
July '23																					
August '23																					
September '23																					
October '23																					
November '23																					
December '23																					
TOTAL	**823,719,250**	**594,888,916**	**228,830,334**	**104,059,295**	**63,888,315**	**40,170,980**	**4,638,026**	**84,591,103**	**98,348,120**	**197,569,756**	**315,655**	**5,872,257**	**1,111,937**	**655,227,212**	**1,113,685,498**	**776,297,887**	**72,480,736**	**118,831,976**	**35,491,504**	**4,337,316**	**4,096,577,528**

Actual Sales

MONTH	DCRES*	DCR	DCAE	DCRAD	DCRADR	DCRADAE	DCRTM	DCMMA	DCGSND	DCGSLV	GS3A	TEMP	DCTN	DCGTLV	DCMGTLV	DCGT3A	DCGT3B	DCMET**	DCSL	DCTS	DC TOTAL
January '23	185,093,741	132,814,019	52,279,722	25,852,796	15,679,330	10,173,466	1,060,364	18,766,936	22,400,082	43,583,145	68,515	1,356,787	228,274	146,120,054	250,947,826	151,945,573	14,971,967	25,904,179	8,244,283	890,442	897,434,964
February '23	161,521,770	116,278,997	45,242,773	21,992,317	13,477,396	8,514,921	989,951	16,107,363	19,106,718	38,323,873	55,508	1,180,398	228,274	127,008,812	213,296,102	151,643,455	14,408,938	23,233,721	8,058,942	890,442	798,046,584
March '23	148,454,552	108,525,730	39,928,822	20,971,131	13,099,557	7,871,574	744,778	15,988,995	18,506,900	36,704,577	62,376	1,383,310	206,183	126,634,039	211,531,477	167,831,166	13,960,271	21,446,880	6,782,720	804,271	792,013,626
April '23	135,007,130	100,869,276	34,137,854	14,554,780	9,299,221	5,255,559	785,413	14,756,028	16,871,784	35,449,082	65,384	478,569	228,274	117,572,345	204,509,722	147,319,863	14,858,734	22,098,890	6,665,181	890,442	732,111,621
May '23	123,274,445	93,379,506	29,894,939	13,108,943	8,936,812	4,172,131	663,747	16,767,201	16,590,594	34,726,792	60,517	995,014	220,910	117,773,071	196,049,368	156,204,427	13,860,620	25,138,008	5,740,378	861,719	722,035,754
June '23																					
July '23																					
August '23																					
September '23																					
October '23																					
November '23																					
December '23																					
TOTAL	**753,351,638**	**551,867,528**	**201,484,110**	**96,479,967**	**60,492,316**	**35,987,651**	**4,244,253**	**82,386,523**	**93,476,078**	**188,787,469**	**312,300**	**5,394,078**	**1,111,915**	**635,108,321**	**1,076,334,495**	**774,944,484**	**72,060,530**	**117,821,678**	**35,491,504**	**4,337,316**	**3,941,642,549**

Amount of Weather Correction

MONTH	DCRES*	DCR	DCAE	DCRAD	DCRADR	DCRADAE	DCRTM	DCMMA	DCGSND	DCGSLV	GS3A	TEMP	DCTN	DCGTLV	DCMGTLV	DCGT3A	DCGT3B	DCMET**	DCSL	DCTS	DC TOTAL
January '23	11,148,915	6,629,664	4,519,251	1,218,295	528,388	689,907	61,111	304,747	808,457	1,490,315	395	75,614	4	3,278,804	6,395,806	0	64,569	157,079	0	0	25,004,111
February '23	28,142,577	16,749,168	11,393,409	3,075,318	1,334,671	1,740,647	154,530	772,371	2,034,089	3,739,545	1,001	191,642	9	8,255,677	16,028,648	0	163,648	398,112	0	0	62,957,167
March '23	14,578,632	8,758,734	5,819,898	1,593,362	696,527	896,835	81,615	418,038	1,015,412	1,808,416	542	103,724	5	4,156,826	7,636,060	0	88,573	215,474	0	0	31,696,679
April '23	9,269,148	5,678,759	3,590,389	1,013,416	449,715	563,701	53,984	289,764	594,384	977,600	376	71,897	3	2,482,667	3,962,797	0	61,395	149,357	0	0	18,926,788
May '23	7,228,340	5,205,063	2,023,277	678,937	386,698	292,239	42,533	419,660	419,700	766,411	1,041	35,302	1	1,944,917	3,327,692	1,353,403	42,021	90,276	0	0	16,350,234
June '23																					
July '23																					
August '23																					
September '23																					
October '23																					
November '23																					
December '23																					
TOTAL	**70,367,612**	**43,021,388**	**27,346,224**	**7,579,328**	**3,395,999**	**4,183,329**	**393,773**	**2,204,580**	**4,872,042**	**8,782,287**	**3,355**	**478,179**	**22**	**20,118,891**	**37,351,003**	**1,353,403**	**420,206**	**1,010,298**	**0**	**0**	**154,934,979**

PHI SERVICE COMPANY
DISTRICT 12 MONTH ENDING DECEMBER 31, 2022 BILLING MONTH WEATHER CORRECTED SALES, KWH

Weather Corrected Sales

MONTH	DCRES*	DCR	DCAE	DCRAD	DCRADR	DCRADAE	DCRTM	DCMMA	DCGSND	DCGSLV	GS3A	TEMP	DCTN	DCGTLV	DCMGTLV	DCGT3A	DCGT3B	DCMET**	DCSL	DCTS	DC TOTAL
January '22	207,267,366	146,628,128	60,639,238	24,838,486	14,502,137	10,336,349	1,171,516	19,860,240	22,987,004	45,989,442	103,809	2,078,256	228,279	148,952,526	242,759,281	142,725,150	16,309,115	18,852,250	8,281,729	890,442	903,294,889
February '22	186,121,105	129,613,810	56,507,295	23,012,197	13,155,274	9,856,923	1,085,953	17,332,663	21,110,160	40,060,160	70,489	1,747,991	228,274	123,557,795	227,635,145	166,803,620	15,754,716	21,042,781	8,090,170	890,442	854,543,661
March '22	174,084,860	123,793,517	50,291,343	22,321,665	13,210,556	9,111,109	972,816	18,408,845	20,143,326	40,578,773	69,453	1,479,001	206,189	143,063,631	222,796,263	154,070,283	14,247,540	16,594,942	6,812,573	804,271	836,654,432
April '22	142,073,406	103,195,964	38,877,442	15,440,066	9,430,351	6,009,715	866,875	16,787,015	17,666,218	37,169,587	79,832	868,080	228,277	122,589,020	208,055,314	148,972,425	13,684,362	15,632,496	6,694,555	890,442	747,697,969
May '22	124,548,047	94,404,428	30,143,619	14,637,062	9,586,256	5,050,807	745,491	16,983,810	16,404,817	35,656,602	65,809	822,508	220,909	119,238,583	199,923,384	169,294,492	16,272,555	18,430,020	5,708,424	861,719	739,814,233
June '22	169,551,913	132,161,559	37,390,354	15,213,748	9,065,400	6,148,347	972,147	24,921,770	18,268,534	41,561,386	85,410	812,301	228,273	129,499,347	238,699,927	201,712,798	14,528,502	17,194,093	5,337,518	890,442	879,478,109
July '22	195,862,807	154,071,480	41,791,327	20,443,114	14,489,426	5,953,688	1,297,259	28,793,810	19,682,123	47,690,275	97,509	836,081	220,910	145,593,414	252,619,884	189,673,484	15,509,667	19,711,122	4,725,258	857,357	943,614,074
August '22	209,708,050	166,561,490	43,146,560	26,523,984	19,260,034	7,263,950	1,239,654	29,574,441	20,806,690	47,798,522	93,609	870,274	228,274	143,722,962	258,087,280	215,930,094	14,987,783	22,250,567	5,038,446	885,935	997,746,562
September '22	189,238,138	148,000,561	41,237,577	20,429,309	14,334,145	6,095,164	1,245,455	31,083,665	20,079,380	48,731,839	99,778	953,718	235,268	151,926,587	263,128,490	208,003,087	15,318,817	20,945,634	5,560,236	885,935	977,865,336
October '22	130,988,528	101,908,377	29,080,151	16,633,586	11,448,530	5,185,056	829,105	19,714,776	16,411,641	36,652,917	71,600	1,050,141	221,340	122,819,161	217,674,316	170,236,075	16,891,190	27,579,184	6,351,321	857,357	784,982,237
November '22	125,717,627	93,470,252	32,247,375	16,985,612	10,847,099	6,138,513	722,206	15,490,357	15,481,071	33,458,793	68,106	416,431	228,824	109,277,043	195,262,466	158,197,623	13,667,832	23,065,313	7,134,076	885,935	716,059,317
December '22	158,219,084	114,647,327	43,571,757	22,024,496	13,543,952	8,480,544	861,048	17,054,947	18,876,045	43,477,715	63,107	901,258	220,910	136,264,305	215,309,902	165,760,642	14,776,085	20,913,425	7,520,171	861,719	823,104,860
TOTAL	**2,013,380,932**	**1,508,456,892**	**504,924,040**	**238,503,325**	**152,873,159**	**85,630,166**	**12,009,525**	**256,006,338**	**227,917,008**	**498,826,011**	**968,510**	**12,836,040**	**2,695,729**	**1,596,504,374**	**2,741,951,652**	**2,091,379,771**	**181,948,163**	**242,211,826**	**77,254,477**	**10,461,996**	**10,204,855,679**

Actual Sales

MONTH	DCRES*	DCR	DCAE	DCRAD	DCRADR	DCRADAE	DCRTM	DCMMA	DCGSND	DCGSLV	GS3A	TEMP	DCTN	DCGTLV	DCMGTLV	DCGT3A	DCGT3B	DCMET**	DCSL	DCTS	DC TOTAL
January '22	197,000,044	140,527,042	56,473,002	23,844,487	14,082,615	9,761,872	1,112,458	19,546,815	22,344,524	44,873,547	103,404	1,996,334	228,274	145,871,151	237,875,802	142,468,768	16,309,115	18,728,089	8,281,729	890,442	881,474,983
February '22	186,035,625	129,602,492	56,433,133	23,006,806	13,155,860	9,850,946	1,086,276	17,339,768	21,105,614	40,035,543	70,498	1,749,848	228,274	123,468,095	227,437,398	166,727,439	15,754,716	21,045,596	8,090,170	890,442	854,072,108
March '22	161,734,841	116,457,595	45,277,246	21,126,238	12,706,220	8,420,018	901,836	18,032,520	19,370,577	39,235,453	68,967	1,380,639	206,183	139,352,744	216,911,233	153,756,733	14,247,540	16,445,864	6,812,573	804,271	810,388,212
April '22	136,551,146	99,863,443	36,687,703	14,901,715	9,199,436	5,702,279	834,057	16,605,874	17,319,622	36,589,230	79,598	820,734	228,274	121,014,553	205,631,943	148,930,311	13,684,362	15,560,738	6,694,555	890,442	736,337,154
May '22	123,781,737	93,390,234	30,391,503	14,641,054	9,537,869	5,103,185	740,900	16,838,946	16,384,856	35,558,425	65,251	833,514	220,910	119,056,768	199,384,569	168,377,157	16,259,246	18,425,592	5,708,424	861,719	737,139,068
June '22	179,205,678	140,243,418	38,962,260	15,838,827	9,537,869	6,300,958	1,030,218	25,728,772	18,761,294	42,636,877	87,952	825,764	228,274	132,060,336	243,648,621	205,419,453	14,582,279	17,299,791	5,337,518	890,442	903,582,096
July '22	193,816,205	152,358,123	41,458,082	20,310,597	14,389,262	5,921,335	1,284,948	28,622,725	19,577,658	47,462,270	96,970	833,227	220,910	145,050,483	251,570,759	188,887,672	15,498,266	19,688,714	4,725,258	857,357	938,504,019
August '22	217,859,819	173,385,921	44,473,898	27,051,809	19,658,993	7,392,816	1,288,690	30,255,884	21,222,783	48,706,681	95,755	881,642	228,274	145,885,495	262,266,023	219,060,043	15,033,193	22,339,820	5,038,446	885,935	1,018,100,292
September '22	198,933,278	156,117,058	42,816,220	21,057,067	14,808,638	6,248,429	1,303,775	31,894,126	20,574,252	49,811,940	102,330	967,238	235,269	154,498,552	268,098,393	211,725,628	15,372,825	21,051,785	5,560,236	885,935	1,002,072,629
October '22	129,156,288	99,599,413	29,556,875	16,626,448	11,336,224	5,290,224	818,122	19,393,553	16,357,954	36,422,161	70,376	1,072,699	221,342	122,377,760	216,431,444	168,236,631	16,862,181	27,567,364	6,351,321	857,357	778,823,001
November '22	119,471,049	89,679,899	29,791,150	16,375,134	10,583,754	5,791,380	684,656	15,280,357	15,088,593	32,810,361	67,835	361,542	228,821	107,529,690	192,603,716	158,188,863	13,667,832	22,982,123	7,134,076	885,935	703,360,583
December '22	157,753,843	114,390,968	43,362,875	21,980,924	13,527,019	8,453,905	858,787	17,045,691	18,847,341	43,419,348	63,095	898,839	220,910	136,092,072	215,008,639	165,711,325	14,776,085	20,909,758	7,520,171	861,719	821,968,547
TOTAL	**2,001,299,553**	**1,505,615,606**	**495,683,947**	**236,761,106**	**152,523,759**	**84,237,347**	**11,944,723**	**256,585,031**	**226,955,068**	**497,561,836**	**972,031**	**12,622,020**	**2,695,715**	**1,592,257,699**	**2,736,868,540**	**2,097,490,023**	**182,047,640**	**242,045,234**	**77,254,477**	**10,461,996**	**10,185,822,692**

Amount of Weather Correction

MONTH	DCRES*	DCR	DCAE	DCRAD	DCRADR	DCRADAE	DCRTM	DCMMA	DCGSND	DCGSLV	GS3A	TEMP	DCTN	DCGTLV	DCMGTLV	DCGT3A	DCGT3B	DCMET**	DCSL	DCTS	DC TOTAL
January '22	10,267,322	6,101,086	4,166,236	993,999	419,522	574,477	59,058	313,425	642,480	1,115,895	405	81,922	5	3,081,375	4,883,479	256,382	0	124,161	0	0	21,819,906
February '22	85,480	11,318	74,162	5,391	-586	5,977	-323	-7,105	4,546	24,617	-9	-1,857	0	89,700	197,747	76,181	0	-2,815	0	0	471,553
March '22	12,350,019	7,335,922	5,014,097	1,195,427	504,336	691,091	70,980	376,325	772,749	1,343,320	486	98,362	6	3,710,887	5,885,030	313,550	0	149,078	0	0	26,266,220
April '22	5,522,260	3,332,521	2,189,739	538,351	230,915	307,436	32,818	181,141	346,596	580,357	234	47,346	3	1,574,467	2,423,371	42,114	0	71,758	0	0	11,360,815
May '22	766,310	1,014,194	-247,884	-3,992	48,387	-52,378	4,591	144,864	19,961	98,177	558	-11,006	-1	181,815	538,815	917,335	13,309	4,428	0	0	2,675,165
June '22	-9,653,765	-8,081,859	-1,571,906	-625,079	-472,469	-152,611	-58,071	-807,002	-492,760	-1,075,491	-2,542	-13,463	-1	-2,560,989	-4,948,694	-3,706,655	-53,777	-105,698	0	0	-24,103,987
July '22	2,046,602	1,713,357	333,245	132,517	100,164	32,353	12,311	171,085	104,465	228,005	539	2,854	0	542,931	1,049,125	785,812	11,401	22,408	0	0	5,110,055
August '22	-8,151,769	-6,824,431	-1,327,338	-527,825	-398,959	-128,866	-49,036	-681,443	-416,093	-908,159	-2,146	-11,368	0	-2,162,533	-4,178,743	-3,129,949	-45,410	-89,253	0	0	-20,353,730
September '22	-9,695,140	-8,116,497	-1,578,643	-627,758	-474,493	-153,265	-58,320	-810,461	-494,872	-1,080,101	-2,552	-13,520	-1	-2,571,965	-4,969,903	-3,722,541	-54,008	-106,151	0	0	-24,207,293
October '22	1,832,240	2,308,964	-476,724	7,138	112,306	-105,168	10,983	321,223	53,687	230,756	1,224	-22,558	-2	441,401	1,242,872	1,999,444	29,009	11,820	0	0	6,159,236
November '22	6,246,578	3,790,353	2,456,225	610,478	263,345	347,133	37,550	210,000	392,478	648,432	271	54,889	3	1,747,353	2,658,750	8,760	0	83,190	0	0	12,698,734
December '22	465,241	256,359	208,882	43,572	16,933	26,639	2,261	9,256	28,704	58,367	12	2,419	0	172,233	301,263	49,317	0	3,667	0	0	1,136,313
TOTAL	**12,081,379**	**2,841,286**	**9,240,093**	**1,742,219**	**349,400**	**1,392,819**	**64,802**	**-578,693**	**961,940**	**1,264,175**	**-3,521**	**214,020**	**14**	**4,246,675**	**5,083,112**	**-6,110,252**	**-99,477**	**166,592**	**0**	**0**	**19,032,987**

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 1

Please provide a breakdown (in an electronic format) of the Company's operations and maintenance ("O&M") expenses in each of the last five years (2018 to 2022) by FERC account and split between labor and non-labor. Please present this information by total company and at the D.C. jurisdictional level.

RESPONSE:

The Company has not prepared the analysis in the format requested. For available information, please see FC 1176 OPC DR 13-1 Attachment which provides an O&M breakout for the requested years between labor and non-labor at the total Pepco Distribution level. This breakout is not available at the jurisdictional level as the Company allocates its costs based on FERC account but does not perform its jurisdictional allocation by expense type.

SPONSOR: Robert T. Leming and Phillip S. Barnett

POTOMAC ELECTRIC POWER COMPANY

Comparative Statement of Operations & Maintenance Expense Accounts
Distribution Only

		Actuals				
Account No.	**Description**	**12 Months Ended 12/31/2018**	**12 Months Ended 12/31/2019**	**12 Months Ended 12/31/2020**	**12 Months Ending 12/31/2021**	**12 Months Ending 12/31/2022**
580	Operation Supervision & Engineering	$ 3,708,109	$ 5,870,310	$ 1,637,915	$ 1,111,617	$ 2,967,829
581	Load Dispatching	5,625,435	6,353,669	6,148,730	6,071,463	3,061,158
582	Station Expenses	1,292,337	1,967,748	1,555,004	265,590	57,889
583	Overhead Line Expenses	1,048,048	3,494,499	4,569,424	4,631,468	2,897,565
584	Underground Line Expenses	5,674,402	5,589,544	5,791,083	5,454,492	5,672,478
585	Street Lighting and Signal System Expenses	634,821	-	188,910	399,661	(37,744)
586	Meter Expenses	6,951,837	6,101,850	5,838,138	6,022,858	5,188,117
587	Customer Installations Expenses	8,438,964	7,423,190	7,031,629	8,196,989	8,107,970
588	Miscellaneous Distribution Expenses	9,179,511	37,807,788	23,528,050	30,139,753	35,911,908
589	Rents	9,440,399	11,918,838	4,844,641	4,228,964	4,221,568
590	Maintenance - Supv & Eng	782,810	174,483	144,021	207,609	208,813
591	Maintenance of Structures	13,536	158,196	606,951	1,136,414	1,202,120
592	Maintenance of Station Equipment	16,992,873	16,832,852	16,399,525	18,938,994	14,493,160
593	Maintenance of Overhead Lines	42,382,829	38,297,045	35,391,940	39,326,338	48,466,254
594	Maintenance of Underground Lines	22,698,059	14,551,887	21,619,208	22,118,014	24,338,399
595	Maintenance of Line Transformers	6,445,668	3,057,192	2,779,278	2,914,982	2,320,723
596	Rout Maint of Street Lighting & Signal System	4,878,991	3,538,659	3,422,342	1,222,420	1,683,005
597	Maintenance of Meters	842,418	507,966	754,550	911,923	774,274
598	Maintenance of Miscellaneous Distribution Plant	2,262,553	4,527,844	4,305,238	2,290,573	3,068,278
901	Supervision - Customer Exp	-	-	-	-	-
902	Meter Reading Expenses	989,971	890,435	907,534	774,078	795,232
903	Customer Records and Collection Expenses	77,888,559	75,039,785	74,393,264	72,839,577	76,613,974

POTOMAC ELECTRIC POWER COMPANY

Comparative Statement of Operations & Maintenance Expense Accounts
Distribution Only

		Actuals				
Account No.	**Description**	**12 Months Ended 12/31/2018**	**12 Months Ended 12/31/2019**	**12 Months Ended 12/31/2020**	**12 Months Ending 12/31/2021**	**12 Months Ending 12/31/2022**
904	Uncollectible Accounts	6,328,224	4,905,542	15,280,970	8,551,374	20,133,354
905	Miscellaneous Customer Accounts Expenses	-	-	-	-	-
907	Supervision - Cust Svc & Info	-	-	-	-	-
908	Customer Assistance Expenses	4,616,928	4,855,338	5,780,134	6,743,432	5,856,396
909	Informational & Instructional Adertising Expenses	2,099,119	1,198,493	883,517	538,247	460,282
910	Miscellaneous Customer Service & Information Exp	-	-	-	-	-
911	Supervision - Sales Expense	-	-	-	-	-
912	Demonstrating and Selling Expenses	-	-	-	-	-
913	Advertising Expenses	-	-	-	-	-
920	Administrative and General Salaries	5,451,910	6,621,747	5,760,641	6,700,484	5,605,136
921	Office Supplies and Expenses	6,501,265	5,160,941	6,742,926	6,024,982	5,168,165
923	Outside Services Employed	123,659,223	111,894,683	115,334,278	108,173,644	108,782,149
924	Property Insurance	1,007,429	906,556	1,314,404	1,508,775	1,386,503
925	Injuries and Damages	4,068,003	3,132,934	1,257,609	889,963	3,656,126
926	Employee Pension and Benefits	16,488,737	20,378,734	16,914,109	13,384,154	12,391,323
928	Regulatory Commission Expenses	3,925,518	6,560,886	7,199,149	1,001,103	2,681,372
929	Duplicate Charges Credit	-	-			
930.1	General Advertising Expenses	873,677	1,945,012	1,386,253	1,794,294	1,404,879
930.2	Miscellaneous General Expenses	1,604,816	1,293,522	1,124,918	1,425,540	1,016,824
931	Rents	-	-	(13,436)		
935	Maintenance of General Plant	64,898	-	37,590	206,606	484,886
Total Distribution Operations & Maintenance Expense		$ 404,861,879	$ 412,958,168	$ 400,860,437	$ 386,146,374	$ 411,040,363

POTOMAC ELECTRIC POWER COMPANY

Comparative Statement of Operations & Maintenance Expense Accounts
Distribution Only

Account No.	Description	Actuals 12 Months Ended 12/31/2018	12 Months Ended 12/31/2019	12 Months Ended 12/31/2020	12 Months Ending 12/31/2021	12 Months Ending 12/31/2022
Total Distribution O&M By Function						
Distribution		$ 241,216,402	$ 255,063,154	$ 243,801,997	$ 245,036,828	$ 268,463,000
Distribution Portion of A&G		163,645,477	157,895,015	157,058,441	141,109,545	142,577,362
		$ 404,861,879	$ 412,958,168	$ 400,860,437	$ 386,146,374	$ 411,040,363
Base Labor and Overtime (OT)						
PEPCO	Base Labor in Distribution	$ 51,696,857	$ 49,272,727	$ 47,160,504	$ 47,234,610	$ 44,960,490
PEPCO	Base Labor in Dist Portion of A&G	2,812,020	5,833,568	8,137,271	8,595,391	8,438,207
PEPCO	OT Labor in Distribution	9,938,337	9,132,433	7,309,371	7,221,301	6,891,575
PEPCO	OT Labor in Dist Portion of A&G	87,076	172,680	193,862	116,681	132,324
PHISCO to Pepco	Base Labor in Distribution	12,060,559	10,794,643	11,654,484	12,414,334	13,591,190
PHISCO to Pepco	Base Labor in Dist Portion of A&G	16,646,340	19,169,488	16,351,219	16,893,378	15,517,111
PHISCO to Pepco	OT Labor in Distribution	237,793	117,928	146,753	199,887	204,533
PHISCO to Pepco	OT Labor in Dist Portion of A&G	118,794	131,012	151,347	114,088	47,949
BSC to Pepco	Base Labor in Dist Portion of A&G	17,154,803	18,477,005	19,546,582	18,808,645	20,449,810
BSC to Pepco	OT Labor in Dist Portion of A&G	247,157	184,247	145,101	161,516	603,666
		$ 110,999,736	$ 113,285,730	$ 110,796,494	$ 111,759,831	$ 110,836,856
Total Base Labor and OT by Function						
Total	Labor in Distribution	$ 73,933,546	$ 69,317,730	$ 66,271,112	$ 67,070,133	$ 65,647,788
Total	Labor in Dist Portion of A&G	37,066,190	43,968,000	44,525,382	44,689,698	45,189,068
		$ 110,999,736	$ 113,285,730	$ 110,796,494	$ 111,759,831	$ 110,836,856
Non- Base Labor and OT Distribution O&M by Function						
Distribution		$ 167,282,856	$ 185,745,424	$ 177,530,884	$ 177,966,696	$ 202,815,212
Distribution Portion of A&G		126,579,287	113,927,015	112,533,059	96,419,847	97,388,295
		$ 293,862,142	$ 299,672,438	$ 290,063,943	$ 274,386,543	$ 300,203,507

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 2

Please provide a breakdown (in an electronic format) of the Company's O&M expenses for the 2023 Bridge Year as shown on the Company's application for a Multiyear Rate Plan ("MYP") by FERC account and split between labor and non-labor. Please present this information by total company and at the D.C. jurisdictional level.

RESPONSE:

The Company has not prepared the analysis in the format requested. For available information, please see FC 1176 OPC DR 13-2 Attachment which provides an O&M breakout for the 2023 MYP Bridge Year between labor and non-labor at the total Pepco Distribution level. This breakout is not available at the jurisdictional level as the Company allocates its costs based on FERC account but does not perform its jurisdictional allocation by expense type.

SPONSOR: Robert T. Leming and Phillip S. Barnett

POTOMAC ELECTRIC POWER COMPANY

Comparative Statement of Operations & Maintenance Expense Accounts
Distribution Only

Account No.	Description		Forecast MYP Bridge Year 12 Months Ending 12/31/2023
580	Operation Supervision & Engineering	$	3,114,424
581	Load Dispatching		3,919,194
582	Station Expenses		121,708
583	Overhead Line Expenses		4,866,814
584	Underground Line Expenses		6,073,273
585	Street Lighting and Signal System Expenses		214,603
586	Meter Expenses		5,675,420
587	Customer Installations Expenses		13,262,384
588	Miscellaneous Distribution Expenses		26,519,923
589	Rents		5,316,779
590	Maintenance - Supv & Eng		110,631
591	Maintenance of Structures		229,280
592	Maintenance of Station Equipment		18,672,168
593	Maintenance of Overhead Lines		42,100,315
594	Maintenance of Underground Lines		16,212,789
595	Maintenance of Line Transformers		1,214,247
596	Rout Maint of Street Lighting & Signal System		563,805
597	Maintenance of Meters		1,525,470
598	Maintenance of Miscellaneous Distribution Plant		2,712,159
901	Supervision - Customer Exp		-
902	Meter Reading Expenses		881,424
903	Customer Records and Collection Expenses		85,190,247
904	Uncollectible Accounts		12,591,884
905	Miscellaneous Customer Accounts Expenses		-
907	Supervision - Cust Svc & Info		-
908	Customer Assistance Expenses		5,550,630

POTOMAC ELECTRIC POWER COMPANY

Comparative Statement of Operations & Maintenance Expense Accounts
Distribution Only

Account No.	Description	Forecast MYP Bridge Year 12 Months Ending 12/31/2023
909	Informational & Instructional Adertising Expenses	298,767
910	Miscellaneous Customer Service & Information Expens	-
911	Supervision - Sales Expense	-
912	Demonstrating and Selling Expenses	-
913	Advertising Expenses	-
920	Administrative and General Salaries	7,212,922
921	Office Supplies and Expenses	2,441,166
923	Outside Services Employed	133,878,373
924	Property Insurance	2,475,603
925	Injuries and Damages	2,309,645
926	Employee Pension and Benefits	20,750,303
928	Regulatory Commission Expenses	2,552,234
929	Duplicate Charges Credit	-
930.1	General Advertising Expenses	1,388,066
930.2	Miscellaneous General Expenses	203,344
931	Rents	-
935	Maintenance of General Plant	77,166
Total Distribution Operations & Maintenance Expense		$ 430,227,160

POTOMAC ELECTRIC POWER COMPANY

Comparative Statement of Operations & Maintenance Expense Accounts
Distribution Only

Account No.	Description		Forecast MYP Bridge Year 12 Months Ending 12/31/2023
Total Distribution O&M By Function			
Distribution		$	256,938,339
Distribution Portion of A&G			173,288,822
		$	430,227,160
Base Labor and Overtime (OT)			
PEPCO	Base Labor in Distribution	$	51,004,665
PEPCO	Base Labor in Dist Portion of A&G		7,446,474
PEPCO	OT Labor in Distribution		6,762,530
PEPCO	OT Labor in Dist Portion of A&G		256,748
PHISCO to Pepco	Base Labor in Distribution		16,183,531
PHISCO to Pepco	Base Labor in Dist Portion of A&G		19,428,078
PHISCO to Pepco	OT Labor in Distribution		167,043
PHISCO to Pepco	OT Labor in Dist Portion of A&G		92,671
BSC to Pepco	Base Labor in Dist Portion of A&G		33,792,863
BSC to Pepco	OT Labor in Dist Portion of A&G		404,375
		$	135,538,977
Total Base Labor and OT by Function			
Total	Labor in Distribution	$	74,117,768
Total	Labor in Dist Portion of A&G		61,421,209
		$	135,538,977
Non- Base Labor and OT Distribution O&M by Function			
Distribution		$	182,820,571
Distribution Portion of A&G			111,867,613
		$	294,688,183

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 4
Please provide a breakdown (in an electronic format) of the Company's O&M expenses for the 12-month period ending December 31, 2023 as included in the October 16, 2023 Traditional Test Year Compliance filing by account and split between labor and non-labor. Please present this information by total company and at the D.C. jurisdictional level.

RESPONSE:

The Company has not prepared the analysis in the format requested. For available information, please see FC 1176 OPC DR 13-4 Attachment which provides an O&M breakout for the 2023 Traditional Test Year Compliance filing between labor and non-labor at the total Pepco Distribution level. This breakout is not available at the jurisdictional level as the Company allocates its costs based on FERC account but does not perform its jurisdictional allocation by expense type.

SPONSOR: Robert T. Leming and Phillip S. Barnett

POTOMAC ELECTRIC POWER COMPANY

Comparative Statement of Operations & Maintenance Expense Accounts
Distribution Only

Account No.	Description	6+6 Forecast TTYCF 12 Months Ending 12/31/2023
580	Operation Supervision & Engineering	$ 2,652,909
581	Load Dispatching	3,563,644
582	Station Expenses	235,340
583	Overhead Line Expenses	4,384,731
584	Underground Line Expenses	5,208,717
585	Street Lighting and Signal System Expenses	79,878
586	Meter Expenses	5,620,498
587	Customer Installations Expenses	10,813,467
588	Miscellaneous Distribution Expenses	58,392,166
589	Rents	5,047,253
590	Maintenance - Supv & Eng	147,672
591	Maintenance of Structures	908,138
592	Maintenance of Station Equipment	16,478,630
593	Maintenance of Overhead Lines	38,349,957
594	Maintenance of Underground Lines	19,949,799
595	Maintenance of Line Transformers	1,321,709
596	Rout Maint of Street Lighting & Signal System	1,631,464
597	Maintenance of Meters	1,180,188
598	Maintenance of Miscellaneous Distribution Plant	2,155,010
901	Supervision - Customer Exp	
902	Meter Reading Expenses	869,243
903	Customer Records and Collection Expenses	84,386,665
904	Uncollectible Accounts	12,593,167
905	Miscellaneous Customer Accounts Expenses	
907	Supervision - Cust Svc & Info	
908	Customer Assistance Expenses	5,596,642
909	Informational & Instructional Adertising Expenses	1,115,552
910	Miscellaneous Customer Service & Information Expens	-
911	Supervision - Sales Expense	
912	Demonstrating and Selling Expenses	
913	Advertising Expenses	

920	Administrative and General Salaries	7,041,254
921	Office Supplies and Expenses	2,938,729
923	Outside Services Employed	130,437,568
924	Property Insurance	1,872,421
925	Injuries and Damages	2,077,737
926	Employee Pension and Benefits	21,093,939
928	Regulatory Commission Expenses	3,313,342
929	Duplicate Charges Credit	-
930.1	General Advertising Expenses	1,407,742
930.2	Miscellaneous General Expenses	791,300
931	Rents	-
935	Maintenance of General Plant	84,664
Total Distribution Operations & Maintenance Expense		$ 453,741,139

Total Distribution O&M By Function			
Distribution		$	282,682,440
Distribution Portion of A&G			171,058,699
		$	453,741,139
Base Labor and Overtime (OT)			
PEPCO	Base Labor in Distribution	$	46,112,779
PEPCO	Base Labor in Dist Portion of A&G		9,082,374
PEPCO	OT Labor in Distribution		6,557,127
PEPCO	OT Labor in Dist Portion of A&G		191,572
PHISCO to Pepco	Base Labor in Distribution		15,746,032
PHISCO to Pepco	Base Labor in Dist Portion of A&G		19,470,099
PHISCO to Pepco	OT Labor in Distribution		179,206
PHISCO to Pepco	OT Labor in Dist Portion of A&G		71,107
BSC to Pepco	Base Labor in Dist Portion of A&G		28,945,682
BSC to Pepco	OT Labor in Dist Portion of A&G		524,370
		$	126,880,350
Total Base Labor and OT by Function			
Total	Labor in Distribution	$	68,595,145
Total	Labor in Dist Portion of A&G		58,285,205
		$	126,880,350
Non- Base Labor and OT Distribution O&M by Function			
Distribution		$	214,087,295
Distribution Portion of A&G			112,773,494
		$	326,860,789

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 5
Please provide a breakdown (in an electronic format) of the Company's forecasted O&M expenses annually for 2024, 2025, and 2026 as included in the Company's application for an MYP by account and split between labor and non-labor. Please present this information by total company and at the D.C. jurisdictional level.

RESPONSE:

The Company has not prepared the analysis in the format requested. For available information, please see FC 1176 OPC DR 13-5 Attachment which provides an O&M breakout for the requested MYP years between labor and non-labor at the total Pepco Distribution level. This breakout is not available at the jurisdictional level as the Company allocates its costs based on FERC account but does not perform its jurisdictional allocation by expense type.

SPONSOR: Robert T. Leming and Phillip S. Barnett

POTOMAC ELECTRIC POWER COMPANY

Comparative Statement of Operations & Maintenance Expense Accounts
Distribution Only

Account No.	Description	MYP Forecast 12 Months Ended 12/31/2024	MYP Forecast 12 Months Ended 12/31/2025	MYP Forecast 12 Months Ended 12/31/2026
580	Operation Supervision & Engineering	$ 3,205,748	$ 3,298,547	$ 3,376,951
581	Load Dispatching	3,907,849	3,949,847	4,019,043
582	Station Expenses	73,026	75,248	38,910
583	Overhead Line Expenses	5,325,974	5,288,629	5,350,416
584	Underground Line Expenses	6,470,182	6,152,660	6,535,328
585	Street Lighting and Signal System Expenses	219,968	225,462	231,106
586	Meter Expenses	5,874,794	6,019,780	6,180,623
587	Customer Installations Expenses	11,602,363	11,786,890	12,195,654
588	Miscellaneous Distribution Expenses	27,229,249	27,779,524	28,289,119
589	Rents	5,426,704	5,298,197	5,026,230
590	Maintenance - Supv & Eng	113,274	113,330	112,973
591	Maintenance of Structures	236,452	242,659	243,676
592	Maintenance of Station Equipment	19,365,711	20,184,081	20,010,969
593	Maintenance of Overhead Lines	40,535,828	41,233,870	41,939,576
594	Maintenance of Underground Lines	20,079,844	20,998,485	20,266,129
595	Maintenance of Line Transformers	1,239,703	1,264,509	1,292,103
596	Rout Maint of Street Lighting & Signal System	582,552	592,210	604,389
597	Maintenance of Meters	1,578,562	1,623,657	1,675,766
598	Maintenance of Miscellaneous Distribution Plant	2,635,176	2,922,270	3,040,525
901	Supervision - Customer Exp			
902	Meter Reading Expenses	873,211	893,676	896,347
903	Customer Records and Collection Expenses	88,007,600	85,002,759	86,287,171

POTOMAC ELECTRIC POWER COMPANY

Comparative Statement of Operations & Maintenance Expense Accounts
Distribution Only

Account No.	Description	MYP Forecast 12 Months Ended 12/31/2024	MYP Forecast 12 Months Ended 12/31/2025	MYP Forecast 12 Months Ended 12/31/2026
904	Uncollectible Accounts	11,439,397	11,058,688	9,483,623
905	Miscellaneous Customer Accounts Expenses			
907	Supervision - Cust Svc & Info			
908	Customer Assistance Expenses	5,645,649	5,721,143	5,814,157
909	Informational & Instructional Adertising Expenses	325,432	382,102	402,104
910	Miscellaneous Customer Service & Information Expenses			
911	Supervision - Sales Expense			
912	Demonstrating and Selling Expenses			
913	Advertising Expenses			
920	Administrative and General Salaries	6,690,272	6,836,708	7,129,787
921	Office Supplies and Expenses	2,649,764	2,767,220	2,722,577
923	Outside Services Employed	141,497,412	144,627,033	149,793,389
924	Property Insurance	2,714,142	2,972,490	3,209,834
925	Injuries and Damages	2,356,316	2,453,450	2,509,655
926	Employee Pension and Benefits	20,055,794	20,572,875	20,483,187
928	Regulatory Commission Expenses	2,234,418	2,259,851	1,105,831
929	Duplicate Charges Credit			
930.1	General Advertising Expenses	1,497,614	1,578,597	1,636,879
930.2	Miscellaneous General Expenses	208,793	215,478	230,321
931	Rents			
935	Maintenance of General Plant	78,743	81,667	83,880
Total Distribution Operations & Maintenance Expense		$ 441,977,516	$ 446,473,590	$ 452,218,228

POTOMAC ELECTRIC POWER COMPANY

Comparative Statement of Operations & Maintenance Expense Accounts
Distribution Only

Account No.	Description	MYP Forecast 12 Months Ended 12/31/2024	MYP Forecast 12 Months Ended 12/31/2025	MYP Forecast 12 Months Ended 12/31/2026
Total Distribution O&M By Function				
Distribution		$ 261,994,248	$ 262,108,221	$ 263,312,888
Distribution Portion of A&G		179,983,268	184,365,369	188,905,340
		$ 441,977,516	$ 446,473,590	$ 452,218,228
Base Labor and Overtime (OT)				
PEPCO	Base Labor in Distribution	$ 51,933,871	$ 55,391,922	$ 57,834,789
PEPCO	Base Labor in Dist Portion of A&G	8,044,361	8,217,021	8,195,933
PEPCO	OT Labor in Distribution	6,985,840	6,887,585	6,890,656
PEPCO	OT Labor in Dist Portion of A&G	261,260	276,149	284,973
PHISCO to Pepco	Base Labor in Distribution	16,905,035	17,922,308	18,451,576
PHISCO to Pepco	Base Labor in Dist Portion of A&G	20,173,826	20,707,108	21,180,405
PHISCO to Pepco	OT Labor in Distribution	168,350	169,984	171,637
PHISCO to Pepco	OT Labor in Dist Portion of A&G	119,620	121,697	124,233
BSC to Pepco	Base Labor in Dist Portion of A&G	35,909,295	37,199,865	38,172,618
BSC to Pepco	OT Labor in Dist Portion of A&G	403,118	361,932	262,566
		$ 140,904,575	$ 147,255,572	$ 151,569,384
Total Base Labor and OT by Function				
Total	Labor in Distribution	$ 75,993,096	$ 80,371,799	$ 83,348,657
Total	Labor in Dist Portion of A&G	64,911,479	66,883,773	68,220,727
		$ 140,904,575	$ 147,255,572	$ 151,569,384
Non- Base Labor and OT Distribution O&M by Function				
Distribution		$ 186,001,151	$ 181,736,422	$ 179,964,231
Distribution Portion of A&G		115,071,789	117,481,596	120,684,612
		$ 301,072,941	$ 299,218,019	$ 300,648,843

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 14
Please refer to page 11 of Witness Leming's October 16, 2023 supplemental direct testimony, PEPCO (2B). Please explain why the Company proposes to use a year-end rate base to calculate its Traditional Test Year revenue requirement when the Company proposed to use a 13-month average rate base in its MYP. Please cite any Commission Orders that support the Company's answer.

RESPONSE:

As discussed in the referenced testimony passage, the year-end balance provides a better picture of the used and useful investments that serve customers during the rate effective period.

When setting rates based on a traditional test period, the year end balances for that test period would be used and useful in providing service to customers in each month of the rate effective period. Said another way, an asset placed in-service in December 2023 would be used and useful in every month in 2024 when rates in this proceeding are anticipated to go into effect. If that asset were to be treated on a 13-month average basis, that asset would only be reflected in 1-month of the 13-month average from December 2022 through December 2023. This means that customers' rates would only reflect a small fraction of the annual cost of service related to this asset, while it is used and useful in providing service in each month of the rate effective period. This has the effect of drastically understating the true cost of service for this asset.

In contrast, in an MYP the test periods used to set rates align with the rate effective period for those rates. Under this construct, if an asset is placed in service in December in 2024, it would only be used and useful in providing service to customers for 1-month out of that rate year. As such, it is more appropriate under an MYP to use a 13-month average rate base to determine revenue requirements as that appropriately reflects the portion of the year that those assets are being used to provide service to customers and appropriately states the cost of service in a given rate year.

SPONSOR: Robert T. Leming

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 16
Please provide all inflation estimates used in the Company's MYP. Please provide workpapers that support any estimates.

RESPONSE:

Pepco relied on labor rates of 3% as an assumption for 2024-2026 given the Company's internal corporate assumption book. A breakdown of this analysis is provided below. Pepco leveraged a non-labor inflation rate of 2.5% in the budgeting system. When developing estimates of growth and inflation, Pepco leveraged the IHS Macro 10-year Baseline Consumer Price Index (CPI) annual percent change from 2023-2026 as well as factored in recent inflation levels, which were in excess of this average.

Inflation Assumptions

	Assumption *(annual %)*	**2023 LRP**	**2024 LRP**	**2025 LRP**	**2026 LRP**
1	Default Inflation Rate (1)	3.9%	2.2%	2.1%	2.2%

Labor Rate Assumptions

	Labor Rate Assumption *(annual %)*	**2023 LRP**	**2024 LRP**	**2025 LRP**	**2026 LRP**
2	Salary Inflation Rate (average)	4.00%	3.00%	3.00%	3.00%
3	Hourly Non-Represented Inflation Rate (average)	4.00%	3.00%	3.00%	3.00%

NOTES
1. IHS U.S. Macro 10-Year Baseline Consumer Price Index [2022 September Vintage/Release]. Annual percent change

SPONSOR: Phillip S. Barnett

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 33
Please refer to the Company's RMA 29 from the October 16, 2023 Traditional Test Year Compliance filing. Please explain why the Company proposes a 5-year amortization for the COVID-19 regulatory asset.

RESPONSE:

The Commission has approved various regulatory asset amortization periods in the past including 3, 5, and 15 years. Given prior Commission approvals for 5-year amortization of regulatory assets of similar size, including DLC Program Costs and the AMI True-up, the Company is proposing a 5-year amortization for the COVID-19 regulatory asset in this proceeding.

SPONSOR: Robert T. Leming

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 39
Please refer to attachment PEPCO (K)-6 which includes the Energy Efficiency Calculations and Inputs. Please answer the following questions.

a. Please provide a program description for each of the included energy efficiency programs.

b. Please update PEPCO (K)-6 to include any actual data through June 2023.

c. Please provide the most recent program evaluation for each of the programs listed in PEPCO (K)-6.

d. Please describe the Company's process for forecasting the energy efficiency savings for programs that do not show any actual savings (or savings before 2023).

e. Please describe the Company's process for forecasting the energy efficiency savings for the behavior based program.

f. Please provide any analysis or studies that support the forecasted energy efficiency savings.

RESPONSE:

a. Program descriptions for each of the included energy efficiency programs in Pepco (K)-6 are provided below:

DC Sustainable Energy Utility: combination of energy efficiency programs administered by the DCSEU.

Efficient Products (Company-run program): provides incentives to increase the market share of Energy Star certified appliances such as clothes washers, dryers, refrigerators, room AC's, dehumidifiers, and heat pump water heaters.

Quick Home Energy Check Up (QHEC) (Company-run program): Energy auditor comes to the home and diagnosis ways for a customer to save energy at no cost. Also provides a number of energy efficient measures such as smart strips at no additional cost.

LMI Home Retrofit (Company-run program): Provides energy audits, rebates for efficient products, as well whole home upgrades directed at limited and moderate income customers. Whole home upgrades would be targeted at residential buildings serving 4 units or less.

Behavior Based (Company-run program): Leverages Pepco's investment in AMI, by providing personalized energy savings tips as well as similar homes comparison to nudge more efficient use of one's energy.

Merger - MF whole building RCx (Company-run program): Pepco's Income Eligible Multifamily Program which provides qualifying properties an energy assessment and energy-saving products installed throughout common areas and residents' units. This program was authorized through FC1148.

Small Business Program (Company-run program): provides incentives for retrofits for commercial customers with less than 100kW demand.

Existing Buildings (Company-run program): provides incentives and technical assistance to commercial customers in buildings less than 50,000 sq ft.

Midstream (Company-run program): Aides customers who purchase efficient equipment directly from distributor or manufacturer by offering instant rebates.

Commercial Behavior (Company-run program): Provides a Customer Engagement Portal to learn more about a customer's Individual energy use, tips for savings, and information on EE programs.

b. Please see FC1176 OPC DR 13-39 Attachment Confidential Electronic Only for actual data through June 2023.

c. Evaluations for the Company run programs listed in Pepco (K)-6 are not available as Pepco administered programs through FC1160 have yet to be approved and commence. For DC Sustainable Energy Utility please refer to the DCSEU for any evaluations done on their behalf.

d. Savings forecasts for energy efficiency programs that had no actual savings prior 2023 were based off the forecasted savings that were presented in Pepco's FC1160 filing. The Company only included savings from programs that were initially approved with modifications by the Commission in Order 21417.

e. The Company's forecast for the behavior-based program was taken from its FC1160 filing. The FC1160 forecast was derived from previously evaluated savings of the behavior-based programs the Company administers in nearby Maryland jurisdictions rescaled to the District's population.

f. Please see Pepco's Application, filed August 2, 2021 in FC1160, Appendix D, pg. 113 which serves as the basis for forecasted energy efficiency savings.

SPONSOR: Ekaterina Efimova and Morlon D. Bell-Izzard

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 14

QUESTION NO. 4
Please refer to the Sale of Electricity line on Exhibit PEPCO (2B)-1. Please explain why the Company has not annualized these revenues for customer growth during the Historic Test Year.

RESPONSE:

As explained in Company Witness Leming's Supplemental Direct Testimony, the test period for the Company's traditional test year compliance filing is the 12 months ending December 31, 2023, with six months of actual data as of June 30, 2023 and six months of projected data from July through December 2023. The Sale of Electricity line item in Exhibit PEPCO (2B)-1 appropriately reflects the Company's revenues for this test period. Calculating test year base distribution revenues based on year-end customer counts would improperly over- or under-state the revenues for each rate class that the Company is allowed during the test year and would be inconsistent with prior traditional test year rate cases.

SPONSOR: Matthew J. Bonikowski & Robert T. Leming

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
VOLUNTARY DISCOVERY DATA REQUEST NO. 1

QUESTION NO. 1

Provide all workpapers in Excel with all formulae intact and supporting documentation for the Supplemental Direct testimony and exhibits of Witness Leming.

RESPONSE:

Please refer to the following attachments. For Exhibits PEPCO (2B)-1, PEPCO (2B)-2 and PEPCO (2B)-3, the excel workpapers have been provided electronically through eBridge as part of the Company's Traditional Test Year Compliance Filing (TTYCF).

Attachment	**Description**
Exhibit Pepco (2B)-1	Revenue Requirements and RMAs
Exhibit Pepco (2B)-2	Functionalized Cost of Service Elements
Exhibit Pepco (2B)-3	Jurisdictional Cost of Service
FC 1176 Voluntary DR 1-01 Attachment A1	Electric Plant in Service
FC 1176 Voluntary DR 1-01 Attachment A2	Accumulated Depreciation
FC 1176 Voluntary DR 1-01 Attachment A3	Accumulated Amortization
FC 1176 Voluntary DR 1-01 Attachment A4	Materials and Supplies
FC 1176 Voluntary DR 1-01 Attachment A5	Cash Working Capital
FC 1176 Voluntary DR 1-01 Attachment A6	Accumulated Deferred Income Taxes
FC 1176 Voluntary DR 1-01 Attachment A7	Prepaid Pension/OPEB Liab. (net of tax)

FC 1176 Voluntary DR 1-01 Attachment A8	Customer Deposits
FC 1176 Voluntary DR 1-01 Attachment A9	Pepco Portion of Servco Assets
FC 1176 Voluntary DR 1-01 Attachment A10	Regulatory Assets
FC 1176 Voluntary DR 1-01 Attachment A11	Unamortized Credit Facility Costs
FC 1176 Voluntary DR 1-01 Attachment A12	Depreciation Expense
FC 1176 Voluntary DR 1-01 Attachment A13	Amortization Expense
FC 1176 Voluntary DR 1-01 Attachment A14	OpResult (Includes Revenues, O&M Exp, Depr & Amort Exp, Other Taxes, AFUDC & Interest Exp and Income taxes)
FC 1176 Voluntary DR 1-01 Attachment B1	RMA 1 - Annualize Test Year Reliability Closings
FC 1176 Voluntary DR 1-01 Attachment B2	RMA 2 - Annualize Amortization Expense
FC 1176 Voluntary DR 1-01 Attachment B3	RMA 3 - Annualize Depreciation Expense
FC 1176 Voluntary DR 1-01 Attachment B4.1	RMA 4 - Annualize Remainder of Rate Base
FC 1176 Voluntary DR 1-01 Attachment B4.2	End of Period Jurisdictional Cost of Service – Supporting RMA 4
FC 1176 Voluntary DR 1-01 Attachment B5	RMA 5 - Annualize Regulatory Asset Amortization
FC 1176 Voluntary DR 1-01 Attachment B6	RMA 6 - Annualize Wage Increases
FC 1176 Voluntary DR 1-01 Attachment B7	RMA 7 - Annualize Employee Health and Welfare Costs
FC 1176 Voluntary DR 1-01 Attachment B8	RMA 8 - Annualize 2023 Pension and Other Post-Employment Benefits (OPEB) Expense
FC 1176 Voluntary DR 1-01 Attachment B9	RMA 9 - Reflection of Three-Year Average Overtime Level

FC 1176 Voluntary DR 1-01 Attachment B10	RMA 10 - Reflection of Three-Year Average Regulatory Expense
FC 1176 Voluntary DR 1-01 Attachment B11	RMA 11 - Reflection of Three-Year Average Storm Costs
FC 1176 Voluntary DR 1-01 Attachment B12	RMA 12 - Reflection of BSA Regulatory Asset in Rate Base
FC 1176 Voluntary DR 1-01 Attachment B13	RMA 13 - Reflection of EDIT 5 Yr Credit Sunset Adjustment
FC 1176 Voluntary DR 1-01 Attachment B14	RMA 14 - Reflection of Regulatory Asset - 5 Year EDIT Credit Over-Return
FC 1176 Voluntary DR 1-01 Attachment B15	RMA 15 - Removal of DC Power Line Undergrounding (DC PLUG) Initiative Costs
FC 1176 Voluntary DR 1-01 Attachment B16	RMA 16 - Removal of Supplemental Executive Retirement Plan (SERP) costs
FC 1176 Voluntary DR 1-01 Attachment B17	RMA 17 - Removal of Certain Executive Incentive Plan Costs
FC 1176 Voluntary DR 1-01 Attachment B18	RMA 18 - Removal of Adjustments to Deferred Compensation Balances
FC 1176 Voluntary DR 1-01 Attachment B19	RMA 19 - Removal of Executive Perquisite Expenses
FC 1176 Voluntary DR 1-01 Attachment B20	RMA 20 - Removal of Employee Association Costs
FC 1176 Voluntary DR 1-01 Attachment B21	RMA 21 - Removal of Industry Contributions and Membership Fees
FC 1176 Voluntary DR 1-01 Attachment B22	RMA 22 - Removal of Institutional Advertising/Selling Expenses
FC 1176 Voluntary DR 1-01 Attachment B23	RMA 23 - Reflection of Customer Deposit Interest Expense and Credit Facility Expense and Maintenance Costs
FC 1176 Voluntary DR 1-01 Attachment B24	RMA 24 - Reflection of Adjustments to BSC Billed Depreciation (Merger Commitment 39)
FC 1176 Voluntary DR 1-01 Attachment B25	RMA 25 - Removal of Buzzard Environmental Accrual
FC 1176 Voluntary DR 1-01 Attachment B26	RMA 26 - Removal of ARSP Environmental Accrual

FC 1176 Voluntary DR 1-01 Attachment B27	RMA 27 - Removal of Benning Environmental Accrual
FC 1176 Voluntary DR 1-01 Attachment B28	RMA 28 - Removal of Benning RI/FS Regulatory Asset and Amortization Per Order 21884 (Jan 2023 - Jun 2023)
FC 1176 Voluntary DR 1-01 Attachment B29	RMA 29 - Reflection of Regulatory Asset for COVID-19 related costs
FC 1176 Voluntary DR 1-01 Attachment B30	RMA 30 - Reflection of HOW Credit Regulatory Asset
FC 1176 Voluntary DR 1-01 Attachment B31	RMA 31 - Reflection of Electric Vehicle Regulatory Asset
FC 1176 Voluntary DR 1-01 Attachment B32	RMA 32 - Reflection of PHISCO DDIT
FC 1176 Voluntary DR 1-01 Attachment B33	RMA 33 - Reflection of Current Rate Case Costs
FC 1176 Voluntary DR 1-01 Attachment B34	RMA 34 - Reflection of Non-Labor Operation & Maintenance (O&M) Inflation Adjustment
FC 1176 Voluntary DR 1-01 Attachment B35	RMA 35 - Reflection of Updated Depreciation Study Depreciation Rates
FC 1176 Voluntary DR 1-01 Attachment B36	RMA 36 - Reflection of 2021 Lead Lag Study Impact on Cash Working Capital Allowance
FC 1176 Voluntary DR 1-01 Attachment B37	RMA 37 - Adjustments to Cash Working Capital Allowance
FC 1176 Voluntary DR 1-01 Attachment B38	RMA 38 - Tax Effect of Proforma Interest Expense

SPONSOR: Robert T. Leming

POTOMAC ELECTRIC POWER COMPANY

Revenues - DISTRIBUTION ONLY
Twelve Months Ended December 31, 2023
Historic Test Year (HTY)

	Actual Jan-23	Actual Feb-23	Actual Mar-23	Actual Apr-23	Actual May-23	Actual Jun-23	Forecast Jul-23	Forecast Aug-23	Forecast Sep-23	Forecast Oct-23	Forecast Nov-23	Forecast Dec-23	HTY Forecast 12 ME Dec 31, 2023
Distr Billed Sale of Electricity													
DC, including BSA Deferral (excl. DCPLUG)	$ 56,512,745	$ 53,633,805	$ 56,367,098	$ 51,613,312	$ 53,360,595	$ 53,594,452	$ 62,721,213	$ 71,130,100	$ 56,759,637	$ 53,978,502	$ 51,802,935	$ 49,830,035	$ 671,304,428
MD, including BSA Deferral	62,008,753	54,150,753	55,293,504	46,882,406	46,440,049	64,258,657	85,394,172	88,608,318	84,215,741	60,362,130	48,009,278	53,879,034	749,502,794
Total Billed Sale of Electricity - Distr	118,521,498	107,784,558	111,660,602	98,495,717	99,800,644	117,853,109	148,115,385	159,738,418	140,975,378	114,340,632	99,812,212	103,709,069	1,420,807,222
Other Revenues Distr- DC													
Forfeited Discount	380,822	38,968	459,693	38,793	101,389	216,379	80,372	80,372	80,372	80,372	80,372	80,372	1,718,274
Returned Check Charge	5,030	4,275	4,900	4,373	5,400	5,100	3,653	3,653	3,653	3,653	3,653	3,653	50,996
Connect Charges	420	3,850	2,065	6,650	36,260	42,630	14,371	14,371	14,371	14,371	14,371	14,371	178,101
Miscellaneous Service	-	-	(143,436)	-	29,169	18,707	(1,899)	(1,899)	(1,899)	(1,899)	(1,899)	(1,899)	(106,957)
Rent from Electric	12,274	12,274	12,274	24,547	12,274	12,274	104,296	104,296	104,296	104,296	104,296	104,296	711,689
DC Pole Attachments	129,113	114,598	114,598	114,598	114,598	114,598	24,213	24,213	24,213	24,213	24,213	24,213	847,382
Other Electric Revenue													
Distribution-Other	57,879	51,813	96,924	45,102	52,551	131,958	48,342	48,342	48,342	48,342	48,342	48,342	726,280
Distribution-Billing Svcs	23,453	25,476	25,548	28,245	22,629	27,732	25,889	25,889	25,889	25,889	25,889	25,889	308,419
Distribution-Acct Mgmt	66,795	91,588	47,638	56,237	48,243	60,768	52,931	52,931	52,931	52,931	52,931	52,931	688,853
Interconnection Application Fee	18,500	10,953	9,000	(99,000)	13,500	17,000	7,652	7,652	7,652	7,652	7,652	7,652	15,863
Intercompany	130,095	138,622	119,629	123,843	143,799	144,956	51,929	51,929	51,929	51,929	51,929	51,929	1,112,519
Total Other Revenues Distr - DC	824,379	492,416	748,832	343,388	579,812	792,101	411,749	411,749	411,749	411,749	411,749	411,749	6,251,419
Other Revenues Distr - MD													
MD Opt Out	16,592	16,782	16,959	16,316	16,707	16,156	17,743	17,743	17,743	17,743	17,743	17,743	205,967
Forfeited Discount	477,253	456,142	485,683	399,431	394,039	198,986	178,196	178,196	178,196	178,196	178,196	178,196	3,480,709
Returned Check Charge	10,250	8,890	10,575	8,350	10,105	11,000	6,963	6,963	6,963	6,963	6,963	6,963	100,947
Connect Charges	2,240	1,890	2,170	36,085	54,915	55,580	44,907	44,907	44,907	44,907	44,907	44,907	422,324
Miscellaneous Service	-	-	(14)	(99)	-	(366)	(1,021)	(1,021)	(1,021)	(1,021)	(1,021)	(1,021)	(6,603)
Rent from Electric	8,591	8,620	8,745	9,888	8,688	8,629	170,560	170,560	170,560	170,560	170,560	170,560	1,076,522
MD Pole Attachments	303,372	208,980	208,980	208,980	208,980	208,980	50,040	50,040	50,040	50,040	50,040	50,040	1,648,508
Other Electric Revenue													
Distribution-Other	-	1	-	-	-	-	-	-	-	-	-	-	1
Distribution-Billing Svcs	59,044	61,377	59,679	58,522	56,311	61,051	62,371	62,371	62,371	62,371	62,371	62,371	730,212
Distribution-Acct Mgmt	17,046	19,408	27,540	17,756	14,580	18,739	17,254	17,254	17,254	17,254	17,254	17,254	218,594
Interconnection Application Fee	15,308	4,902	6,743	(79,389)	5,387	11,595	5,110	5,110	5,110	5,110	5,110	5,110	(4,794)
Intercompany	167,154	178,112	153,707	159,122	184,763	186,249	67,311	67,311	67,311	67,311	67,311	67,311	1,432,976
Total Other Revenues Distr- MD	1,076,849	965,104	980,767	834,963	954,474	776,599	619,434	619,434	619,434	619,434	619,434	619,434	9,305,361
Total Other Operating Revenues - Distr	1,901,229	1,457,519	1,729,598	1,178,351	1,534,286	1,568,700	1,031,183	1,031,183	1,031,183	1,031,183	1,031,183	1,031,183	15,556,780
Total Distr Operating Revenues													
DC	57,337,124	54,126,221	57,115,930	51,956,700	53,940,406	54,386,553	63,132,962	71,541,849	57,171,386	54,390,250	52,214,683	50,241,784	677,555,847
MD	63,085,602	55,115,856	56,274,270	47,717,368	47,394,524	65,035,256	86,013,606	89,227,752	84,835,175	60,981,565	48,628,712	54,498,468	758,808,155
Total Distr Operating Revenues	**$ 120,422,726**	**$ 109,242,077**	**$ 113,390,200**	**$ 99,674,068**	**$ 101,334,930**	**$ 119,421,809**	**$ 149,146,568**	**$ 160,769,601**	**$ 142,006,561**	**$ 115,371,815**	**$ 100,843,395**	**$ 104,740,252**	**$ 1,436,364,002**

Potomac Electric Power Company

Residential Weather Normalized Usage Per Customer

Line	Description (1)	Weather Normalized kWh (2)	Number of Customers (3)	Usage Per Customer (4)	Percentage Change (5)
1	2018	2,187,618,636	273,633	666	
2	2019	2,206,375,793	281,192	654	-1.85%
3	2020	2,262,395,189	289,503	651	-0.40%
4	2021	2,292,238,281	297,377	642	-1.36%
5	2022	2,263,893,783	305,510	618	-3.87%
6	5-Year Average				-1.87%
7	2023			636	
8	2024			625	-1.64%
9	2025			615	-1.61%
10	2026			605	-1.70%

Sources and Notes:
Lines 1 to 5: Pepco Response to OPC Data Request 3-9 and Pepco (K)-5_No_No_.60.
Lines 6 to 10: Pepco (K)-16_No_No_.71.

Potomac Electric Power Company

Multi-Year Plan Residential Sales Forecast Adjustment

Line	Description	Number of Customers (2)	MWh (3)	Adj. Use Per Customer[1] (2)	Revenue at Effective Rates (4)	Difference (5)	Percentage Difference (6)
	Pepco Proposed						
1	MYP Year 1 - 2024	3,840,834	2,400,407	625	$ 101,837,085		
2	MYP Year 2 - 2025	3,924,264	2,413,167	615	129,003,729		
3	MYP Year 3 - 2026	4,007,590	2,422,591	605	156,170,373		
	Adjusted						
4	MYP Year 1 - 2024	3,840,834	2,441,081	636	$ 102,515,514	$ 678,429	0.67%
5	MYP Year 2 - 2025	3,924,264	2,494,105	636	131,081,157	2,077,428	1.61%
6	MYP Year 3 - 2026	4,007,590	2,547,064	636	160,469,527	4,299,154	2.75%

Note:
[1] Annual Average Use Adjusted for EVPC and SolarPC which remains unchanged between the Company and OPC usage.

Potomac Electric Power Company

Overview of Pepco's O&M Expenses
($000)

Line	Account	Description	Historical 2018 (1)	2019 (2)	2020 (3)	2021 (4)	2022 (5)	Bridge 2023 (6)	MYP 2024 (7)	2025 (8)	2026 (9)
1	580	Operation Supervision & Engineering	$ 3,708	$ 5,870	$ 1,638	$ 1,112	$ 2,968	$ 3,114	$ 3,206	$ 3,299	$ 3,377
2	581	Load Dispatching	5,625	6,354	6,149	6,071	3,061	3,919	3,908	3,950	4,019
3	582	Station Expenses	1,292	1,968	1,555	266	58	122	73	75	39
4	583	Overhead Line Expenses	1,048	3,494	4,569	4,631	2,898	4,867	5,326	5,289	5,350
5	584	Underground Line Expenses	5,674	5,590	5,791	5,454	5,672	6,073	6,470	6,153	6,535
6	585	Street Lighting and Signal System Expenses	635	-	189	400	(38)	215	220	225	231
7	586	Meter Expenses	6,952	6,102	5,838	6,023	5,188	5,675	5,875	6,020	6,181
8	587	Customer Installations Expenses	8,439	7,423	7,032	8,197	8,108	13,262	11,602	11,787	12,196
9	588	Miscellaneous Distribution Expenses	9,180	37,808	23,528	30,140	35,912	26,520	27,229	27,780	28,289
10	589	Rents	9,440	11,919	4,845	4,229	4,222	5,317	5,427	5,298	5,026
11	590	Maintenance - Supv & Eng	783	174	144	208	209	111	113	113	113
12	591	Maintenance of Structures	14	158	607	1,136	1,202	229	236	243	244
13	592	Maintenance of Station Equipment	16,993	16,833	16,400	18,939	14,493	18,672	19,366	20,184	20,011
14	593	Maintenance of Overhead Lines	42,383	38,297	35,392	39,326	48,466	42,100	40,536	41,234	41,940
15	594	Maintenance of Underground Lines	22,698	14,552	21,619	22,118	24,338	16,213	20,080	20,998	20,266
16	595	Maintenance of Line Transformers	6,446	3,057	2,779	2,915	2,321	1,214	1,240	1,265	1,292
17	596	Rout Maint of Street Lighting & Signal System	4,879	3,539	3,422	1,222	1,683	564	583	592	604
18	597	Maintenance of Meters	842	508	755	912	774	1,525	1,579	1,624	1,676
19	598	Maintenance of Miscellaneous Distribution Plant	2,263	4,528	4,305	2,291	3,068	2,712	2,635	2,922	3,041
20	901	Supervision - Customer Exp	-	-	-	-	-	-	-	-	-
21	902	Meter Reading Expenses	990	890	908	774	795	881	873	894	896
22	903	Customer Records and Collection Expenses	77,889	75,040	74,393	72,840	76,614	85,190	88,008	85,003	86,287
23	904	Uncollectible Accounts	6,328	4,906	15,281	8,551	20,133	12,592	11,439	11,059	9,484
24	905	Miscellaneous Customer Accounts Expenses	-	-	-	-	-	-	-	-	-
25	907	Supervision - Cust Svc & Info	-	-	-	-	-	-	-	-	-
26	908	Customer Assistance Expenses	4,617	4,855	5,780	6,743	5,856	5,551	5,646	5,721	5,814
27	909	Informational & Instructional Adertising Expenses	2,099	1,198	884	538	460	299	325	382	402
28	910	Miscellaneous Customer Service & Information Exp	-	-	-	-	-	-	-	-	-
29	911	Supervision - Sales Expense	-	-	-	-	-	-	-	-	-
30	912	Demonstrating and Selling Expenses	-	-	-	-	-	-	-	-	-
31	913	Advertising Expenses	-	-	-	-	-	-	-	-	-
32	920	Administrative and General Salaries	5,452	6,622	5,761	6,700	5,605	7,213	6,690	6,837	7,130
33	921	Office Supplies and Expenses	6,501	5,161	6,743	6,025	5,168	2,441	2,650	2,767	2,723
34	923	Outside Services Employed	123,659	111,895	115,334	108,174	108,782	133,878	141,497	144,627	149,793
35	924	Property Insurance	1,007	907	1,314	1,509	1,387	2,476	2,714	2,972	3,210
36	925	Injuries and Damages	4,068	3,133	1,258	890	3,656	2,310	2,356	2,453	2,510
37	926	Employee Pension and Benefits	16,489	20,379	16,914	13,384	12,391	20,750	20,056	20,573	20,483
38	928	Regulatory Commission Expenses	3,926	6,561	7,199	1,001	2,681	2,552	2,234	2,260	1,106
39	929	Duplicate Charges Credit	-	-	-	-	-	-	-	-	-
40	930	General Advertising Expenses	874	1,945	1,386	1,794	1,405	1,388	1,498	1,579	1,637
41	930	Miscellaneous General Expenses	1,605	1,294	1,125	1,426	1,017	203	209	215	230
42	931	Rents	-	-	(13)	-	-	-	-	-	-
43	935	Maintenance of General Plant	65	-	38	207	485	77	79	82	84
44		Total Distribution	$ 404,862	$ 412,958	$ 400,860	$ 386,146	$ 411,040	$ 430,227	$ 441,978	$ 446,474	$ 452,218

Source:
Pepco response to OPC Data Requests 13-1, 13-2, and 13-5. Provided in Exhibit OPC (B)-4.

Potomac Electric Power Company

Labor and Non-Labor O&M Expenses
($000)

Line	Description	Historical 2018 (1)	Historical 2019 (2)	Historical 2020 (3)	Historical 2021 (4)	Historical 2022 (5)	Bridge 2023 (6)	MYP 2024 (7)	MYP 2025 (8)	MYP 2026 (9)
	Total Distribution O&M By Function									
1	Distribution	$ 241,216	$ 255,063	$ 243,802	$ 245,037	$ 268,463	$ 256,938	$ 261,994	$ 262,108	$ 263,313
2	Distribution Portion of A&G	163,645	157,895	157,058	141,110	142,577	173,289	179,983	184,365	188,905
3	Total	$ 404,862	$ 412,958	$ 400,860	$ 386,146	$ 411,040	$ 430,227	$ 441,978	$ 446,474	$ 452,218
	Base Labor and Overtime (OT)									
4	PEPCO Base Labor in Distribution	$ 51,697	$ 49,273	$ 47,161	$ 47,235	$ 44,960	$ 51,005	$ 51,934	$ 55,392	$ 57,835
5	PEPCO Base Labor in Dist Portion of A&G	2,812	5,834	8,137	8,595	8,438	7,446	8,044	8,217	8,196
6	PEPCO OT Labor in Distribution	9,938	9,132	7,309	7,221	6,892	6,763	6,986	6,888	6,891
7	PEPCO OT Labor in Dist Portion of A&G	87	173	194	117	132	257	261	276	285
8	PHISCO to Pepco Base Labor in Distribution	12,061	10,795	11,654	12,414	13,591	16,184	16,905	17,922	18,452
9	PHISCO to Pepco Base Labor in Dist Portion of A&G	16,646	19,169	16,351	16,893	15,517	19,428	20,174	20,707	21,180
10	PHISCO to Pepco OT Labor in Distribution	238	118	147	200	205	167	168	170	172
11	PHISCO to Pepco OT Labor in Dist Portion of A&G	119	131	151	114	48	93	120	122	124
12	BSC to Pepco Base Labor in Dist Portion of A&G	17,155	18,477	19,547	18,809	20,450	33,793	35,909	37,200	38,173
13	BSC to Pepco OT Labor in Dist Portion of A&G	247	184	145	162	604	404	403	362	263
14	Total	$ 111,000	$ 113,286	$ 110,796	$ 111,760	$ 110,837	$ 135,539	$ 140,905	$ 147,256	$ 151,569
	Total Base Labor and OT by Function									
15	Total Labor in Distribution	$ 73,934	$ 69,318	$ 66,271	$ 67,070	$ 65,648	$ 74,118	$ 75,993	$ 80,372	$ 83,349
16	Total Labor in Dist Portion of A&G	37,066	43,968	44,525	44,690	45,189	61,421	64,911	66,884	68,221
17	Total Base Labor and OT by Function	111,000	113,286	110,796	111,760	110,837	135,539	140,905	147,256	151,569
	Non- Base Labor and OT Distribution O&M by Function									
18	Distribution	$ 167,283	$ 185,745	$ 177,531	$ 177,967	$ 202,815	$ 182,821	$ 186,001	$ 181,736	$ 179,964
19	Distribution Portion of A&G	126,579	113,927	112,533	96,420	97,388	111,868	115,072	117,482	120,685
20	Total	$ 293,862	$ 299,672	$ 290,064	$ 274,387	$ 300,204	$ 294,688	$ 301,073	$ 299,218	$ 300,649

Source:
Pepco response to OPC Data Requests 13-1, 13-2, and 13-5. Provided in Exhibit OPC (B)-4.

Potomac Electric Power Company

PHI Service Company

Schedule XVII-Analysis of Billing-Associate Companies

Line	Name of Associate Company	2018 (1)	2019 (2)	2020 (3)	2021 (4)	2022 (5)
1	Potomac Electric Company	$168,104,640	$156,860,379	$145,829,374	$144,319,934	$146,230,520
2	Delmarva Power & Light Company	$135,965,026	$120,505,027	$114,577,718	$120,310,064	$120,812,870
3	Atlantic City Electric Company	$119,339,831	$108,464,539	$102,893,978	$105,337,269	$105,181,457
4	Exelon Business Services Company, LLC	$8,808,630	$8,576,489	$8,429,626	$8,303,550	$7,372,355
5	Pepco Holdings LLC	$1,124,341	$105,957	$130,066	$42,167	$327,852
6	Constellation NewEnergy, Inc.	$759,294	$637,174	$105,785	$104,125	$0
7	PECO Energy Company	$23,368	$56,696	$42,921	$78,880	$75,881
8	Baltimore Gas and Electric Company	$21,932	$43,658	$25,080	$109,486	$141,938
9	Commonwealth Edison Company	$12,999	$141,111	$123,597	$199,390	$184,747
10	Exelon Generation Company, LLC	$0	$16,598	$0	$0	$0
11	Aerolab Enterprises	$0	$0	$7,225	$0	$0
12	Conective Property & Investments, Inc	$0	$0	$0	$22,176	$11,458
13	Exelon Corporation	$0	$0	$0	$11,758	$0
14	Exelon Generation Power	$0	$0	$0	$0	$2,472
15	Conectiv LLC	$0	$0	$0	$0	$1,915
16	**Total**	**$434,160,061**	**$395,407,628**	**$372,165,370**	**$378,838,799**	**$380,343,465**
17	**Percent Change**		**-8.93%**	**-5.88%**	**1.79%**	**0.40%**
18	**Potomac Electric Power Company of Total C**	**38.72%**	**39.67%**	**39.18%**	**38.10%**	**38.45%**

Source:
Federal Energy Regulatory Commission Form 60, Schedule XVII.

Potomac Electric Power Company

Exelon Business Service Company
Schedule XVII-Analysis of Billing-Associate Companies

Line	Name of Associate Company	2018 (1)	2019 (2)	2020 (3)	2021 (4)	2022 (5)
1	Aerolab Enterprises, LLC	$460,902	$4,490,809	$9,064,414	$14,678,237	$0
2	Atlantic City Electric Co.	$63,406,304	$62,729,485	$85,255,324	$85,949,594	$110,610,624
3	ATNP Finance Company	$5,295	$5,949	$2,681	$2,185	$6,658
4	Baltimore Gas and Electric Company	$236,438,860	$282,477,391	$303,091,592	$281,355,062	$326,162,004
5	BGE Home Products & Services, LLC	$562,980	$2,375,787	$1,500,027	$1,797,010	$146,875
6	CER Generation LLC (Hillabee)	$31,992	$20,527	$235,420	$237,670	$2,115
7	Cltn Battery Utility, LLC	$8,018	$35,663	$0	$0	$0
8	Colorado Bend II Power, LLC.	$99,580	$9,485	$0	$0	$0
9	Commonwealth Edison Company	$399,373,621	$411,886,492	$471,971,897	$510,488,739	$632,220,535
10	Constellation Energy Comm Grp.	$69,985,189	$63,784,161	$54,221,159	$46,082,720	$3,591,406
11	Constellation Energy Nuclear Group, LLC (dba CENG, LLC)	$8,143,824	$4,122,499	$3,738,272	$5,042,269	$295,861
12	Constellation Mystic Pwr, LLC	$1,209,512	$522,104	-$527	$20,629	$0
13	Constellation NewEnergy, Inc	$63,094,735	$58,043,642	$56,402,244	$62,472,071	$5,045,392
14	Constellation Power Source Gen.	$426,955	$101,928	$150,132	$0	$0
15	Constellation Power, Inc.	$79,956	$73,460	$67,391	$92,223	$7,993
16	Data Center Enterprises, LLC	$410,178	$1,483,139	$1,421,404	-$68	$0
17	Delmarva Power & Light Co.	$82,073,990	$79,722,604	$104,830,135	$104,016,618	$115,898,297
18	Exelon Corporation	$11,495,040	$9,892,453	$10,962,281	$37,857,018	$54,294,819
19	Exelon Enterprises Company,LLC	$2,304	$5,400	$4,082	$3,084	$29,002
20	Exelon Framingham, LLC	$32,671	-$12	$164	$533	$51
21	Exelon Generation Company, LLC	$594,099,463	$517,014,636	$510,272,188	$613,389,082	$47,757,895
22	Exelon Generation Finance Company, LLC	$6,798	$5,816	$3,167	$3,237	$0
23	Exelon Generation Texas Power, LLC.	$32,234	$0	$0	$0	$0
24	ExGen Handley Power, LLC	$140,902	$96,727	$0	$0	$0
25	Exelon Nuclear Security, LLC.	$4,503	$0	$0	$15	$0
26	Exelon PowerLabs, LLC	$26,506	$2,971	$2,365	$3,927	$374
27	Exelon Transmission Company, LLC	$950,015	-$24,262	$66,096	$15,274	$6,037
28	Exelon West Medway, LLC	$26,955	$2,084	$1,613	$3,039	$302
29	Exelon West Medway II, LLC	$425,177	$323,968	$88,967	-$3,158	$0
30	Exelon Wind, LLC	$2,376,531	$2,396,507	$1,933,249	$2,054,689	$115,589
31	Exelon Wyman, LLC	$40	$18	$11	$21	$4
32	EZEV Enterprise, LLC	$477,661	$1,727,095	$74,111	$0	$0
33	Handsome Lake Energy, LLC	$139,381	$13,368	$0	$0	$0
34	PECO Energy Company	$209,665,693	$236,831,119	$227,604,455	$250,988,138	$313,827,052
35	PEPCO Holdings Inc.	$8,356,557	$5,717,103	$6,153,935	$5,732,568	$5,763,325
36	PHI Service Company.	$49,764,368	$31,848,553	$24,741,074	$24,900,274	$27,161,375
37	Potomac Electric Power Co.	$133,318,147	$128,202,052	$140,483,051	$146,394,653	$170,458,866
38	Wolf Hollow II Power, LLC.	$191,805	$83	$0	$0	$0
39	Distrigas of Massachusetts LLC	$0	$242,749	$228,200	$246,818	$4,144
40	Exelorate Enterprises, LLC.	$0	$2,963,967	$0	$0	$0
41	Exelon Solar Chicago, LLC	$0	$44,894	$15,824	$13,420	$0
42	ExTex LaPorte Limited Partnership	$0	$23,758	$0	$0	$0
43	Breakerbox, LLC.	$0	$0	$195	$6,502	$0
44	Exelorate Enterprises, LLC	$0	$0	$5,284,543	$2,898,782	$327,449
45	Exelon New Boston, LLC	$0	$0	$0	$73	$6
46	Exelon New England Holdings, LLC	$0	$0	$0	$27	$2
47	RITELine Transmission Development, LLC	$0	$0	$0	$2	-$2
48	Constellation Solar Holdings, LLC.	$0	$0	$0	$0	$0
49	Exelon Clearsight, LLC	$0	$0	$0	$0	$1,562,022
50	**Total**	**$1,937,344,642**	**$1,909,216,172**	**$2,019,871,136**	**$2,196,742,977**	**$1,815,296,072**
51	**Percent Change**		**-1.45%**	**5.80%**	**8.76%**	**-17.36%**
52	**Potomac Electric Power Company of Total Cost**	**6.88%**	**6.71%**	**6.96%**	**6.66%**	**9.39%**

Source:
Federal Energy Regulatory Commission Form 60, Schedule XVII.

Potomac Electric Power Company

Multi-Year Plan Service Company Charges Adjustment

Line	Year	PHISCO Allocated to Pepco (1)	BSC Allocated to Pepco (2)	Total Charges (3)	Adjustment (4)	Revised Total Charges (5)	Allocation Factor (6)	D.C. Distribution Impact (7)
1	2022	$29,360,783	$21,053,476	$50,414,259		$50,414,259		
2	2023	35,871,323	34,197,238	70,068,561		70,068,561		
3	2024	37,366,831	36,312,413	73,679,244	(3,610,683)	70,068,561	44%	(1,573,021)
4	2025	38,921,097	37,561,797	76,482,894	(6,414,333)	70,068,561	44%	(2,790,431)
5	2026	39,927,851	38,435,184	78,363,035	(8,294,474)	70,068,561	44%	(3,658,005)

Source:
Pepco response to OPC Data Requests 13-1, 13-2, and 13-5. Provided in Exhibit OPC (B)-4.

Potomac Electric Power Company

Multi-Year Plan Regulatory Assets Adjustment
COVID-19 Regulatory Asset - ($000)

Line	Description		MYP Year 1 12 ME Dec 31, 2024 (1)	MYP Year 2 12 ME Dec 31, 2025 (2)	MYP Year 3 12 ME Dec 31, 2026 (3)
	Pepco Proposed				
	Earnings				
1	COVID Costs Deferred Balance - Actual through October 2021	$ 12,746			
2	Adjustment to Amortization Expense (5 year amortization period)		$ 2,549	$ 2,549	$ 2,549
3	Adjustment to D.C. Income Tax Expense		$ (210)	$ (210)	$ (210)
4	Adjustment to Federal Income Tax Expense		$ (491)	$ (491)	$ (491)
5	Total Earnings		$ (1,848)	$ (1,848)	$ (1,848)
	Rate Base				
6	Average DC regulatory asset balance	$ 12,746			
7	Decline in balance After Year 1	(1,275)			
8	Total average unamortized rate base balances		$ 11,471	$ 8,922	$ 6,373
9	Adjustment to accumulated deferred income taxes		(3,157)	(2,455)	(1,754)
10	Adjustment to rate base, net of accumulated deferred taxes		8,314	6,467	4,619
11	Total Rate Base		$ 8,314	$ 6,467	$ 4,619
12	**Revenue Requirement Impact**		**$ 3,372**	**$ 3,190**	**$ 3,008**
	Adjusted				
	Earnings				
13	COVID Costs Deferred Balance - Actual through October 2021	$ 12,746			
14	Adjustment to Amortization Expense (6 year amortization period)		$ 2,124	$ 2,124	$ 2,124
15	Adjustment to D.C. Income Tax Expense		$ (175)	$ (175)	$ (175)
16	Adjustment to Federal Income Tax Expense		$ (409)	$ (409)	$ (409)
17	Total Earnings		$ (1,540)	$ (1,540)	$ (1,540)
	Rate Base				
18	Average DC regulatory asset balance	$ 12,746			
19	Decline in balance After Year 1	(1,062)			
20	Total average unamortized rate base balances		$ 11,684	$ 9,560	$ 7,436
21	Adjustment to accumulated deferred income taxes		(3,215)	(2,631)	(2,046)
22	Adjustment to rate base, net of accumulated deferred taxes		8,469	6,929	5,390
23	Total Rate Base		$ 8,469	$ 6,929	$ 5,390
24	**Revenue Requirement Impact**		**$ 2,962**	**$ 2,811**	**$ 2,659**
25	**Difference**		**$ (410)**	**$ (379)**	**$ (348)**

Source:
PEPCO (B), RMA 17.

Potomac Electric Power Company

Multi-Year Plan Regulatory Assets Adjustment
EDIT Balance - ($000)

Line	Description	MYP Year 1 12 ME Dec 31, 2024 (1)	MYP Year 2 12 ME Dec 31, 2025 (2)	MYP Year 3 12 ME Dec 31, 2026 (3)
	Pepco Proposed			
	Earnings			
1	5-Year Excess Deferred Income Tax Balance (Regulatory Asset)			
2	Non-Property Related (5 year amortization)	$ 750	$ 750	$ 750
3	Adjustment to Amortization expense	$ 150	$ 150	$ 150
4	Adjustment to D.C. Income Tax Expense	$ (12)	$ (12)	$ (12)
5	Adjustment to Federal Income Tax Expense	(29)	(29)	(29)
6	Total Earnings	$ (109)	$ (109)	$ (109)
	Rate Base			
7	DC Regulatory Asset Balance	$ 750	$ 750	$ 750
8	Decrease in balance due to amortization expense	(150)	(300)	(450)
9	Net Rate Base Impact - DC Regulatory Asset	$ 600	$ 450	$ 300
10	Average Rate Base	$ 300	$ 525	$ 375
11	Adjustment to accumulated deferred income taxes	(83)	(144)	(103)
12	Adjustment to rate base, net of accumulated deferred taxes	$ 217	$ 381	$ 272
13	Total Rate Base	$ 217	$ 381	$ 272
14	**Revenue Requirement Impact**	**$ 172**	**$ 188**	**$ 177**
	Adjusted			
	Earnings			
15	5-Year Excess Deferred Income Tax Balance (Regulatory Asset)			
16	Non-Property Related (5 year amortization)	$ 750	$ 750	$ 750
17	Adjustment to Amortization expense	$ 125	$ 125	$ 125
18	Adjustment to D.C. Income Tax Expense	$ (10)	$ (10)	$ (10)
19	Adjustment to Federal Income Tax Expense	(24)	(24)	(24)
20	Total Earnings	**$ (91)**	**$ (91)**	**$ (91)**
	Rate Base			
21	DC Regulatory Asset Balance	$ 750	$ 750	$ 750
22	Decrease in balance due to amortization expense	(125)	(250)	(375)
23	Net Rate Base Impact - DC Regulatory Asset	$ 625	$ 500	$ 375
24	Average Rate Base	$ 313	$ 563	$ 438
25	Adjustment to accumulated deferred income taxes	(86)	(155)	(121)
26	Adjustment to rate base, net of accumulated deferred taxes	$ 227	$ 408	$ 317
27	Total Rate Base	**$ 227**	**$ 408**	**$ 317**
28	**Revenue Requirement Impact**	**$ 148**	**$ 166**	**$ 157**
29	**Difference**	**$ (24)**	**$ (22)**	**$ (20)**

Source:
PEPCO (B), RMA 20.

Potomac Electric Power Company

Multi-Year Plan Regulatory Assets Adjustment
Electric Vehicle Regulatory Asset - ($000)

Line	Description	MYP Year 1 12 ME Dec 31, 2024 (1)	MYP Year 2 12 ME Dec 31, 2025 (2)	MYP Year 3 12 ME Dec 31, 2026 (3)
	Pepco Proposed			
	Earnings			
1	Electric Vehicle Costs Deferred Balance	$ 3,571	$ 3,571	$ 3,571
2	Adjustment to Amortization Expense (5 year amortization period)	$ 714	$ 714	$ 714
3	Adjustment to D.C. Income Tax Expense	$ (59)	$ (59)	$ (59)
4	Adjustment to Federal Income Tax Expense	$ (138)	$ (138)	$ (138)
5	Total Earnings	$ (517)	$ (517)	$ (517)
	Rate Base			
6	Electric Vehicle Costs Deferred Balance (Regulatory Asset)	$ 3,571	$ 3,571	$ 3,571
7	Decrease in balance due to amortization expense	(714)	(1,428)	(2,142)
8	Net Rate Base Impact - DC Regulatory Asset	$ 2,857	$ 2,143	$ 1,429
9	Average Rate Base	$ 2,452	$ 2,500	$ 1,786
10	Adjustment to accumulated deferred income taxes	(675)	(688)	(491)
11	Adjustment to rate base, net of accumulated deferred taxes	$ 1,777	$ 1,812	$ 1,295
12	Total Rate Base	$ 1,777	$ 1,812	$ 1,295
13	**Revenue Requirement Impact**	**$ 889**	**$ 893**	**$ 842**
	Adjusted			
	Earnings			
14	Electric Vehicle Costs Deferred Balance	$ 3,571	$ 3,571	$ 3,571
15	Adjustment to Amortization Expense (6 year amortization period)	$ 595	$ 595	$ 595
16	Adjustment to D.C. Income Tax Expense	$ (49)	$ (49)	$ (49)
17	Adjustment to Federal Income Tax Expense	$ (115)	$ (115)	$ (115)
18	Total Earnings	$ (431)	$ (431)	$ (431)
	Rate Base			
19	Electric Vehicle Costs Deferred Balance (Regulatory Asset)	$ 3,571	$ 3,571	$ 3,571
20	Decrease in balance due to amortization expense	(595)	(1,190)	(1,785)
21	Net Rate Base Impact - DC Regulatory Asset	$ 2,976	$ 2,381	$ 1,786
22	Average Rate Base	$ 2,512	$ 2,679	$ 2,084
23	Adjustment to accumulated deferred income taxes	(691)	(737)	(573)
24	Adjustment to rate base, net of accumulated deferred taxes	$ 1,821	$ 1,942	$ 1,511
25	Total Rate Base	$ 1,821	$ 1,942	$ 1,511
26	**Revenue Requirement Impact**	**$ 775**	**$ 787**	**$ 745**
27	**Difference**	**$ (114)**	**$ (106)**	**$ (97)**

Source:
PEPCO (B), RMA 23.

Potomac Electric Power Company

Traditional Test Year Annualized Sales

Line	Month	Rate Class: R (1)	MMA (2)	GS ND (3)	GS LV (4)	GS 3A (5)	MGT LV (6)	GT LV (7)	GT 3A (8)	GT 3B (9)
	Monthly Number of Customers									
1	Jan-23	309,951	52,534	18,563	4,461	5	3,490	341	153	1
2	Feb-23	310,373	52,522	18,563	4,461	5	3,496	340	153	1
3	Mar-23	311,232	52,522	18,552	4,464	5	3,504	343	154	1
4	Apr-23	311,573	52,518	18,537	4,461	5	3,502	344	154	1
5	May-23	311,744	52,429	18,638	4,333	5	3,521	343	154	1
6	Jun-23	311,520	52,429	18,648	4,341	5	3,521	343	153	1
7	Jul-23	313,365	52,375	18,543	4,397	6	3,460	348	150	1
8	Aug-23	313,947	52,348	18,545	4,389	6	3,460	349	150	1
9	Sep-23	314,529	52,321	18,545	4,381	6	3,460	350	150	1
10	Oct-23	315,111	52,293	18,544	4,373	6	3,460	351	150	1
11	Nov-23	315,693	52,266	18,544	4,365	6	3,460	352	150	1
12	Dec-23	316,276	52,239	18,544	4,357	6	3,460	353	150	1
	2023 BSA Revenue per Customer Targets									
13	Jan-23	$ 28.76	$ 22.32	$ 78.74	$ 606.30	$ 847.31	$ 4,130.41	$ 29,514.47	$ 35,450.90	$ 49,673.63
14	Feb-23	26.78	20.73	76.17	619.42	850.69	4,173.14	29,233.04	32,985.08	42,640.50
15	Mar-23	25.26	19.85	77.59	646.01	880.03	4,468.95	29,937.95	36,388.66	44,453.42
16	Apr-23	23.86	21.07	74.66	597.08	780.29	4,158.31	27,257.93	33,442.60	45,531.38
17	May-23	21.84	21.30	76.16	640.48	830.91	4,440.78	27,927.79	35,621.63	50,642.38
18	Jun-23	27.95	21.14	86.59	660.29	875.60	4,051.58	25,902.25	33,481.98	46,734.29
19	Jul-23	32.00	20.17	97.02	778.52	965.16	4,657.01	31,115.81	38,998.45	44,654.63
20	Aug-23	33.53	20.63	109.94	922.44	1,122.98	5,455.29	38,588.26	47,668.67	65,744.57
21	Sep-23	30.98	23.49	88.01	663.24	816.45	3,875.16	27,679.45	33,267.20	51,814.17
22	Oct-23	24.80	21.48	86.60	691.89	929.24	4,174.09	28,518.10	35,730.86	44,966.44
23	Nov-23	22.83	18.65	75.13	620.42	754.87	4,173.07	28,011.31	33,889.95	16,239.68
24	Dec-23	24.88	19.11	70.95	551.84	739.11	3,734.90	26,047.30	30,591.80	38,589.24
	Pepco Revenue Forecast									
25	Jan-23	$ 8,914,191	$ 1,172,559	$ 1,461,651	$ 2,704,704	$ 4,237	$ 14,415,131	$ 10,064,434	$ 5,423,988	$ 49,674
26	Feb-23	8,311,789	1,088,781	1,413,944	2,763,233	4,253	14,589,297	9,939,234	5,046,717	42,641
27	Mar-23	7,861,720	1,042,562	1,439,450	2,883,789	4,400	15,659,201	10,268,717	5,603,854	44,453
28	Apr-23	7,434,132	1,106,554	1,383,972	2,663,574	3,901	14,562,402	9,376,728	5,150,160	45,531
29	May-23	6,808,489	1,116,738	1,419,470	2,775,200	4,155	15,635,986	9,579,232	5,485,731	50,642
30	Jun-23	8,706,984	1,108,349	1,614,730	2,866,319	4,378	14,265,613	8,884,472	5,122,743	46,734
31	Jul-23	10,027,680	1,056,404	1,799,042	3,423,152	5,791	16,113,255	10,828,302	5,849,768	44,655
32	Aug-23	10,526,643	1,079,939	2,038,837	4,048,589	6,738	18,875,303	13,467,303	7,150,301	65,745
33	Sep-23	9,744,108	1,229,020	1,632,145	2,905,654	4,899	13,408,054	9,687,808	4,990,080	51,814
34	Oct-23	7,814,753	1,123,254	1,605,910	3,025,635	5,575	14,442,351	10,009,853	5,359,629	44,966
35	Nov-23	7,207,271	974,761	1,393,211	2,708,133	4,529	14,438,822	9,859,981	5,083,493	16,240
36	Dec-23	7,868,947	998,287	1,315,697	2,404,367	4,435	12,922,754	9,194,697	4,588,770	38,589
37	**Total (All Rate Classes)**		**$533,957,460**							
	Revised Revenue Forecast									
38	Jan-23	$ 9,096,098	$ 1,165,974	$ 1,460,155	$ 2,641,649	$ 5,084	$ 14,291,219	$ 10,418,608	$ 5,317,635	$ 49,674
39	Feb-23	8,469,871	1,082,914	1,412,496	2,698,813	5,104	14,439,064	10,319,263	4,947,762	42,641
40	Mar-23	7,989,132	1,036,944	1,438,829	2,814,666	5,280	15,462,567	10,568,096	5,458,299	44,453
41	Apr-23	7,546,345	1,100,676	1,384,495	2,601,478	4,682	14,387,753	9,622,049	5,016,390	45,531
42	May-23	6,907,468	1,112,691	1,412,311	2,790,571	4,985	15,365,099	9,858,510	5,343,245	50,642
43	Jun-23	8,839,914	1,104,332	1,605,725	2,876,884	5,254	14,018,467	9,143,494	5,022,297	46,734
44	Jul-23	10,120,832	1,053,661	1,799,139	3,392,012	5,791	16,113,255	10,983,881	5,849,768	44,655
45	Aug-23	10,604,734	1,077,691	2,038,727	4,019,071	6,738	18,875,303	13,621,656	7,150,301	65,745
46	Sep-23	9,798,230	1,227,094	1,632,057	2,889,737	4,899	13,408,054	9,770,846	4,990,080	51,814
47	Oct-23	7,843,645	1,122,094	1,605,910	3,014,565	5,575	14,442,351	10,066,889	5,359,629	44,966
48	Nov-23	7,220,581	974,257	1,393,211	2,703,170	4,529	14,438,822	9,887,992	5,083,493	16,240
49	Dec-23	7,868,947	998,287	1,315,697	2,404,367	4,435	12,922,754	9,194,697	4,588,770	38,589
50	**Total (All Rate Classes)**		**$535,060,544**							
51	**Difference**		**$ 1,103,083**							

Source:
PEPCO (2E)-6.

Exhibit OPC (B)-13
Formal Case No. 1176

Potomac Electric Power Company

Traditional Test Year Regulatory Assets
COVID-19 Adjustment
($000)

Line	Description		Pepco Proposed (1)	Adjusted (2)
			12 ME Dec 31, 2023	12 ME Dec 31, 2023
	Earnings			
1	Add Back Lost Revenues to Other Revenues & Bad Debt Reserve	$ 12,746	$ 12,746	$ 12,746
2	Adjustment to Amortization Expense		2,549	2,124
3	Adjustment to DC income tax expense		(210)	(175)
4	Adjustment to federal income tax expense		(491)	(409)
5	**Total Earnings**		**$ (1,848)**	**$ (1,540)**
	Rate Base			
6	Test year average unamortized rate base, net of accumulated deferred taxes:			
7	Average DC regulatory asset balance	$ 12,746		
8	Decline in balance After Year 1		(1,275)	(1,062)
9	Total average unamortized rate base balances		$ 11,471	$ 11,684
10	Adjustment to accumulated deferred income taxes		(3,157)	(3,215)
11	Adjustment to rate base, net of accumulated deferred taxes		8,314	8,469
12	**Total Rate Base**		**$ 8,314**	**$ 8,469**
13	**Revenue Requirement Impact**		**$ 3,373**	**$ 2,964**
14	**Difference**			**$ (410)**

Source:
PEPCO (2B), RMA 29.

Potomac Electric Power Company

Traditional Test Year Regulatory Assets
Electric Vehicles Adjustment
($000)

Line	Description	Pepco Proposed (1) 12 ME Dec 31, 2023	Adjusted (2) 12 ME Dec 31, 2023
	Earnings		
1	Electric Vehicle Costs Deferred Balance (Reg Asset)	$ 2,047	$ 2,047
2	Adjustment to Amortization Expense	409	341
3	Adjustment to DC income tax expense	(34)	(28)
4	Adjustment to federal income tax expense	(79)	(66)
5	**Total Earnings**	**$ (296)**	**$ (247)**
	Rate Base		
6	Average Regulatory Asset Balance - EV	$ 1,024	$ 1,024
7	Average decrease in Reg Asset Year 1	(205)	(171)
8	Average Net Rate Base Impact - DC Regulatory Asset	$ 819	$ 853
9	Adjustment to accumulated deferred income taxes	(225)	(235)
10	**Total Rate Base**	**$ 594**	**$ 618**
11	**Revenue Requirement Impact**	**$ 467**	**$ 402**
12	**Difference**		**$ (65)**

Source:
PEPCO (2B), RMA 31.

Potomac Electric Power Company

Traditional Test Year Regulatory Assets
EDIT Adjustment
($000)

Line	Description	Pepco Proposed (1)		Adjusted (2)	
	Earnings	**12 ME Dec 31, 2023**		**12 ME Dec 31, 2023**	
1	5-Year Excess Deferred Income Tax Balance (Regulatory Asset) Non-Property Related	$	775	$	775
2	Adjustment to Amortization expense		155		129
3	Adjustment to DC Income Tax expense		(13)		(11)
4	Adjustment to Federal Income Tax expense		(30)		(25)
5	**Total Earnings**	**$**	**(112)**	**$**	**(93)**
	Rate Base				
6	DC Regulatory Asset Balance	$	775	$	775
7	Increase in amortization		155		129
8	Rate Base impact of current period amortization	$	620	$	646
9	Average Rate Base - Regulatory Asset		310		323
10	Adjustment to accumulated deferred income taxes		(85)		(89)
11	**Total Rate Base**	**$**	**225**	**$**	**234**
12	**Revenue Requirement Impact**	**$**	**177**	**$**	**151**
13	**Difference**			**$**	**(25)**

Source:
PEPCO (2B), RMA 14.

Exhibit OPC (B)-14
Formal Case No. 1176

Potomac Electric Power Company

Traditional Test Year Inflation Adjustment
($000)

Line	Description	Pepco Proposed (1)	Adjusted (2)
		12 ME Dec 31, 2023	12 ME Dec 31, 2023
	Earnings		
1	Non-Labor OM Expense	$ 89,031	$ 89,031
2	Inflation Factor	3.63%	3.20%
3	Adjustment to D.C. operations and maintenance expense	$ 3,232	$ 2,849
4	Adjustment to D.C. Income Tax Expense	(267)	(235)
5	Adjustment to Federal Income Tax Expense	(623)	(549)
6	**Total Earnings**	**$ (2,342)**	**$ (2,065)**
7	**Revenue Requirement Impact**	**$ 3,231**	**$ 2,849**
8	**Difference**		**$ (382)**

Source:
PEPCO (2B), RMA 34.

Potomac Electric Power Company

BSA Deferral Adjustment
($000)

Line	Description	Pepco Proposed (1)	Adjusted (2)
		12 ME Dec 31, 2023	12 ME Dec 31, 2023
	Rate Base		
1	DC Regulatory Asset Balance	$ 113,781	$ -
2	**Total Rate Base**	**$ 113,781**	**$ -**
3	**Revenue Requirement Impact**	**$ 10,252**	**$ -**
4	**Difference**		**$ (10,252)**

Source:
PEPCO (2B), RMA 12.

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In the Matter of	§	
	§	
The Application of the Potomac	§	
Electric Power Company for	§	**Formal Case No. 1176**
Authority to Implement a Multiyear	§	
Rate Plan for Electric Distribution	§	
Service in the District of Columbia	§	

DIRECT TESTIMONY
AND SUPPORTING EXHIBITS OF
CHRISTOPHER C. WALTERS

Exhibit OPC (C)

On behalf of the
Office of the People's Counsel
for the District of Columbia

January 12, 2024

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I. INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A My name is Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Principal of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND RELEVANT EMPLOYMENT EXPERIENCE.

A This information is included in Exhibit OPC (C)-1.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing in this proceeding on behalf of the Office of the People's Counsel for the District of Columbia ("OPC").

II. SUMMARY

Q WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A My testimony will address the current market cost of equity, and resulting overall rate of return, for Potomac Electric Power Company ("Pepco" or the "Company"). My silence in regard to any issue should not be construed as an endorsement of Pepco's position

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS AND CONCLUSIONS.

A In Section III of my testimony, I review and analyze the regulated utility industry's access to capital, credit rating trends and outlooks, as well as the overall trend in the authorized Return on Equity ("ROE") for utilities throughout the country. I conclude that the trend in authorized ROEs for utilities has declined over the last several years and has remained below 10.0% more recently. I also review the impact that the Federal Reserve's (the "Fed") monetary policy actions have had on the cost of capital.

In Section IV of my testimony, I outline how a fair ROE should be established, provide an overview of the market's perception of the Company's investment risk, comment on the Company's proposed capital structure, and present the analyses I relied on to estimate an appropriate ROE for Pepco. Based on the results of several cost of equity estimation methods performed on publicly traded utility companies, I estimate the current fair market ROE for the Company to fall within the range of 9.20% to 9.90%, with a midpoint of 9.55%. This would be my recommendation under a traditional test year scenario without the BSA decoupling mechanism. Should the Commission allow Pepco to continue under a MYRP with, or without, the BSA, I would urge the Commission to adopt an ROE in the lower half of my recommended range of 9.20% to 9.55%, with a point estimate of 9.35%. This point estimate is 20 basis points below the midpoint of my recommended range and is consistent with the findings of this Commission's Order and Opinion in Formal Case No. 1156.[1]

In Section V of my testimony, I respond to the Company's witness Mr. McKenzie' estimate of the current market cost of equity for Pepco. Mr. McKenzie

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[1] In its Order and Opinion issued in Formal Case No. 1156, the Commission noted that "Also, we find that Pepco would be benefiting from the combined risk-reducing effects of the BSA and the EMRP, which further supports our recommended ROE range with a midpoint that is 25 basis points below the currently approved ROE of 9.525%.", Order No. 20755, pg. 98, para. 243.

recommends the Company be authorized an ROE of 10.40% at the Company's proposed common equity ratio of 50.50%. I demonstrate that his recommendations are excessive and should be rejected.

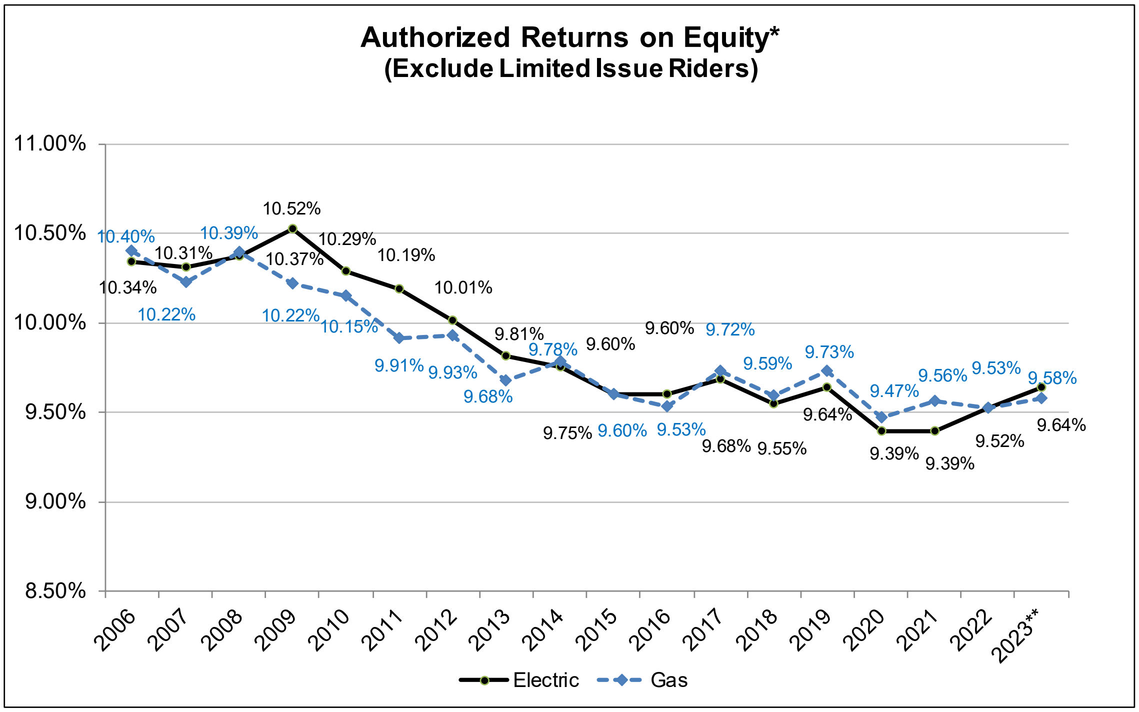
III. ACCESS TO CAPITAL AND ECONOMIC ENVIRONMENT

A. Regulated Utility Industry Authorized ROEs, Access to Capital, and Credit Strength

Q PLEASE DESCRIBE THE OBSERVABLE EVIDENCE ON TRENDS IN AUTHORIZED ROES FOR ELECTRIC AND GAS UTILITIES.

A Authorized ROEs for both electric and gas utilities have declined over the last ten years, as illustrated in Figure CCW-1, and have been below 10.0% for about the last ten years.

FIGURE CCW-1



Source and Notes:
* ROEs exclude Limited Issue Riders.
** *S&P Global Market Intelligence*, RRA Regulatory Focus, Major Rate Case Decisions -- January - June 2023, July 31, 2023 at page 4.

Q PLEASE DESCRIBE THE DISTRIBUTION OF AUTHORIZED ROES FOR ELECTRIC UTILITIES OVER THE LAST FEW YEARS.

A The distribution of authorized returns, annually, since 2016 is summarized in Table CCW-1.

TABLE CCW-1

Distribution of Authorized ROEs
(All Electric Utilities)*

Line	Year (1)	Average (2)	Median (3)	Share of Decisions ≤ 9.5%	Share of Decisions ≤ 9.7%	Share of Decisions ≤ 10.0%
1	2016	9.60%	9.60%	41%	53%	94%
2	2017[1]	9.67%	9.60%	42%	67%	81%
3	2018[2]	9.54%	9.57%	47%	63%	100%
4	2019	9.64%	9.65%	39%	58%	88%
5	2020[3]	9.38%	9.48%	64%	79%	100%
6	2021	9.39%	9.49%	58%	81%	97%
7	2022	9.52%	9.50%	53%	63%	84%
8	2023	9.61%	9.59%	38%	65%	92%
9	Average	9.54%	9.56%	48%	66%	92%
10	Median	9.57%	9.58%	45%	64%	93%

Source and Notes:
S&P Global Market Intelligence, data through October 13, 2023.
[1]Includes authorized base ROE of 9.4% for Nevada Power Company, which excludes incentives associated with the Lenzie facility.
[2]Includes authorized base ROE of 9.6% for Interstate Power & Light Co., which excludes allowed ROE for generating facilities subject to special ratemaking principles.
[3]Includes authorized base ROE of 9.8% for Interstate Power & Light Co., which excludes allowed ROE for generating facilities subject to special ratemaking principles.
*Excludes Limited Issue Rider Cases.

The distribution shows that over the last few years, the majority of authorized ROEs since 2016 have been below 9.7%, with many of those being below 9.5%.

Q HOW HAS THE AUTHORIZED COMMON EQUITY RATIO FLUCTUATED OVER THE SAME TIME PERIOD FOR UTILITIES?

A In general, the utility industry's common equity ratio has not really deviated too much from the range of 50.0% to 52.0%. As shown in Table CCW-2 below, I have provided the authorized common equity ratios for utilities around the country, excluding the reported common equity ratios for Arkansas, Florida, Indiana and Michigan because these jurisdictions include sources of capital outside of investor-supplied capital such as accumulated deferred income taxes. As such, the reported common equity ratios in these states would result in a downward bias in the reported permanent common equity ratios authorized for ratemaking purposes within my trend analysis.

TABLE CCW-2

Trends in State Authorized Common Equity Ratios
(Industry)

Line	Year	Electric[1] Average	Electric[1] Median
	(1)	(2)	(3)
1	2016	49.70%	49.99%
2	2017	50.02%	49.85%
3	2018	50.60%	50.23%
4	2019	51.55%	51.37%
5	2020	50.94%	51.17%
6	2021	51.01%	52.00%
7	2022	51.66%	51.92%
8	2023	51.68%	52.29%
9	Average	50.90%	51.10%
10	Median	50.98%	51.27%

Source and Notes:
[1] S&P Global Market Intelligence, data through October 13, 2023.
[2] Excludes Arkansas, Florida, Indiana, and Michigan, because they include non-investor capital.

Q HAVE REGULATED UTILITY COMPANIES BEEN ABLE TO MAINTAIN RELATIVELY STRONG CREDIT RATINGS DURING PERIODS OF DECLINING AUTHORIZED ROES?

A Yes. As shown below in Table CCW-3, the credit ratings of the industry have improved since 2009. In 2009, approximately 53% of the industry was rated BBB+ or higher. Currently, 82% of the industry has a rating of BBB+ or higher.[2]

TABLE CCW-3

S&P Ratings by Category
Electric Utility Subsidiaries
(Year End)

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
A or higher	12%	12%	12%	11%	13%	13%	13%	10%	10%	8%	14%	14%	10%	10%	12%
A-	18%	20%	19%	22%	26%	26%	34%	43%	52%	54%	54%	53%	37%	37%	36%
BBB+	23%	24%	28%	28%	25%	28%	24%	32%	21%	22%	18%	19%	35%	36%	35%
BBB	36%	26%	24%	22%	26%	23%	18%	4%	7%	13%	12%	3%	16%	16%	16%
BBB-	9%	16%	15%	17%	11%	11%	11%	11%	11%	2%	1%	1%	0%	0%	0%
Below BBB-	2%	2%	2%	0%	0%	0%	0%	0%	0%	0%	0%	10%	1%	1%	1%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Source: S&P CAPITAL IQ and Market Intelligence, downloaded 9/7/23.
Note: Subsidiary ratings used.

Q HAVE UTILITIES BEEN ABLE TO ACCESS EXTERNAL CAPITAL TO SUPPORT CAPITAL EXPENDITURE PROGRAMS?

A Yes. Regulatory Research Associates ("RRA"), a division of S&P Global Market Intelligence, published a financial focus document entitled "Seismic shift in capex plans reported by utilities for 2023 through 2025" on March 16, 2023. In the Capex Report, RRA made several relevant comments about the record levels of utility investments generally (underlining added):

- 2023 is anticipated to be a record year of utility industry capital investments, with the aggregated forecast for the 46 tracked energy utilities exceeding $171 billion in

[2] May not add due to rounding.

capex this year, according to the results of analysis by Regulatory Research Associates.

- 2023 forecast capital expenditures by the RRA-tracked energy utilities are expected to be the greatest spending magnitude of any year-to-date, with the anticipated aggregate capex rising more than 18% compared with the 2022 realized spending of $144 billion by these 46 tracked utilities.

- Capex in the years 2024 and 2025 is forecast to expand incrementally each year to $173.4 billion and $177.1 billion, respectively, on spending growth in electric transmission, distribution and generation assets, as well as in the renewables sector.

- The nation's electric, gas and water utilities are investing in infrastructure at record levels to upgrade aging transmission and distribution systems; build new gas, solar and wind generation; and implement new technologies, including those related to smart meter deployment, smart grid systems, cybersecurity measures, electric vehicles and battery storage. The considerable spending levels are expected to serve as the basis for solid profit expansion in the utility industry for the foreseeable future.

- Several catalysts are anticipated to impel elevated spending over the next several years, including replacement of aging infrastructure, state renewable portfolio standards, federal infrastructure investment plans and tax credits that incentivize conversion of the nation's power generation network to zero-carbon sources. The federal Inflation Reduction Act of 2022 is also expected to play a substantial role over the next decade.[3]

As shown in Figure CCW-2 below, capital expenditures for the regulated utilities have increased considerably from 2022 into 2023, and the forecasted capital expenditures remain elevated through the end of 2025.

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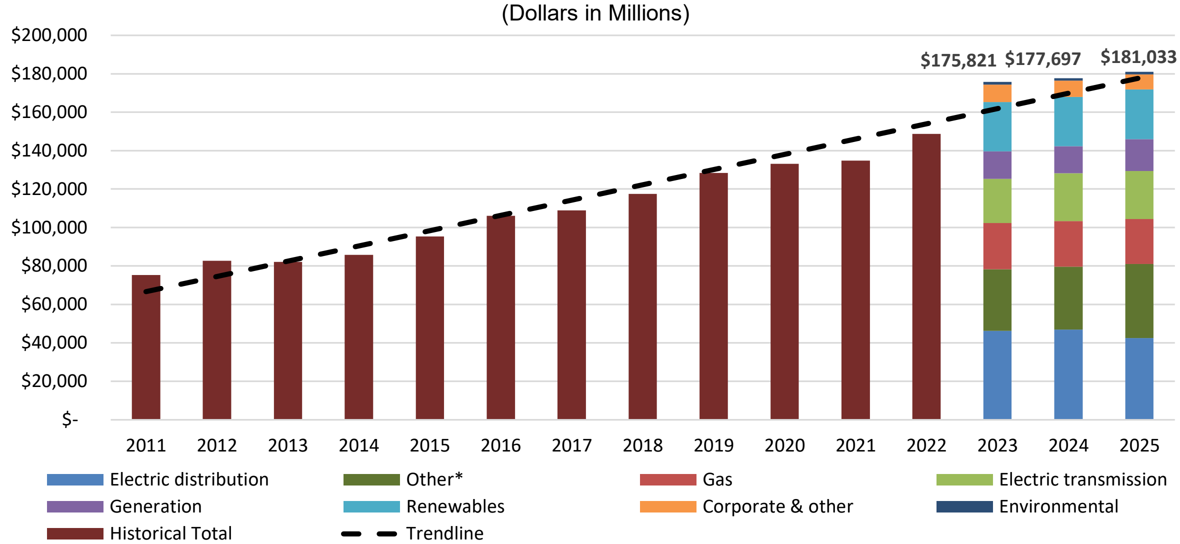
[3] S&P Global Market Intelligence "Seismic shift in capex plans reported by utilities for 2023 through 2025." March 16, 2023.

FIGURE 2

Utility Capital Expenditures
(Dollars in Millions)



*Other category consists of utilities that do not report capital expenditures by category: Avangrid, Hawaiian Electric, PG&E and Portland General Electric.
Source: *S&P Global Market Intelligence, RRA Financial Focus*, Utility Capital Expenditures Update, March 14, 2023, Tables 1 and 3.

As outlined in Figure CCW-2, and in the comments made in the Capex Report, capital investments for the utility industry continue to stay at elevated levels, and these capital expenditures are expected to fuel utilities' profit growth into the foreseeable future.

Q WHAT IS THE SIGNIFICANCE OF THESE FINDINGS?

A This is clear evidence that the capital investments are enhancing shareholder value and are attracting both equity and debt capital to the utility industry in a manner that allows for these elevated capital investments. While capital markets embrace these profit-driven capital investments, regulatory commissions also must be careful to maintain reasonable prices and tariff terms and conditions to protect customers' need for reliable utility service but at competitive and affordable tariff prices.

Q IS THERE EVIDENCE OF ROBUST VALUATIONS OF REGULATED UTILITY EQUITY SECURITIES?

A Yes. Robust valuations are an indication that utilities can sell securities at a premium, which is a strong indication that they can access equity capital under reasonable terms and conditions, and at relatively low cost. As shown on Exhibit OPC (C)-2, the historical valuation of utilities followed by *The Value Line Investment Survey* (*Value Line*)[4], based on a price-to-earnings (P/E) ratio, price-to-cash flow (P/CF) ratio, and market price-to-book value (M/B) ratio, indicates utility security valuations today are very strong and robust relative to the long-term average. These strong valuations of utility stocks indicate that utilities have access to equity capital under reasonable terms.

Q WHAT CONCLUSION DO YOU DRAW FROM THIS OBSERVABLE MARKET DATA INFORMING YOUR RECOMMENDED ROE AND OVERALL RATE OF RETURN?

A Generally, authorized ROEs, credit standing, and access to capital have been quite robust for utilities over the last several years, even throughout the duration of the global pandemic, elevated inflation, rising interest rates, and geopolitical events. It is critical that the Commission ensure that utility rates are increased no more than necessary to provide fair compensation and maintain financial integrity.

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[4] Value Line is an independent investment research and financial publishing firm that offers a broad array of investment research services and data.

B. Federal Reserve Monetary Policy

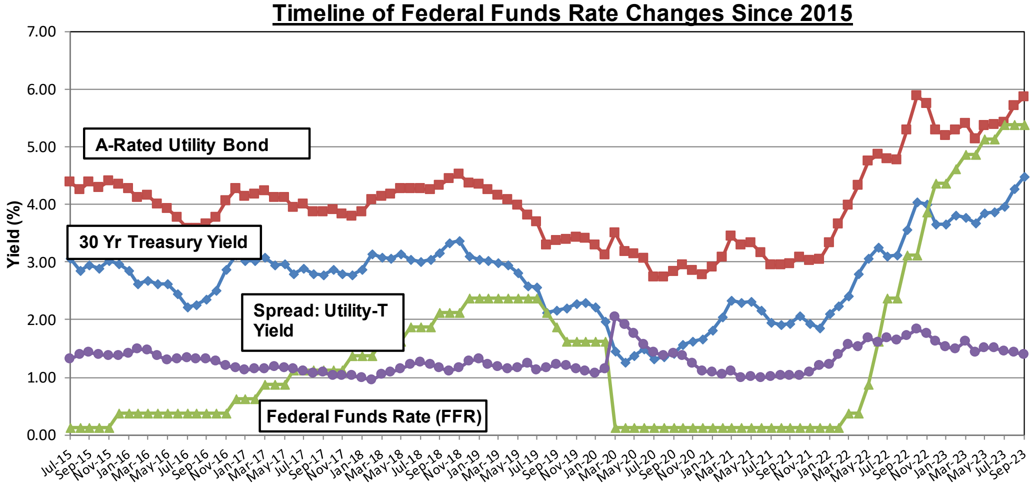
Q ARE THE FEDERAL OPEN MARKET COMMITTEE'S ("FOMC") ACTIONS KNOWN TO THE MARKET PARTICIPANTS, AND IS IT REASONABLE TO BELIEVE THEY ARE REFLECTED IN THE MARKET'S VALUATION OF BOTH DEBT AND EQUITY SECURITIES?

A Yes to both questions. The Fed has been transparent about its efforts to support the economy to achieve maximum employment, and to manage long-term inflation to around a 2% level. The Fed has implemented procedures to support the economy's efforts to achieve these policy objectives. Specifically, the Fed had previously lowered the Federal Overnight Rate for securities and had engaged in a Quantitative Easing program where the Fed was buying, on a monthly basis, Treasury and mortgage-backed securities in order to moderate the demand in the marketplaces and support the economy. Currently, the Fed is unwinding its Quantitative Easing program and taking actions towards monetary policy normalization. Such monetary policy actions include raising the target federal funds rate and allowing bonds to mature and come off its balance sheet.

A visualization of the market's reaction to the Fed's actions on the federal funds rate is shown below Figure CCW-3.

FIGURE CCW-3

Timeline of Federal Funds Rate Changes Since 2015



Fed FFR Actions:

1	December 2015	0.25	→	0.50	14	March 2020	0.00	→	0.25
2	December 2016	0.50	→	0.75	15	March 2022	0.25	→	0.50
3	March 2017	0.75	→	1.00	16	May 2022	0.75	→	1.00
4	June 2017	1.00	→	1.25	17	June 2022	1.50	→	1.75
5	December 2017	1.25	→	1.50	18	July 2022	2.25	→	2.50
6	March 2018	1.50	→	1.75	19	September 2022	3.00	→	3.25
7	June 2018	1.75	→	2.00	20	November 2022	3.75	→	4.00
8	September 2018	2.00	→	2.25	21	December 2022	4.25	→	4.50
9	December 2018	2.25	→	2.50	22	February 2023	4.50	→	4.75
10	August 2019	2.00	→	2.25	23	March 2023	4.75	→	5.00
11	September 2019	1.75	→	2.00	24	May 2023	5.00	→	5.25
12	October 2019	1.50	→	1.75	25	July 2023	5.25	→	5.50
13	March 2020	1.00	→	1.25					

Sources:
Federal Reserve Bank of New York, https://apps.newyorkfed.org/markets/autorates/fed-funds-search-page
Board of Governors of the Federal Reserve System, https://www.federalreserve.gov/datadownload/
Moody's Credit Trends, https://credittrends.moodys.com/

As shown in Figure CCW-3 above, the rise in the Federal Funds Rate has far outpaced the rise in Utility and Treasury yields while the spread of Utility bonds over Treasury bond yields have stabilized recently.

Q **HAS THE FED MADE RECENT COMMENTS CONCERNING MONETARY POLICY AND THE POTENTIAL IMPACT ON INTEREST RATES?**

A Yes. In its recent press release, the FOMC stated the following:

> Recent indicators suggest that economic activity has continued to expand at a modest pace. Job gains have been robust in recent months, and the unemployment rate has remained low. Inflation remains elevated. The U.S. banking system is sound and resilient. Tighter credit conditions for households and businesses are likely to weigh on economic activity, hiring, and inflation. The extent of these effects remains uncertain. The Committee remains highly attentive to inflation risks.
>
> The Committee seeks to achieve maximum employment and inflation at the rate of 2 percent over the longer run. In support of these goals, the Committee decided to maintain the target range for the federal funds rate at 5 to 5-1/4 percent. Holding the target range steady at this meeting allows the Committee to assess additional information and its implications for monetary policy. In determining the extent of additional policy firming that may be appropriate to return inflation to 2 percent over time, the Committee will take into account the cumulative tightening of monetary policy, the lags with which monetary policy affects economic activity and inflation, and economic and financial developments. In addition, the Committee will continue reducing its holdings of Treasury securities and agency debt and agency mortgage-backed securities, as described in its previously announced plans. The Committee is strongly committed to returning inflation to its 2 percent objective.
>
> In assessing the appropriate stance of monetary policy, the Committee will continue to monitor the implications of incoming information for the economic outlook. The Committee would be prepared to adjust the stance of monetary policy as appropriate if risks emerge that could impede the attainment of the Committee's goals. The Committee's assessments will take into account a wide range of information, including readings on labor market conditions, inflation pressures and inflation expectations, and financial and international developments.[5]

The above quotes suggest that the FOMC has recently shown signs of success in, and remains committed to, stabilizing consumer prices, and promoting maximum employment through its monetary policy tools.

5 Found here: https://www.federalreserve.gov/newsevents/pressreleases/monetary20230614a.htm, June 14, 2023.

Q WHAT DO INDEPENDENT ECONOMISTS' OUTLOOKS FOR FUTURE INTEREST RATES INDICATE?

A Independent economists, surveyed by *Blue Chip Financial Forecasts,* expect current capital costs to increase at mixed rates over the near term, while maintaining levels that are still low by historical standards. For example, independent projections show that the consensus is the federal funds rate will increase at a rate much faster than that of long-term interest rates as measured by the 30-year Treasury bond. Inflation, as measured through the Gross Domestic Product (GDP) price index, is expected to cool off in the near to intermediate term over the next six quarters.

The consensus projections for the next several quarters are provided in Table CCW-4 below.

TABLE CCW-4

Blue Chip Financial Forecasts
Projected Federal Funds Rate, 30-Year Treasury Bond Yields, and GDP Price Index

Publication Date	4Q 2021	1Q 2022	2Q 2022	3Q 2022	4Q 2022	1Q 2023	2Q 2023	3Q 2023	4Q 2023	1Q 2024	2Q 2024	3Q 2024	4Q 2024	1Q 2025
Federal Funds Rate														
Jan-22	0.1	0.1	0.3	0.5	0.7	0.9	1.1							
Feb-22	0.1	0.2	0.5	0.8	1.0	1.3	1.5							
Mar-22	**0.1**	0.2	0.6	1.0	1.3	1.6	1.8							
Apr-22		0.1	0.8	1.4	1.8	2.2	2.4	2.6						
May-22		0.1	1.0	1.7	2.2	2.6	2.9	3.0						
Jun-22		**0.1**	1.0	1.9	2.4	2.8	3.0	3.1						
Jul-22			0.7	2.4	3.1	3.5	3.5	3.5	3.4					
Aug-22			0.8	2.5	3.2	3.5	3.5	3.4	3.3					
Sep-22			**0.8**	2.5	3.4	3.6	3.6	3.5	3.4					
Oct-22				2.1	3.8	4.3	4.4	4.3	4.2	3.9				
Nov-22				2.2	3.9	4.6	4.7	4.6	4.4	4.1				
Dec-22				**2.2**	4.0	4.7	4.9	4.8	4.6	4.4				
Jan-23					3.6	4.7	5.0	4.9	4.7	4.4	4.0			
Feb-23					3.7	4.7	5.0	4.9	4.7	4.3	4.0			
Mar-23					**3.7**	4.7	5.1	5.1	5.0	4.7	4.2			
Apr-23						4.5	5.0	5.1	4.9	4.6	4.2	3.8		
May-23						4.5	5.0	5.1	5.0	4.7	4.2	3.8		
Jun-23						**4.5**	5.0	5.1	5.0	4.6	4.2	3.9		
Jul-23							5.0	5.3	5.2	5.0	4.6	4.3	3.9	
Aug-23							5.0	5.4	5.4	5.2	4.9	4.4	4.0	
Sep-23							**5.0**	5.3	5.4	5.3	5.0	4.6	4.2	
Oct-23								5.3	5.4	5.4	5.1	4.7	4.3	4.0
T-Bond, 30 yr.														
Jan-22	2.0	2.1	2.2	2.4	2.5	2.7	2.8							
Feb-22	2.0	2.2	2.3	2.5	2.6	2.7	2.8							
Mar-22	**2.0**	2.2	2.5	2.6	2.7	2.9	3.0							
Apr-22		2.3	2.6	2.8	3.0	3.2	3.3	3.3						
May-22		2.3	2.9	3.1	3.2	3.4	3.5	3.5						
Jun-22		**2.3**	3.0	3.3	3.4	3.5	3.6	3.6						
Jul-22			3.0	3.5	3.6	3.7	3.8	3.8	3.8					
Aug-22			3.0	3.2	3.4	3.5	3.5	3.5	3.5					
Sep-22			**3.0**	3.1	3.4	3.5	3.6	3.6	3.6					
Oct-22				3.2	3.8	3.9	4.0	3.9	3.8	3.8				
Nov-22				3.3	4.0	4.1	4.1	4.0	3.9	3.9				
Dec-22				**3.3**	4.0	4.2	4.2	4.1	3.9	3.9				
Jan-23					3.9	4.0	4.0	3.9	3.9	3.8	3.8			
Feb-23					3.9	3.8	3.9	3.9	3.8	3.8	3.7			
Mar-23					**3.9**	3.9	4.0	3.9	3.9	3.8	3.8			
Apr-23						3.8	3.9	3.8	3.8	3.8	3.8	3.7		
May-23						3.7	3.8	3.8	3.8	3.8	3.7	3.7		
Jun-23						**3.7**	3.8	3.8	3.8	3.8	3.8	3.7		
Jul-23							3.8	3.9	3.9	3.9	3.8	3.8	3.8	
Aug-23							3.8	4.0	3.9	4.0	3.9	3.9	3.8	
Sep-23							**3.8**	4.1	4.2	4.1	4.0	4.0	3.9	
Oct-23								4.2	4.4	4.3	4.2	4.2	4.1	4.0
GDP Price Index														
Jan-22	4.6	3.7	3.1	2.8	2.6	2.5	2.5							
Feb-22	6.9	4.3	3.4	3.0	2.8	2.6	2.5							
Mar-22	**7.1**	4.8	3.8	3.1	2.8	2.6	2.5							
Apr-22		4.8	5.1	3.7	3.0	2.8	2.6	2.6						
May-22		8.0	5.6	4.0	3.4	3.0	2.8	2.6						
Jun-22		**8.1**	5.9	4.6	3.5	3.1	2.8	2.7						
Jul-22			5.9	5.2	3.9	3.4	2.8	2.7	2.6					
Aug-22			8.7	5.3	3.8	3.3	2.7	2.7	2.6					
Sep-22			**8.9**	4.9	4.1	3.3	2.7	2.7	2.5					
Oct-22				4.9	4.3	3.5	3.0	2.8	2.7	2.5				
Nov-22				4.1	4.6	3.8	3.1	2.7	2.7	2.3				
Dec-22				**4.3**	4.3	3.8	3.0	2.7	2.6	2.3				
Jan-23					4.3	3.6	3.0	2.7	2.5	2.3	2.2			
Feb-23					3.5	3.3	3.0	2.7	2.6	2.4	2.3			
Mar-23					**3.9**	3.2	2.8	2.6	2.5	2.5	2.3			
Apr-23						3.2	3.2	2.9	2.7	2.5	2.3	2.2		
May-23						4.0	3.2	2.9	2.7	2.5	2.3	2.2		
Jun-23						**4.2**	3.3	2.8	2.7	2.5	2.5	2.2		
Jul-23							3.3	2.9	2.8	2.5	2.4	2.2	2.2	
Aug-23							2.2	2.7	2.6	2.5	2.3	2.3	2.3	
Sep-23							**2.0**	2.7	2.6	2.4	2.3	2.2	2.2	
Oct-23								2.7	2.7	2.4	2.2	2.2	2.2	2.2

Source and Note:
Blue Chip Financial Forecasts, Jan 2022 through October 2023.
Actual Yields in Bold.

Further, the outlook for long-term interest rates in the intermediate to longer term is also impacted by the current Fed actions and the expectation that eventually the Fed's monetary actions will return to more normal levels. Long-term interest rate projections are illustrated in Table CCW-5 below.

TABLE CCW-5

30-Year Treasury Bond Yield Actual Vs. Projection

Description	Actual	Near-Term Projected*	5- to 10-Year Projected
2019			
Q1	3.01%	3.50%	
Q2	2.78%	3.17%	3.6% - 3.8%
Q3	2.30%	2.70%	
Q4	2.30%	2.50%	3.2% - 3.7%
2020			
Q1	1.88%	2.57%	
Q2	1.38%	1.90%	3.0% - 3.8%
Q3	1.36%	1.87%	
Q4	1.62%	1.97%	2.8% - 3.6%
2021			
Q1	2.07%	2.23%	
Q2	2.26%	2.77%	3.5% - 3.9%
Q3	1.93%	2.63%	
Q4	1.95%	2.70%	3.4% - 3.8%
2022			
Q1	2.25%	2.87%	
Q2	3.04%	3.47%	3.8% - 3.9%
Q3	3.26%	3.63%	
Q4	3.90%	3.87%	3.9% - 4.0%
2023			
Q1	3.74%	3.77%	
Q2	3.80%	3.70%	3.8% - 3.9%

Source and Note:
Blue Chip Financial Forecasts, January 2019 through September 2023.
*Average of all 3 reports in Quarter.

As outlined in Table CCW-5, the outlook for increases in interest rates has moderated since 2021. Indeed, interest rates are expected to remain flat, or even decline over the near and intermediate term. In fact, as shown on Figure CCW-3 above, increases in the federal funds rate do not necessarily translate into increases in longer-term yields.

C. Market Sentiments and Utility Industry Outlook

Q PLEASE DESCRIBE THE CREDIT RATING OUTLOOK FOR REGULATED UTILITIES.

A Credit analysts are concerned about rate affordability, driven by increases in commodity costs within rate base or capital investments, increases in interest rates, and credit analysts' concerns about utility rate affordability to customers. Each of these current outlooks for the credit standing of utility companies is discussed related to Standard & Poor's Ratings Service (S&P), Moody's Investors Service (Moody's), and Fitch Ratings (Fitch) perspectives. Specifically, S&P Global Ratings recently issued an "Industry Top Trends" report on North American Regulated Utilities which stated as follows:

> The industry outlook remains negative and has been negative since early 2020. Over this timeframe downgrades have outpaced upgrades by more than 3:1 [...]. While the industry's percentage of negative outlooks has decreased to about 15% from 35% at year-end 2020, prolonged inflationary risks or a deeper-than-expected recession could harm the industry's credit quality in 2023.[6]

At the time, the S&P Report noted that the industry outlook was negative; that the credit quality of the industry has changed to BBB+ from an A- rating over the last

---

6 S&P Global Ratings, "Industry Top Trends Update | North America: Regulated Utilities," January 23, 2023.

few years; that interest rates have increased for utilities; and that utilities have increased the use of securitization bonds for recovering storm, hurricane, and wildfire costs. S&P notes in the Report that key assumptions in its forecasted outlook for utilities include inflation outlooks (but expects inflation to decrease to around 4% by year-end 2023), continued robust capital spending for utilities (projecting over $190 billion expected to be spent in 2023), and increasing asset sales by utilities reflecting sales in minority interests in utilities and non-utility assets. S&P believes that the risks around its outlook include uncertainty about commodity prices, regulatory risks in responding to capital spending, other rate pressures on utilities to allow them to recover their cost of service, and physical risks to utility infrastructure from weather events and wildfires.

The credit analysts also use as a credit rating factor their concern regarding customers' ability to afford to pay their utility bills. S&P notes at page 4 the following related to the credit risks in 2023 and beyond:

> *Affordability of customer bill*
>
> Customer bills may become less affordable because of rising commodity prices, interest rates, inflation, and capital spending. During 2022, Henry Hub natural gas prices, the U.S. benchmark, peaked at about $9 per mmBTU. Although prices have since retreated to about $4/mmBTU and the forward curve reflects $3.50-$4.50/mmBTU, they remain substantially higher than preinflation levels, pressuring the customer bill. While we estimate the industry's average electric bill represents only about 2.5% of after-tax household income, sharp increases and bill volatility often results in increasing customer dissatisfaction that can ultimately heighten regulatory scrutiny and constrain the industry's ability to effectively manage regulatory risk.[7]

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[7] *Id.*

Moody's had also changed the industry outlook to "Negative." Specifically, Moody's states:

> » **We have revised our outlook on the US regulated utilities sector to negative from stable.** We changed the outlook because of increasingly challenging business and financial conditions stemming from higher natural gas prices, inflation and rising interest rates. These developments raise residential customer affordability issues, increasing the level of uncertainty with regard to the timely recovery of costs for fuel and purchased power, as well as for rate cases more broadly.
>
> * * *
>
> » **What could change our outlook:** The outlook could return to stable if the sector's regulatory support remains intact, natural gas prices settle at a level where most utilities are able to fully recover fuel and purchased power costs without a delay beyond 12 months, overall inflation moderates, interest rates stabilize and/or the sector's aggregate (FFO)-to-debt ratio remains between 14% to 15%. We could change our outlook to positive if utility regulation turns broadly more credit supportive resulting in timelier cash flow recovery or we expect the sector's aggregate (FFO)-to-debt ratio to rise above 17% on a sustained basis.[8]

Fitch also revised its outlook for the utility sector due to the expectation for recession:

> Fitch Ratings sees high natural gas prices, record capital spending and rising interest rates among the cost pressures weighing on the U.S. utilities sector in 2023. The rating agency has a "deteriorating" outlook on the sector after years of a stable view.
>
> Other factors behind Fitch's outlook include the Edison Electric Institute predicting elevated levels of capital expenditures for U.S. electric utilities. EEI forecasts $154.7 billion of capital expenditures in 2022, $159.2 billion in 2023 and $155.2 billion in 2024, a sharp increase from $134.1 billion in 2021.

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[8] *Moody's Investors Service Outlook*: "Regulated Electric and Gas Utilities – US; 2023 Outlook – Negative on higher natural gas prices, inflation and rising interest rates," November 10, 2022 at page 1 (emphasis added).

> Fitch is also mindful of how a "sharp escalation" in retail rates, which have increased 14% in 2022, and bill affordability will impact credit metrics. Higher natural gas prices are a key driver of this spike in retail rates.[9]

As outlined above, S&P, Moody's, and Fitch all state concern about utilities' rates affordability as a critical aspect of utility credit rating. Rate affordability largely should be considered by the Commission in ensuring that while certain aspects of utilities' cost of service are increasing, and must be reflected in the development of rates, other aspects such as fair rate of return including ROE and ratemaking capital structure may have discretionary elements which the Commission should consider in awarding an overall rate of return that is fair and reasonable to both the utility and, its investors, and is consistent with adjusting rates with a mind toward maintaining rate affordability to customers.

More recently, S&P has upgraded the outlook for regulated utilities from "negative" to "stable" due to improving economic conditions. Specifically, S&P notes:

> More recently, economic indicators have gradually improved. Inflation is increasing at a considerably slower pace with April's consumer price index (CPI) at 4.9% compared 9.1% in June 2022. Additionally, natural gas prices have significantly retreated from August 2022 highs when prices at Henry Hub approximated $9 per MMbtu. These healthier economic developments are consistent with S&P Global economists' forecast of CPI at about 4.7% by year-end 2023. This economic strengthening is also important for the utility industry. When gas prices peaked during 2022, many utilities deferred the recovery of these higher costs and are only now starting to bill ratepayers. The recent drop in natural gas prices provides some customer bill cushion, allowing the

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[9] *S&P Capital IQPro*: "Fitch sees various cost pressures behind 'deteriorating' US utilities outlook at page 1, November 14, 2022 (emphasis added).

> utilities to bill customers for the previously deferred higher commodity costs without overwhelming the customer.[10]

In fact, in a July update, S&P further discussed the outlook for regulated utilities. Specifically, S&P notes:

> **Industry outlook.** In May we revised the industry's outlook to stable from negative, where it had been since early 2020. During the past three years, downgrades outpaced upgrades by more than 3:1 and the median industry rating fell to 'BBB+' from 'A-'. Over the next two years, we expect upgrades and downgrades will be more balanced.
>
> **Economic indicators are improving**. Over the past year, inflation increased at a slower rate and natural gas prices significantly retreated from 2022 highs of $9 per MMBtu, improving the industry's financial performance.
>
> **Credit-supportive tools reduce the impact of physical risks**. We don't expect the pace of hurricanes, wildfires, or storms to decline because of climate change. But we do expect system hardening, wildfire mitigation, higher storm reserves, self-insurance, and securitization will reduce much of the associated credit risks.[11]

D. Additional Remarks

Q PLEASE COMMENT ON RUSSIA'S INVASION OF UKRAINE AND ITS IMPACT ON THE MARKET.

A In late February 2022, Russia invaded Ukraine. The response from the United States and several other countries around the world has included several rounds of economic sanctions on Russia.

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[10] S&P Global Ratings, *The Outlook For North American Regulated Utilities Turns Stable*, May 18, 2023, at page 7.

[11] S&P Global Ratings, "Industry Top Trends Update | North America: Regulated Utilities – Credit quality should stabilize", July 18, 2023.

While the actual and ongoing impact to the markets and global economy due to the current conflict remains to be seen, research on the markets during previous wars and armed combat situations provides an idea of what can be expected.

For example, a monograph published by the CFA Institute Research Foundation concluded as follows:

> Both wars and terrorist attacks tend to have only a transitory impact on financial markets, but clear exceptions test that tendency. The macroeconomic impact of wars tends to be significantly bigger in small economies and developing countries that cannot digest the negative effects of war as easily as large, open economies—such as that of the United States—can.[12]

While it is undeniable that a level of uncertainty exists because of the conflict in Ukraine, historical evidence indicates that the impact on financial markets is generally transitory.

Q IN LIGHT OF HIGHER LEVELS OF INFLATION, EXPECTATIONS OF HIGHER INTEREST RATES, AND THE WAR IN UKRAINE, HOW HAS THE MARKET PERCEIVED UTILITIES AS INVESTMENT OPTIONS?

A In 2023, the utility sector has underperformed the S&P 500. However, it should be noted that the performance of the S&P 500 is being driven by a handful of "mega cap" companies. Because the S&P 500 is a market capitalization weighted index (meaning the higher the market capitalization a company has, the more influence it has on the index's performance.) For example, in the S&P Dow Jones Indices report "U.S. Equity Market Attributes June 2023," it is noted that:

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[12] Klement CFA, Joachim, CFA Institute Research Foundation, 2021, "Geo-Economics: The interplay of geopolitics, economics, and investments," 46 (emphasis added).

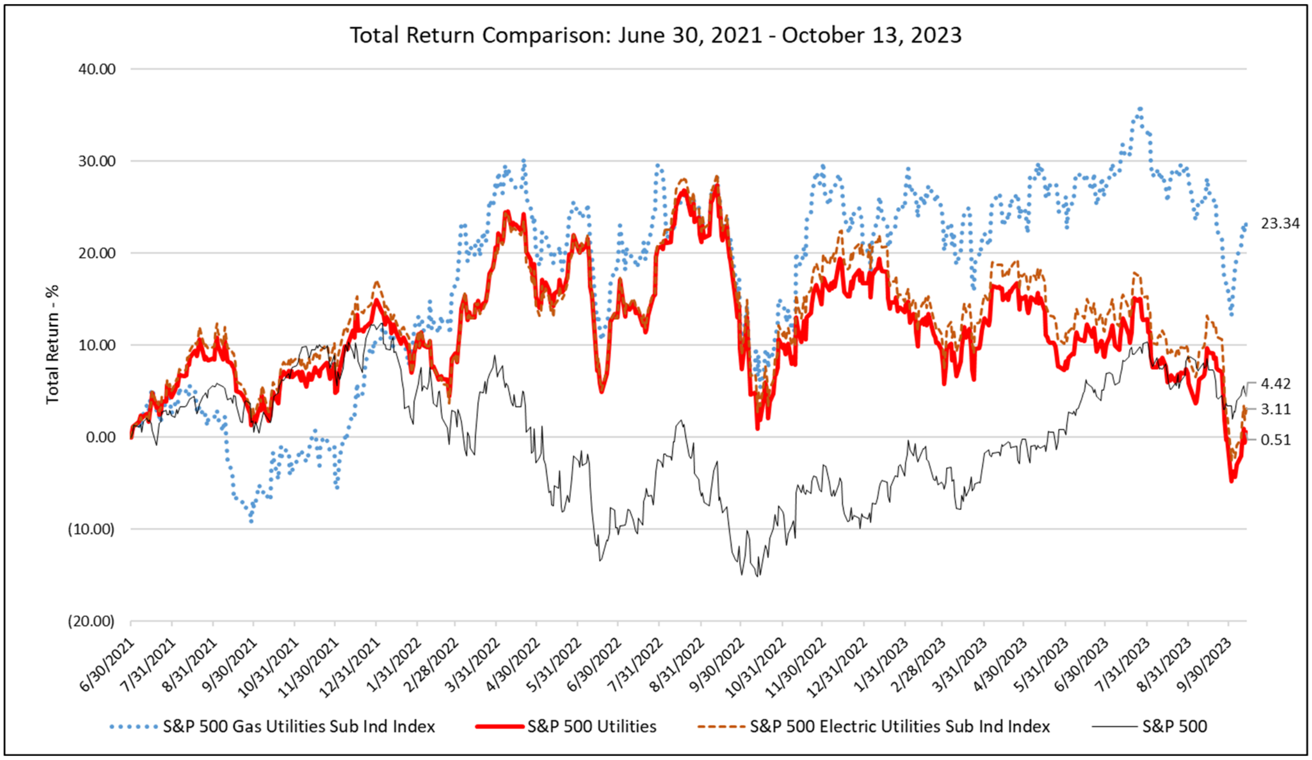
> For June, the S&P 500 total return was up 6.61%, with broad contributions across issues, compared to previous months when high-market-value issues dominated the market; underlying breadth (and contributions) remained negative. <u>That dominance still exists, as the index's total return was up 16.89% YTD, but without the top 44 issues, the index would be negative YTD, though that 44 was 8 in May.</u> Apple (AAPL) and Tesla (TSLA) were still on top for the month, with Alphabet (GOOG/L) (then Salesforce [CRM]) the largest negative contributor for the month.
>
> Meanwhile, the positive contributions were broad for June, even though they remain highly concentrated YTD. <u>The index is still top heavy, with the top 10 issues accounting for 30.5% of the market value (below 20% is more typical)</u>. Of note to the top of the market, semiconductor issue NVIDIA (NVDA) joined the USD 1 trillion in market value club this month, as Apple (which set a record at 7.72% of the index) became the first public issue to trade above USD 3 trillion in market value; the other three members of the club are Microsoft (MSFT), Alphabet and Amazon (AMZN).[13]

Notably, since the end of the second quarter 2021, utilities in general, as measured by the S&P 500 Utilities index as well as electric utilities specifically as measured by the S&P 500 Electric Utilities index, had largely performed on par with, or even outperformed the market as measured by the S&P 500. In early October, these indices experienced a significant decline due, in part, to the significant decline to the most valuable utility stock in the industry (as measured by market capitalization), NextEra Energy, which fell more than 25% in one week. Because S&P indices are value-weighted, meaning stocks with higher market capitalizations will have more weight in the index than lower market capitalization stocks, NextEra's major decline weighed heavily on the S&P utilities indices. This is presented below in Figure CCW-4. Notwithstanding that material decline, the graph below indicates that utility valuations

[13] https://www.spglobal.com/spdji/en/documents/commentary/market-attributes-us-equities-202306.pdf

remained robust, even during a period of elevated inflation, rising interest rates, and uncertainty because of geopolitical events around the world.

FIGURE CCW-4



IV. RETURN ON EQUITY

Q PLEASE DESCRIBE WHAT IS MEANT BY A "UTILITY'S COST OF COMMON EQUITY."

A A utility's cost of common equity is the expected return that investors require on an investment in the utility. Investors expect to earn their required return from receiving dividends and through stock price appreciation.

Q PLEASE DESCRIBE THE FRAMEWORK FOR DETERMINING A REGULATED UTILITY'S COST OF COMMON EQUITY.

A In general, determining a fair cost of common equity for a regulated utility has been framed by two hallmark decisions of the U.S. Supreme Court: Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944). In these decisions, the Supreme Court found that just compensation depends on many circumstances and must be determined by fair and enlightened judgments based on relevant facts. The Court also found that a utility is entitled to such rates as would permit it to earn a return on a property devoted to the convenience of the public that is generally consistent with the same returns available in other investments of corresponding risk. The Court continued that the utility has "no constitutional rights to profits" such as those "realized or anticipated in highly profitable enterprises or speculative ventures,"[14] and defined the ratepayer/investor balance as follows:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[15]

As such, a fair rate of return is based on the expectation that the utility costs reflect efficient and economical management, and the return will support its credit standing and access to capital, but the return will not be in excess of this level. Utility

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[14] *Bluefield,* 262 U.S. at 692-93.
[15] *Ibid*. at 693 (emphasis added).

rates that are consistent with these standards will be just and reasonable, and compensation to the utility will be fair and support financial integrity and credit standing, under economic management of the utility.

Q PLEASE DESCRIBE THE METHODS YOU HAVE USED TO ESTIMATE PEPCO'S COST OF COMMON EQUITY.

A I have used several models based on financial theory to estimate Pepco's cost of common equity. These models are: (1) a constant growth Discounted Cash Flow ("DCF") model using consensus analysts' growth rate projections; (2) a constant growth DCF using sustainable growth rate estimates; (3) a multi-stage growth DCF model; (4) a Risk Premium model; and (5) a Capital Asset Pricing Model ("CAPM").

A. Pepco's Investment Risk

Q PLEASE DESCRIBE THE MARKET'S ASSESSMENT OF PEPCO'S INVESTMENT RISK.

A The market's assessment of a company's investment risk is generally described by credit rating analysts' reports. The current credit ratings for Pepco, from S&P and Moody's are A- and Baa1, respectively.[16] The Company currently has a "Stable" outlook from Moody's and a "Stable" outlook from S&P. S&P notes that its "stable" outlook on Pepco reflects its expectation that the Company's stand-alone financial measures will be consistent with the middle of the range for S&P's "significant" financial risk profile category, including funds from operations ("FFO") to debt of about 16%-18%.

Specifically, in its most recent report covering Pepco, S&P states:

[16] S&P Capital IQ, accessed on February 24, 2023.

Business Risk

Our assessment reflects the company's lower-risk, rate-regulated electric T&D operations. Pepco is a midsize utility providing services to more than 900,000 customers in Washington, D.C. and surrounding areas in Maryland. The company's residential customer base, which accounts for about 35% of its revenue, provides some cash flow stability and mitigates its exposure to the economic cyclicality that tends to be more pronounced with a higher proportion of industrial customers, which accounts for less than 50%.

Its distribution operations (about 80% of utility rate base) are regulated by the D.C. and Maryland PSCs, both of which have been somewhat challenging. The reliance on fully historical test periods in rate-setting contributes to regulatory lag and difficultly in earning authorized ROEs. With the implementation of the MRP in both jurisdictions, we expect reduced regulatory lag, enhanced rate predictability, and a greater opportunity for Pepco to earn its authorized ROE. In addition, further enhancing cash flow stability, Pepco utilizes a bill stabilization adjustment mechanism in both jurisdictions to mitigate the volatility of revenues and customer bills from weather and energy efficiency programs.

Financial Risk

Our base-case scenario that includes stand-alone FFO to debt in the 16%-18% range through 2024, the middle of the benchmark range for its financial risk profile category. We expect Pepco's leverage (current adjusted debt to EBITDA in the high-4x to low-5x range) to be aggressive through 2024. However, over the same period, we expect our supplemental ratio of adjusted FFO cash interest coverage will be in the 5x-5.5x range, bolstering our financial risk profile assessment. We expect Pepco's DCF to remain negative due to its dividends and robust capital spending, indicating external funding needs that we anticipate will include debt issuances. This necessitates that Pepco has consistent access to capital markets. We assess Pepco's financial risk profile using our medial volatility financial benchmarks, reflecting lower-risk regulated utility operations and effective management of regulatory risk. These benchmarks are more relaxed than those used for typical corporate issuers.[17]

[17] *S&P RatingsDirect®:* "Full Analysis: Potomac Electric Power Co.," December 8, 2022.

Q DO YOU BELIEVE THE PRESENCE OF AN MYRP REDUCES RISK TO SHAREHOLDERS?

A Yes, I do. There is substantial evidence to suggest that MYRPs are viewed as significant risk mitigating mechanisms to utility shareholders. For example, S&P had the following to say with regard to Ameren Illinois, which is a gas and wires-only electric utility operations:

> Legislation enacted in 2021 extends the FRP framework through 2023. Thereafter, companies can opt to file traditional base rate proceedings or a multiyear rate plan that would apply over a four-year period, each based on future test periods. Earlier this year, Ameren Illinois filed for a roughly $450 million total increase over a four-year period (2024-2027) to its electric distribution rates. <u>We believe either option is credit supportive because the use of a future test period minimizes regulatory lag. However, the four-year rate plan offers added predictability of rate recovery, which lowers uncertainty for the utility company and its stakeholders and promotes regulatory stability, which reduces business risk.</u>[18]

Further, RRA (a group within S&P Capital IQ) raised its assessment of North Carolina's regulatory climate upon enactment of the legislation allowing MYRPs, writing:

> On Oct. 13, 2021, RRA raised its ranking of North Carolina to Above Average/3 from Average/1 following the signing into law of comprehensive energy legislation that provides utilities the ability to file multiyear rate plans with the commission and develop performance-based incentives, with the ability to pursue regulatory approval for increases of up to 4% over three years rather than initiating a new rate case each year. The bill also effectively solidifies North Carolina's regulated energy monopoly system, maintaining the vertically integrated public utility model and commission regulatory authority. In doing so, it shuts down, at least for now, any hopes the state might move to an unregulated/competitive power market structure. The bill (House Bill

[18] *S&P RatingsDirect®:* "Full Analysis: Ameren Illinois Co.", March 23, 2023. (emphasis added).

> 951) also provides securitization as an option to recover costs associated with retiring coal plants.[19]

Further, this Commission has recognized as much as well in its Order and Opinion in Pepco's previous MYRP proceeding stating as follows:

> Based on the record, the Commission rejects Pepco's Original MRP and determines that Pepco's EMRP with modifications that we adopt, meets the statutory requirements for approval and will result in just and reasonable rates. The Commission, therefore, approves Pepco's EMRP, as modified (Modified EMRP) to include overarching terms as follows:
>
> a. A cumulative revenue requirement of $108.6 million representing a 33% reduction in revenue requirements from Pepco's original $162.0 million MRP proposal;
>
> b. <u>An authorized ROE of 9.275% and overall ROR of 7.17% to recognize the reduction in financial risk and regulatory lag</u>[20]

Q WHAT IS YOUR SUMMARY OF PEPCO'S INVESTMENT RISK?

A Pepco has strong credit ratings from S&P and Moody's. This is a result of its lower risk utility operations that benefit from constructive credit supportive mechanisms such as a MYRP and the BSA.

B. Pepco's Proposed Capital Structure

Q WHAT IS PEPCO'S PROPOSED CAPITAL STRUCTURE?

A Pepco's proposed capital structure is summarized in Table CCW-6 below:

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19 *See, e.g., S&P Capital IQ:* "Duke Energy Carolinas files 1st NC multiyear rate request, seeking $833M," January 20, 2023.

20 Public Service Commission of The District Of Columbia, Formal Case No. 1156, Order and Opinion at para. 142. (emphasis added).

TABLE CCW-6

Investor-Supplied Capital Structure

Description	Weight
Long-Term Debt	49.50%
Common Equity	50.50%
Total	100.00%

Q **DO YOU HAVE ANY COMMENTS ON PEPCO'S PROPOSED CAPITAL STRUCTURE?**

A Yes. As I will discuss later, Pepco's proposed equity ratio of 50.50% significantly exceeds the equity ratio for the proxy group used to estimate the cost of equity for Pepco. As shown on Exhibit OPC (C)-3, the proxy group has an average common equity ratio of 39.0% (including short-term debt) and 42.9% (excluding short-term debt). The differences in financial risk need to be considered in the cost of equity estimation.

Q **ARE YOU AWARE OF OTHER REGULATORY COMMISSIONS RECOGNIZING THE NEED TO ALIGN THE COST OF EQUITY WITH THE CAPITAL STRUCTURE?**

A Yes. In a recent Order, the Arkansas Public Service Commission imputed the capital structure of Southwestern Electric Power Company ("SWEPCO") to be more in-line with the comparable companies used to estimate the cost of equity.[21] The adjustment

[21] APSC Docket No. 21-170-U, Doc. No. 323, May 23, 2022, Order No. 14.

was to recognize that there must be *congruence* between the cost of equity and the capital structure. Specifically, the Order states as follows:

> Consistent with our ruling in Order No. 10 of Docket No. 06-101-U, the Commission holds that there should be congruence between the estimated cost of equity and the [debt-to-equity "DTE")] ratio, whereby a lower DTE ratio decreases financial risk and decreases the cost of equity. The evidence of record supports imputing the average capital structure of companies with comparable risk to SWEPCO for the purposes of determining SWEPCO's overall cost of capital.[22]

As I described above, the proxy group has an average common equity ratio of 39.0% (including short-term debt) and 42.9% (excluding short-term debt) as calculated by S&P Global Market Intelligence and *Value Line*, respectively. The Company's proposed equity ratio of 50.50% (excluding short-term debt) is nearly 11 percentage points higher than that of the proxy group's comparable equity ratio. Clearly, Pepco's requested equity ratio exceeds the equity ratios of the proxy group used to assess the Company's cost of equity.

Q WHAT ARE YOUR CONCLUSIONS AS IT RELATES TO PEPCO'S PROPOSED CAPITAL STRUCTURE?

A As I explain above, the Company's proposed equity ratio of 50.50% (excluding short-term debt) significantly exceeds the equity ratios of the proxy group. While I am not making an adjustment to the capital structure, the differences in financial risk are taken into consideration of my overall recommendation.

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[22] *Ibid*. at 25.

C. Development of Proxy Group

Q PLEASE BRIEFLY DESCRIBE WHY A PROXY GROUP IS NEEDED IN ESTIMATING THE COST OF EQUITY.

A There are a few reasons why a proxy group is needed to estimate the cost of equity. As an initial matter, to be consistent with the *Hope* and *Bluefield* standards, as described above, the allowed return should be commensurate with returns on investments in other firms of comparable risk. A proxy group of similarly situated companies of comparable risk is needed to assess the Company's proposal under this standard.

Even if Pepco were a publicly traded company whose securities could be used to estimate its cost of equity, there exists the potential for certain errors and biases making the reliance on a single estimate undesirable and potentially less accurate. A proxy group of comparable risk companies adds reliability to the estimates by mitigating the potential for bias that may be introduced by measurement errors of model inputs.

Q PLEASE DESCRIBE HOW YOU IDENTIFIED A PROXY UTILITY GROUP THAT COULD BE USED TO ESTIMATE PEPCO'S CURRENT MARKET COST OF EQUITY.

A I relied on the same proxy group developed by Pepco witness Mr. McKenzie.

Q HOW DOES THE INVESTMENT RISK OF PEPCO COMPARE TO THAT OF THE PROXY GROUP?

A As shown on my Exhibit OPC (C)-3, the proxy group has average credit ratings of BBB+ and Baa2 from S&P and Moody's, respectively. The proxy group's average rating of BBB+ from S&P is one notch lower than Pepco's A- rating from S&P, as well as the Company's Stand Alone Credit Profile ("SACP") rating of 'a-' from S&P. The proxy group's average rating of Baa2 from Moody's is also one notch lower than Pepco's rating of Baa1.

As shown on the same exhibit, the proxy group has an average common equity ratio of 39.0% (including short-term debt) and 42.9% (excluding short-term debt) as calculated by S&P Global Market Intelligence and *Value Line*, respectively. Pepco's requested common equity ratio of 50.50% (excluding short-term debt) significantly exceeds the proxy group's equity ratio as described above.

The differences in financial risk as measured by book value capital structures as well as the differences in credit ratings are indicative that the Company is of lower risk than the proxy group in general. This supports the premise that an ROE in the lower half of my recommended range is necessary should the Commission continue to allow Pepco to continue under a MYRP with, or without, the BSA.

D. DCF Model

Q PLEASE DESCRIBE THE DCF MODEL.

A The DCF model posits that a stock price equals the sum of the present value of expected future cash flows discounted at the investor's required rate of return or cost of capital. This model is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} \; .\;.\;.\;. \; \frac{D_\infty}{(1+K)^\infty} \qquad \text{(Equation 1)}$$

P_0 = Current stock price
D = Dividends in periods 1 - ∞
K = Investor's required return

This model can be rearranged in order to estimate the discount rate or investor-required return, known as "K." If it is reasonable to assume that earnings and dividends will grow at a constant rate, then Equation 1 can be rearranged as follows:

$$K = D_1/P_0 + G \qquad \text{(Equation 2)}$$

K = Investor's required return
D_1 = Dividend in first year
P_0 = Current stock price
G = Expected constant dividend growth rate

Equation 2 is referred to as the annual "constant growth" DCF model.

Q PLEASE DESCRIBE THE INPUTS TO YOUR CONSTANT GROWTH DCF MODEL.

A As shown in Equation 2 above, the DCF model requires a current stock price, the expected dividend, and the expected growth rate in dividends.

Q WHAT STOCK PRICE HAVE YOU RELIED ON IN YOUR CONSTANT GROWTH DCF MODEL?

A I relied on the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on October 13, 2023. An average stock price is less susceptible to market price variations than a price at a single point in time. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not reflect the stock's long-term value. Similarly, it is not ideal to use a very long period of historical prices such that the average price reflects stale and/or information that is no longer relevant to the stock's valuation.

Q WHAT DIVIDEND DID YOU USE IN YOUR CONSTANT GROWTH DCF MODEL?

A I used each proxy company's most recently paid quarterly dividend as reported in *Value Line*.[23] This dividend was annualized (multiplied by 4) and adjusted for next year's growth to produce the D_1 factor for use in Equation 2 above. In other words, I calculate D_1 by multiplying the annualized dividend (D_0) by (1+G).

Q WHAT DIVIDEND GROWTH RATES HAVE YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A There are several methods that can be used to estimate the expected growth in dividends. However, regardless of the method, for purposes of determining the market-required return on common equity, one must attempt to estimate investors' expectations about what the dividend, or earnings growth rate will be and not what an individual investor or analyst may use to make individual investment decisions.

As predictors of future returns, securities analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data.[24] That is, assuming the market generally makes rational investment decisions, analysts' growth projections are more likely to influence investors' decisions, which are captured in observable stock prices, than growth rates derived only from historical data.

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional securities analysts' earnings growth estimates as a proxy for investors'

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[23] *The Value Line Investment Survey*.

[24] *See*, e.g., David Gordon, Myron Gordon, and Lawrence Gould, Choice Among Methods of Estimating Share Yield, The Journal of Portfolio Management, Spring 1989.

dividend growth rate expectations for each of the proxy group companies. I used the average of analysts' growth rate estimates from three sources: Zacks, S&P Capital IQ Market Intelligence ("MI"), and Yahoo! Finance. All such projections were available on October 13, 2023, and all were reported online.[25]

Each growth rate projection is based on a survey of independent securities analysts. There is no clear evidence whether a particular analyst is most influential on general market investors. Therefore, a single analyst's projection does not predict investor outlooks as reliably as does a consensus of market analysts' projections. The consensus of estimates is a simple arithmetic average, or mean, of surveyed analysts' earnings growth forecasts. A simple average of the growth forecasts gives equal weight to all surveyed analysts' projections. Therefore, a simple average, or arithmetic mean, of analysts' forecasts is a good proxy for investor expectations.

The growth rates I used in my DCF analysis are shown in Exhibit OPC (C)-4. The average growth rate for my proxy group is 6.16% and a median growth rate of 6.21%.

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[25] www.zacks.com; https://finance.yahoo.com; and https://www.capitaliq.spglobal.com/.

Q WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL?

A As shown in Exhibit OPC (C)-5, page 1, the average and median constant growth DCF returns for my proxy group for the 13-week analysis are 10.24% and 10.21%, respectively.

Q DO YOU HAVE ANY COMMENTS ON THE RESULTS OF YOUR CONSTANT GROWTH DCF ANALYSIS?

A Yes. The constant growth DCF analysis for my proxy group is based on a group average long-term growth rate of 6.16%. The three- to five-year growth rates are approximately 36% higher than the long-term projected GDP growth rate of 4.04%, described below. As I explain in detail below, a utility's growth rate cannot exceed the growth rate of the economy in which it provides services in perpetuity, which is the time period assumed by the DCF model.

Q HOW DID YOU IDENTIFY THE LONG-TERM PROJECTED GDP GROWTH RATE?

A Although there may be short-term peaks, the long-term sustainable growth rate for a utility stock cannot exceed the growth rate of the economy in which it sells its goods and services. The long-term maximum sustainable growth rate for a utility investment is limited by the projected long-term GDP growth rate as that reflects the projected long-term growth rate of the economy as a whole. *Blue Chip Economic Indicators* projects that over the next 5 and 10 years, the U.S. nominal GDP will grow at an annual rate of approximately 4.04%.[26] As such, the average nominal growth rate over the next 10 years is around 4.04%, which I believe is a reasonable proxy of long-term growth.

Later in this testimony, I discuss academic and investment practitioner support for using the projected long-term GDP growth outlook as a maximum long-term growth rate projection. Using the long-term GDP growth rate as a conservative projection for the maximum growth rate is logical, and is generally consistent with academic and economic practitioner accepted practices.

E. Sustainable Growth DCF

Q PLEASE DESCRIBE WHAT THE SUSTAINABLE GROWTH DCF METHOD IS AND HOW YOU ESTIMATED A SUSTAINABLE GROWTH RATE FOR YOUR SUSTAINABLE GROWTH DCF MODEL.

A The sustainable growth rate, also referred to as the internal growth rate, is determined by the proportion of the utility's earnings that is retained and reinvested in its plant and equipment. These reinvested earnings enhance the earnings base, also known as the rate base. The earnings grow as the plant, funded by the reinvested earnings, is put into operation, allowing the utility to receive its authorized return on the additional rate base investment.

The internal growth approach is linked to the percentage of earnings retained within the company, as opposed to being paid out as dividends. The earnings retention ratio is calculated as 1 minus the dividend payout ratio. As the payout ratio decreases,

[26] Blue Chip Economic Indicators October 10, 2023, at page 14.

the retention ratio increases, leading to stronger growth as the company funds more investments using retained earnings.

The payout ratios of the proxy group are shown in my Exhibit OPC (C)-6. These dividend payout ratios and earnings retention ratios then can be used to develop a long-term growth rate driven by earnings retention.

The data used to estimate the long-term sustainable growth rate is based on the Company's current market-to-book ratio and on *Value Line*'s three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances.

As shown in Exhibit OPC (C)-7, the average and median sustainable growth rates for the proxy group using this internal growth rate model are 4.89% and 5.08%, respectively.

Q WHAT IS THE DCF ESTIMATE USING THESE SUSTAINABLE GROWTH RATES?

A A DCF estimate based on these sustainable growth rates is developed in Exhibit OPC (C)-8. As shown there, and using the same formula in Equation 2 above, a sustainable growth DCF analysis produces proxy group average and median DCF results for the 13-week period of 8.93% and 8.88%, respectively.

F. Multi-Stage Growth DCF Model

Q HAVE YOU CONDUCTED ANY OTHER DCF STUDIES?

A Yes. As previously noted, the DCF model is intended to represent the present value of an endless series of future cash flows. Nevertheless, the initial constant growth DCF that I created is based on analyst growth rate projections, providing a plausible representation of rational investment expectations over the next three to five years. The limitation of this constant growth DCF model is that it cannot reflect a reasonable expectation of a shift in growth from a high or low short-term rate to a rate that aligns more with long-term sustainable growth. To accommodate changing growth expectations, I conducted a multi-stage DCF analysis that reflects growth rate change over time.

Q WHY DO YOU BELIEVE GROWTH RATES CAN CHANGE OVER TIME?

A The growth rate projections for the next three to five years by analysts are subject to change as the outlook for utility earnings growth evolves. Utility companies experience fluctuations in their investment cycles. When these companies are undertaking substantial investments, the growth of their rate base accelerates, leading to an increase in earnings growth. However, once a major construction cycle reaches completion or plateaus, the growth in the utility rate base slows down, and its earnings growth rate declines from an abnormally high three to five-year rate to a lower, sustainable growth rate.

As construction cycles become longer in duration, even with an aggressive construction plan, the growth rate of the utility will naturally slow due to a decrease in rate base growth, as the utility has limited human and capital resources to expand its construction activities. Therefore, the three to five-year growth rate projection should be viewed as a long-term sustainable growth rate, but not without considering the current market conditions, industry trends, and determining whether the three to five-year growth outlook is feasible and sustainable.

Q PLEASE DESCRIBE YOUR MULTI-STAGE DCF MODEL.

A The multi-stage DCF model reflects the possibility of non-constant growth for a company over time. The multi-stage DCF model reflects three growth periods: (1) a short-term growth period consisting of the first five years; (2) a transition period, consisting of the next five years (6 through 10); and (3) a long-term growth period starting in year 11 and extending into perpetuity.

For the short-term growth period, I relied on the consensus of analysts' growth projections described above in relationship to my constant growth DCF model. For the transition period, the growth rates were reduced or increased by an equal factor reflecting the difference between the analysts' growth rates and the long-term sustainable growth rate. For the long-term growth period, I assumed each company's growth would converge to the maximum sustainable long-term growth rate.

Q WHY IS THE GDP GROWTH PROJECTION A REASONABLE PROXY FOR THE MAXIMUM SUSTAINABLE LONG-TERM GROWTH RATE?

A Utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services. Utilities' earnings and dividend growth is created by increased utility investment in its rate base. Examples of what can drive such investment are service area economic growth, system reliability upgrades, or state and federal green energy initiatives. As a result, nominal GDP growth is a reasonable upper limit for utility sales growth, rate base growth, and earnings growth in the long-run. Therefore, the U.S. GDP nominal growth rate is a conservative proxy for the highest sustainable long-term growth rate of a utility.

Q IS THERE RESEARCH THAT SUPPORTS YOUR POSITION THAT, OVER THE LONG-TERM, A COMPANY'S EARNINGS AND DIVIDENDS CANNOT GROW AT A RATE GREATER THAN THE GROWTH OF THE U.S. GDP?

A Yes. This concept is supported in published analyst literature and academic work. Specifically, in a textbook titled "Fundamentals of Financial Management," published by Eugene Brigham and Joel F. Houston, the authors state as follows:

> The constant growth model is most appropriate for mature companies with a stable history of growth and stable future expectations. Expected growth rates vary somewhat among companies, but <u>dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation)</u>.[27]

The use of the economic growth rate is also supported by investment practitioners as outlined as follows:

> **Estimating Growth Rates**
>
> One of the advantages of a three-stage discounted cash flow model is that it fits with life cycle theories in regards to company growth. In these theories, companies are assumed to have a life cycle with varying growth characteristics. Typically, the potential for extraordinary growth in the near term eases over time and eventually growth slows to a more stable level.
>
> * * *
>
> Another approach to estimating long-term growth rates is to focus on estimating the overall economic growth rate. Again, this is the approach used in the *Ibbotson Cost of Capital Yearbook*. To obtain the economic growth rate, a forecast is made of the growth rate's component parts. Expected growth can be broken into two main parts: expected inflation and expected real growth. By analyzing these components separately, it is easier to see the factors that drive growth.[28]

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27 *Fundamentals of Financial Management*, Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at 298 (emphasis added).

28 Morningstar, Inc., Ibbotson SBBI 2013 Valuation Yearbook at 51 and 52.

Q ARE YOU AWARE OF ANY RESEARCH THAT DEMONSTRATING THAT MULTI-STAGE DCF MODELS ARE USED IN THE INVESTMENT INDUSTRY?

A Yes. The CFA Institute curriculum text states as follows:

> Multistage models are a staple valuation discipline of investment management firms using DCF valuation models.
> A survey of CFA Institute members with job responsibility for equity analysis indicates that, among respondents using a dividend discount model, two-stage and multistage models are used more often than the single-stage model (Stowe, Pinto, and Robinson 2018). Among analysts using a dividend discount model, 55% use a two-stage model, 11% use an H-model (a type of two-stage model), and 50% use a model with more than two stages (Stowe, Pinto, and Robinson 2018).[29]

As Stowe *et al* have revealed, the majority of equity analysts rely on multi-stage models more frequently than single stage or constant growth models.

Q HOW DID YOU DETERMINE A LONG-TERM GROWTH RATE THAT REFLECTS THE CURRENT CONSENSUS OF INDEPENDENT MARKET PARTICIPANTS?

A I relied on the consensus of long-term GDP growth projections as projected by independent economists. *Blue Chip Financial Forecasts* publishes the consensus for GDP growth projections twice a year. These projections reflect current outlooks for GDP and are likely to be influential on investors' expectations of future growth outlooks. The consensus of projected GDP growth is about 4.04% over the next 10 years.[30]

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[29] Chartered Financial Analyst Institute, 2023 CFA Program Level 2 Refresher Reading, Equity Valuation: Discounted Dividend Valuation, at 30. [footnote omitted].

[30] Blue Chip Economic Indicators October 10, 2023, at page 14.

Q DO YOU CONSIDER OTHER SOURCES OF PROJECTED LONG-TERM GDP GROWTH?

A Yes, and these alternative sources corroborate the consensus analysts' projections I relied on. Several projections are shown in Table CCW-7 below.

TABLE CCW-7

GDP Forecasts

Source	Projected Period	Real GDP	Inflation	Nominal GDP
Blue Chip Financial Forecasts [1]	5-10 Yrs	1.9%	2.2%	4.0%
EIA - Annual Energy Outlook[2]	27 Yrs	1.9%	2.3%	4.3%
Congressional Budget Office[3]	30 Yrs	1.6%	2.1%	3.7%
Moody's Analytics[4]	31 Yrs	2.0%	2.0%	4.0%
Social Security Administration[5]	77 Yrs	1.6%	2.4%	4.1%
Economist Intelligence Unit[6]	29 Yrs	1.7%	2.2%	3.9%

Sources:
[1]Blue Chip Financial Forecasts, October 10, 2023 at 14.
[2]U.S. EnergyInformation Administration (EIA), Annual Energy Outlook 2023, September, 2022.
[3]Congressional Budget Office, Long-Term Budget Outlook, July 2022.
[4]Moody's Analytics Forecast, downloaded January 17, 2023.
[5]Social Security Administration, "2023 OASDI Trustees Report," Table VI.G6. March 31, 2023.
[6]S&P MI, Economist Intelligence Unit, downloaded on April 5, 2023.

As shown in the table above, the real GDP and the inflation fall in the range of 1.6% to 2.1% and 2.0% to 2.4%, respectively. This results in a nominal GDP in the range of 3.7% to 4.3%, with an average of 4.1%. Therefore, the nominal GDP growth projections made by these independent sources support my use of 4.04% as a reasonable estimate of market participants' expectations for long-term GDP growth. The real GDP and nominal GDP growth projections made by these independent sources support my use of 4.04% as a reasonable estimate of market participants' expectations for long-term GDP growth.

Q WHAT STOCK PRICE, DIVIDEND, AND GROWTH RATES DID YOU USE IN YOUR MULTI-STAGE DCF ANALYSIS?

A I relied on the same 13-week average stock prices and the most recent quarterly dividend payment data discussed above. For the first stage, I used the consensus of analysts' growth rate projections discussed above in my constant growth DCF model. The first stage covers the first five years, consistent with the time horizon of the securities analysts' growth rate projections. The second stage, or transition stage, begins in year 6 and extends through year 10. The second stage growth transitions the growth rate from the first stage (consensus growth rate estimates) to the third stage (long-term GDP) using a straight linear trend. For the third stage, or long-term sustainable growth stage, starting in year 11, I used a 4.04% long-term sustainable growth rate based on the consensus of economists' long-term projected nominal GDP growth rate.

Q WHAT ARE THE RESULTS OF YOUR MULTI-STAGE DCF MODEL?

A As shown in Exhibit OPC (C)-9, the average and median DCF ROEs for my proxy group using the 13-week average stock price are 8.59% and 8.53%, respectively.

Q PLEASE SUMMARIZE THE RESULTS FROM YOUR DCF ANALYSES.

A The DCF results are summarized in Table CCW-8 below. As noted above, the much higher Constant Growth DCF Model (Analysts' Growth) result is based on a projected growth rate that far exceeds projected GDP growth, which is unsustainable in perpetuity. It is my opinion a reasonable ROE based on the DCF results summarized in Table CCW-8 is 9.20%.

TABLE CCW-8

Summary of DCF Results

Description	Proxy Group Average	Proxy Group Median
Constant Growth DCF Model (Analysts' Growth)	10.24%	10.21%
Constant Growth DCF Model (Sustainable Growth)	8.93%	8.88%
Multi-Stage DCF Model	8.59%	8.53%

G. Risk Premium Model

Q PLEASE DESCRIBE YOUR BOND YIELD PLUS RISK PREMIUM MODEL.

A This model is based on the principle that investors require a higher return to assume greater risk. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations. In contrast, companies are not required to pay dividends or guarantee returns on common equity investments. Therefore, common equity securities are considered to be riskier than bond securities.

This risk premium model is based on two estimates of an equity risk premium. First, I quantify the difference between regulatory commission-authorized returns on common equity and contemporary U.S. Treasury bonds. The difference between the authorized return on common equity and the Treasury bond yield is the risk premium. I estimated the risk premium on an annual basis for each year since January 1986. The authorized ROEs were based on regulatory commission-authorized returns for utility companies. Authorized returns are typically based on expert witnesses' estimates of the investor-required return at the time of the proceeding.

The second equity risk premium estimate is based on the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields by Moody's. I selected the period 1986 through the present because public utility stocks have consistently traded at a premium to book value during that period. This is illustrated in Exhibit OPC (C)-10, which shows the market-to-book ratio since 1986 for the utility industry was consistently above a multiple of 1.0x. Over this period, an analyst can infer that authorized ROEs were sufficient to support market prices that at least exceeded book value. This is an indication that commission-authorized returns on common equity supported a utility's ability to issue additional common stock without diluting existing shares. It further demonstrates that utilities were able to access equity markets without a detrimental impact on current shareholders.

Based on this analysis, as shown in Exhibit OPC (C)-11, the average indicated equity risk premium over U.S. Treasury bond yields has been 5.72%. Since the risk premium can vary depending upon market conditions and changing investor risk perceptions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity for a risk premium methodology.

I assessed the five-year and ten-year rolling average risk premiums over the study period to gauge the variability over time of risk premiums. These rolling average risk premiums mitigate the impact of anomalous market conditions and skewed risk premiums over an entire business cycle. As shown on my Exhibit OPC (C)-11, the five-year rolling average risk premium over Treasury bonds ranged from 4.25% to 7.09%, while the ten-year rolling average risk premium ranged from 4.38% to 6.91%.

As shown on my Exhibit OPC (C)-12, the average indicated equity risk premium over contemporary "A" rated Moody's utility bond yields was 4.35%. The five-year and ten-year rolling average risk premiums ranged from 2.88% to 5.90% and 3.20% to 5.73%, respectively.

Q WHY ARE THE TIME PERIODS USED TO DERIVE THESE EQUITY RISK PREMIUM ESTIMATES APPROPRIATE TO FORM ACCURATE CONCLUSIONS ABOUT CONTEMPORARY MARKET CONDITIONS?

A Contemporary market conditions can change dramatically during the period that rates determined in this proceeding will be in effect. A relatively long period of time where stock valuations reflect premiums to book value indicates that the authorized ROEs and the corresponding equity risk premiums were supportive of investors' return expectations and provided utilities access to the equity markets under reasonable terms and conditions. Further, this time period is long enough to smooth abnormal market movement that might distort equity risk premiums. While market conditions and risk premiums do vary over time, this historical time period is a reasonable period to estimate contemporary risk premiums.

Q PLEASE EXPLAIN OTHER MARKET EVIDENCE YOU RELIED ON IN DETERMINING AN APPROPRIATE EQUITY RISK PREMIUM.

A The equity risk premium should reflect the market's perception of risk in the utility industry today. I have gauged investor perceptions in utility risk today in Exhibit OPC (C)-13, where I show the yield spread between utility bonds and Treasury bonds since 1980. As shown in this schedule, the average utility bond yield spreads over Treasury bonds for "A" and "Baa" rated utility bonds for this historical period are 1.49% and 1.91%, respectively.

A current 13-week average "A" rated utility bond yield of 5.81% when compared to the current Treasury bond yield of 4.39%, as shown in Exhibit OPC (C)-14, page 1, implies a yield spread of 1.42%. This current utility bond yield spread is identical to the long-term average spread for "A" rated utility bonds of 1.49%. The 13-week average yield on "Baa" rated utility bonds is 6.10%. This indicates a current spread for the "Baa" rated utility bond yield of 1.71%, which is slightly lower than the long-term average of 1.91%.

Q WHAT IS YOUR RECOMMENDED RETURN FOR THE COMPANY BASED ON YOUR RISK PREMIUM STUDY?

A Considering the current and projected economic environment, current yield spreads and equity risk premiums, as well as current levels of interest rates and interest rate projections, a more normalized equity risk premium is warranted. As such, I believe an average equity risk premium over Treasury yields of 5.72% is appropriate. Adding this risk premium to the projected Treasury yield of 4.00% produces an ROE of 9.72%.

Applying a similar methodology as described above, the average of the rolling five-year average risk premiums over A-rated utility bonds is 4.35%. The A-rated utility bond yield has averaged 5.81% over the 13-week period ending October 13, 2023 while the Baa-rated utility bond yield has averaged 6.10% over the same period. Adding this risk premium to the 13-week A-rated utility bond yield of 5.81% produces an estimated cost of equity of 10.16%. Adding this risk premium to the 13-week Baa-rated utility bond yield of 6.10% produces an estimated cost of equity of 10.45%.

The A-rated utility bond yield has averaged 5.58% over the 26-week period ending October 13, 2023 while the Baa-rated utility bond yield has averaged 5.90% over the same period. Adding this risk premium to the 26-week A-rated utility bond yield of 5.58% produces an estimated cost of equity of 9.93%. Adding this risk premium to the 26-week Baa-rated utility bond yield of 5.90% produces an estimated cost of equity of 10.25%.

The results of my risk premium analyses are summarized in Table CCW-9. Because the exercise of determining the cost of equity is forward looking, in my opinion, based on these results, my risk premium analyses yield a recommended ROE of 9.90%.

TABLE CCW-9

Summary of Risk Premium Results

Description	
Projected Treasury Yield	9.72%
13-Week Yields	
A-Rated Utility Bond	10.16%
Baa-Rated Utility Bond	10.45%
26-Week Yields	
A-Rated Utility Bond	9.93%
Baa-Rated Utility Bond	10.25%

Q HOW DO YOUR EQUITY RISK PREMIUMS COMPARE TO WHAT HAS BEEN REALIZED YEAR-TO-DATE?

A Year-to-Date, the equity risk premium over prevailing bond yields has been near long-term averages. As such, a more modest equity risk premium such as the long-term average or medians would be reasonable considerations at this time.

H. Capital Asset Pricing Model ("CAPM")

Q PLEASE DESCRIBE THE CAPM.

A The CAPM method of analysis is based upon the theory that the market-required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. This relationship between risk and return can be expressed mathematically as follows:

$R_i = R_f + B_i \times (R_m - R_f)$ where:

R_i = Required return for stock i
R_f = Risk-free rate
R_m = Expected return for the market portfolio
B_i = Beta - Measure of the risk for stock

The term "beta" in the equation represents the stock-specific risk that cannot be reduced through diversification. In a well-diversified portfolio, specific risks related to individual stocks can be reduced by balancing the portfolio with securities that offset the impact of firm-specific factors, such as business cycle, competition, product mix, and production limitations.

Non-diversifiable risks, on the other hand, are related to market conditions and are referred to as systematic risks. These risks cannot be reduced through diversification and are considered market risks. Conversely, non-systematic risks, also known as business risks, can be reduced through diversification.

According to the CAPM, the market does not compensate investors for taking on risks that can be diversified away. Thus, investors are only compensated for taking on systematic, or non-diversifiable, risks. Beta is a measure of these systematic risks.

Q PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.

A The CAPM requires an estimate of the market risk-free rate, the company's beta, and the market risk premium.

Q WHAT DID YOU USE AS AN ESTIMATE OF THE MARKET RISK-FREE RATE?

A As previously noted, *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield is 4.00%.[31] The current 30-year Treasury bond yield is 4.39%, as shown in Exhibit OPC (C)-14 at page 1. I used *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield of 4.00% for my CAPM analysis.

Q WHY DID YOU USE LONG-TERM TREASURY BOND YIELDS AS AN ESTIMATE OF THE RISK-FREE RATE?

A Treasury securities are backed by the full faith and credit of the United States government, so long-term Treasury bonds are considered to have negligible credit risk. Also, long-term Treasury bonds have an investment horizon similar to that of common stock. As a result, investor-anticipated long-run inflation expectations are reflected in both common stock required returns and long-term bond yields. Therefore, the nominal risk-free rate (or expected inflation rate and real risk-free rate) included in a long-term bond yield is a reasonable estimate of the nominal risk-free rate included in common stock returns.

Treasury bond yields, however, do include risk premiums related to future inflation and liquidity. In this regard, a Treasury bond yield is not entirely risk-free. Risk premiums related to unanticipated inflation and interest rates reflect systematic market risks. Consequently, for a company with a beta less than 1.0, using the Treasury

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[31] Blue Chip Financial Forecasts, October 2, 2023 at 2.

bond yield as a proxy for the risk-free rate in the CAPM analysis can produce an overstated estimate of the CAPM return.

Q WHAT BETA DID YOU USE IN YOUR ANALYSIS?

A As shown in Exhibit OPC (C)-15, the current proxy group average and median *Value Line* beta estimates are 0.92 and 0.90, respectively. In my experience, these beta estimates are abnormally high and are unlikely to be sustained over the long-term. Because these beta estimates are calculated using five years of historical prices, they reflect the market's fallout when the market lost more than 40% of its value in early 2020 as a result of the COVID-19 pandemic. As shown on Exhibit OPC (C)-15, page 2, utility stock betas were on a declining trend and at the lowest point since 2014 leading up to the pandemic. In other words, current *Value Line* betas are being heavily impacted by the onset of extreme market volatility and fear from a two-month period over February and March of 2020, and likely do not accurately represent current investor expectations. As such, I have also considered the historical average of the proxy group's *Value Line* betas. The historical average *Value Line* beta since 2014 is 0.77 and has ranged from 0.56 to 0.92. Prior to the recent pandemic, the high end of this range was 0.75.

In addition to *Value Line*, I have also included adjusted beta estimates as provided by Market Intelligence's Beta Generator Model. This model relied on a five-year period on a weekly basis ending October 13, 2023. The average and median Market Intelligence betas are 0.85 and 0.84, respectively. Market Intelligence betas as calculated using its Beta Generator Model are adjusted using the Vasicek method and calculated using the S&P 500 as the proxy for the investable market. This is in stark contrast with the *Value Line* beta estimates that are adjusted using a constant weighting of 67%/35% to the raw beta/market beta and use the New York Stock Exchange as the proxy for the investable market. Because I rely on the S&P 500 to estimate the expected return on the investable market, it makes sense to rely on beta estimates that are calculated using the S&P 500 as the benchmark for the market. Further, as S&P explains:

> The Vasicek Method is a superior alternative to the Bloomberg Beta adjustment. The Bloomberg adjustment is not appropriate for a vast number of situations, as it assigns constant weighting regardless of the standard error in the raw beta estimation (Bloomberg Beta = 1/3*market beta + 2/3*Raw Beta). Given the statistical fact that a larger sample size yields a smaller error, the Vasicek method more appropriately adjusts the raw beta via weights determined by the variance of the individual security versus the variance of a larger sample of comparable companies. The weights are designed to bring the raw beta closer to whichever beta estimation has the smallest error. This is a feature the Bloomberg beta cannot replicate.[32]

Q HOW DID YOU DERIVE YOUR MARKET RISK PREMIUM ESTIMATES?

A My market risk premium estimates are derived using two general approaches: a risk premium approach and a DCF approach. I also consider the normalized market risk

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[32] S&P Market Intelligence, Beta Generator Model. Notably, while S&P makes reference to the Bloomberg method of applying 2/3 and 1/3 weights to the raw beta and market beta, respectively, the comparison still applies to *Value Line's* methodology of applying 67% and 35% weights. Both methods are forms of the Blume adjustment. While the weights are slightly different between the Bloomberg and *Value Line* methods, they are similar and apply a constant weight without any regard to accuracy. As such, the criticisms of the betas offered by S&P apply to both Bloomberg betas and *Value Line* betas.

premium of 5.50% with the normalized risk-free rate of 4.58% as recommended by Kroll, formerly known as Duff & Phelps.

Q PLEASE DESCRIBE YOUR MARKET RISK PREMIUM ESTIMATE DERIVED USING THE RISK PREMIUM METHODOLOGY.

A The forward-looking risk premium-based estimate was derived by estimating the expected return on the market (as represented by the S&P 500) and subtracting the risk-free rate from this estimate. I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. The real return on the market represents the achieved return above the rate of inflation.

The Kroll *2023 SBBI Yearbook* estimates the historical arithmetic average real market return over the period 1926 to 2022 to be 8.90%.[33] A current consensus for projected inflation, as measured by the Consumer Price Index ("CPI"), is 2.30%.[34] Using these estimates, the expected market return is 11.40%.[35] The market risk premium then is the difference between the 11.40% expected market return and the projected risk-free rate of 4.00%, or 7.40%.

Q PLEASE DESCRIBE YOUR MARKET RISK PREMIUM ESTIMATES DERIVED USING THE DCF METHODOLOGY.

A I employed two versions of the constant growth DCF model to develop estimates of the market risk premium. I first employed the Federal Energy Regulatory Commission's

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33 Kroll, 2023 SBBI Yearbook at 138.
34 Blue Chip Financial Forecasts, October 2, 2023 at 2.
35 [(1 +8.90%) ∗ (1 + 2.30%) - 1] ∗ 100.

("FERC") method of estimating the expected return on the market that was established in its Opinion No. 569-A. FERC's method for estimating the expected return on the market is to perform a constant growth DCF analysis on each of the dividend paying companies of the S&P 500 index. The growth rate component is based on the average of the growth projections excluding companies with growth rates that were negative or greater than 20%.[36] The weighted average growth rate for the remaining companies is 9.50%. After reflecting the FERC prescribed method of adjusting the dividend yield by (1+ 0.5g), the weighted average expected dividend yield is 2.20%. Thus, the DCF-derived expected return on the market is the sum of those two components, or 11.70%. The market risk premium then is the expected market return of 11.70% less the projected risk-free rate of 4.00%, or approximately 7.70%.

My second DCF-based market risk premium estimate was derived by performing the same DCF analysis described above, except I used all companies in the S&P 500 index rather than just the dividend paying companies. The weighted average growth rate for these companies is 10.20%. After reflecting the FERC prescribed method of adjusting the dividend yield by (1+ 0.5g), the weighted average expected dividend yield is 1.79%. Thus, the DCF-derived expected return on the market is the sum of those two components, or 11.99%. The market risk premium then is the expected market return of 11.99% less the projected risk-free rate of 4.00%, or 8.00%.

The average expected market return based on the DCF model is 11.85% and the average market risk premium based on the two DCF estimates is 7.85%.

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[36] Opinion No. 569-A, at p. 210.

Q HOW DO YOUR EXPECTED MARKET RETURNS COMPARE TO CURRENT EXPECTATIONS OF FINANCIAL INSTITUTIONS?

A As shown in Table CCW-10, my average expected market return of 11.11%[37] exceeds long-term market expectations of several financial institutions.

TABLE CCW-10

Long-Term Expected Return on the Market

Source	Term	Expected Return Large Cap Equities
BlackRock Capital Management[1]	30 Years	8.20%
JP Morgan Chase[2]	10 - 15 Years	7.90%
Vanguard[3]	10 Years	4.7% - 6.7%
Research Affiliates[4]	10 Years	5.80%

Sources:
[1]BlackRock Investment Institute, September 2022 report.
[2]JP Morgan Chase, Long-Term Capital Market Assumptions, 2023 Report.
[3]Vanguard economic and market outlook for 2023: Beating back inflation.
[4]Research Affiliates, Asset Allocation Interactive. Retrieved 12/31/2022.

When compared to the expected market returns of financial institutions above, my average expected market return of 11.11% is more than two times higher than all

[37] 11.11% = (10.08% + 11.85% + 11.40%) / 3.

but one projection. For these reasons, my expected market returns, and the associated market risk premiums, should be considered reasonable, if not high-end estimates.

Q HOW DO YOUR ESTIMATED MARKET RISK PREMIUMS COMPARE TO THAT ESTIMATED BY KROLL?

A The Kroll analysis indicates a market risk premium falls somewhere in the range of 5.50% to 7.17%. My market risk premium estimates are in the range of 5.50% to 7.85%.

Q HOW DOES KROLL MEASURE A MARKET RISK PREMIUM?

A Kroll's range is based on several methodologies. First, Kroll estimated a market risk premium of 7.17% based on the difference between the total market return on common stocks (S&P 500) less the income return on 20-year Treasury bond investments over the 1926-2022 period.[38]

Second, Kroll used the Ibbotson & Chen supply-side model which produced a market risk premium estimate of 6.35%.[39] Kroll explains that the historical market risk premium based on the S&P 500 was influenced by an abnormal expansion of P/E ratios relative to earnings and dividend growth. In order to control for the volatility of extraordinary events and their impacts on P/E ratios, Kroll takes into consideration the three-year average P/E ratio as the current P/E ratio. Therefore, Kroll adjusted this market risk premium estimate to normalize the growth in the P/E ratio to be more in line with the growth in dividends and earnings.

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[38] Kroll, 2023 SBBI Yearbook at 191.
[39] *Ibid.* at 199.

Finally, Kroll develops its own recommended equity, or market risk premium, by employing an analysis that takes into consideration a wide range of economic information, multiple risk premium estimation methodologies, and the current state of the economy by observing measures such as the level of stock indices and corporate spreads as indicators of perceived risk. Based on this methodology, and utilizing a "normalized" risk-free rate of 4.58%, Kroll concludes that the current expected, or forward-looking, market risk premium is 5.50%, implying an expected return on the market of 10.08%.[40]

Q WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A As shown in Exhibit OPC (C)-16, I have provided the results of nine different applications of the CAPM. The first three results presented are based on the proxy group's current average *Value Line* beta of 0.92. The results of the CAPM based on these inputs range from 9.64% to 11.23%.

The next set of three results presented are based on the proxy group's historical *Value Line* beta of 0.77. The results of the CAPM based on these inputs range from 8.82% to 10.05%.

The last set of three results presented are based on the proxy group's current S&P Global Market Intelligence beta of 0.85. The results of the CAPM based on these

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40 Kroll, *Kroll Increases U.S. Normalized Risk-Free Rate from 3.0% to 3.5%, but Spot 20-Year U.S. Treasury Yield Preferred When Higher*, June 16, 2022. Kroll's method uses the greater of 3.50% or current 20-year Treasury yields as the risk-free rate.

inputs range from 9.24% to 10.65%. My CAPM results are summarized in Table CCW-11.

TABLE CCW-11

CAPM Results Summary

Description	Current VL Beta	Historical VL Beta	Current MI Beta
D&P Normalized Method	9.64%	8.82%	9.24%
Risk Premium Method	10.82%	9.70%	10.27%
FERC DCF	11.23%	10.05%	10.65%

Q **WHAT IS YOUR RECOMMENDED RETURN FOR THE COMPANY BASED ON YOUR CAPM?**

A As I explain above, the current *Value Line* beta estimates are heavily impacted by the market fallout in early 2020 as a result of the COVID-19 pandemic, and likely do not reflect current investor expectations. Based on the results summarized above, I recommend a CAPM return estimate of 9.80%.

I. Return on Equity Summary

Q **BASED ON THE RESULTS OF YOUR RETURN ON COMMON EQUITY ANALYSES DESCRIBED ABOVE, WHAT RETURN ON COMMON EQUITY DO YOU RECOMMEND FOR THE COMPANY?**

A The results of my analyses are summarized in Table CCW-12.

TABLE CCW-12

Return on Common Equity Summary

Description	Results
DCF	9.20%
Risk Premium	9.90%
CAPM	9.80%

Based on my analyses described above, I estimate the Company's current market cost of equity to be in the reasonable range of 9.20% to 9.90%. Should the Commission order Pepco to operate under a traditional test year scenario without the BSA decoupling mechanism, I would recommend that Pepco be authorized an ROE of 9.55%, which is the midpoint of my recommended range.[41] Should the Commission allow Pepco to continue under a MYRP and/or the BSA, I recommend an ROE of 9.35%, which is in the lower half of my range (i.e. 9.20% to 9.55%). This point estimate is 20 basis points below the midpoint of my recommended range and is consistent with the findings of this Commission's Order and Opinion in Formal Case No. 1156. This recommendation is further supported by Pepco's lower financial risk and higher credit ratings relative to the proxy group.

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[41] The midpoint is defined as the average of the low-end and high-end point estimates of my recommended range.

V. RESPONSE TO MR. ADRIEN MCKENZIE

A. Summary of Rebuttal to Mr. McKenzie

Q WHAT RETURN ON COMMON EQUITY IS PEPCO PROPOSING FOR THIS PROCEEDING?

A In his direct testimony, Mr. McKenzie's proxy group results produce a return on equity range of 9.9% to 11.1%, with a point estimate of 10.5%. In his supplemental direct testimony under a traditional test year, Mr. McKenzie reiterated his initial recommended range and ROE for Pepco.

Q HOW DID MR. MCKENZIE DEVELOP HIS ROE RANGE?

A Mr. McKenzie developed his ROE recommendation based on the results of his applications of the DCF, traditional CAPM, and a Risk Premium model. Further, he references the results of an Expected Earnings analysis and a non-utility DCF analysis as an attempt to corroborate his results.

Table CCW-13 below shows the average results of Mr. McKenzie's analyses that he relies on to conclude that a ROE in the range of 9.90% to 11.10%, with a point of 10.50%, is reasonable for Pepco. However, as I demonstrate throughout the balance of my testimony, reasonable adjustments to Mr. McKenzie's analyses reduce his ROE estimate for Pepco to no higher than my recommended ROE of 9.35%.

TABLE CCW-13

Mr. McKenzie's ROE Analysis

Model	**Average (1)**
DCF	8.9% - 10.0%
CAPM	11.1%
ECAPM	11.3%
Utility Risk Premium	10.6%
Expected Earnings	11.3%
Non-Utility DCF	10.2% - 10.5%
Range	9.9% - 11.1%
Recommended ROE	**10.50%**

Source: Exhibit PEPCO (F)-2.

Q PLEASE SUMMARIZE YOUR GENERAL CONCERNS WITH MR. MCKENZIE'S ANALYSES AND DETERMINATIONS.

A Mr. McKenzie developed there are several flaws with each of his methods that inherently bias his model results and recommendations upwards. For example:

- His DCF is biased upward because he (1) arbitrarily removes what he has determined to be 15 low-end outliers and one high-end outlier, and (2) he relies heavily on the midpoint of the individual results as a measure of central tendency. The more reasonable approach would be to not remove any outliers and rely on the median as a measure of central tendency.

- His CAPM is inflated by his inclusion of a size adjustment, an excessive market risk premium, and sole reliance on inflated Value Line beta estimates. He should have considered multiple measures of the market risk premium and beta values. He has not demonstrated that the size adjustment is applicable to price-regulated utilities.

- His ECAPM shares the same flaws identified above with respect to his CAPM. In addition to those flaws, he incorrectly includes an adjusted beta value from Value Line in the application of the ECAPM. The more accurate method would be to use an unadjusted beta.

- His utility bond yield plus risk premium method is overstated as a result of an arbitrary projected Baa utility bond yield that he develops on his own, does not account for interest rate projections to decline, and relies on an overly simplistic linear regression model that overstates a utility equity risk premium.

- His Expected Earnings analysis is not a market based measure of the cost of equity and has been rejected several times.

- His non-utility proxy group DCF is applied to 33 non-regulated companies that do not share underlying business risks similar to Pepco and could be based on highly profitable and speculative companies. This violates the Hope & Bluefield standards and should be rejected.

- In addition, Mr. McKenzie's recommended ROE of 10.50% falls significantly outside a reasonable range for a low-risk distribution electric utilities when compared to observable benchmarks such as recent authorized ROEs for electric utilities, especially considering the lower-risk nature of distribution-only electric utilities that operate under a MYP.

B. Mr. McKenzie's DCF

Q PLEASE DESCRIBE MR. MCKENZIE'S DCF ANALYSIS.

A Mr. McKenzie applied the traditional DCF model to his utility proxy group. Mr. McKenzie observed the average and midpoint results of his proxy group's DCF results. He relied on earnings growth rates from *Value Line*, IBES, and Zacks. In addition to analyst growth rates from the aforementioned providers, he also estimated a sustainable growth rate based on Value Line data in a similar fashion to my sustainable growth DCF model described above. Mr. McKenzie makes reference to the average and midpoint estimates of his results after excluding what he has deemed to be outliers. The average DCF results from his four iterations fall in the range of 8.9% to 10.0% for his proxy group.[42] He also considers the midpoint of his proxy group's DCF results after he excludes outliers.

Q DO YOU HAVE ANY ISSUES WITH MR. MCKENZIE'S DCF ANALYSIS?

A Yes, I have two concerns with Mr. McKenzie's DCF analysis. First, I disagree with his use of the midpoint of his proxy group's individual DCF results as the midpoint of the raw individual results are generally not an accurate method of measuring the central tendency.

In addition, I disagree with Mr. McKenzie's proposal to selectively exclude what he believes to be outliers from the proxy group which has the effect of manipulating the results of the proxy group. Notably, he excludes 15 low-end results from his DCF analysis, while only removing one outlier for being too high. Mr. McKenzie simply narrows the range of the proxy group results to produce a result which he finds to be reasonable.

A better methodology would be to rely on all the results of the proxy group, by assessing the central tendency of the proxy group results. In the presence of outliers, a

[42] Exhibit PEPCO (F)-5.

more accurate method of measuring the central tendency of the proxy group's results would be to measure the median of all the DCF return estimates.

Q CAN YOU PROVIDE AN EXAMPLE OF WHY THE MIDPOINT IS NOT A GOOD MEASURE OF CENTRAL TENDENCY FOR A SAMPLE OF INDIVIDUAL OBSERVATIONS?

A Yes. Real life examples can be household incomes or even housing values. For instance, let us assume the lowest priced home available for sale in the United States is $100,000 while the highest priced home available is $25 million (notably, this is approximately $163 million lower than the highest priced home that sold in the United States last year). The midpoint of these two figures is $12.55 million, which is nearly 30x higher than the recently reported median home sales price of approximately $437,000.

Q CAN MR. MCKENZIE'S DCF ANALYSIS BE ADJUSTED TO PRODUCE A REASONABLE RETURN ON EQUITY FOR PEPCO?

A Yes. Instead of eliminating individual results, measuring the median without excluding what he has determined to be outlier results is the appropriate method. The median DCF results for his electric proxy group without exclusions is in the range of 8.4% to 9.5%. The average of the unadjusted median results for his electric group is 9.15%.

C. Mr. McKenzie's Traditional CAPM

Q PLEASE DESCRIBE MR. MCKENZIE'S TRADITIONAL CAPM ANALYSIS.

A Mr. McKenzie developed a traditional CAPM analysis based on current Treasury bond yields. His current bond yield of approximately 3.7% is measured as the average for the six months ended January 2023.[43] To estimate the market risk premium, Mr. McKenzie begins with performing a constant growth DCF analysis to the dividend paying companies of the S&P 500. Mr. McKenzie excluded companies from the DCF analysis that have growth rates less than 0.0% and greater than 20.0%. This produced an expected market return of 11.6%. From this market return estimate, he subtracts his risk-free rate of 3.7% to arrive at a market risk premium of 7.9%.[44] He relies on the *Value Line* utility betas for the companies included in his proxy group to produce an average cost of equity 10.8%.[45]

Then he adjusts each of his CAPM return estimates to account for any size premium based on each company's market capitalization. This size adjustment has increased his proxy group's CAPM returns by an average of 30 basis points. Therefore, his size-adjusted traditional CAPM analysis produces an average result in the range of 11.1%.

Q IS MR. MCKENZIE'S CAPM ANALYSIS REASONABLE?

A No. I believe Mr. McKenzie's CAPM analysis is overstated for at least three reasons: (1) his expected return on the market of 11.6% is based on an unsustainable growth rate of 9.5%, causing a bias and does not include any consideration of the long-run average return on the market; (2) his sole reliance on Value Line betas is at odds with his use of the S&P 500 as the benchmark for the overall market and is heavily influenced by the market volatility from the Spring of 2020 as a result of the onset of the COVID-19

43 PEPCO (F)-7.
44 Exhibit PEPCO (F)-7.
45 *Id*.

pandemic, and; (3) his size adjustment is unreasonable and not shown to be applicable to utility stocks.

Q WHY DO YOU BELIEVE MR. MCKENZIE'S EXPECTED RETURN ON THE MARKET IS UNREASONABLE?

A Mr. McKenzie recognizes the need to apply multiple analytical methods for estimating the cost of equity[46], however, he only chose to apply, and consider the results of the constant growth DCF to estimate the cost of equity for the S&P 500. As Mr. McKenzie states in his testimony, "The DCF method, which is frequently referenced and relied on by regulators, is only one theoretical approach to evaluate the return investors require. There are a number of other accepted methodologies for estimating the cost of capital."[47] In fact, Mr. McKenzie even goes on to state that "while the DCF model is a recognized approach to estimating the ROE, it is not without shortcomings and does not otherwise eliminate the need to ensure that the end result is fair."[48]

To be consistent with his testimony, Mr. McKenzie should have implemented alternative measures of the expected market return and market risk premium. As Dr. Morin notes in his book, *New Regulatory Finance,*

> Although realized returns for a particular time period can deviate substantially from what was expected, it is reasonable to believe that long-run average realized returns provide an unbiased estimate of what were expected returns. This is the fundamental rationale behind the historical risk premium approach. Analysts and regulators often assume that the average historical risk premium over long periods is the best proxy for the future risk premium.[49]

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46 McKenzie Direct at 31.
47 *Id.*
48 *Id.* at 32.
49 Morin, Dr. Roger A, "New Regulatory Finance," at p. 156.

In his book, Dr. Morin concludes that "[t]here are two broad approaches to estimating the risk premium: retrospective and prospective. Each has its own strengths and weaknesses, hence the need to utilize both methods."[50] As such, Mr. McKenzie should have considered the results of multiple estimates of the expected market return from multiple methods. Examples of other such methods are described above in reference to my application of the CAPM.

Q WHY DO YOU FIND MR. MCKENZIE'S SOLE RELIANCE ON VALUE LINE BETAS IN HIS CAPM ANALYSIS TO BE INAPPROPRIATE?

A As I explain above, my CAPM analysis relies on beta estimates from Value Line and S&P Global Market Intelligence's Beta Generator model. There are two distinct differences between the MI Beta I relied on and the Value Line Beta: (1) the benchmark index used as the proxy for the market in the MI Beta estimates is the S&P 500 whereas *Value Line* relies on the New York Stock Exchange ("NYSE"); and (2) the MI Betas I used are adjusted using the Vasicek method whereas the *Value Line* Betas are adjusted using a modified form of the Blume adjustment.

Because Mr. McKenzie is not presenting a CAPM analysis that relies on the NYSE as a proxy for the market, or the expected market return, which the market risk premium ("MRP") is calculated from, this alone makes the *Value Line* Betas less preferable. Betas employed in a CAPM should be calculated using the benchmark index that is also used as a proxy for the overall market. Mr. McKenzie and I both relied on

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[50] *Id.* at p. 162.

the S&P 500 as the proxy for the overall market in estimating our MRP. While *Value Line* Betas are commonly used in CAPM analyses presented in regulatory proceedings such as this one, it is theoretically incorrect to do so unless the NYSE is used as the proxy for the overall market used to calculate the MRP.

In addition, *Value Line* betas are based on five years of historical prices, meaning that the significant market volatility as a result of the COVID-19 pandemic is captured in his *Value Line* betas and considered "expected." It is not rational to "expect" a global pandemic going forward. As such, current *Value Line* betas should be viewed with skepticism and caution should be exercised when employing them in estimating the cost of capital at the current time.

Q WHY DO YOU FIND MR. MCKENZIE'S SIZE ADJUSTMENT INAPPROPRIATE?

A Mr. McKenzie's size adjustment ROE adder is based on estimates made by Kroll's Cost of Capital Navigator. Kroll estimates various size adjustments based on differentials in beta estimates tied to the size of a company. The main concern with these size adjustments as applied by Mr. McKenzie, is that they are not based on risk comparable companies relative to the utility industry or the Company. In addition, there is empirical evidence which concludes that, while size premiums are present in industrial companies, such a size premium is not present in utility companies, nor are they appropriate to include in valuing utilities.[51]

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[51] Wong, Annie, 1993, Utility stocks and the size effect: An empirical analysis, Journal of the Midwest Finance Association, 95-101.

Q CAN MR. MCKENZIE'S CAPM ANALYSIS BE ADJUSTED TO PRODUCE MORE REASONABLE RESULTS?

A Yes. The following adjustments are necessary: (1) reflecting more recent data for the DCF on the market (11.85%); (2) include other estimates of the expected return on the market such as the normalized cost of equity from Kroll (10.08%) and the expected return based on the historical real return adjusted for projected inflation (11.40%); (3) eliminating his size adjustments; and (4) incorporating beta estimates that are calculated relative to the S&P 500 such as those presented in my CAPM analysis.

Reflecting more recent estimates of the DCF return on the market as well as including the two additional estimates of the expected return on the market produce an average expected return of 11.11%.[52] Subtracting his risk-free rate from this expected return on the market, produces market risk premium of 7.4%. Notably, this market risk premium is consistent with the empirical evidence discussed in Dr. Morin's *Modern Regulatory Finance.*[53] Applying these market risk premiums to his proxy group's average *Value Line* beta of 0.90 produces average CAPM results of 10.36%. Similarly, applying the same market risk premium to the proxy group's average historical average *Value Line* beta since 2014 of 0.77 as provided in my CAPM analysis, produces CAPM results of 9.40%.

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52 11.11% = (10.08% + 11.85% + 11.40%) / 3

53 Dr. Morin notes in his new textbook, that the market risk premium "most likely falls within a range of 6% - 8%", Morin, Dr. Roger A, *Modern Regulatory Finance,* at p. 178.

Q DID MR. MCKENZIE ALSO PERFORM AN ECAPM ANALYSIS?

A Yes. Mr. McKenzie performed an ECAPM analysis that relied on the same current risk-free rate of 3.7%, on the same market risk premium of 7.9%, and the same average *Value Line* beta that he used in his traditional CAPM analyses.

He then uses an ECAPM model that applies a 25% weighting factor to the market beta of 1, and a 75% weighting factor to the utility group beta. This produces an average ECAPM of 11.0%.

Finally, Mr. McKenzie applied the same size adjustment of approximately 0.3% to his utility group's ECAPM estimates to produce a size-adjusted average of 11.3%.[54]

Q ARE MR. MCKENZIE'S CURRENT AND PROJECTED ECAPM ANALYSES REASONABLE?

A No. Mr. McKenzie's ECAPM analyses share all of the same flaws as his traditional CAPM analyses. More importantly, Mr. McKenzie's proposal to apply an ECAPM while using adjusted betas published by Value Line inflates his results. Mr. McKenzie's analysis and results should be disregarded.

Q PLEASE EXPLAIN THE ISSUES YOU HAVE WITH MR. MCKENZIE'S CURRENT AND PROJECTED ECAPM ANALYSES.

A Mr. McKenzie's ECAPM analysis is flawed because his model was developed using adjusted utility betas. An ECAPM analysis flattens the security market line, and is designed for raw beta estimates, not adjusted betas such as the ones published by *Value*

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54 PEPCO (F)-8.

Line. Beta adjustments, on their own, accomplish virtually the same thing as an ECAPM analysis. They flatten the security market line and increase the intercept at the risk-free rate. An ECAPM analysis is not designed to be used with adjusted betas, but rather is designed to be used with unadjusted betas. Mr. McKenzie's proposal to use adjusted betas within an ECAPM analysis is unreasonable and double counts the attempt to flatten the security market line and increase CAPM return estimates for companies with betas below 1, and decrease CAPM return estimates for companies with betas greater than 1.

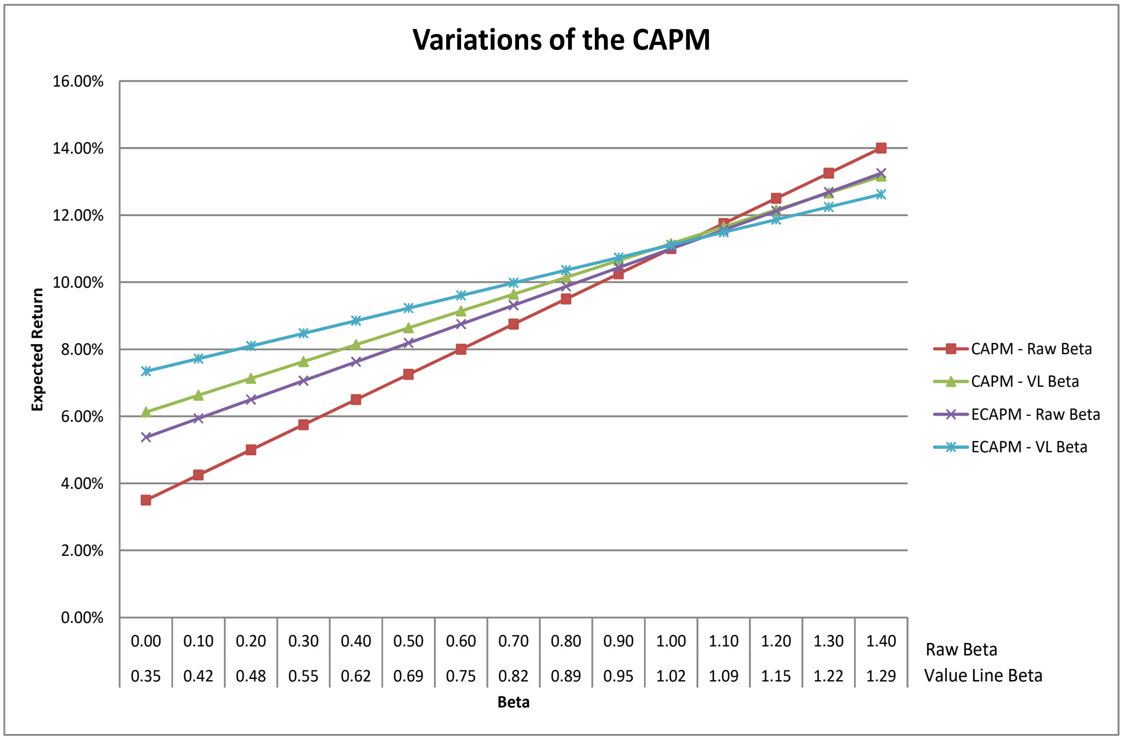
Q DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING THE ECAPM AND ADJUSTED BETAS?

A Yes. The notion that an adjustment to beta is still necessary when applying the ECAPM adjustment is not true. The *Value Line* beta adjustment alters the CAPM return at both the vertical axis (the intercept point) and the horizontal axis, the slope of the CAPM return line (along the horizontal axis). This is depicted in Figure CCW-5 below.

As shown in Figure CCW-5, I have modeled the expected returns at various levels of raw beta using both the traditional CAPM and ECAPM methodologies assuming a risk-free rate of 3.50%, and a market risk premium of 7.50%. I also show the expected CAPM and ECAPM returns using the associated adjusted (*Value Line*) beta estimates for each raw beta estimate. As shown in Figure CCW-5, the impact on the traditional CAPM return using a raw beta and a traditional CAPM using an adjusted beta has the effect of increasing the intercept point at a zero raw beta (y-axis) from: (1) risk-free rate to (2) the combination of the risk-free rate plus 35% of the market risk premium. Further, as the unadjusted beta is increased above zero, the adjusted beta increases the CAPM return when the raw beta is less than one, and decreases the CAPM return when the raw beta is greater than one. In other words, the beta adjustment raises the CAPM return at the vertical axis point and flattens the security market across the horizontal axis as the raw beta increases above zero.

The ECAPM using raw betas has the same impact on the traditional CAPM using an adjusted beta: the ECAPM increases the CAPM return at a zero raw beta from: (1) the risk-free rate, to (2) the risk-free rate plus 25% of the market risk premium. Further, the ECAPM using raw betas flattens the traditional CAPM return line across the horizontal axis as the raw betas increase above zero.

FIGURE CCW-5



Assumptions:
Market Risk Premium is 7.50%
Risk-Free Rate is 3.50%

As shown in the graph above, compared to the traditional CAPM using a raw beta, the traditional CAPM using an adjusted beta raises the intercept point (a y-axis impact) and flattens the slope of the security market line (an x-axis impact). Similarly, using a raw beta estimate, the ECAPM raises the intercept point at the y-axis and flattens the CAPM return for all raw beta estimates.

Significantly, if an adjusted beta is used in an ECAPM return model, the CAPM return at the y axis increases from: (1) the risk-free rate, up to (2) the risk-free rate plus approximately 51% of the market risk premium. Further, the CAPM return for betas less than one starts at an inflated y-axis intercept point and increases as the raw beta increases above zero.

Mathematically, *Value Line*'s beta adjustments produce nearly the same effect on the estimated CAPM return as does an ECAPM using a raw beta. Using an adjusted beta in an ECAPM model, as Mr. McKenzie has proposed, produces a flawed and inflated CAPM return estimate. Mr. McKenzie's ECAPM analysis should be rejected in its entirety.

D. Utility Risk Premium

Q PLEASE DESCRIBE MR. MCKENZIE'S UTILITY EQUITY RISK PREMIUM ANALYSIS.

A Mr. McKenzie's utility equity risk premium analysis is presented in his Exhibit PEPCO (F)-9. As shown on these exhibits, Mr. McKenzie measured the annual equity risk premium over the period of 1974 through 2022 by subtracting the average utility bond yield from the average authorized ROE. This produces an average equity risk premium of 3.89%.

Mr. McKenzie then performs a regression analysis to measure the inverse relationship between interest rates and equity risk premiums. Using this regression analysis, Mr. McKenzie adjusts his equity risk premium from 3.89%, up to 4.93% based on current utility bond yields.[55] He then adds these adjusted equity risk premiums to the current Baa-rated utility bond yields of 5.39%. This method produces a ROE in the range of 10.59%.[56]

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[55] Exhibits PEPCO (F)-9.
[56] *Id*.

Q DO YOU HAVE ANY CONCERNS WITH MR. MCKENZIE'S UTILITY EQUITY RISK PREMIUM?

A Yes. My main concerns with his utility equity risk premium analysis are: (1) his exclusive reliance on Baa-rated utility bond yields; (2) his use of a simple inverse relationship to estimate an equity risk premium through changes in interest rates, and; (3) his result produces an estimate higher than the average ROE for electric distribution utilities in any year that had at least three rate case decisions dating back to 2001.

As I explain above, Mr. McKenzie adds current Baa-rated utility bond yields to his adjusted equity risk premium. Mr. McKenzie's analysis fails to acknowledge that Pepco is not a Baa/BBB rated utility. Rather, Pepco is a split-rated utility with Baa1/A- ratings. Mr. McKenzie's sole reliance on Baa-rated utility bond yields overstates the cost of equity for Pepco.

As I explain above, because the risk premium can vary depending upon market conditions and changing investor risk perceptions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity for a risk premium methodology. In my opinion, measuring the five-year and ten-year rolling average risk premiums over the study period are a reasonable method of estimating the equity risk premium. These rolling average risk premiums mitigate the impact of anomalous market conditions and skewed risk premiums over an entire business cycle. Based on more recent data and my estimates of the equity risk premium detailed above, a more comprehensive Risk Premium-derived ROE estimate is 9.9%.

E. Mr. McKenzie's Expected Earnings

Q PLEASE DESCRIBE MR. MCKENZIE'S EXPECTED EARNINGS ANALYSIS.

A As shown on his Direct Exhibit PEPCO (F)-10, Mr. McKenzie's expected earnings analysis is based on *Value Line*'s projected earned return on book equities for his proxy group, adjusted to reflect average year equity returns. Based on a review of projected earnings over the next three to five years, Mr. McKenzie estimates an average ROE of 11.3%.

Q IS THE EXPECTED EARNINGS ANALYSIS A REASONABLE METHOD FOR ESTIMATING A FAIR ROE FOR THE COMPANY?

A No. An expected earnings analysis does not measure the return an investor requires in order to make an investment. In other words, the accounting measure of the earned ROE does not measure the opportunity cost of capital. Rather, it measures the earned return on book equity that companies have experienced in the past or are projected to achieve in the future. The returns investors require in order to assume the risk of an investment are measured from prevailing stock market prices.

In addition, FERC has recently found that the Expected Earnings model does not satisfy the requirements of *Hope*. In part, FERC states as follows:

> As a result, the expected return on a utility's book value does not reflect "returns on investments in other enterprises" because book value does not reflect the value of any investment that is available to an investor in the market, outside of the unlikely situation in which market value and book value are exactly equal. Accordingly, we find that relying on the Expected Earnings model would not satisfy the requirements of *Hope*.
>
> The return on book value is also not indicative of what return an investor requires to invest in the utility's equity or what return an investor receives on the equity investment, because those returns are determined

> with respect to the current market price that an investor must pay in order to invest in the equity.[57]

Later in the same Opinion, FERC observes that Expected Earnings model does not identify investments of comparable risk. It states as follows:

> Moreover, we find that the record demonstrates that the Expected Earnings model does not identify investments of comparable risk and which alternatives will have a higher expected return as MISO TOs' witness Mr. McKenzie indicates.[footnote omitted] In particular, because the Expected Earnings model measures returns on book value, without consideration of what market price an investor would have to pay to invest in the relevant company, it does not accurately measure the investor's expected returns on its investment.[58]

Additionally, the historical and projected earned ROE for these holding companies can be significantly influenced by the financial performance of nonregulated operations. For these reasons, Mr. McKenzie's expected earnings analysis should be disregarded.

F. Non-Utility DCF

Q DO YOU HAVE ANY ADDITIONAL COMMENTS IN REGARDS TO MR. MCKENZIE'S RETURN ESTIMATES?

A Yes. Mr. McKenzie also performed a DCF model on a proxy group of 33 non-regulated companies, which he found to be a reasonable risk proxy for Pepco. The average adjusted DCF results fall within the range of 10.2% to 10.6%. Mr. McKenzie opines that the analysis is relevant in evaluating a fair ROE for the Company.[59] I disagree with his assessment. However, because Mr. McKenzie did not rely on these results in

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[57] Opinion No. 569, 169 FERC ¶ 61,129 at p. 201-202.
[58] *Id*. at p. 205.
[59] McKenzie Direct at 53.

developing his inflated recommendation, I will not comment on his non-utility analysis any further.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

480707

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In the Matter of the	)	
	)	
Application of Potomac Electric Power Company	)	**Formal Case No. 1176**
for Authority to Implement a Multiyear Rate	)	
Plan for Electric Distribution Service	)	
in the District of Columbia	)	

AFFIDAVIT

I declare under penalty of perjury that the foregoing testimony was prepared by me or under my direction and is true and correct to the best of my knowledge, information, and belief.

Signature

Date: January 10, 2024

MARIA E. DECKER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis City
My Commission Expires: May 5, 2025
Commission # 13706793

Maria E. Decker

Qualifications of Christopher C. Walters

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I received a Bachelor of Science Degree in Business Economics and Finance from Southern Illinois University Edwardsville. I have also received a Master of Business Administration Degree from Lindenwood University.

As a Principal at BAI, I perform detailed technical analyses and research to support regulatory projects including expert testimony covering various regulatory issues. Since my career at BAI began in 2011, I have held the positions of Analyst, Associate Consultant, Consultant, Senior Consultant, and Associate. Throughout my tenure, I have been involved with several regulated projects for electric, natural gas and water and wastewater utilities, as well as competitive procurement of electric power and gas supply. My regulatory project work includes estimating the cost of equity capital, capital structure evaluations, assessing financial integrity, merger and acquisition related issues, risk management related issues, depreciation rate studies, and other revenue requirement issues.

BAI was formed in April 1995. BAI and its predecessor firm have participated in more than 700 regulatory proceedings in 40 states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Detroit, Michigan; Louisville, Kentucky and Phoenix, Arizona.

Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A Yes. I have sponsored testimony before state regulatory commissions including: Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, South Carolina, Texas, Utah, and Wyoming. In addition, I have also sponsored testimony before the City Council of New Orleans and an affidavit before the FERC.

Q PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A I earned the Chartered Financial Analyst ("CFA") designation from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting and reporting analysis, corporate finance, economics, fixed income and equity valuation, derivatives, alternative investments, risk management, and professional and ethical conduct. I am a member of the CFA Institute and the CFA Society of St. Louis.

Exhibit OPC (C)-2
Formal Case No. 1176

Exhibit OPC (C)-2
Page 1 of 16

		Price to Earnings (P/E) Ratio [1]																						
Line	Company	22-Year Average (1)	2023 [2] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)	2005 (20)	2004 (21)	2003 (22)	2002 (23)
1	ALLETE	18.07	13.90	18.10	20.60	18.30	24.70	22.20	23.00	18.60	15.10	17.20	18.60	15.90	14.70	16.00	16.10	13.90	14.80	16.55	17.91	25.21	N/A	N/A
2	Alliant Energy	17.02	17.40	21.40	21.20	21.20	21.20	19.10	20.60	22.30	18.10	16.60	15.30	14.50	14.50	12.50	13.90	13.40	15.10	16.82	12.59	14.00	12.69	19.93
3	Ameren Corp.	16.85	18.10	21.50	21.40	22.20	22.10	18.30	20.60	18.30	17.50	16.70	16.50	13.40	11.90	9.70	9.30	14.20	17.40	19.39	16.72	16.28	13.51	15.78
4	American Electric Power	15.14	14.40	21.10	17.10	19.60	21.40	18.00	19.30	15.20	15.80	15.90	14.50	13.80	11.90	13.40	10.00	13.10	16.30	12.91	13.70	12.42	10.66	12.68
5	Avangrid, Inc.	23.92	18.40	19.60	23.20	23.60	23.10	26.10	27.30	20.50	33.50	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	18.38	16.00	20.00	20.20	21.20	15.00	24.50	23.40	18.80	17.60	17.30	14.60	19.30	14.10	12.70	11.40	15.00	30.90	15.39	19.45	24.43	13.84	19.27
7	Black Hills	17.67	15.30	18.10	17.70	17.00	21.20	16.80	19.50	22.30	16.10	19.00	18.20	17.10	31.10	18.10	9.90	NMF	15.00	15.77	17.27	17.13	15.95	12.52
8	CenterPoint Energy	16.72	17.00	18.70	26.10	15.90	19.50	37.00	17.90	21.90	18.10	17.00	18.70	14.80	14.60	13.80	11.80	11.30	15.00	10.27	19.06	17.84	6.05	5.59
9	CMS Energy Corp.	18.31	18.00	22.90	23.60	23.30	24.30	20.30	21.30	20.90	18.30	17.30	16.30	15.10	13.60	12.50	13.60	10.90	26.80	22.18	12.60	12.39	N/A	N/A
10	Consol. Edison	16.19	19.20	20.30	17.20	19.00	19.70	17.10	19.80	18.80	15.60	15.90	14.70	15.40	15.10	13.30	12.50	12.30	13.80	15.49	15.13	18.21	14.30	13.28
11	Dominion Resources	18.18	14.80	18.70	19.50	22.60	18.20	17.50	22.20	21.30	22.10	23.00	19.20	18.90	17.30	14.30	12.70	13.80	20.60	15.98	24.89	15.07	15.24	12.05
12	DTE Energy	16.62	14.60	22.40	30.00	16.30	19.90	17.40	18.60	19.00	18.10	14.90	17.90	14.90	13.50	12.30	10.40	14.80	18.30	17.43	13.80	16.04	13.69	11.28
13	Duke Energy	17.16	16.10	19.60	18.90	17.10	17.70	17.00	19.90	21.30	18.20	17.90	17.40	17.50	13.80	12.70	13.30	17.30	16.10	N/A	N/A	N/A	N/A	N/A
14	Edison Int'l	17.09	14.40	40.60	29.70	34.90	16.70	N/A	17.20	17.90	14.80	13.00	12.70	9.70	11.80	10.30	9.70	12.40	16.00	12.99	11.74	37.59	6.97	7.78
15	El Paso Electric	17.68	N/A	N/A	N/A	N/A	N/A	26.85	21.78	18.66	18.33	16.38	15.88	14.47	12.60	10.72	10.79	11.89	15.26	16.92	26.72	22.03	18.26	22.99
16	Entergy Corp.	14.14	14.20	21.10	15.00	15.30	16.50	13.80	15.00	10.90	12.50	12.90	13.20	11.20	9.10	11.60	12.00	16.60	19.30	14.28	16.28	15.09	13.77	11.53
17	Eversource Energy	18.41	16.30	20.90	22.20	23.70	22.10	18.70	19.50	18.70	18.10	17.90	16.90	19.90	15.40	13.40	12.00	13.70	18.70	27.07	19.76	20.77	13.35	16.07
18	Evergy, Inc.	19.62	15.40	19.90	16.20	21.70	21.80	22.70	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	14.47	17.40	19.90	16.60	12.40	14.70	13.30	13.40	12.50	12.60	16.00	13.40	19.10	11.30	11.00	11.50	18.00	18.20	16.53	15.37	12.99	11.77	10.46
20	FirstEnergy Corp.	15.22	15.20	17.00	14.10	15.70	17.10	13.60	11.40	12.70	12.60	13.20	13.10	21.10	22.40	11.70	13.00	15.60	15.60	14.23	16.07	14.13	22.47	12.95
21	Fortis Inc.	19.38	19.10	21.10	21.20	20.60	19.20	17.10	16.80	21.60	18.00	24.30	20.00	20.10	18.80	18.20	16.40	17.50	21.10	17.68	N/A	N/A	N/A	N/A
22	Great Plains Energy	15.52	N/A	N/A	N/A	N/A	N/A	N/A	NMF	17.98	19.37	16.47	14.19	15.53	16.11	12.10	16.03	20.55	16.35	18.30	13.96	12.59	12.23	11.09
23	Hawaiian Elec.	18.16	16.60	18.50	18.20	21.50	21.30	18.90	20.70	13.60	20.40	15.90	16.20	15.80	17.10	18.60	19.80	23.20	21..6	20.33	18.27	19.18	13.76	13.47
24	IDACORP, Inc.	17.23	20.00	21.00	20.80	19.90	22.30	20.50	20.60	19.10	16.20	14.70	13.40	12.40	11.50	11.80	10.20	13.90	18.20	15.07	16.70	15.49	26.51	18.88
25	MGE Energy	20.13	21.80	24.70	25.50	26.40	28.40	25.10	29.40	24.90	20.30	17.20	17.00	17.20	15.80	15.00	15.10	14.20	15.00	15.88	22.40	17.98	17.55	15.96
26	NextEra Energy, Inc.	18.91	23.10	27.80	31.30	28.90	26.80	24.80	21.60	20.70	16.90	17.30	16.60	14.40	11.50	10.80	13.40	14.50	18.90	13.65	17.88	13.65	17.88	13.60
27	NorthWestern Corp	17.06	16.30	17.30	17.40	18.60	19.90	16.80	17.80	17.20	18.40	16.20	16.90	15.70	12.60	12.90	11.50	13.90	21.70	25.95	17.09	N/A	N/A	N/A
28	OGE Energy	15.33	15.80	17.20	14.30	16.20	19.00	16.50	18.30	17.70	17.70	18.30	17.70	15.20	14.40	13.30	10.80	12.40	13.80	13.68	14.95	14.13	11.84	14.12
29	Otter Tail Corp.	20.77	16.60	9.50	12.30	18.30	23.50	22.20	22.10	20.20	18.20	18.80	21.10	21.70	47.50	NMF	31.20	30.10	19.00	17.35	15.40	17.34	17.77	16.01
30	Pinnacle West Capital	16.06	19.60	17.10	14.10	16.70	19.40	17.80	19.30	18.70	16.00	15.90	15.30	14.30	14.60	12.60	13.70	16.10	14.90	13.69	19.24	15.80	13.96	14.43
31	PNM Resources	18.41	16.80	17.40	19.90	19.60	22.20	19.40	20.40	22.40	18.70	18.70	16.10	15.00	14.50	14.00	18.10	N/A	35.60	15.57	17.38	15.02	14.73	15.08
32	Portland General	16.87	17.10	18.20	17.70	16.60	22.30	18.40	20.00	19.10	17.70	15.30	16.90	14.00	12.40	12.00	14.40	16.30	11.90	23.35	N/A	N/A	N/A	N/A
33	PPL Corp.	16.28	17.10	20.00	54.10	13.90	13.30	11.30	17.60	12.80	13.90	14.10	12.80	10.90	10.50	11.90	25.70	17.60	17.30	14.10	15.12	12.51	10.59	11.06
34	Public Serv. Enterprise	14.48	18.00	18.50	16.80	15.70	18.00	16.60	16.30	15.30	14.10	12.60	13.50	12.80	10.40	10.40	10.00	13.60	16.50	17.81	16.74	14.26	10.58	10.00
35	SCANA Corp.	13.96	N/A	N/A	N/A	N/A	N/A	N/A	14.46	16.80	14.67	13.68	14.43	14.80	13.67	12.93	11.63	12.67	14.96	15.42	14.44	13.57	13.05	12.17
36	Sempra Energy	15.59	16.10	16.80	15.40	17.50	22.50	20.40	24.30	24.40	19.70	21.90	19.70	14.90	11.80	12.60	10.10	11.80	14.00	11.50	11.79	8.65	8.96	8.19
37	Southern Co.	16.24	17.80	19.60	18.40	17.90	17.60	15.10	15.50	17.80	15.80	16.00	16.20	17.00	15.80	14.90	13.50	16.10	16.00	16.19	15.92	14.68	14.83	14.63
38	Vectren Corp.	17.05	N/A	N/A	N/A	N/A	N/A	N/A	23.54	19.18	17.92	19.98	20.66	15.02	15.83	15.10	12.89	16.79	15.33	18.92	15.11	17.57	14.80	14.16
39	WEC Energy Group	17.47	17.40	21.90	22.30	24.90	23.50	19.60	20.00	19.90	21.30	17.70	16.50	15.80	14.20	14.00	13.30	14.80	16.50	15.97	14.46	17.51	12.43	10.46
40	Westar Energy	15.58	N/A	N/A	N/A	N/A	N/A	N/A	23.40	21.59	18.45	15.36	14.04	13.43	14.78	12.96	14.95	16.96	14.10	12.18	14.79	17.44	10.78	14.02
41	Xcel Energy Inc.	18.02	18.70	22.20	22.50	23.90	22.30	18.90	20.20	18.50	16.50	15.40	15.00	14.80	14.20	14.10	12.70	13.70	16.70	14.80	15.36	13.65	11.62	40.80
42	Average	17.08	17.06	20.29	20.91	19.95	20.51	19.43	19.85	18.75	17.58	16.77	16.19	15.56	15.30	13.16	13.57	15.27	17.66	16.51	16.56	16.65	13.83	14.31
43	Median	16.26	16.90	19.90	19.70	19.30	21.20	18.55	20.00	18.80	17.81	16.47	16.20	15.02	14.20	12.80	12.70	14.20	16.32	15.92	15.99	15.49	13.69	13.47

Sources:
The current year P/E ratio is based on the forward P/E (price over expected earnings per share). All historical year P/E ratios are based on annual average share price over achieved earnings per share.
[1] Data for years 2019 and prior were retreived from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, July 21, August 11, and September 8, 2023.

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Potomac Electric Power Company

Electric Utilities
(Valuation Metrics)

		Market Price to Cash Flow (MP/CF) Ratio [1]																						
Line	Company	22-Year Average (1)	2023 [2] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)	2005 (20)	2004 (21)	2003 (22)	2002 (23)
1	ALLETE	9.20	7.20	7.56	8.61	8.14	11.38	10.16	10.95	8.26	7.49	8.80	9.15	8.18	7.91	8.04	8.51	9.29	10.30	11.06	11.54	11.46	N/A	N/A
2	Alliant Energy	8.26	9.64	10.43	10.31	10.66	10.74	9.71	13.21	10.67	8.86	8.40	7.52	7.50	7.21	6.59	6.23	7.49	7.92	8.00	5.09	5.52	4.76	5.20
3	Ameren Corp.	7.45	8.94	9.54	9.03	9.63	9.45	7.95	8.38	7.44	6.87	6.95	6.61	5.48	5.02	4.23	4.25	6.35	7.69	8.57	8.57	8.24	6.74	7.96
4	American Electric Power	6.74	8.00	8.67	7.57	8.41	9.34	8.03	8.81	7.57	7.09	7.00	6.57	5.93	5.46	5.54	4.71	5.71	6.84	5.54	6.07	5.50	4.69	5.19
5	Avangrid, Inc.	9.67	8.44	8.69	11.19	9.39	9.11	10.24	10.14	8.56	11.30	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	7.04	8.30	9.39	8.03	7.80	7.34	10.14	9.35	7.63	6.76	7.30	6.21	6.88	6.40	5.80	4.06	5.12	7.58	5.30	6.58	7.58	5.36	5.90
7	Black Hills	7.95	8.44	8.92	8.84	8.56	10.65	8.83	9.20	9.33	8.06	8.81	8.03	6.04	7.85	6.16	4.25	11.26	7.62	6.92	7.57	6.69	6.89	5.92
8	CenterPoint Energy	5.57	7.72	8.01	7.95	5.94	7.03	8.45	6.97	5.96	5.75	6.25	6.56	5.15	5.39	4.70	4.05	4.29	5.17	3.94	4.70	4.26	2.08	2.16
9	CMS Energy Corp.	6.52	8.50	9.43	9.27	9.87	9.85	8.40	8.75	8.50	7.53	7.13	6.68	6.03	5.41	4.48	3.64	3.45	5.57	4.40	4.04	3.20	2.88	NMF
10	Consol. Edison	8.24	8.21	8.70	7.26	8.35	9.46	8.73	9.64	9.39	7.96	7.89	7.77	8.31	8.15	7.39	6.72	6.89	8.31	8.65	8.59	9.31	7.90	7.64
11	Dominion Resources	9.82	7.65	9.35	11.15	14.59	13.47	10.94	11.35	11.59	11.84	12.27	10.88	9.92	9.45	8.12	6.98	8.27	8.65	7.81	10.09	7.68	7.51	6.53
12	DTE Energy	6.79	7.96	7.96	10.62	7.85	9.67	8.54	9.05	8.64	8.52	6.42	6.65	5.91	5.18	4.69	3.59	4.90	5.73	5.21	5.54	6.00	5.62	5.20
13	Duke Energy	7.62	7.28	7.75	7.89	8.06	7.40	7.65	8.40	8.57	7.95	8.12	8.11	9.53	6.56	6.01	5.96	7.13	7.16	N/A	N/A	N/A	N/A	N/A
14	Edison Int'l	6.01	5.56	6.83	7.14	7.57	7.25	13.46	7.05	6.77	5.92	5.68	5.46	4.59	4.22	4.11	3.95	5.63	7.01	5.87	5.61	6.84	2.82	2.96
15	El Paso Electric	5.93	N/A	N/A	N/A	N/A	N/A	9.43	8.54	7.46	6.47	6.33	6.19	5.78	5.16	4.31	3.98	4.95	6.44	6.25	6.67	4.65	3.90	4.39
16	Entergy Corp.	5.80	5.97	7.15	5.61	5.78	6.05	4.92	4.66	4.01	4.11	4.21	4.03	4.23	3.90	4.66	5.68	7.96	9.21	7.16	8.76	7.12	6.84	5.57
17	Eversource Energy	7.56	8.49	9.39	11.41	12.53	11.47	9.16	10.36	10.14	10.12	10.14	8.08	9.30	6.99	4.97	4.61	4.12	6.18	6.02	3.55	3.78	2.85	2.75
18	Evergy, Inc.	7.89	7.60	8.66	7.41	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	6.04	6.16	7.69	5.08	4.44	5.29	5.05	4.45	4.80	4.70	5.09	4.61	5.54	5.86	5.10	5.98	9.65	9.89	8.62	7.97	6.29	5.71	4.97
20	FirstEnergy Corp.	6.93	8.48	8.93	6.60	9.23	11.09	8.84	4.76	5.12	5.38	7.43	6.15	7.42	7.33	4.49	4.91	7.58	7.89	7.53	6.04	5.15	6.90	5.10
21	Fortis Inc.	8.50	8.97	9.10	9.57	9.50	9.46	7.97	8.23	10.46	7.29	9.25	7.93	8.09	8.38	7.40	6.76	7.58	9.18	7.89	N/A	N/A	N/A	N/A
22	Great Plains Energy	6.89	N/A	N/A	N/A	N/A	N/A	N/A	14.62	8.63	6.66	6.45	5.73	6.09	5.74	4.49	5.06	7.71	7.13	7.68	6.70	6.52	5.92	5.14
23	Hawaiian Elec.	8.06	7.98	7.95	8.23	8.69	9.30	8.34	9.21	7.44	9.25	7.64	8.15	8.05	7.73	7.81	6.95	9.10	7.95	8.47	8.29	8.44	6.12	6.20
24	IDACORP, Inc.	9.02	12.07	12.42	11.84	11.38	12.75	11.72	11.56	10.95	9.37	8.59	7.78	7.05	6.64	6.52	5.31	7.10	8.23	7.73	7.55	7.15	7.27	7.53
25	MGE Energy	11.71	13.00	13.63	N/A	14.90	15.58	15.04	17.33	15.66	12.53	11.42	11.20	10.77	9.48	9.05	8.40	8.42	9.23	9.30	11.73	11.04	10.20	8.09
26	NextEra Energy, Inc.	9.34	13.94	15.17	20.40	15.48	12.33	10.77	11.61	9.24	7.93	7.98	7.60	7.58	5.98	5.33	6.09	7.34	9.02	6.51	6.71	6.71	5.97	5.77
27	NorthWestern Corp	7.92	8.43	8.65	8.83	8.88	9.93	8.19	8.82	8.65	8.99	9.01	7.61	6.85	5.89	5.79	5.05	5.57	8.45	9.39	7.31	8.13	N/A	N/A
28	OGE Energy	7.95	8.02	8.36	7.64	8.38	10.58	9.36	10.52	9.03	9.25	10.65	9.93	7.35	7.48	6.61	5.37	6.43	7.58	7.50	7.04	6.73	5.62	5.39
29	Otter Tail Corp.	9.44	11.72	7.70	8.61	9.99	12.42	11.58	11.09	9.38	9.04	9.45	9.58	8.43	9.04	8.07	8.01	11.65	9.53	8.66	8.18	9.01	8.13	8.33
30	Pinnacle West Capital	6.18	5.90	5.19	6.19	7.49	8.30	7.09	8.73	7.89	6.91	7.03	6.85	6.34	5.80	5.65	3.84	4.19	4.76	4.48	7.48	5.88	4.80	5.21
31	PNM Resources	6.90	6.96	6.95	7.81	7.87	7.92	7.57	7.40	7.64	6.95	7.48	6.47	5.80	4.94	4.58	4.53	7.10	10.67	7.50	7.62	6.84	5.55	5.72
32	Portland General	6.00	6.60	6.65	6.48	6.72	7.65	6.56	7.45	7.12	6.73	5.49	6.06	5.08	4.86	4.13	4.63	4.81	5.34	5.74	N/A	N/A	N/A	N/A
33	PPL Corp.	7.89	8.84	8.82	13.74	7.46	7.99	7.02	10.11	8.37	8.73	7.32	6.59	5.87	5.98	7.46	8.82	9.17	8.90	7.58	7.57	6.49	5.41	5.30
34	Public Serv. Enterprise	7.96	9.89	10.53	11.32	8.22	8.72	9.48	8.67	8.56	6.66	6.48	6.40	6.40	6.03	6.04	6.20	8.46	9.83	8.41	8.59	7.17	6.79	6.24
35	SCANA Corp.	7.09	N/A	N/A	N/A	N/A	N/A	N/A	8.26	9.59	8.33	7.50	7.49	7.40	6.75	6.52	5.88	6.38	7.15	7.03	5.40	6.86	6.59	6.36
36	Sempra Energy	8.47	9.30	9.75	13.23	10.40	12.05	10.10	10.65	10.88	9.99	10.77	9.37	7.26	6.13	6.53	6.07	7.07	8.61	7.22	6.96	5.16	4.85	4.00
37	Southern Co.	8.30	8.80	9.63	8.72	8.34	8.80	7.05	7.49	8.83	8.23	8.42	8.30	8.75	8.22	7.79	7.08	8.18	8.62	8.47	8.41	8.28	8.28	7.83
38	Vectren Corp.	7.08	N/A	N/A	N/A	N/A	N/A	N/A	10.32	8.60	7.82	7.57	6.82	5.79	5.81	5.58	5.24	6.90	6.53	7.37	7.06	7.63	7.27	6.92
39	WEC Energy Group	9.26	10.67	11.81	11.99	13.67	12.88	10.82	11.04	10.95	12.90	10.27	9.58	9.24	8.43	8.15	6.87	7.57	7.84	7.27	6.40	6.27	4.91	4.27
40	Westar Energy	6.91	N/A	N/A	N/A	N/A	N/A	N/A	10.87	10.86	9.05	7.93	7.23	6.71	6.67	5.51	5.32	7.09	6.88	5.81	7.00	6.54	4.24	2.94
41	Xcel Energy Inc.	7.06	8.08	8.62	9.19	10.07	9.44	7.90	8.50	8.10	7.62	7.31	7.00	6.85	6.47	6.28	5.43	5.71	6.51	5.54	5.62	5.31	4.27	5.46
42	Average	7.68	8.55	9.00	9.28	9.26	9.78	9.03	9.41	8.68	8.07	7.90	7.41	7.01	6.56	6.02	5.61	7.01	7.77	7.17	7.18	6.82	5.75	5.58
43	Median	7.50	8.36	8.69	8.72	8.56	9.46	8.78	9.13	8.58	7.94	7.57	7.23	6.85	6.40	5.80	5.37	7.10	7.84	7.44	7.05	6.72	5.66	5.46

Sources:
The current year P/E ratio is based on the forward P/E (price over expected earnings per share). All historical year P/E ratios are based on annual average share price over achieved earnings per share.
[1] Data for years 2019 and prior were retreived from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, July 21, August 11, and September 8, 2023.

Note:
[a] Based on the average of the high and low price and the projected Cash Flow per share.

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Potomac Electric Power Company

Electric Utilities
(Valuation Metrics)

		Market Price to Book Value (MP/BV) Ratio [1]																			
Line	Company	19-Year Average (1)	2023 [2] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)	2005 (20)
1	ALLETE	1.55	1.24	1.24	1.43	1.39	1.91	1.79	1.78	1.53	1.37	1.42	1.51	1.34	1.35	1.28	1.15	1.55	1.89	2.09	2.22
2	Alliant Energy	1.82	2.00	2.25	2.26	2.30	2.32	2.16	2.38	2.17	1.86	1.86	1.70	1.57	1.46	1.31	1.04	1.33	1.67	1.52	1.33
3	Ameren Corp.	1.60	2.11	2.15	2.13	2.21	2.26	1.95	1.93	1.67	1.46	1.45	1.29	1.18	0.90	0.83	0.78	1.25	1.60	1.62	1.68
4	American Electric Power	1.64	1.67	1.99	1.87	2.09	2.20	1.82	1.88	1.81	1.55	1.54	1.40	1.31	1.23	1.23	1.08	1.48	1.85	1.56	1.57
5	Avangrid, Inc.	0.91	0.80	0.89	1.01	0.97	1.02	1.02	0.93	0.83	0.72	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	1.33	1.23	1.33	1.42	1.37	1.54	1.88	1.73	1.57	1.36	1.33	1.25	1.21	1.19	1.07	0.94	1.11	1.29	1.30	1.13
7	Black Hills	1.51	1.40	1.54	1.52	1.55	1.95	1.61	2.06	1.94	1.59	1.79	1.62	1.21	1.14	1.07	0.83	1.22	1.57	1.47	1.63
8	CenterPoint Energy	2.27	1.74	1.99	1.74	1.90	2.21	2.18	2.59	2.73	2.43	2.27	2.30	1.99	1.87	1.96	1.77	2.49	3.13	2.75	3.06
9	CMS Energy Corp.	2.18	2.39	2.71	2.69	3.24	3.28	2.81	2.93	2.72	2.43	2.26	2.09	1.91	1.66	1.48	1.10	1.23	1.82	1.42	1.32
10	Consol. Edison	1.43	1.60	1.55	1.34	1.44	1.59	1.49	1.63	1.58	1.42	1.34	1.38	1.47	1.38	1.22	1.08	1.17	1.47	1.47	1.52
11	Dominion Resources	2.55	1.73	2.34	2.37	2.72	2.18	2.40	2.94	3.15	3.34	3.55	2.97	2.84	2.37	2.01	1.80	2.42	2.69	2.07	2.50
12	DTE Energy	1.66	2.11	2.41	2.82	1.80	2.07	1.91	2.01	1.82	1.65	1.62	1.51	1.35	1.20	1.16	0.89	1.10	1.35	1.29	1.39
13	Duke Energy	1.28	1.50	1.63	1.58	1.47	1.47	1.33	1.41	1.35	1.29	1.28	1.19	1.12	1.11	1.00	0.91	1.06	1.15	N/A	N/A
14	Edison Int'l	1.71	1.95	2.08	1.67	1.62	1.80	1.97	2.17	1.92	1.76	1.68	1.57	1.53	1.24	1.07	1.04	1.56	2.05	1.80	1.93
15	El Paso Electric	1.56	N/A	N/A	N/A	N/A	N/A	1.94	1.87	1.68	1.48	1.52	1.49	1.59	1.64	1.17	0.98	1.33	1.69	1.71	1.76
16	Entergy Corp.	1.75	1.64	1.81	1.75	1.93	2.03	1.74	1.76	1.67	1.40	1.33	1.21	1.31	1.35	1.62	1.66	2.44	2.65	1.89	2.01
17	Eversource Energy	1.55	1.70	1.86	2.00	2.11	1.99	1.68	1.73	1.64	1.53	1.47	1.38	1.28	1.50	1.31	1.12	1.31	1.60	1.22	1.05
18	Evergy, Inc.	1.48	1.42	1.52	1.50	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	2.08	1.65	1.88	1.37	1.20	1.43	1.31	1.20	1.20	1.14	1.28	1.17	1.46	1.95	2.07	2.57	4.39	4.79	3.89	3.60
20	FirstEnergy Corp.	2.06	2.12	2.37	2.33	2.81	3.39	2.67	3.53	2.37	1.16	1.15	1.28	1.44	1.33	1.36	1.54	2.52	2.23	1.92	1.64
21	Fortis Inc.	1.48	1.46	1.56	1.48	1.47	1.41	1.24	1.41	1.26	1.33	1.35	1.45	1.59	1.59	1.56	1.33	1.48	1.63	1.96	N/A
22	Great Plains Energy	1.21	N/A	N/A	N/A	N/A	N/A	N/A	1.33	1.17	1.12	1.11	1.02	0.96	0.93	0.87	0.80	1.11	1.66	1.77	1.86
23	Hawaiian Elec.	1.69	1.89	1.94	1.81	1.82	2.02	1.76	1.76	1.63	1.71	1.49	1.54	1.62	1.54	1.44	1.16	1.61	1.57	2.01	1.78
24	IDACORP, Inc.	1.52	1.83	1.91	1.88	1.84	2.10	1.96	1.94	1.76	1.54	1.45	1.33	1.19	1.17	1.13	0.92	1.09	1.26	1.37	1.22
25	MGE Energy	2.16	2.50	2.47	N/A	2.54	2.88	2.59	2.88	2.60	2.10	2.10	2.06	1.92	1.75	1.65	1.54	1.62	1.75	1.83	2.09
26	NextEra Energy, Inc.	2.42	3.52	4.07	4.27	3.58	2.75	2.32	2.35	2.30	2.09	2.15	1.93	1.74	1.55	1.49	1.70	2.06	2.34	1.80	1.93
27	NorthWestern Corp	1.44	1.21	1.25	1.43	1.45	1.74	1.48	1.64	1.68	1.60	1.54	1.56	1.42	1.35	1.22	1.07	1.15	1.48	1.65	1.42
28	OGE Energy	1.82	1.66	1.74	1.67	1.86	2.06	1.75	1.82	1.73	1.79	2.22	2.24	1.94	1.90	1.70	1.37	1.52	1.98	1.91	1.80
29	Otter Tail Corp.	1.93	2.52	2.30	2.33	2.04	2.62	2.49	2.33	1.90	1.78	1.90	1.96	1.58	1.35	1.19	1.18	1.71	1.93	1.76	1.74
30	Pinnacle West Capital	1.42	1.44	1.31	1.45	1.63	1.91	1.74	1.91	1.72	1.52	1.44	1.47	1.39	1.25	1.14	0.95	1.00	1.26	1.26	1.25
31	PNM Resources	1.37	1.76	1.81	1.86	1.87	2.28	1.83	1.84	1.56	1.33	1.21	1.09	0.98	0.80	0.69	0.56	0.66	1.23	1.21	1.45
32	Portland General	1.37	1.45	1.58	1.55	1.57	1.84	1.56	1.69	1.56	1.42	1.37	1.28	1.14	1.09	0.94	0.92	1.05	1.32	1.36	N/A
33	PPL Corp.	2.00	1.45	1.44	1.52	1.63	1.86	1.81	2.40	2.46	2.24	1.64	1.55	1.58	1.47	1.61	2.10	3.19	3.05	2.43	2.50
34	Public Serv. Enterprise	1.94	2.12	2.32	2.11	1.70	1.97	1.81	1.68	1.67	1.58	1.57	1.44	1.46	1.59	1.67	1.78	2.58	2.99	2.46	2.45
35	SCANA Corp.	1.51	N/A	N/A	N/A	N/A	N/A	N/A	1.65	1.74	1.47	1.48	1.48	1.48	1.36	1.33	1.20	1.45	1.62	1.64	1.72
36	Sempra Energy	1.80	1.77	1.84	1.64	1.84	2.22	2.06	2.24	2.00	2.17	2.20	1.84	1.53	1.28	1.35	1.32	1.60	1.87	1.70	1.73
37	Southern Co.	2.12	2.40	2.53	2.39	2.20	2.13	1.89	2.07	2.01	1.99	2.02	2.04	2.15	1.99	1.83	1.73	2.12	2.24	2.23	2.35
38	Vectren Corp.	1.83	N/A	N/A	N/A	N/A	N/A	N/A	2.75	2.29	2.11	2.08	1.82	1.57	1.53	1.41	1.34	1.64	1.74	1.77	1.82
39	WEC Energy Group	2.07	2.46	2.57	2.61	2.84	2.62	2.11	2.10	2.09	1.82	2.34	2.21	2.05	1.81	1.65	1.40	1.57	1.77	1.71	1.62
40	Westar Energy	1.37	N/A	N/A	N/A	N/A	N/A	N/A	1.94	1.95	1.49	1.44	1.33	1.26	1.20	1.10	0.93	1.10	1.36	1.30	1.41
41	Xcel Energy Inc.	1.74	2.11	2.22	2.27	2.46	2.34	1.97	2.06	1.88	1.66	1.55	1.50	1.51	1.41	1.32	1.19	1.30	1.53	1.40	1.38
42	Average	1.74	1.82	1.96	1.92	1.96	2.10	1.89	2.01	1.86	1.67	1.69	1.60	1.52	1.43	1.35	1.25	1.63	1.90	1.78	1.80
43	Median	1.71	1.73	1.89	1.75	1.84	2.06	1.86	1.92	1.75	1.57	1.54	1.50	1.47	1.36	1.31	1.15	1.48	1.69	1.71	1.73

Sources:
The current year P/E ratio is based on the forward P/E (price over expected earnings per share). All historical year P/E ratios are based on annual average share price over achieved earnings per share.
[1] Data for years 2019 and prior were retreived from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, July 21, August 11, and September 8, 2023.

Notes:

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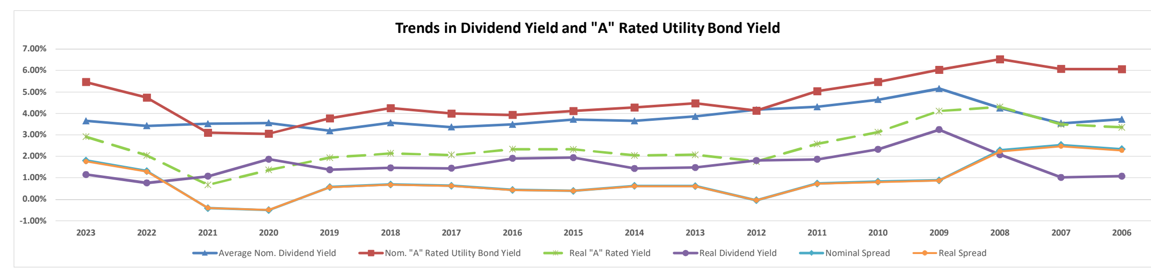
Potomac Electric Power Company

Electric Utilities
(Valuation Metrics)

		Dividend Yield[1]																		
Line	Company	18-Year Average (1)	2023 [2/a] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)
1	ALLETE	4.00%	4.46%	4.47%	3.88%	4.03%	2.85%	2.99%	2.97%	3.56%	3.97%	3.92%	3.89%	4.49%	4.58%	5.03%	5.79%	4.37%	3.60%	3.16%
2	Alliant Energy	3.60%	3.42%	3.04%	2.97%	2.90%	2.88%	3.20%	3.07%	3.21%	3.60%	3.53%	3.74%	4.07%	4.28%	4.61%	5.73%	4.10%	3.13%	3.32%
3	Ameren Corp.	4.10%	2.97%	2.74%	2.74%	2.57%	2.59%	3.04%	3.12%	3.50%	3.96%	4.02%	4.61%	4.97%	5.28%	5.76%	5.98%	6.21%	4.88%	4.93%
4	American Electric Power	3.96%	3.80%	3.41%	3.61%	3.28%	3.10%	3.60%	3.42%	3.54%	3.80%	3.83%	4.23%	4.58%	4.96%	4.90%	5.50%	4.20%	3.40%	4.06%
5	Avangrid, Inc.	3.82%	4.35%	3.94%	3.53%	3.69%	3.52%	3.49%	3.79%	4.26%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	3.84%	4.53%	4.26%	3.94%	4.03%	3.48%	2.93%	3.14%	3.39%	3.97%	3.99%	4.51%	4.55%	4.54%	4.76%	4.49%	3.39%	2.68%	2.52%
7	Black Hills	3.71%	3.87%	3.44%	3.50%	3.42%	2.74%	3.31%	2.75%	2.87%	3.55%	2.84%	3.19%	4.39%	4.64%	4.79%	6.17%	4.21%	3.40%	3.79%
8	CenterPoint Energy	4.14%	2.62%	2.46%	2.77%	4.38%	2.98%	4.09%	4.79%	4.70%	5.06%	3.94%	3.57%	4.04%	4.27%	5.29%	6.37%	4.98%	3.87%	4.39%
9	CMS Energy Corp.	3.19%	3.21%	2.92%	2.92%	2.65%	2.64%	3.03%	2.88%	2.99%	3.36%	3.59%	3.76%	4.16%	4.25%	3.98%	3.97%	2.69%	1.16%	N/A
10	Consol. Edison	4.28%	3.45%	3.51%	4.10%	3.87%	3.44%	3.68%	3.40%	3.62%	4.12%	4.38%	4.25%	4.07%	4.46%	5.16%	5.99%	5.67%	4.84%	5.04%
11	Dominion Resources	4.04%	4.75%	3.66%	3.38%	4.31%	4.76%	4.72%	3.88%	3.82%	3.66%	3.43%	3.78%	4.06%	4.13%	4.41%	5.20%	3.77%	3.32%	3.60%
12	DTE Energy	3.97%	3.41%	3.17%	3.06%	3.57%	3.07%	3.34%	3.15%	3.34%	3.53%	3.54%	3.84%	4.19%	4.68%	4.75%	6.29%	5.24%	4.36%	4.86%
13	Duke Energy	4.60%	4.19%	3.98%	4.02%	4.35%	4.17%	4.54%	4.15%	4.26%	4.34%	4.26%	4.45%	4.68%	5.21%	5.71%	6.25%	5.16%	4.44%	N/A
14	Edison Int'l	3.36%	4.34%	4.45%	4.39%	4.29%	3.73%	3.84%	2.87%	2.81%	2.83%	2.62%	2.85%	2.97%	3.37%	3.66%	3.95%	2.69%	2.21%	2.58%
15	El Paso Electric	2.74%	N/A	N/A	N/A	N/A	N/A	2.55%	2.49%	2.75%	3.13%	2.97%	2.99%	2.97%	2.11%	N/A	N/A	N/A	N/A	N/A
16	Entergy Corp.	4.02%	4.18%	3.70%	3.84%	3.55%	3.52%	4.41%	4.49%	4.55%	4.59%	4.47%	5.07%	4.91%	4.85%	4.20%	3.97%	2.92%	2.39%	2.82%
17	Eversource Energy	3.25%	3.49%	3.09%	2.85%	2.63%	2.81%	3.32%	3.14%	3.22%	3.34%	3.40%	3.48%	3.52%	3.23%	3.64%	4.16%	3.25%	2.60%	3.27%
18	Evergy, Inc.	3.79%	4.12%	3.66%	3.59%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	3.74%	3.46%	2.89%	3.17%	3.82%	3.06%	3.32%	3.51%	3.75%	3.88%	3.69%	4.69%	5.73%	4.96%	4.95%	4.26%	2.78%	2.48%	2.83%
20	FirstEnergy Corp.	4.30%	4.07%	3.71%	4.39%	4.17%	3.50%	5.17%	4.62%	4.31%	4.23%	4.26%	4.26%	4.90%	5.23%	5.76%	5.09%	3.21%	3.12%	3.40%
21	Fortis Inc.	3.70%	3.99%	3.82%	3.77%	3.66%	3.60%	4.07%	3.69%	3.80%	3.76%	3.88%	3.84%	3.64%	3.58%	3.80%	4.21%	3.76%	3.01%	2.79%
22	Great Plains Energy	4.52%	N/A	N/A	N/A	N/A	N/A	N/A	3.58%	3.64%	3.76%	3.62%	3.84%	4.08%	4.15%	4.49%	5.03%	6.96%	5.49%	5.60%
23	Hawaiian Elec.	4.37%	3.65%	3.59%	3.44%	3.40%	3.02%	3.54%	3.65%	3.99%	4.05%	4.76%	4.72%	4.70%	5.04%	5.51%	6.89%	5.00%	5.18%	4.59%
24	IDACORP, Inc.	3.15%	3.01%	2.86%	2.89%	2.92%	2.49%	2.61%	2.58%	2.77%	3.06%	3.12%	3.21%	3.28%	3.10%	3.44%	4.46%	3.95%	3.55%	3.39%
25	MGE Energy	3.00%	2.20%	2.15%	N/A	2.10%	1.94%	2.16%	1.95%	2.23%	2.78%	2.78%	2.91%	3.25%	3.63%	3.98%	4.36%	4.24%	4.14%	4.25%
26	NextEra Energy, Inc.	2.87%	2.40%	2.11%	1.90%	2.10%	2.41%	2.68%	2.79%	2.91%	3.01%	3.02%	3.30%	3.65%	3.96%	3.90%	N/A	N/A	N/A	N/A
27	NorthWestern Corp	4.12%	4.47%	4.51%	4.00%	4.02%	3.28%	3.86%	3.52%	3.43%	3.61%	3.30%	3.66%	4.17%	4.51%	4.93%	5.75%	5.38%	4.09%	3.65%
28	OGE Energy	3.82%	4.50%	4.30%	4.81%	4.68%	3.54%	3.98%	3.61%	3.87%	3.51%	2.63%	2.48%	2.94%	3.06%	3.68%	4.96%	4.52%	3.77%	3.99%
29	Otter Tail Corp.	3.84%	2.33%	2.44%	2.81%	3.45%	2.74%	2.92%	3.12%	3.87%	4.33%	4.14%	4.11%	5.21%	5.57%	5.68%	5.38%	3.63%	3.46%	3.92%
30	Pinnacle West Capital	4.50%	4.45%	4.90%	4.44%	3.97%	3.29%	3.55%	3.16%	3.46%	3.88%	4.09%	3.98%	5.32%	4.81%	5.43%	6.76%	6.17%	4.75%	4.67%
31	PNM Resources	3.15%	3.17%	3.04%	2.09%	2.80%	2.45%	2.79%	2.53%	2.69%	2.90%	2.79%	2.99%	2.96%	3.19%	4.09%	4.76%	4.85%	3.36%	3.21%
32	Portland General	3.68%	3.90%	3.63%	3.62%	3.47%	2.85%	3.27%	2.92%	3.06%	3.27%	3.34%	3.67%	4.11%	4.37%	5.20%	5.36%	4.28%	3.34%	2.54%
33	PPL Corp.	4.47%	3.36%	3.23%	5.83%	5.84%	5.24%	5.61%	4.24%	4.25%	4.55%	4.45%	4.81%	5.07%	5.10%	5.12%	4.51%	3.10%	2.69%	3.41%
34	Public Serv. Enterprise	3.74%	3.75%	3.37%	3.37%	3.64%	3.19%	3.49%	3.74%	3.78%	3.81%	3.92%	4.35%	4.55%	4.24%	4.30%	4.30%	3.26%	2.73%	3.47%
35	SCANA Corp.	4.37%	N/A	N/A	N/A	N/A	N/A	N/A	4.03%	3.29%	3.90%	4.05%	4.15%	4.25%	4.78%	4.93%	5.67%	4.92%	4.29%	4.21%
36	Sempra Energy	2.99%	3.15%	2.99%	3.39%	3.24%	2.88%	3.20%	2.92%	2.92%	2.71%	2.61%	3.03%	3.71%	3.65%	3.08%	3.23%	2.62%	2.08%	2.47%
37	Southern Co.	4.58%	4.13%	3.82%	4.17%	4.36%	4.41%	5.27%	4.63%	4.42%	4.78%	4.69%	4.61%	4.29%	4.63%	5.13%	5.52%	4.58%	4.39%	4.52%
38	Vectren Corp.	4.38%	N/A	N/A	N/A	N/A	N/A	N/A	2.79%	3.31%	3.60%	3.62%	4.15%	4.82%	5.06%	5.53%	5.85%	4.79%	4.53%	4.52%
39	WEC Energy Group	3.05%	3.40%	3.08%	3.00%	2.68%	2.81%	3.38%	3.31%	3.35%	3.49%	3.40%	3.49%	3.24%	3.35%	2.97%	3.16%	2.41%	2.14%	2.18%
40	Westar Energy	4.37%	N/A	N/A	N/A	N/A	N/A	N/A	3.00%	2.90%	3.73%	3.88%	4.27%	4.57%	4.84%	5.32%	6.27%	5.22%	4.16%	4.28%
41	Xcel Energy Inc.	3.68%	3.12%	2.90%	2.81%	2.58%	2.75%	3.25%	3.10%	3.33%	3.69%	3.83%	3.86%	3.90%	4.20%	4.54%	5.14%	4.70%	4.05%	4.40%
42	**Average**	**3.82%**	**3.66%**	**3.42%**	**3.52%**	**3.56%**	**3.19%**	**3.56%**	**3.36%**	**3.49%**	**3.72%**	**3.66%**	**3.86%**	**4.18%**	**4.30%**	**4.64%**	**5.16%**	**4.25%**	**3.54%**	**3.73%**
43	Median	3.67%	3.70%	3.43%	3.50%	3.57%	3.06%	3.36%	3.16%	3.45%	3.73%	3.69%	3.84%	4.17%	4.46%	4.78%	5.20%	4.24%	3.46%	3.65%
44	20-Yr Treasury Yields[3]	3.24%	4.08%	3.30%	1.98%	1.35%	2.40%	3.02%	2.65%	2.23%	2.55%	3.07%	3.12%	2.54%	3.62%	4.03%	4.11%	4.36%	4.91%	4.99%
45	20-Yr TIPS[3]	1.06%	1.57%	0.64%	-0.43%	-0.30%	0.60%	0.94%	0.75%	0.66%	0.78%	0.87%	0.75%	0.21%	1.19%	1.73%	2.21%	2.19%	2.36%	2.31%
46	Implied Inflation[b]	2.16%	2.47%	2.64%	2.42%	1.66%	1.79%	2.06%	1.89%	1.56%	1.75%	2.19%	2.35%	2.33%	2.40%	2.26%	1.85%	2.13%	2.49%	2.62%
47	**Real Dividend Yield[c]**	**1.63%**	**1.16%**	**0.77%**	**1.07%**	**1.86%**	**1.37%**	**1.47%**	**1.44%**	**1.91%**	**1.94%**	**1.43%**	**1.48%**	**1.81%**	**1.86%**	**2.33%**	**3.24%**	**2.07%**	**1.02%**	**1.08%**
	A-Rated Utility																			
48	**Nominal "A" Rated Yield[4]**	**4.70%**	**5.46%**	**4.74%**	**3.10%**	**3.05%**	**3.77%**	**4.25%**	**4.00%**	**3.93%**	**4.12%**	**4.28%**	**4.48%**	**4.13%**	**5.04%**	**5.46%**	**6.04%**	**6.53%**	**6.07%**	**6.07%**
49	**Real "A" Rated Yield**	**2.48%**	**2.92%**	**2.05%**	**0.67%**	**1.37%**	**1.94%**	**2.14%**	**2.07%**	**2.34%**	**2.33%**	**2.04%**	**2.08%**	**1.76%**	**2.58%**	**3.13%**	**4.11%**	**4.31%**	**3.49%**	**3.36%**
	Baa-Rated Utility																			
50	**Nominal "Baa" Rated Yield**	**5.20%**	**5.76%**	**5.05%**	**3.36%**	**3.44%**	**4.19%**	**4.67%**	**4.38%**	**4.67%**	**5.03%**	**4.80%**	**4.98%**	**4.83%**	**5.57%**	**5.96%**	**7.06%**	**7.25%**	**6.33%**	**6.32%**
51	**Real "Baa" Rated Yield**	**2.98%**	**3.21%**	**2.35%**	**0.91%**	**1.74%**	**2.36%**	**2.55%**	**2.44%**	**3.07%**	**3.22%**	**2.55%**	**2.57%**	**2.44%**	**3.09%**	**3.62%**	**5.11%**	**5.01%**	**3.74%**	**3.60%**
	Spreads (A-Rated Utility Bond - Stock)																			
52	**Nominal Spread[d]**	**0.87%**	**1.80%**	**1.32%**	**-0.41%**	**-0.50%**	**0.58%**	**0.69%**	**0.64%**	**0.44%**	**0.40%**	**0.62%**	**0.61%**	**-0.05%**	**0.74%**	**0.82%**	**0.88%**	**2.28%**	**2.53%**	**2.34%**
53	**Real Spread[e]**	**0.85%**	**1.76%**	**1.28%**	**-0.40%**	**-0.49%**	**0.57%**	**0.68%**	**0.62%**	**0.43%**	**0.39%**	**0.61%**	**0.60%**	**-0.05%**	**0.72%**	**0.80%**	**0.87%**	**2.23%**	**2.47%**	**2.28%**
	Spreads (Baa-Rated Utility Bond - Stock)																			
54	**Nominal Spread[b]**	**1.38%**	**2.10%**	**1.63%**	**-0.16%**	**-0.12%**	**1.00%**	**1.11%**	**1.01%**	**1.18%**	**1.31%**	**1.14%**	**1.12%**	**0.65%**	**1.26%**	**1.32%**	**1.90%**	**3.00%**	**2.79%**	**2.58%**
55	**Real Spread[c]**	**1.35%**	**2.05%**	**1.58%**	**-0.16%**	**-0.12%**	**0.98%**	**1.09%**	**1.00%**	**1.16%**	**1.29%**	**1.12%**	**1.09%**	**0.63%**	**1.23%**	**1.29%**	**1.87%**	**2.93%**	**2.72%**	**2.52%**
	Spreads (Treasury Bond - Stock)																			
56	**Nominal[f]**	**-0.58%**	**0.43%**	**-0.12%**	**-1.54%**	**-2.20%**	**-0.79%**	**-0.54%**	**-0.71%**	**-1.27%**	**-1.17%**	**-0.58%**	**-0.74%**	**-1.63%**	**-0.68%**	**-0.61%**	**-1.05%**	**0.11%**	**1.37%**	**1.26%**
57	**Real[g]**	**-0.57%**	**0.42%**	**-0.12%**	**-1.50%**	**-2.17%**	**-0.77%**	**-0.53%**	**-0.70%**	**-1.25%**	**-1.15%**	**-0.57%**	**-0.73%**	**-1.60%**	**-0.67%**	**-0.60%**	**-1.03%**	**0.11%**	**1.33%**	**1.23%**



Sources:
[1] Data for years 2019 and prior were retreived from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, July 21, August 11, and September 8, 2023.
[3] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.
[4] www.moodys.com, Bond Yields and Key Indicators, through October 13, 2023.
Notes:
[a] Based on the average of the high and low price and the projected Dividends Declared per share, published in the Value Line Investment Survey.
[b] Line 47 = (1 + Line 45) / (1 + Line 46) - 1.
[c] Line 48 = (1 + Line 43) / (1 +Line 47) - 1.
[d] The spread being measured here is the nominal A-rated utility bond yield over the average nominal utility dividend yield; (Line 49 - Line 43).
[e] The spread being measured here is the real A-rated utility bond yield over the average real utility dividend yield; Line 50 - Line 48)
[f] The spread being measured here is the nominal 20-Year Treasury yield over the average nominal utility dividend yield; (Line 45 - Line 43).
[g] The spread being measured here is the real 20-Year TIPS yield over the average real utility dividend yield; Line 48 - Line 46)

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Potomac Electric Power Company

Electric Utilities
(Valuation Metrics)

Line	Company	18-Year Average (1)	2023[2] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)
		Dividend per Share[1]																		
1	ALLETE	2.05	2.71	2.60	2.52	2.47	2.35	2.24	2.14	2.08	2.02	1.96	1.90	1.84	1.78	1.76	1.76	1.72	1.64	1.45
2	Alliant Energy	1.12	1.81	1.71	1.61	1.52	1.42	1.34	1.26	1.18	1.10	1.02	0.94	0.90	0.85	0.79	0.75	0.70	0.64	0.58
3	Ameren Corp.	1.95	2.52	2.36	2.20	2.00	1.92	1.85	1.78	1.72	1.66	1.61	1.60	1.60	1.56	1.54	1.54	2.54	2.54	2.54
4	American Electric Power	2.23	3.35	3.17	3.00	2.84	2.71	2.53	2.39	2.27	2.15	2.03	1.95	1.88	1.85	1.71	1.64	1.64	1.58	1.50
5	Avangrid, Inc.	1.75	1.76	1.76	1.76	1.76	1.76	1.74	1.73	1.73	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	1.25	1.84	1.76	1.69	1.62	1.55	1.49	1.43	1.37	1.32	1.27	1.22	1.16	1.10	1.00	0.81	0.69	0.60	0.57
7	Black Hills	1.75	2.53	2.41	2.29	2.17	2.05	1.93	1.81	1.68	1.62	1.56	1.52	1.48	1.46	1.44	1.42	1.40	1.37	1.32
8	CenterPoint Energy	0.85	0.77	0.72	0.66	0.90	0.86	1.12	1.35	1.03	0.99	0.95	0.83	0.81	0.79	0.78	0.76	0.73	0.68	0.60
9	CMS Energy Corp.	1.15	1.95	1.84	1.74	1.63	1.53	1.43	1.33	1.24	1.16	1.08	1.02	0.96	0.84	0.66	0.50	0.36	0.20	N/A
10	Consol. Edison	2.66	3.24	3.16	3.10	3.06	2.96	2.86	2.76	2.68	2.60	2.52	2.46	2.42	2.40	2.38	2.36	2.34	2.32	2.30
11	Dominion Resources	2.42	2.67	2.67	2.52	3.45	3.67	3.34	3.04	2.80	2.59	2.40	2.25	2.11	1.97	1.83	1.75	1.58	1.46	1.38
12	DTE Energy	2.93	3.81	3.54	3.88	4.12	3.85	3.59	3.36	3.06	2.84	2.69	2.59	2.42	2.32	2.18	2.12	2.12	2.12	2.08
13	Duke Energy	3.32	4.06	3.98	3.90	3.82	3.75	3.64	3.49	3.36	3.24	3.15	3.09	3.03	2.97	2.91	2.82	2.70	2.58	N/A
14	Edison Int'l	1.86	2.99	2.84	2.69	2.58	2.48	2.43	2.23	1.98	1.73	1.48	1.37	1.31	1.29	1.27	1.25	1.23	1.18	1.10
15	El Paso Electric	1.11	N/A	N/A	N/A	N/A	N/A	1.42	1.32	1.23	1.17	1.11	1.05	0.97	0.66	N/A	N/A	N/A	N/A	N/A
16	Entergy Corp.	3.38	4.30	4.10	3.86	3.74	3.66	3.58	3.50	3.42	3.34	3.32	3.32	3.32	3.32	3.24	3.00	3.00	2.58	2.16
17	Eversource Energy	1.62	2.70	2.55	2.41	2.27	2.14	2.02	1.90	1.78	1.67	1.57	1.47	1.32	1.10	1.03	0.95	0.83	0.78	0.73
18	Evergy, Inc.	2.33	2.49	2.33	2.18	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	1.62	1.44	1.35	1.53	1.53	1.45	1.38	1.31	1.26	1.24	1.24	1.46	2.10	2.10	2.10	2.10	2.05	1.82	1.64
20	FirstEnergy Corp.	1.78	1.62	1.56	1.56	1.56	1.53	1.82	1.44	1.44	1.44	1.44	1.65	2.20	2.20	2.20	2.20	2.20	2.05	1.85
21	Fortis Inc.	1.46	2.29	2.17	2.08	1.97	1.86	1.75	1.65	1.55	1.43	1.30	1.25	1.21	1.17	1.12	1.04	1.00	0.82	0.67
22	Great Plains Energy	1.11	N/A	N/A	N/A	N/A	N/A	N/A	1.10	1.06	1.00	0.94	0.88	0.86	0.84	0.83	0.83	1.66	1.66	1.66
23	Hawaiian Elec.	1.27	1.44	1.40	1.36	1.32	1.28	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24
24	IDACORP, Inc.	1.94	3.20	3.04	2.88	2.72	2.56	2.40	2.24	2.08	1.92	1.76	1.57	1.37	1.20	1.20	1.20	1.20	1.20	1.20
25	MGE Energy	1.18	1.67	1.59	N/A	1.45	1.38	1.32	1.26	1.21	1.16	1.11	1.07	1.04	1.01	0.99	0.97	0.96	0.94	0.93
26	NextEra Energy, Inc.	0.90	1.87	1.70	1.54	1.40	1.25	1.11	0.98	0.87	0.77	0.73	0.66	0.60	0.55	0.50	0.47	0.45	0.41	0.38
27	NorthWestern Corp	1.84	2.56	2.52	2.48	2.40	2.30	2.20	2.10	2.00	1.92	1.60	1.52	1.48	1.44	1.36	1.34	1.32	1.28	1.24
28	OGE Energy	1.10	1.66	1.64	1.63	1.58	1.51	1.40	1.27	1.16	1.05	0.95	0.85	0.80	0.76	0.73	0.71	0.70	0.68	0.67
29	Otter Tail Corp.	1.31	1.75	1.65	1.56	1.48	1.40	1.34	1.28	1.25	1.23	1.21	1.19	1.19	1.19	1.19	1.19	1.19	1.17	1.15
30	Pinnacle West Capital	2.60	3.48	3.42	3.36	3.23	3.04	2.87	2.70	2.56	2.44	2.33	2.23	2.67	2.10	2.10	2.10	2.10	2.10	2.03
31	PNM Resources	0.89	1.49	1.41	0.98	1.25	1.18	1.09	0.99	0.88	0.80	0.76	0.68	0.58	0.50	0.50	0.50	0.61	0.91	0.86
32	Portland General	1.26	1.88	1.79	1.70	1.59	1.52	1.43	1.34	1.26	1.18	1.12	1.10	1.08	1.06	1.04	1.01	0.97	0.93	0.68
33	PPL Corp.	1.40	0.95	0.88	1.66	1.66	1.65	1.64	1.58	1.52	1.50	1.49	1.47	1.44	1.40	1.40	1.38	1.34	1.22	1.10
34	Public Serv. Enterprise	1.61	2.28	2.16	2.04	1.96	1.88	1.80	1.72	1.64	1.56	1.48	1.44	1.42	1.37	1.37	1.33	1.29	1.17	1.14
35	SCANA Corp.	2.00	N/A	N/A	N/A	N/A	N/A	N/A	2.45	2.30	2.18	2.10	2.03	1.98	1.94	1.90	1.88	1.84	1.76	1.68
36	Sempra Energy	2.83	4.76	4.58	4.40	4.18	3.87	3.58	3.29	3.02	2.80	2.64	2.52	2.40	1.92	1.56	1.56	1.37	1.24	1.20
37	Southern Co.	2.13	2.78	2.70	2.62	2.54	2.46	2.38	2.30	2.22	2.15	2.08	2.01	1.94	1.87	1.80	1.73	1.66	1.60	1.54
38	Vectren Corp.	1.42	N/A	N/A	N/A	N/A	N/A	N/A	1.71	1.62	1.54	1.46	1.43	1.41	1.39	1.37	1.35	1.31	1.27	1.23
39	WEC Energy Group	1.66	3.12	2.91	2.71	2.53	2.36	2.21	2.08	1.98	1.74	1.56	1.45	1.20	1.04	0.80	0.68	0.54	0.50	0.46
40	Westar Energy	1.30	N/A	N/A	N/A	N/A	N/A	N/A	1.60	1.52	1.44	1.40	1.36	1.32	1.28	1.24	1.20	1.16	1.08	0.98
41	Xcel Energy Inc.	1.33	2.08	1.95	1.83	1.72	1.62	1.52	1.44	1.36	1.28	1.20	1.11	1.07	1.03	1.00	0.97	0.94	0.91	0.88
42	**Average**	**1.76**	**2.44**	**2.33**	**2.28**	**2.23**	**2.14**	**2.03**	**1.90**	**1.79**	**1.70**	**1.61**	**1.56**	**1.54**	**1.46**	**1.42**	**1.38**	**1.39**	**1.32**	**1.24**
43	**Industry Average Growth**	**4.07%**	**4.65%**	**2.08%**	**2.47%**	**4.36%**	**5.29%**	**6.91%**	**5.99%**	**5.44%**	**5.35%**	**3.49%**	**1.01%**	**5.77%**	**2.46%**	**3.13%**	**-0.48%**	**4.89%**	**6.45%**	

Sources:
[1] Data for years 2019 and prior were retreived from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
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[2] The Value Line Investment Survey, July 21, August 11, and September 8, 2023.

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Potomac Electric Power Company

Electric Utilities
(Valuation Metrics)

Line	Company	18-Year Average (1)	2023[2] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)
			Earnings per Share[1]																	
1	ALLETE	2.97	3.70	3.38	3.23	3.35	3.33	3.38	3.13	3.14	3.38	2.90	2.63	2.58	2.65	2.19	1.89	2.82	3.08	2.77
2	Alliant Energy	1.82	2.85	2.73	2.63	2.47	2.33	2.19	1.99	1.65	1.69	1.74	1.65	1.53	1.38	1.38	0.95	1.27	1.35	1.03
3	Ameren Corp.	2.99	4.38	4.14	3.84	3.50	3.35	3.32	2.77	2.68	2.38	2.40	2.10	2.41	2.47	2.77	2.78	2.88	2.98	2.66
4	American Electric Power	3.67	5.25	5.09	4.96	4.42	4.08	3.90	3.62	4.23	3.59	3.34	3.18	2.98	3.13	2.60	2.97	2.99	2.86	2.86
5	Avangrid, Inc.	1.87	1.95	2.32	1.97	1.88	2.26	1.92	1.67	1.98	0.86	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	1.83	2.30	2.12	2.10	1.90	2.97	2.07	1.95	2.15	1.89	1.84	1.85	1.32	1.72	1.65	1.58	1.36	0.72	1.47
7	Black Hills	2.70	3.75	3.97	3.74	3.73	3.53	3.47	3.38	2.63	2.83	2.89	2.61	1.97	1.01	1.66	2.32	0.18	2.68	2.21
8	CenterPoint Energy	1.25	1.65	1.59	0.94	1.29	1.49	0.74	1.57	1.00	1.08	1.42	1.24	1.35	1.27	1.07	1.01	1.30	1.17	1.33
9	CMS Energy Corp.	1.83	3.05	2.84	2.58	2.64	2.39	2.32	2.17	1.98	1.89	1.74	1.66	1.53	1.45	1.33	0.93	1.23	0.64	0.64
10	Consol. Edison	3.90	4.90	4.55	4.74	3.94	4.08	4.55	4.10	3.94	4.05	3.62	3.93	3.86	3.57	3.47	3.14	3.36	3.48	2.95
11	Dominion Resources	2.95	3.60	4.11	3.19	1.82	2.19	3.25	3.53	3.44	3.20	3.05	3.09	2.75	2.76	2.89	2.64	3.04	2.13	2.40
12	DTE Energy	4.53	6.20	5.52	4.10	7.08	6.31	6.17	5.73	4.83	4.44	5.10	3.76	3.88	3.67	3.74	3.24	2.73	2.66	2.45
13	Duke Energy	4.10	5.65	5.27	4.93	3.92	5.07	4.13	4.22	3.71	4.10	4.13	3.98	3.71	4.14	4.02	3.39	3.03	3.60	2.73
14	Edison Int'l	3.23	4.75	1.60	2.00	1.72	3.98	-1.26	4.51	3.94	4.15	4.33	3.78	4.55	3.23	3.35	3.24	3.68	3.32	3.28
15	El Paso Electric	2.02	N/A	N/A	N/A	N/A	N/A	2.07	2.42	2.39	2.03	2.27	2.20	2.26	2.48	2.07	1.50	1.73	1.63	1.27
16	Entergy Corp.	6.13	6.80	5.37	6.87	6.90	6.30	5.88	5.19	6.88	5.81	5.77	4.96	6.02	7.55	6.66	6.30	6.20	5.60	5.36
17	Eversource Energy	2.70	4.40	4.09	3.54	3.55	3.45	3.25	3.11	2.96	2.76	2.58	2.49	1.89	2.22	2.10	1.91	1.86	1.59	0.82
18	Evergy, Inc.	3.58	3.65	3.26	3.83	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	2.84	2.40	2.26	1.74	2.60	3.01	2.07	2.78	1.80	2.54	2.10	2.31	1.92	3.75	3.87	4.29	4.10	4.03	3.50
20	FirstEnergy Corp.	2.57	2.55	2.41	2.69	1.85	1.84	1.33	2.73	2.10	2.00	0.85	2.97	2.13	1.88	3.25	3.32	4.38	4.22	3.82
21	Fortis Inc.	2.02	2.90	2.78	2.61	2.60	2.68	2.52	2.66	1.89	2.11	1.38	1.63	1.65	1.74	1.62	1.51	1.52	1.29	1.36
22	Great Plains Energy	1.33	N/A	N/A	N/A	N/A	N/A	N/A	-0.06	1.61	1.37	1.57	1.62	1.35	1.25	1.53	1.03	1.16	1.85	1.62
23	Hawaiian Elec.	1.65	2.20	2.20	2.25	1.81	1.99	1.85	1.64	2.29	1.50	1.64	1.62	1.67	1.44	1.21	0.91	1.07	1.11	1.33
24	IDACORP, Inc.	3.73	5.15	5.11	4.85	4.69	4.61	4.49	4.21	3.94	3.87	3.85	3.64	3.37	3.36	2.95	2.64	2.18	1.86	2.35
25	MGE Energy	2.12	3.35	3.07	N/A	2.60	2.51	2.43	2.20	2.18	2.06	2.32	2.16	1.86	1.76	1.67	1.47	1.59	1.51	1.37
26	NextEra Energy, Inc.	1.55	3.15	2.90	1.81	2.10	1.94	1.67	1.63	1.45	1.52	1.40	1.21	1.14	1.21	1.19	0.99	1.02	0.82	0.81
27	NorthWestern Corp	2.72	3.45	3.29	3.60	3.06	3.53	3.40	3.34	3.39	2.90	2.99	2.46	2.26	2.53	2.14	2.02	1.77	1.44	1.31
28	OGE Energy	1.80	2.00	2.25	2.36	2.08	2.24	2.12	1.92	1.69	1.69	1.98	1.94	1.79	1.73	1.50	1.33	1.25	1.32	1.23
29	Otter Tail Corp.	2.13	5.70	6.78	4.23	2.34	2.17	2.06	1.86	1.60	1.56	1.55	1.37	1.05	0.45	0.38	0.71	1.09	1.78	1.69
30	Pinnacle West Capital	3.76	4.15	4.26	5.47	4.87	4.77	4.54	4.43	3.95	3.92	3.58	3.66	3.50	2.99	3.08	2.26	2.12	2.96	3.17
31	PNM Resources	1.57	2.70	2.69	2.27	2.15	2.28	1.66	1.92	1.65	1.64	1.45	1.41	1.31	1.08	0.87	0.58	0.11	0.76	1.72
32	Portland General	2.04	2.70	2.74	2.72	1.72	2.39	2.37	2.29	2.16	2.04	2.18	1.77	1.87	1.95	1.66	1.31	1.39	2.33	1.14
33	PPL Corp.	2.15	1.60	1.41	0.53	2.04	2.37	2.58	2.11	2.79	2.37	2.38	2.38	2.61	2.61	2.29	1.19	2.45	2.63	2.29
34	Public Serv. Enterprise	2.95	3.45	3.47	2.55	3.61	3.90	2.76	2.82	2.83	3.30	2.99	2.45	2.44	3.11	3.07	3.08	2.90	2.59	1.85
35	SCANA Corp.	3.30	N/A	N/A	N/A	N/A	N/A	N/A	4.20	4.16	3.81	3.79	3.39	3.15	2.97	2.98	2.85	2.95	2.74	2.59
36	Sempra Energy	5.21	9.00	9.21	4.01	6.58	5.97	5.48	4.63	4.24	5.23	4.63	4.22	4.35	4.47	4.02	4.78	4.43	4.26	4.23
37	Southern Co.	2.83	3.65	3.61	3.42	3.25	3.17	3.00	3.21	2.83	2.84	2.77	2.70	2.67	2.55	2.36	2.32	2.25	2.28	2.10
38	Vectren Corp.	1.94	N/A	N/A	N/A	N/A	N/A	N/A	2.60	2.55	2.39	2.02	1.66	1.94	1.73	1.64	1.79	1.63	1.83	1.44
39	WEC Energy Group	2.76	4.60	4.46	4.11	3.79	3.58	3.34	3.14	2.96	2.34	2.59	2.51	2.35	2.18	1.92	1.60	1.52	1.42	1.32
40	Westar Energy	1.96	N/A	N/A	N/A	N/A	N/A	N/A	2.27	2.43	2.09	2.35	2.27	2.15	1.79	1.80	1.28	1.31	1.84	1.88
41	Xcel Energy Inc.	2.15	3.35	3.17	2.96	2.79	2.64	2.47	2.30	2.21	2.10	2.03	1.91	1.85	1.72	1.56	1.49	1.46	1.35	1.35
42	**Average**	**2.75**	**3.80**	**3.61**	**3.24**	**3.16**	**3.28**	**2.87**	**2.90**	**2.81**	**2.68**	**2.65**	**2.52**	**2.44**	**2.43**	**2.35**	**2.17**	**2.19**	**2.25**	**2.09**
43	**Industry Average Growth**	**3.67%**	**5.28%**	**11.50%**	**2.47%**	**-3.54%**	**14.00%**	**-0.78%**	**3.26%**	**4.58%**	**1.09%**	**5.23%**	**3.58%**	**0.03%**	**3.76%**	**8.23%**	**-0.89%**	**-2.75%**	**7.36%**	

Sources:
[1] Data for years 2019 and prior were retreived from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, July 21, August 11, and September 8, 2023.

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Potomac Electric Power Company

Electric Utilities
(Valuation Metrics)

Line	Company	Cash Flow / Capital Spending[1] 2020 (1)	2021 (2)	2022 (3)	2023 (4)	2024[2] (5)	3 - 5 yr[2] Projection (6)
1	ALLETE	0.74x	0.80x	2.26x	1.42x	1.47x	1.31x
2	Alliant Energy	0.82x	0.97x	0.94x	0.95x	0.99x	1.19x
3	Ameren Corp.	0.51x	0.59x	0.72x	0.74x	0.80x	0.94x
4	American Electric Power	0.74x	0.69x	0.73x	0.72x	0.82x	1.05x
5	Avangrid, Inc.	0.56x	0.62x	0.61x	0.57x	0.59x	0.66x
6	Avista Corp.	0.85x	0.87x	0.83x	0.78x	0.82x	0.97x
7	Black Hills	0.72x	0.76x	0.85x	0.82x	0.84x	1.00x
8	CenterPoint Energy	0.88x	0.62x	0.62x	0.57x	0.57x	0.53x
9	CMS Energy Corp.	0.82x	0.77x	0.78x	0.92x	0.81x	0.87x
10	Consol. Edison	0.82x	0.89x	0.83x	0.72x	0.83x	0.88x
11	Dominion Resources	1.00x	0.89x	0.74x	0.63x	0.61x	0.87x
12	DTE Energy	0.67x	0.70x	0.75x	0.82x	0.83x	0.92x
13	Duke Energy	0.86x	0.93x	0.81x	0.79x	0.77x	0.87x
14	Edison Int'l	0.67x	0.74x	0.67x	0.75x	0.83x	0.85x
15	El Paso Electric	1.00x	0.83x	N/A	N/A	N/A	N/A
16	Entergy Corp.	0.81x	1.05x	0.98x	0.85x	0.26x	0.96x
17	Eversource Energy	0.95x	0.74x	0.72x	0.86x	0.85x	0.98x
18	Evergy, Inc.	1.06x	0.96x	0.94x	0.86x	0.89x	0.97x
19	Exelon Corp.	1.30x	1.32x	0.96x	0.99x	1.03x	1.07x
20	FirstEnergy Corp.	0.96x	0.91x	0.86x	0.80x	0.82x	0.88x
21	Fortis Inc.	0.60x	0.74x	0.75x	0.82x	0.80x	0.91x
22	Hawaiian Elec.	1.10x	1.42x	1.30x	1.51x	1.47x	1.49x
23	IDACORP, Inc.	1.25x	1.16x	0.83x	0.63x	0.58x	0.97x
24	MGE Energy	0.73x	0.87x	N/A	1.26x	1.56x	1.33x
25	NextEra Energy, Inc.	0.58x	0.69x	0.54x	0.59x	0.63x	0.74x
26	NorthWestern Corp	0.98x	0.82x	0.66x	0.75x	0.93x	1.19x
27	OGE Energy	1.43x	1.13x	0.99x	0.97x	0.98x	1.32x
28	Otter Tail Corp.	0.45x	1.42x	1.45x	1.08x	0.99x	0.96x
29	Pinnacle West Capital	0.98x	0.85x	0.78x	0.95x	0.89x	1.00x
30	PNM Resources	0.59x	0.51x	0.63x	0.63x	0.76x	0.93x
31	Portland General	0.75x	0.97x	1.01x	0.58x	0.79x	0.94x
32	PPL Corp.	1.06x	1.12x	1.35x	0.98x	0.90x	0.93x
33	Public Serv. Enterprise	1.00x	1.05x	0.82x	0.87x	0.91x	1.07x
34	Sempra Energy	0.92x	0.78x	0.92x	0.96x	1.02x	1.26x
35	Southern Co.	1.01x	0.93x	0.97x	0.97x	1.02x	1.23x
36	WEC Energy Group	0.70x	0.75x	0.87x	0.92x	0.97x	1.15x
37	Xcel Energy Inc.	0.99x	0.86x	0.80x	0.92x	0.94x	1.06x
38	Average	0.86x	0.88x	0.89x	0.86x	0.88x	1.01x
39	Median	0.85x	0.86x	0.83x	0.84x	0.84x	0.97x

Source:
[1] Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, July 21, August 11, and September 8, 2023.
Notes:
Based on the projected Cash Flow per share and Capital Spending per share.

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Potomac Electric Power Company

Electric Utilities
(Valuation Metrics)

		Percent Dividends to Book Value [1]																		
Line	Company	18-Year Average	2023 [2/a]	2022	2021	2020	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
1	ALLETE	5.90%	5.52%	5.52%	5.56%	5.61%	5.44%	5.35%	5.29%	5.45%	5.45%	5.59%	5.86%	6.04%	6.18%	6.46%	6.67%	6.78%	6.80%	6.62%
2	Alliant Energy	6.39%	6.82%	6.84%	6.73%	6.68%	6.68%	6.90%	7.32%	6.96%	6.70%	6.56%	6.36%	6.37%	6.26%	6.06%	5.98%	5.48%	5.23%	5.04%
3	Ameren Corp.	6.03%	6.27%	5.88%	5.84%	5.67%	5.87%	5.92%	6.01%	5.86%	5.78%	5.82%	5.93%	5.87%	4.76%	4.79%	4.66%	7.74%	7.84%	7.97%
4	American Electric Power	6.31%	6.37%	6.80%	6.74%	6.86%	6.82%	6.56%	6.43%	6.42%	5.90%	5.91%	5.91%	5.99%	6.10%	6.04%	5.97%	6.23%	6.28%	6.32%
5	Avangrid, Inc.	3.15%	3.49%	3.51%	3.57%	3.58%	3.57%	3.57%	3.54%	3.53%	0.00%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	5.06%	5.58%	5.65%	5.61%	5.53%	5.37%	5.52%	5.41%	5.33%	5.38%	5.33%	5.65%	5.51%	5.42%	5.07%	4.23%	3.77%	3.44%	3.26%
7	Black Hills	5.34%	5.41%	5.32%	5.32%	5.32%	5.34%	5.31%	5.67%	5.55%	5.66%	5.06%	5.17%	5.31%	5.30%	5.14%	5.10%	5.15%	5.34%	5.58%
8	CenterPoint Energy	9.29%	4.57%	4.90%	4.82%	8.35%	6.59%	8.94%	12.39%	12.82%	12.30%	8.96%	8.23%	8.05%	7.97%	10.36%	11.28%	12.40%	12.12%	12.09%
9	CMS Energy Corp.	6.70%	7.68%	7.89%	7.87%	8.57%	8.66%	8.52%	8.43%	8.14%	8.16%	8.10%	7.86%	7.94%	7.05%	5.90%	4.38%	3.31%	2.11%	0.00%
10	Consol. Edison	5.99%	5.51%	5.42%	5.48%	5.56%	5.46%	5.49%	5.55%	5.72%	5.84%	5.87%	5.88%	5.97%	6.15%	6.27%	6.47%	6.60%	7.12%	7.40%
11	Dominion Resources	10.13%	8.20%	8.54%	8.00%	11.72%	10.39%	11.31%	11.41%	12.04%	12.20%	12.16%	11.24%	11.50%	9.81%	8.86%	9.38%	9.14%	8.95%	7.46%
12	DTE Energy	6.26%	7.20%	7.64%	8.64%	6.43%	6.34%	6.38%	6.34%	6.09%	5.81%	5.72%	5.79%	5.66%	5.60%	5.49%	5.59%	5.76%	5.91%	6.28%
13	Duke Energy	5.47%	6.29%	6.47%	6.34%	6.39%	6.12%	6.04%	5.85%	5.73%	5.61%	5.45%	5.28%	5.22%	5.81%	5.72%	5.66%	5.45%	5.12%	0.00%
14	Edison Int'l	5.66%	8.48%	9.24%	7.36%	6.96%	6.73%	7.56%	6.23%	5.39%	4.97%	4.41%	4.48%	4.54%	4.16%	3.90%	4.12%	4.19%	4.53%	4.65%
15	El Paso Electric	2.94%	N/A	N/A	N/A	5.13%	N/A	4.94%	4.67%	4.62%	4.63%	4.53%	4.46%	4.72%	3.47%	0.00%	0.00%	0.00%	0.00%	0.00%
16	Entergy Corp.	6.73%	6.84%	6.68%	6.72%	6.85%	7.13%	7.65%	7.90%	7.58%	6.44%	5.95%	6.15%	6.42%	6.53%	6.82%	6.59%	7.13%	6.34%	5.34%
17	Eversource Energy	5.05%	5.93%	5.74%	5.69%	5.54%	5.59%	5.57%	5.43%	5.27%	5.12%	4.99%	4.82%	4.49%	4.86%	4.75%	4.66%	4.26%	4.16%	4.00%
18	Evergy, Inc.	5.53%	5.83%	5.57%	5.41%	5.32%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	7.03%	5.71%	5.42%	4.36%	4.62%	4.38%	4.34%	4.23%	4.51%	4.42%	4.72%	5.49%	8.38%	9.68%	10.25%	10.96%	12.21%	11.87%	11.02%
20	FirstEnergy Corp.	8.78%	8.62%	8.78%	10.26%	11.70%	11.86%	13.82%	16.34%	10.21%	4.91%	4.88%	5.44%	7.03%	6.93%	7.85%	7.84%	8.10%	6.96%	6.54%
21	Fortis Inc.	5.42%	5.83%	5.95%	5.59%	5.39%	5.08%	5.03%	5.19%	4.80%	5.00%	5.22%	5.58%	5.81%	5.70%	5.91%	5.60%	5.55%	4.90%	5.47%
22	Great Plains Energy	5.31%	N/A	N/A	N/A	N/A	N/A	N/A	4.78%	4.27%	4.21%	4.02%	3.91%	3.93%	3.84%	3.90%	4.03%	7.76%	9.13%	9.94%
23	Hawaiian Elec.	7.19%	6.87%	6.96%	6.22%	6.17%	6.12%	6.24%	6.43%	6.51%	6.91%	7.10%	7.27%	7.62%	7.77%	7.91%	7.96%	8.08%	8.11%	9.22%
24	IDACORP, Inc.	4.69%	5.52%	5.48%	5.45%	5.36%	5.24%	5.11%	5.02%	4.87%	4.70%	4.53%	4.26%	3.91%	3.62%	3.87%	4.11%	4.32%	4.48%	4.66%
25	MGE Energy	6.12%	5.48%	5.32%	N/A	5.22%	5.59%	5.60%	5.61%	5.79%	5.82%	5.84%	6.01%	6.22%	6.36%	6.56%	6.72%	6.87%	7.24%	7.77%
26	NextEra Energy, Inc.	6.72%	8.42%	8.61%	8.13%	7.51%	6.61%	6.22%	6.55%	6.69%	6.29%	6.49%	6.36%	6.34%	6.12%	5.82%	5.99%	6.30%	6.22%	6.21%
27	NorthWestern Corp	5.81%	5.39%	5.65%	5.73%	5.84%	5.69%	5.70%	5.76%	5.77%	5.78%	5.08%	5.71%	5.90%	6.08%	6.01%	6.13%	6.21%	6.06%	6.00%
28	OGE Energy	6.86%	7.46%	7.47%	8.04%	8.71%	7.28%	6.96%	6.59%	6.70%	6.30%	5.84%	5.56%	5.70%	5.81%	6.24%	6.79%	6.89%	7.47%	7.61%
29	Otter Tail Corp.	7.03%	5.87%	5.61%	6.54%	7.05%	7.19%	7.29%	7.27%	7.34%	7.70%	7.86%	8.07%	8.25%	7.52%	6.77%	6.33%	6.22%	6.67%	6.90%
30	Pinnacle West Capital	6.21%	6.43%	6.40%	6.43%	6.47%	6.29%	6.16%	6.03%	5.93%	5.91%	5.89%	5.84%	7.38%	6.00%	6.20%	6.42%	6.15%	5.98%	5.87%
31	PNM Resources	4.02%	5.59%	5.52%	3.88%	5.23%	5.59%	5.12%	4.67%	4.18%	3.85%	3.37%	3.26%	2.89%	2.55%	2.84%	2.65%	3.20%	4.13%	3.89%
32	Portland General	4.89%	5.65%	5.75%	5.61%	5.45%	5.24%	5.09%	4.94%	4.78%	4.64%	4.56%	4.70%	4.70%	4.78%	4.90%	4.93%	4.48%	4.42%	3.45%
33	PPL Corp.	8.49%	4.87%	4.66%	8.89%	9.55%	9.74%	10.13%	10.18%	10.44%	10.19%	7.28%	7.43%	8.00%	7.48%	8.24%	9.47%	9.89%	8.20%	8.27%
34	Public Serv. Enterprise	7.00%	7.96%	7.82%	7.12%	6.18%	6.28%	6.31%	6.27%	6.31%	6.03%	6.14%	6.28%	6.66%	6.75%	7.20%	7.66%	8.40%	8.15%	8.54%
35	SCANA Corp.	6.44%	N/A	N/A		N/A	N/A	N/A	6.67%	5.74%	5.72%	6.01%	6.14%	6.29%	6.48%	6.54%	6.80%	7.12%	6.94%	6.89%
36	Sempra Energy	5.34%	5.56%	5.49%	5.56%	5.96%	6.39%	6.59%	6.53%	5.83%	5.89%	5.74%	5.60%	5.66%	4.68%	4.16%	4.27%	4.18%	3.89%	4.19%
37	Southern Co.	9.58%	9.93%	9.67%	9.96%	9.59%	9.42%	9.95%	9.59%	8.89%	9.53%	9.48%	9.39%	9.22%	9.22%	9.38%	9.55%	9.74%	9.83%	10.07%
38	Vectren Corp.	7.71%	N/A	N/A	N/A	N/A	N/A	N/A	7.67%	7.60%	7.57%	7.51%	7.55%	7.57%	7.74%	7.78%	7.84%	7.85%	7.86%	7.97%
39	WEC Energy Group	6.42%	8.35%	7.92%	7.83%	7.62%	7.36%	7.12%	6.94%	7.00%	6.35%	7.96%	7.71%	6.65%	6.05%	4.92%	4.42%	3.78%	3.77%	3.72%
40	Westar Energy	5.71%	N/A	N/A	N/A	N/A	N/A	N/A	5.82%	5.66%	5.57%	5.60%	5.70%	5.77%	5.81%	5.84%	5.83%	5.75%	5.64%	5.56%
41	Xcel Energy Inc.	6.19%	6.58%	6.43%	6.38%	6.34%	6.42%	6.39%	6.38%	6.26%	6.13%	5.94%	5.78%	5.88%	5.91%	5.97%	6.09%	6.13%	6.19%	6.16%
42	Average	6.34%	6.45%	6.46%	6.50%	6.65%	6.57%	6.69%	6.73%	6.46%	6.13%	6.09%	6.11%	6.29%	6.11%	6.07%	6.13%	6.37%	6.29%	6.10%
43	Median	6.09%	6.10%	5.92%	6.34%	6.18%	6.29%	6.23%	6.25%	5.85%	5.82%	5.84%	5.84%	5.99%	6.08%	6.01%	5.99%	6.22%	6.22%	6.21%

Sources:
[1] Data for years 2019 and prior were retreived from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, July 21, August 11, and September 8, 2023.
[a] Based on the projected 2022 Dividend Declared per share and Book Value per share,
published in The Value Line Investment Survey, April 21, May 12, and June 9, 2023.

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Potomac Electric Power Company

Electric Utilities
(Valuation Metrics)

		Dividends to Earnings Ratio [1]																		
Line	Company	18-Year Average (1)	2023 [2/a] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)
1	ALLETE	0.70	0.73	0.77	0.78	0.74	0.71	0.66	0.68	0.66	0.60	0.68	0.72	0.71	0.67	0.80	0.93	0.61	0.53	0.52
2	Alliant Energy	0.61	0.64	0.63	0.61	0.62	0.61	0.61	0.63	0.72	0.65	0.59	0.57	0.59	0.62	0.57	0.79	0.55	0.47	0.56
3	Ameren Corp.	0.66	0.58	0.57	0.57	0.57	0.57	0.56	0.64	0.64	0.70	0.67	0.76	0.66	0.63	0.56	0.55	0.88	0.85	0.95
4	American Electric Power	0.61	0.64	0.62	0.60	0.64	0.66	0.65	0.66	0.54	0.60	0.61	0.61	0.63	0.59	0.66	0.55	0.55	0.55	0.52
5	Avangrid, Inc.	0.89	0.90	0.76	0.89	0.94	0.78	0.91	1.03	0.87	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	0.68	0.80	0.83	0.80	0.85	0.52	0.72	0.73	0.64	0.70	0.69	0.66	0.88	0.64	0.61	0.51	0.51	0.83	0.39
7	Black Hills	1.06	0.67	0.61	0.61	0.58	0.58	0.56	0.54	0.64	0.57	0.54	0.58	0.75	1.45	0.87	0.61	7.78	0.51	0.60
8	CenterPoint Energy	0.71	0.47	0.45	0.70	0.70	0.58	1.51	0.86	1.03	0.92	0.67	0.67	0.60	0.62	0.73	0.75	0.56	0.58	0.45
9	CMS Energy Corp.	0.57	0.64	0.65	0.67	0.62	0.64	0.62	0.61	0.63	0.61	0.62	0.61	0.63	0.58	0.50	0.54	0.29	0.31	N/A
10	Consol. Edison	0.69	0.66	0.69	0.65	0.78	0.73	0.63	0.67	0.68	0.64	0.70	0.63	0.63	0.67	0.69	0.75	0.70	0.67	0.78
11	Dominion Resources	0.85	0.74	0.65	0.79	1.90	1.68	1.03	0.86	0.81	0.81	0.79	0.73	0.77	0.71	0.63	0.66	0.52	0.69	0.58
12	DTE Energy	0.66	0.61	0.64	0.95	0.58	0.61	0.58	0.59	0.63	0.64	0.53	0.69	0.62	0.63	0.58	0.65	0.78	0.80	0.85
13	Duke Energy	0.80	0.72	0.76	0.79	0.97	0.74	0.88	0.83	0.91	0.79	0.76	0.78	0.82	0.72	0.72	0.83	0.89	0.72	N/A
14	Edison Int'l	0.47	0.63	1.78	1.35	1.50	0.62	- 1.93	0.50	0.50	0.42	0.34	0.36	0.29	0.40	0.38	0.38	0.33	0.35	0.34
15	El Paso Electric	0.50	N/A	N/A	N/A	N/A	N/A	0.68	0.54	0.51	0.57	0.49	0.48	0.43	0.27	N/A	N/A	N/A	N/A	N/A
16	Entergy Corp.	0.55	0.63	0.76	0.56	0.54	0.58	0.61	0.67	0.50	0.57	0.58	0.67	0.55	0.44	0.49	0.48	0.48	0.46	0.40
17	Eversource Energy	0.60	0.61	0.62	0.68	0.64	0.62	0.62	0.61	0.60	0.61	0.61	0.59	0.70	0.50	0.49	0.50	0.44	0.49	0.88
18	Evergy, Inc.	0.66	0.68	0.71	0.57	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	0.60	0.60	0.60	0.88	0.59	0.48	0.67	0.47	0.70	0.49	0.59	0.63	1.09	0.56	0.54	0.49	0.50	0.45	0.47
20	FirstEnergy Corp.	0.78	0.64	0.65	0.58	0.84	0.83	1.37	0.53	0.69	0.72	1.69	0.56	1.03	1.17	0.68	0.66	0.50	0.49	0.48
21	Fortis Inc.	0.72	0.79	0.78	0.80	0.76	0.69	0.69	0.62	0.82	0.68	0.94	0.77	0.73	0.67	0.69	0.69	0.66	0.64	0.49
22	Great Plains Energy	- 0.82	N/A	N/A	N/A	N/A	N/A	N/A	-18.33	0.66	0.73	0.60	0.54	0.63	0.67	0.54	0.81	1.43	0.90	1.02
23	Hawaiian Elec.	0.82	0.65	0.64	0.60	0.73	0.64	0.67	0.76	0.54	0.83	0.76	0.77	0.74	0.86	1.02	1.36	1.16	1.12	0.93
24	IDACORP, Inc.	0.51	0.62	0.59	0.59	0.58	0.56	0.53	0.53	0.53	0.50	0.46	0.43	0.41	0.36	0.41	0.45	0.55	0.65	0.51
25	MGE Energy	0.57	0.50	0.52	N/A	0.56	0.55	0.54	0.57	0.56	0.56	0.48	0.50	0.56	0.57	0.60	0.66	0.60	0.62	0.68
26	NextEra Energy, Inc.	0.56	0.59	0.59	0.85	0.67	0.64	0.66	0.60	0.60	0.51	0.52	0.55	0.53	0.45	0.42	0.47	0.44	0.50	0.47
27	NorthWestern Corp	0.69	0.74	0.77	0.69	0.78	0.65	0.65	0.63	0.59	0.66	0.54	0.62	0.65	0.57	0.64	0.66	0.75	0.89	0.95
28	OGE Energy	0.60	0.83	0.73	0.69	0.76	0.67	0.66	0.66	0.68	0.62	0.48	0.44	0.45	0.44	0.49	0.54	0.56	0.52	0.55
29	Otter Tail Corp.	0.99	0.31	0.24	0.37	0.63	0.65	0.65	0.69	0.78	0.79	0.78	0.87	1.13	2.64	3.13	1.68	1.09	0.66	0.68
30	Pinnacle West Capital	0.71	0.84	0.80	0.61	0.66	0.64	0.63	0.61	0.65	0.62	0.65	0.61	0.76	0.70	0.68	0.93	0.99	0.71	0.64
31	PNM Resources	0.85	0.55	0.52	0.43	0.58	0.52	0.65	0.52	0.53	0.49	0.52	0.48	0.44	0.46	0.57	0.86	5.50	1.20	0.50
32	Portland General	0.62	0.70	0.65	0.63	0.92	0.64	0.60	0.59	0.58	0.58	0.51	0.62	0.57	0.54	0.62	0.77	0.70	0.40	0.59
33	PPL Corp.	0.78	0.59	0.62	3.13	0.81	0.70	0.64	0.75	0.54	0.63	0.63	0.62	0.55	0.54	0.61	1.16	0.55	0.46	0.48
34	Public Serv. Enterprise	0.55	0.66	0.62	0.80	0.54	0.48	0.65	0.61	0.58	0.47	0.49	0.59	0.58	0.44	0.45	0.43	0.44	0.45	0.62
35	SCANA Corp.	0.61	N/A	N/A		N/A	N/A	N/A	0.58	0.55	0.57	0.55	0.60	0.63	0.65	0.64	0.66	0.62	0.64	0.65
36	Sempra Energy	0.54	0.53	0.50	1.10	0.64	0.65	0.65	0.71	0.71	0.54	0.57	0.60	0.55	0.43	0.39	0.33	0.31	0.29	0.28
37	Southern Co.	0.75	0.76	0.75	0.77	0.78	0.78	0.79	0.72	0.79	0.76	0.75	0.75	0.73	0.73	0.76	0.75	0.74	0.70	0.73
38	Vectren Corp.	0.75	N/A	N/A	N/A	N/A	N/A	N/A	0.66	0.64	0.64	0.72	0.86	0.72	0.80	0.84	0.75	0.80	0.69	0.85
39	WEC Energy Group	0.56	0.68	0.65	0.66	0.67	0.66	0.66	0.66	0.67	0.74	0.60	0.58	0.51	0.48	0.42	0.42	0.36	0.35	0.35
40	Westar Energy	0.68	N/A	N/A	N/A	N/A	N/A	N/A	0.70	0.63	0.69	0.60	0.60	0.61	0.72	0.69	0.94	0.89	0.59	0.52
41	Xcel Energy Inc.	0.62	0.62	0.62	0.62	0.62	0.61	0.62	0.63	0.62	0.61	0.59	0.58	0.58	0.60	0.64	0.65	0.64	0.67	0.65
42	Average	0.65	0.65	0.68	0.78	0.75	0.66	0.64	0.18	0.65	0.64	0.64	0.62	0.65	0.67	0.68	0.70	0.96	0.62	0.61
43	Median	0.63	0.64	0.64	0.68	0.67	0.64	0.65	0.63	0.64	0.62	0.60	0.61	0.63	0.62	0.62	0.66	0.61	0.60	0.57

Sources:
[1] Data for years 2019 and prior were retreived from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, July 21, August 11, and September 8, 2023.
Note:
[b] Based on the projected 2022 Dividends Declared per share and Earnings per share,
published in The Value Line Investment Survey, April 21, May 12, and June 9, 2023.

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Potomac Electric Power Company

Electric Utilities
(Valuation Metrics)

		Cash Flow to Capital Spending Ratio [1]																		
Line	Company	18-Year Average (1)	2023 [2/a] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)
1	ALLETE	0.91	1.42	2.12	0.55	0.55	0.63	1.22	1.61	1.32	1.16	0.45	0.67	0.49	0.77	0.63	0.39	0.46	0.65	1.23
2	Alliant Energy	0.82	0.95	0.91	0.95	N/A	N/A	N/A	0.49	N/A	0.81	0.91	1.01	0.57	0.91	0.67	0.39	0.57	1.04	1.27
3	Ameren Corp.	0.86	0.74	0.71	0.62	0.62	0.79	0.80	0.75	0.75	0.75	0.75	0.89	1.07	1.31	1.36	0.81	0.66	0.97	1.21
4	American Electric Power	0.86	0.72	0.81	0.81	0.81	0.75	0.68	0.67	0.85	0.85	0.87	0.91	1.07	1.19	1.24	1.02	0.70	0.77	0.75
5	Avangrid, Inc.	0.70	0.55	0.79	0.56	0.56	0.62	0.85	0.57	0.86	0.89	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	0.88	0.75	0.73	0.88	0.88	0.92	0.78	0.77	0.84	0.76	0.80	0.86	0.80	0.90	0.99	1.15	0.97	0.73	1.36
7	Black Hills	0.67	0.83	0.86	0.61	0.61	0.53	0.87	1.17	0.71	0.64	0.70	0.74	0.71	0.40	0.41	0.61	0.35	0.76	0.55
8	CenterPoint Energy	0.98	0.57	0.52	0.73	0.73	0.83	0.98	1.22	1.12	0.92	1.20	1.18	1.37	1.12	0.88	0.99	1.16	0.98	1.08
9	CMS Energy Corp.	0.87	0.89	0.82	0.78	0.78	0.79	0.77	0.89	0.81	0.81	0.74	0.82	0.82	1.05	1.13	0.97	1.11	0.55	1.07
10	Consol. Edison	0.82	0.72	0.88	0.83	0.83	0.87	0.82	0.76	0.65	0.76	0.88	0.86	1.01	0.98	0.90	0.75	0.70	0.81	0.74
11	Dominion Resources	0.78	0.60	0.86	0.73	0.73	0.96	1.04	0.81	0.65	0.64	0.63	0.77	0.73	0.79	0.87	0.75	0.83	0.74	0.85
12	DTE Energy	0.98	0.82	0.86	0.74	0.74	0.83	0.84	0.94	0.93	0.84	1.02	0.96	0.93	1.09	1.51	1.50	0.98	1.07	1.03
13	Duke Energy	0.89	0.79	0.87	0.85	0.85	0.80	0.81	0.87	0.82	0.96	1.20	1.09	0.87	0.89	0.78	0.77	0.71	1.09	0.97
14	Edison Int'l	0.74	0.81	0.62	0.55	0.55	0.68	0.34	0.94	0.91	0.80	0.83	0.80	0.76	0.61	0.60	0.79	0.93	0.88	0.93
15	El Paso Electric	0.87	N/A	N/A	0.83	N/A	N/A	0.86	1.04	0.85	0.67	0.69	0.79	0.85	1.03	0.98	0.68	0.78	0.84	1.26
16	Entergy Corp.	0.94	0.75	0.62	0.74	0.74	0.79	0.73	0.76	1.08	1.05	1.19	1.03	0.88	1.15	1.24	1.02	0.93	1.14	1.13
17	Eversource Energy	0.85	0.83	0.89	0.80	0.80	0.75	0.83	0.79	0.87	0.91	0.90	1.13	0.86	0.80	1.05	0.96	0.77	0.68	0.67
18	Evergy, Inc.	0.89	0.86	0.78	1.03	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	1.21	0.99	0.84	1.09	1.09	1.20	1.05	1.06	0.76	0.82	0.93	1.07	0.98	1.19	1.66	1.66	1.61	1.84	1.86
20	FirstEnergy Corp.	1.00	0.80	0.98	0.83	0.83	0.80	0.76	1.03	0.94	0.93	0.54	0.91	0.85	1.05	1.32	1.22	0.95	1.56	1.75
21	Fortis Inc.	0.69	0.82	0.89	0.65	0.65	0.68	0.72	0.76	0.76	0.65	0.60	0.77	0.72	0.66	0.68	0.63	0.66	0.57	0.63
22	Great Plains Energy	0.79	N/A	N/A		N/A	N/A	N/A	0.78	1.17	0.90	0.79	0.91	0.86	1.03	0.86	0.50	0.35	0.69	0.64
23	Hawaiian Elec.	1.13	1.43	1.56	1.27	1.27	1.08	0.85	0.81	1.37	0.98	1.03	0.92	0.99	1.30	1.50	0.79	0.87	1.15	1.23
24	IDACORP, Inc.	1.09	0.63	1.00	1.33	1.33	1.46	1.42	1.33	1.16	1.15	1.21	1.34	1.24	0.86	0.78	0.96	0.82	0.64	0.89
25	MGE Energy	1.10	1.26	1.12	0.82	0.82	0.97	0.66	1.19	1.44	1.60	1.31	0.96	1.05	1.56	1.57	1.13	0.87	0.59	0.80
26	NextEra Energy, Inc.	0.61	0.59	0.55	0.58	0.58	0.67	0.56	0.53	0.63	0.71	0.77	0.68	0.39	0.58	0.69	0.60	0.63	0.56	0.73
27	NorthWestern Corp	1.01	0.80	0.75	0.84	0.84	1.13	1.23	1.21	1.13	1.01	0.93	0.92	0.88	1.04	0.76	0.88	1.27	1.23	1.29
28	OGE Energy	0.91	0.97	0.87	1.24	1.24	1.27	1.30	0.81	1.00	1.18	1.19	0.69	0.63	0.51	0.69	0.61	0.60	0.79	0.84
29	Otter Tail Corp.	0.92	1.08	2.13	0.48	0.48	0.80	1.49	1.10	0.84	0.74	0.70	0.67	0.85	1.16	1.09	0.56	0.37	0.65	1.44
30	Pinnacle West Capital	0.95	0.91	0.89	0.91	0.91	1.03	1.06	0.76	0.81	0.92	0.97	0.87	0.96	0.91	0.97	1.06	0.86	0.99	1.28
31	PNM Resources	0.70	0.63	0.63	0.72	0.72	0.78	0.82	0.84	0.57	0.57	0.63	0.80	0.87	0.77	0.82	0.70	0.44	0.43	0.89
32	Portland General	0.82	0.53	0.86	0.78	0.78	1.03	1.00	1.07	0.88	0.80	0.47	0.59	1.28	1.25	0.81	0.44	0.77	0.72	0.78
33	PPL Corp.	0.97	0.98	1.05	0.90	0.90	0.98	0.93	0.82	1.00	0.72	0.75	0.69	0.91	1.07	1.11	1.07	1.25	1.13	1.18
34	Public Serv. Enterprise	1.10	0.85	1.05	1.13	1.13	1.08	0.70	0.64	0.61	0.80	1.04	0.93	0.96	1.30	1.23	1.41	1.34	1.64	1.94
35	SCANA Corp.	0.86	N/A	N/A		N/A	N/A	N/A	0.86	0.66	0.83	0.90	0.83	0.77	0.88	0.86	0.76	0.76	0.92	1.26
36	Sempra Energy	0.82	0.96	0.92	0.77	0.77	0.88	0.80	0.67	0.56	0.81	0.74	0.84	0.73	0.72	0.90	1.02	0.87	0.90	0.93
37	Southern Co.	0.90	0.97	0.97	0.99	0.99	0.88	0.83	0.90	0.77	0.88	0.80	0.86	0.93	0.94	0.93	0.78	0.87	0.91	1.00
38	Vectren Corp.	1.00	N/A	N/A		N/A	N/A	N/A	0.82	0.87	0.95	0.98	1.05	1.13	1.20	1.31	0.83	0.82	0.98	1.00
39	WEC Energy Group	0.98	0.92	1.09	0.97	0.97	0.91	0.90	0.92	1.20	0.97	1.37	1.42	1.30	1.02	0.97	0.89	0.61	0.56	0.69
40	Westar Energy	0.72	N/A	N/A		N/A	N/A	N/A	0.91	0.63	0.86	0.70	0.72	0.67	0.71	0.88	0.68	0.36	0.48	1.00
41	Xcel Energy Inc.	0.77	0.92	0.93	0.66	0.66	0.78	0.77	0.84	0.79	0.63	0.68	0.60	0.76	0.83	0.76	0.89	0.75	0.71	0.90
42	Average	0.89	0.85	0.94	0.83	0.82	0.88	0.89	0.89	0.89	0.87	0.87	0.89	0.88	0.96	0.98	0.86	0.80	0.88	1.05
43	Median	0.83	0.83	0.87	0.81	0.79	0.83	0.83	0.84	0.85	0.83	0.83	0.86	0.87	0.98	0.90	0.81	0.78	0.81	1.00

Sources:
[1] Data for years 2019 and prior were retreived from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, July 21, August 11, and September 8, 2023.
Notes:
[c] Based on the projected Cash Flow per share and Capital Spending per share
published in The Value Line Investment Survey, April 21, May 12, and June 9, 2023.

Exhibit OPC (C)-2
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Potomac Electric Power Company

Natural Gas Utilities
(Valuation Metrics)

Price to Earnings (P/E) Ratio [1]

Line	Company	18-Year Average (1)	2023 [2] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)
1	Atmos Energy	17.52	18.70	19.30	18.80	22.30	23.20	21.70	22.00	20.80	17.50	16.10	15.90	15.90	14.40	13.20	12.50	13.60	15.90	13.52
2	Chesapeake Utilities	19.44	22.60	25.80	25.60	21.60	24.70	22.90	27.80	22.30	19.10	17.70	15.60	14.80	14.20	12.20	14.20	14.20	16.70	17.85
3	New Jersey Resources	17.18	15.70	17.00	17.50	17.70	24.30	15.60	22.40	21.30	16.60	11.70	16.00	16.80	16.80	15.00	14.90	12.30	21.60	16.13
4	NiSource Inc.	22.04	16.30	19.60	18.00	18.70	21.30	19.30	64.40	23.20	37.30	22.70	18.90	17.90	19.40	15.30	14.30	12.10	18.80	19.16
5	Northwest Nat. Gas	20.54	13.90	19.60	19.50	25.00	30.90	26.60	NMF	26.90	23.70	20.70	19.40	21.10	19.00	17.00	15.20	18.10	16.70	15.85
6	ONE Gas Inc.	21.07	18.00	19.90	18.90	21.70	25.30	23.10	23.50	22.70	19.80	17.80	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	South Jersey Inds.	18.64	N/A	19.40	15.10	14.89	28.28	22.64	27.92	21.70	17.95	18.03	18.90	16.94	18.48	16.81	14.96	15.90	17.18	11.86
8	Southwest Gas	17.51	17.40	NMF	14.30	16.80	21.30	20.60	22.20	21.60	19.40	17.90	15.80	15.00	15.70	14.00	12.20	20.30	17.30	15.94
9	Spire Inc.	18.31	14.20	17.50	13.60	51.10	22.80	16.70	19.80	19.60	16.50	19.80	21.30	14.50	13.00	13.70	13.40	14.30	14.20	13.60
10	UGI Corp.	15.25	7.50	14.10	13.90	13.80	23.40	17.80	20.80	19.30	17.70	15.80	15.40	16.40	15.00	10.90	10.30	13.30	15.10	13.97
11	Average	18.55	16.03	19.13	17.52	22.36	24.55	20.69	27.87	21.94	20.55	17.82	17.47	16.59	16.22	14.23	13.55	14.90	17.05	15.32
12	Median	17.23	16.30	19.40	17.75	20.15	23.85	21.15	22.40	21.65	18.52	17.85	16.00	16.40	15.70	14.00	14.20	14.20	16.70	15.85

Market Price to Cash Flow (MP/CF) Ratio [1]

Line	Company	18-Year Average (1)	2023 [2] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)
13	Atmos Energy	9.36	11.85	11.87	10.99	13.11	13.35	12.02	11.99	11.36	9.30	8.79	7.72	7.02	6.87	6.15	5.76	6.48	7.44	6.36
14	Chesapeake Utilities	10.60	13.86	14.21	14.20	12.31	14.17	12.24	13.78	12.06	10.16	9.25	8.12	7.46	7.35	6.36	9.48	7.88	8.58	9.40
15	New Jersey Resources	11.95	11.62	11.55	11.56	11.10	15.98	11.44	14.45	13.94	11.71	8.95	11.29	12.29	12.71	11.32	11.34	9.15	13.76	11.01
16	NiSource Inc.	7.87	7.63	8.13	7.89	7.83	8.81	8.91	12.11	8.56	10.38	10.56	8.71	7.81	6.81	5.09	4.06	4.87	6.69	6.87
17	Northwest Nat. Gas	12.16	7.52	8.76	8.57	10.10	13.13	11.75	59.72	11.57	9.46	8.84	8.61	9.48	9.08	8.94	8.26	8.75	8.54	7.83
18	ONE Gas Inc.	10.37	8.63	9.91	9.32	10.85	12.75	11.85	11.89	11.10	9.19	8.16	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	South Jersey Inds.	10.59	N/A	10.81	9.26	7.54	12.38	10.72	12.33	10.88	10.70	10.57	11.57	10.95	11.98	10.78	9.57	10.38	11.23	8.32
20	Southwest Gas	7.16	6.09	19.83	6.87	7.05	8.92	9.32	9.10	7.41	6.56	6.35	5.94	5.55	5.60	4.91	3.84	4.89	5.42	5.28
21	Spire Inc.	9.59	7.40	8.34	7.55	14.01	11.27	9.60	10.39	10.32	8.47	12.03	13.76	8.80	8.08	8.12	8.58	8.95	8.46	8.46
22	UGI Corp.	7.89	6.27	7.20	9.56	7.39	12.95	9.01	10.09	9.02	8.47	7.49	6.55	6.30	7.51	6.02	5.74	7.11	7.92	7.48
23	Average	9.65	8.99	11.06	9.58	10.13	12.37	10.69	16.59	10.62	9.44	9.10	9.14	8.41	8.44	7.52	7.40	7.61	8.67	7.89
24	Median	8.76	7.63	10.36	9.29	10.47	12.85	11.08	12.05	10.99	9.38	8.90	8.61	7.81	7.51	6.36	8.26	7.88	8.46	7.83

Market Price to Book Value (MP/BV) Ratio [1]

Line	Company	18-Year Average (1)	2023 [2] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)
25	Atmos Energy	1.59	1.62	1.65	1.59	1.95	2.10	2.03	2.16	2.11	1.72	1.55	1.39	1.28	1.30	1.18	1.05	1.20	1.40	1.34
26	Chesapeake Utilities	2.07	2.40	2.69	2.77	2.27	2.69	2.50	2.51	2.28	2.19	2.12	1.83	1.66	1.61	1.40	1.37	1.64	1.84	1.85
27	New Jersey Resources	2.27	2.28	2.35	2.26	1.90	2.75	2.63	2.70	2.52	2.28	2.13	2.05	2.33	2.31	2.09	2.16	1.92	2.17	2.01
28	NiSource Inc.	1.57	1.41	2.15	1.86	1.95	2.09	1.92	1.96	1.84	1.95	1.94	1.58	1.37	1.15	0.92	0.69	0.94	1.16	1.19
29	Northwest Nat. Gas	1.85	1.32	1.51	1.45	1.98	2.38	2.35	2.41	1.92	1.63	1.59	1.56	1.72	1.70	1.78	1.73	1.96	2.05	1.69
30	ONE Gas Inc.	1.69	1.49	1.73	1.57	1.90	2.20	1.93	1.89	1.67	1.26	1.07	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
31	South Jersey Inds.	2.02	N/A	1.62	1.54	1.52	2.06	2.11	2.29	1.79	1.77	2.07	2.27	2.21	2.59	2.38	1.95	2.08	2.21	1.93
32	Southwest Gas	1.55	1.22	1.62	1.32	1.49	1.84	1.79	2.13	1.96	1.68	1.68	1.61	1.51	1.43	1.24	0.97	1.20	1.46	1.46
33	Spire Inc.	1.56	1.29	1.43	1.47	1.67	1.78	1.63	1.65	1.64	1.44	1.33	1.34	1.51	1.46	1.39	1.68	1.71	1.66	1.71
34	UGI Corp.	1.99	1.55	1.39	1.64	1.87	2.92	2.30	2.62	2.41	2.29	1.97	1.69	1.45	1.75	1.55	1.66	2.01	2.16	2.21
35	Average	1.80	1.62	1.81	1.75	1.85	2.28	2.12	2.23	2.01	1.82	1.75	1.70	1.67	1.70	1.55	1.47	1.63	1.79	1.71
36	Median	1.71	1.49	1.64	1.58	1.90	2.15	2.07	2.22	1.94	1.74	1.81	1.61	1.51	1.61	1.40	1.66	1.71	1.84	1.71

Sources:
The current year P/E ratio is based on the forward P/E (price over expected earnings per share). All historical year P/E ratios are based on annual average share price over achieved earnings per share.
[1] Data for years 2019 and prior were retreived from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, August 25, 2023.
Notes:
[a] Based on the average of the high and low price for year and the projected Cash Flow per share, published in The Value Line Investment Survey.
[b] Based on the average of the high and low price for the year and the projected Book Value per share, published in The Value Line Investment Survey.

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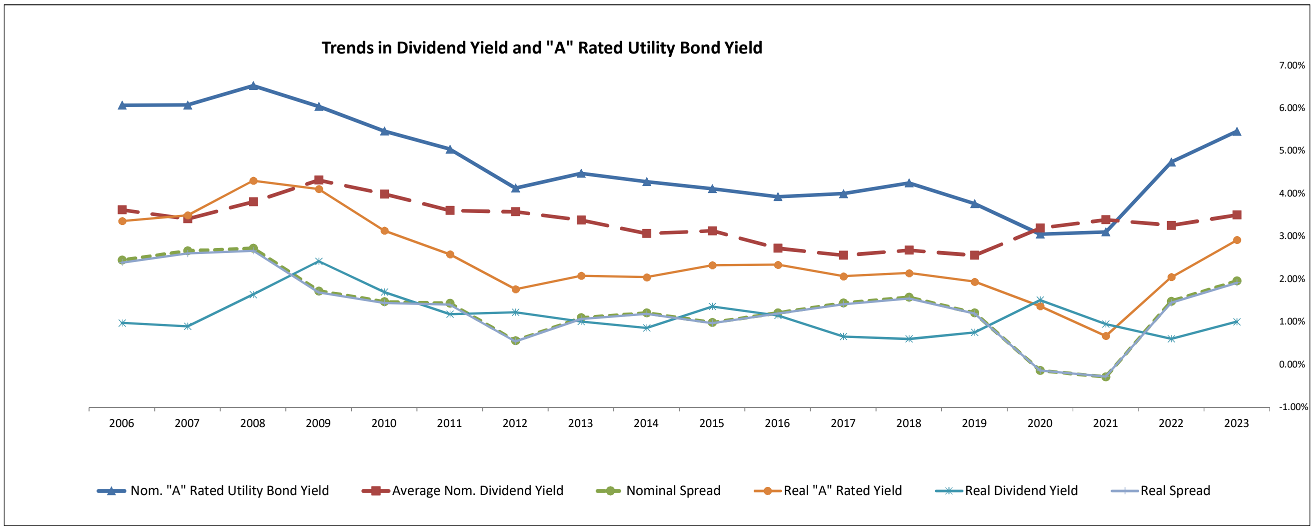
Potomac Electric Power Company

Natural Gas Utilities
(Valuation Metrics)

Line	Company	18-Year Average (1)	2023 [2/a] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)
		Dividend Yield[1]																		
1	Atmos Energy	3.35%	2.56%	2.46%	2.63%	2.19%	2.08%	2.23%	2.27%	2.39%	2.88%	3.11%	3.53%	4.13%	4.19%	4.70%	5.34%	4.78%	4.16%	4.66%
2	Chesapeake Utilities	2.64%	1.85%	1.61%	1.50%	1.86%	1.68%	1.76%	1.69%	1.91%	2.18%	2.44%	2.87%	3.25%	3.36%	3.91%	4.09%	4.10%	3.62%	3.76%
3	New Jersey Resources	3.21%	3.16%	3.25%	3.50%	3.47%	2.50%	2.61%	2.69%	2.86%	3.14%	3.50%	3.71%	3.38%	3.33%	3.69%	3.46%	3.35%	3.02%	3.19%
4	NiSource Inc.	3.94%	3.64%	3.33%	3.60%	3.41%	2.86%	3.10%	2.79%	2.76%	3.53%	2.69%	3.30%	3.84%	4.53%	5.66%	7.64%	5.69%	4.29%	4.21%
5	Northwest Nat. Gas	3.61%	4.22%	3.86%	3.90%	3.33%	2.81%	3.05%	3.02%	3.28%	4.01%	4.14%	4.22%	3.83%	3.85%	3.63%	3.73%	3.27%	3.12%	3.73%
6	ONE Gas Inc.	2.67%	3.31%	3.08%	3.21%	2.70%	2.25%	2.46%	2.37%	2.32%	2.71%	2.28%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	South Jersey Inds.	3.53%	N/A	4.28%	4.88%	4.76%	3.66%	3.62%	3.20%	3.64%	3.95%	3.40%	3.14%	3.22%	2.81%	3.00%	3.43%	3.08%	2.81%	3.15%
8	Southwest Gas	3.00%	4.07%	3.20%	3.65%	3.28%	2.60%	2.74%	2.46%	2.62%	2.87%	2.72%	2.69%	2.75%	2.78%	3.15%	4.01%	3.19%	2.56%	2.60%
9	Spire Inc.	3.81%	4.28%	3.89%	3.79%	3.38%	2.95%	3.10%	3.09%	3.08%	3.53%	3.78%	3.96%	4.11%	4.31%	4.70%	3.91%	3.94%	4.43%	4.34%
10	UGI Corp.	2.99%	4.42%	3.61%	3.25%	3.56%	2.16%	2.09%	2.01%	2.35%	2.50%	2.61%	3.01%	3.68%	3.30%	3.48%	3.23%	2.85%	2.69%	2.96%
11	**Average**	**3.32%**	**3.50%**	**3.26%**	**3.39%**	**3.19%**	**2.56%**	**2.68%**	**2.56%**	**2.72%**	**3.13%**	**3.07%**	**3.38%**	**3.58%**	**3.61%**	**3.99%**	**4.32%**	**3.81%**	**3.41%**	**3.62%**
12	Median	3.33%	3.64%	3.29%	3.55%	3.35%	2.55%	2.68%	2.57%	2.69%	3.01%	2.91%	3.30%	3.68%	3.36%	3.69%	3.91%	3.35%	3.12%	3.73%
13	20-Yr Treasury Yields[3]	3.24%	4.08%	3.30%	1.98%	1.35%	2.40%	3.02%	2.65%	2.23%	2.55%	3.07%	3.12%	2.54%	3.62%	4.03%	4.11%	4.36%	4.91%	4.99%
14	20-Yr TIPS[3]	1.06%	1.57%	0.64%	-0.43%	-0.30%	0.60%	0.94%	0.75%	0.66%	0.78%	0.87%	0.75%	0.21%	1.19%	1.73%	2.21%	2.19%	2.36%	2.31%
15	Implied Inflation[b]	2.16%	2.47%	2.64%	2.42%	1.66%	1.79%	2.06%	1.89%	1.56%	1.75%	2.19%	2.35%	2.33%	2.40%	2.26%	1.85%	2.13%	2.49%	2.62%
16	**Real Dividend Yield[c]**	**1.14%**	**1.00%**	**0.60%**	**0.95%**	**1.51%**	**0.75%**	**0.60%**	**0.65%**	**1.15%**	**1.36%**	**0.86%**	**1.01%**	**1.22%**	**1.18%**	**1.69%**	**2.42%**	**1.64%**	**0.89%**	**0.97%**
	Utility																			
17	**Nominal "A" Rated Yield[4]**	**4.70%**	**5.46%**	**4.74%**	**3.10%**	**3.05%**	**3.77%**	**4.25%**	**4.00%**	**3.93%**	**4.12%**	**4.28%**	**4.48%**	**4.13%**	**5.04%**	**5.46%**	**6.04%**	**6.53%**	**6.07%**	**6.07%**
18	**Real "A" Rated Yield**	**2.48%**	**2.92%**	**2.05%**	**0.67%**	**1.37%**	**1.94%**	**2.14%**	**2.07%**	**2.34%**	**2.33%**	**2.04%**	**2.08%**	**1.76%**	**2.58%**	**3.13%**	**4.11%**	**4.31%**	**3.49%**	**3.36%**
	Spreads (Utility Bond - Stock)																			
19	**Nominal[d]**	**1.38%**	**1.96%**	**1.48%**	**-0.29%**	**-0.14%**	**1.21%**	**1.57%**	**1.44%**	**1.21%**	**0.99%**	**1.21%**	**1.09%**	**0.56%**	**1.43%**	**1.47%**	**1.72%**	**2.72%**	**2.66%**	**2.44%**
20	**Real[e]**	**1.35%**	**1.91%**	**1.44%**	**-0.28%**	**-0.14%**	**1.19%**	**1.54%**	**1.41%**	**1.19%**	**0.97%**	**1.19%**	**1.07%**	**0.54%**	**1.40%**	**1.44%**	**1.69%**	**2.67%**	**2.60%**	**2.38%**
	Spreads (Treasury Bond - Stock)																			
21	**Nominal[f]**	**-0.08%**	**0.58%**	**0.04%**	**-1.41%**	**-1.84%**	**-0.15%**	**0.34%**	**0.09%**	**-0.50%**	**-0.58%**	**0.01%**	**-0.26%**	**-1.03%**	**0.01%**	**0.04%**	**-0.21%**	**0.56%**	**1.50%**	**1.37%**
22	**Real[g]**	**-0.08%**	**0.57%**	**0.04%**	**-1.38%**	**-1.81%**	**-0.15%**	**0.34%**	**0.09%**	**-0.49%**	**-0.57%**	**0.01%**	**-0.26%**	**-1.01%**	**0.01%**	**0.04%**	**-0.21%**	**0.54%**	**1.46%**	**1.33%**



Sources:
[1] Data for years 2019 and prior were retreived from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, August 25, 2023.
[3] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.
[4] www.moodys.com, Bond Yields and Key Indicators, through October 13, 2023.
Notes:
[a] Based on the average of the high and low price for the year and the projected Dividends Declared per share published in the Value Line Investment Survey.
[b] Line 16 = (1 + Line 14) / (1 + Line 15) - 1.
[c] Line 17 = (1 + Line 12) / (1 +Line 16) - 1.
[d] The spread being measured here is the nominal A-rated utility bond yield over the average nominal utility dividend yield; (Line 18 - Line 12).
[e] The spread being measured here is the real A-rated utility bond yield over the average real utility dividend yield; Line 19 - Line 17)
[f] The spread being measured here is the nominal 20-Year Treasury yield over the average nominal utility dividend yield; (Line 14 - Line 12).
[g] The spread being measured here is the real 20-Year TIPS yield over the average real utility dividend yield; Line 15 - Line 17)

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Potomac Electric Power Company

Natural Gas Utilities
(Valuation Metrics)

Dividend per Share[1]

Line	Company	18-Year Average (1)	2023[2] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)	2018 CAGR (20)	2017 CAGR (21)
1	Atmos Energy	1.66	2.96	2.72	2.30	1.40	1.38	1.94	1.80	1.68	1.56	1.48	1.40	1.38	1.36	1.34	1.32	1.30	1.28	1.26	2.78%	3.15%
2	Chesapeake Utilities	1.16	2.25	2.03	1.69	1.01	0.96	1.39	1.26	1.19	1.12	1.07	1.01	0.96	0.91	0.87	0.83	0.81	0.78	0.77	3.86%	4.42%
3	New Jersey Resources	0.88	1.56	1.45	1.27	0.81	0.77	1.11	1.04	0.98	0.93	0.86	0.81	0.77	0.72	0.68	0.62	0.56	0.51	0.48	5.32%	6.75%
4	NiSource Inc.	0.90	1.00	0.94	0.84	0.98	0.94	0.78	0.70	0.64	0.83	1.02	0.98	0.94	0.92	0.92	0.92	0.92	0.92	0.92	-1.08%	-2.45%
5	Northwest Nat. Gas	1.76	1.95	1.93	1.91	1.83	1.79	1.89	1.88	1.87	1.86	1.85	1.83	1.79	1.75	1.68	1.60	1.52	1.44	1.39	1.81%	2.45%
6	ONE Gas Inc.	1.78	2.60	2.48	2.16	N/A	N/A	1.84	1.68	1.40	1.20	0.84	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	6.16%	11.87%
7	South Jersey Inds.	0.87	N/A	1.25	1.19	0.90	0.83	1.13	1.10	1.06	1.02	0.96	0.90	0.83	0.75	0.68	0.61	0.56	0.51	0.46	5.46%	7.33%
8	Southwest Gas	1.49	2.48	2.48	2.26	1.32	1.18	2.08	1.98	1.80	1.62	1.46	1.32	1.18	1.06	1.00	0.95	0.90	0.86	0.82	6.00%	7.88%
9	Spire Inc.	1.88	2.88	2.74	2.49	1.70	1.66	2.25	2.10	1.96	1.84	1.76	1.70	1.66	1.61	1.57	1.53	1.49	1.45	1.40	2.94%	3.42%
10	UGI Corp.	0.83	1.47	1.41	1.32	0.74	0.71	1.02	0.96	0.93	0.89	0.79	0.74	0.71	0.68	0.60	0.52	0.50	0.48	0.46	5.08%	6.48%
11	**Average**	**1.29**	**2.13**	**1.94**	**1.74**	**1.19**	**1.13**	**1.54**	**1.45**	**1.35**	**1.29**	**1.21**	**1.19**	**1.13**	**1.08**	**1.04**	**0.99**	**0.95**	**0.91**	**0.88**	**3.83%**	**5.13%**
12	**Industry Average Growth**	**6.06%**	**9.51%**	**11.47%**	**46.70%**	**4.71%**	**-26.47%**	**6.43%**	**7.33%**	**4.97%**	**6.51%**	**1.70%**	**4.71%**	**4.63%**	**4.50%**	**4.87%**	**4.16%**	**3.94%**	**3.41%**			

Sources:
[1] Data for years 2019 and prior were retreived from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, August 25, 2023.

Potomac Electric Power Company

Natural Gas Utilities
(Valuation Metrics)

		Earnings per Share[1]																		
Line	Company	18-Year Average	2023 [2]	2022	2021	2020	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
1	Atmos Energy	3.32	5.95	5.60	5.12	4.72	4.35	4.00	3.60	3.38	3.09	2.96	2.50	2.10	2.26	2.16	1.97	2.00	1.94	2.00
2	Chesapeake Utilities	2.77	4.90	4.97	4.70	4.21	3.72	3.45	2.68	2.86	2.68	2.47	2.26	1.99	1.91	1.82	1.43	1.39	1.29	1.15
3	New Jersey Resources	1.71	2.70	2.50	2.16	2.07	1.96	2.72	1.73	1.61	1.78	2.08	1.37	1.36	1.29	1.23	1.20	1.35	0.78	0.93
4	NiSource Inc.	1.20	1.60	1.47	1.35	1.32	1.31	1.30	0.39	1.00	0.63	1.67	1.57	1.37	1.05	1.06	0.84	1.34	1.14	1.14
5	Northwest Nat. Gas	2.16	2.70	2.54	2.50	2.30	2.19	2.33	-1.94	2.12	1.96	2.16	2.24	2.22	2.39	2.73	2.83	2.57	2.76	2.35
6	ONE Gas Inc.	3.25	4.10	4.08	3.85	3.68	3.51	3.25	3.02	2.65	2.24	2.07	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	South Jersey Inds.	1.38	N/A	1.70	1.65	1.68	1.12	1.38	1.23	1.34	1.44	1.57	1.52	1.52	1.45	1.35	1.19	1.14	1.05	1.23
8	Southwest Gas	2.90	2.95	3.10	3.80	4.14	3.94	3.68	3.62	3.18	2.92	3.01	3.11	2.86	2.43	2.27	1.94	1.39	1.95	1.98
9	Spire Inc.	3.06	4.30	3.95	4.96	1.44	3.52	4.33	3.43	3.24	3.16	2.35	2.02	2.79	2.86	2.43	2.92	2.64	2.31	2.37
10	UGI Corp.	1.97	2.80	2.90	2.96	2.67	2.28	2.74	2.29	2.05	2.01	1.92	1.59	1.17	1.37	1.59	1.57	1.33	1.18	1.10
11	**Average**	**2.32**	**3.56**	**3.28**	**3.31**	**2.82**	**2.79**	**2.92**	**2.01**	**2.34**	**2.19**	**2.23**	**2.02**	**1.93**	**1.89**	**1.85**	**1.77**	**1.68**	**1.60**	**1.58**
12	**Industry Average Growth**	**5.47%**	**8.37%**	**-0.73%**	**17.07%**	**1.18%**	**-4.39%**	**45.54%**	**-14.43%**	**6.94%**	**-1.55%**	**10.22%**	**4.59%**	**2.15%**	**2.25%**	**4.66%**	**4.97%**	**5.20%**	**1.02%**	

Sources:
[1] Data for years 2019 and prior were retreived from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, August 25, 2023.

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Potomac Electric Power Company

Natural Gas Utilities
(Valuation Metrics)

		Cash Flow / Capital Spending[1]						
Line	**Company**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024[2]**	**3 - 5 yr[2] Projection**
		(1)	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(5)**
1	Atmos Energy	0.53x	0.53x	0.53x	0.54x	0.54x	0.56x	0.69x
2	Chesapeake Utilities	0.66x	0.64x	0.82x	1.23x	0.84x	0.81x	0.94x
3	New Jersey Resources	1.41x	0.65x	0.72x	0.59x	0.68x	0.88x	0.79x
4	NiSource Inc.	0.66x	0.65x	0.69x	0.55x	0.43x	0.58x	0.61x
5	Northwest Nat. Gas	0.77x	0.75x	0.61x	0.60x	0.68x	0.83x	0.83x
6	ONE Gas Inc.	0.78x	0.88x	0.86x	0.74x	0.83x	0.86x	0.98x
7	South Jersey Inds.	0.48x	0.47x	0.49x	0.55x	0.59x	N/A	N/A
8	Southwest Gas	0.62x	0.53x	0.61x	0.31x	0.84x	0.96x	0.92x
9	Spire Inc.	0.65x	0.65x	0.70x	0.80x	0.71x	0.75x	0.90x
10	UGI Corp.	1.33x	1.54x	1.66x	1.42x	1.33x	1.37x	1.29x
11	Average	0.79x	0.73x	0.77x	0.73x	0.75x	0.84x	0.88x
12	Median	0.66x	0.65x	0.69x	0.60x	0.69x	0.83x	0.90x

Sources:
[1] The Value Line Investment Survey, February 28, 2020.
[2] The Value Line Investment Survey, August 25, 2023.
Notes:
Based on the projected Cash Flow per share and Capital Spending per share.

Potomac Electric Power Company

Natural Gas Utilities
(Valuation Metrics)

Percent Dividends to Book Value [1]

Line	Company	18-Year Average (1)	2023 [2/a] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)
1	Atmos Energy	4.99%	4.15%	4.07%	4.19%	4.26%	4.36%	4.53%	4.90%	5.04%	4.96%	4.81%	4.92%	5.28%	5.44%	5.55%	5.61%	5.75%	5.82%	6.25%
2	Chesapeake Utilities	5.11%	4.42%	4.32%	4.15%	4.23%	4.53%	4.39%	4.23%	4.35%	4.78%	5.18%	5.25%	5.39%	5.42%	5.49%	5.60%	6.71%	6.66%	6.95%
3	New Jersey Resources	7.21%	7.19%	7.63%	7.92%	6.60%	6.85%	6.87%	7.26%	7.21%	7.16%	7.45%	7.60%	7.86%	7.69%	7.72%	7.48%	6.42%	6.54%	6.40%
4	NiSource Inc.	5.65%	5.14%	7.15%	6.69%	6.64%	5.99%	5.96%	5.46%	5.08%	6.89%	5.22%	5.22%	5.25%	5.19%	5.22%	5.25%	5.34%	4.97%	5.02%
5	Northwest Nat. Gas	6.44%	5.58%	5.83%	5.66%	6.57%	6.69%	7.16%	7.27%	6.30%	6.53%	6.58%	6.59%	6.57%	6.55%	6.44%	6.43%	6.41%	6.39%	6.32%
6	ONE Gas Inc.	4.43%	4.93%	5.31%	5.04%	5.14%	4.96%	4.73%	4.48%	3.88%	3.41%	2.44%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	South Jersey Inds.	6.98%	N/A	6.94%	7.53%	7.21%	7.53%	7.63%	7.34%	6.53%	6.98%	7.04%	7.12%	7.09%	7.26%	7.13%	6.69%	6.40%	6.22%	6.09%
8	Southwest Gas	4.49%	4.96%	5.17%	4.80%	4.87%	4.79%	4.90%	5.25%	5.14%	4.82%	4.57%	4.33%	4.16%	3.98%	3.90%	3.89%	3.83%	3.74%	3.80%
9	Spire Inc.	5.85%	5.51%	5.58%	5.56%	5.63%	5.25%	5.06%	5.09%	5.06%	5.07%	5.04%	5.31%	6.22%	6.30%	6.53%	6.56%	6.74%	7.33%	7.43%
10	UGI Corp.	5.66%	6.85%	5.02%	5.34%	6.65%	6.30%	4.82%	5.28%	5.65%	5.72%	5.14%	5.07%	5.35%	5.77%	5.41%	5.35%	5.72%	5.82%	6.54%
11	Average	5.74%	5.42%	5.70%	5.69%	5.78%	5.72%	5.60%	5.66%	5.42%	5.63%	5.35%	5.71%	5.91%	5.96%	5.93%	5.87%	5.92%	5.94%	6.09%
12	Median	5.45%	5.14%	5.45%	5.45%	6.10%	5.62%	4.98%	5.26%	5.11%	5.40%	5.16%	5.25%	5.39%	5.77%	5.55%	5.61%	6.40%	6.22%	6.32%

Dividends to Earnings Ratio [1]

Line	Company	18-Year Average (1)	2023 [2/a] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)
13	Atmos Energy	0.55	0.50	0.49	0.49	0.49	0.48	0.49	0.50	0.50	0.50	0.50	0.56	0.66	0.60	0.62	0.67	0.65	0.66	0.63
14	Chesapeake Utilities	0.47	0.46	0.41	0.39	0.40	0.42	0.40	0.47	0.42	0.42	0.43	0.45	0.48	0.48	0.48	0.58	0.58	0.61	0.67
15	New Jersey Resources	0.55	0.58	0.58	0.63	0.61	0.61	0.41	0.60	0.61	0.52	0.41	0.59	0.57	0.56	0.55	0.52	0.41	0.65	0.51
16	NiSource Inc.	0.81	0.63	0.64	0.65	0.64	0.61	0.60	1.79	0.64	1.32	0.61	0.62	0.69	0.88	0.87	1.10	0.69	0.81	0.81
17	Northwest Nat. Gas	0.65	0.72	0.76	0.77	0.83	0.87	0.81	- 0.97	0.88	0.95	0.86	0.82	0.81	0.73	0.62	0.57	0.59	0.52	0.59
18	ONE Gas Inc.	0.56	0.63	0.61	0.60	0.59	0.57	0.57	0.56	0.53	0.54	0.41	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	South Jersey Inds.	0.65	N/A	0.74	0.74	0.71	1.04	0.82	0.89	0.79	0.71	0.61	0.59	0.54	0.52	0.50	0.51	0.49	0.48	0.37
20	Southwest Gas	0.54	0.84	0.80	0.63	0.55	0.55	0.57	0.55	0.57	0.55	0.49	0.42	0.41	0.44	0.44	0.49	0.65	0.44	0.41
21	Spire Inc.	0.68	0.67	0.69	0.52	1.73	0.67	0.52	0.61	0.60	0.58	0.75	0.84	0.59	0.56	0.65	0.52	0.56	0.63	0.59
22	UGI Corp.	0.45	0.53	0.49	0.46	0.49	0.50	0.37	0.42	0.45	0.44	0.41	0.46	0.60	0.50	0.38	0.33	0.38	0.41	0.41
23	Average	0.59	0.62	0.62	0.59	0.70	0.63	0.55	0.54	0.60	0.65	0.55	0.60	0.59	0.58	0.57	0.59	0.56	0.58	0.56
24	Median	0.59	0.63	0.62	0.61	0.60	0.59	0.54	0.55	0.59	0.55	0.49	0.59	0.59	0.56	0.55	0.52	0.58	0.61	0.59

Cash Flow to Capital Spending Ratio [1]

Line	Company	18-Year Average (1)	2023 [2/a] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)
25	Atmos Energy	0.65	0.52	0.54	0.58	0.52	0.53	0.55	0.62	0.59	0.60	0.65	0.55	0.59	0.68	0.77	0.78	0.81	0.94	0.82
26	Chesapeake Utilities	0.77	0.81	1.23	0.81	0.78	0.62	0.39	0.50	0.50	0.53	0.71	0.65	0.79	1.12	1.10	1.14	0.83	0.82	0.45
27	New Jersey Resources	1.20	0.83	0.59	0.62	0.71	0.51	0.85	0.70	0.59	0.67	1.79	1.46	1.48	1.51	1.55	1.75	2.11	1.67	2.14
28	NiSource Inc.	0.73	0.45	0.55	0.68	0.66	0.61	0.58	0.41	0.59	0.53	0.56	0.57	0.65	0.75	1.11	1.06	0.94	1.11	1.37
29	Northwest Nat. Gas	0.90	0.68	0.60	0.68	0.66	0.69	0.71	0.14	1.01	1.12	1.15	0.98	1.01	1.33	0.55	1.02	1.35	1.21	1.34
30	ONE Gas Inc.	0.84	0.78	0.74	0.86	0.83	0.89	0.84	0.87	0.92	0.86	0.79	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
31	South Jersey Inds.	0.81	N/A	0.55	0.55	0.54	0.40	0.73	0.81	0.76	0.50	0.53	0.51	0.58	0.70	0.75	1.01	1.67	1.70	1.40
32	Southwest Gas	0.84	1.00	0.31	0.86	0.69	0.53	0.56	0.68	0.83	0.84	0.99	1.05	0.90	0.82	1.37	1.28	0.85	0.78	0.72
33	Spire Inc.	1.03	0.68	0.80	0.75	0.42	0.44	0.77	0.72	0.96	0.92	0.98	0.78	0.95	1.53	1.61	1.93	1.64	1.42	1.28
34	UGI Corp.	1.45	1.31	1.42	1.32	1.59	1.22	1.64	1.29	1.35	1.48	1.53	1.32	1.52	1.28	1.36	1.52	1.72	1.62	1.69
35	Average	0.93	0.79	0.73	0.77	0.74	0.64	0.76	0.68	0.81	0.81	0.97	0.87	0.94	1.08	1.13	1.28	1.32	1.25	1.24
36	Median	0.79	0.78	0.60	0.72	0.67	0.57	0.72	0.69	0.80	0.75	0.88	0.78	0.90	1.12	1.11	1.14	1.35	1.21	1.34

Sources:
[1] Data for years 2019 and prior were retreived from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, August 25, 2023.
Notes:
[a] Based on the projected Dividends Declared per share and Book Value per share, published in The Value Line Investment Survey.
[b] Based on the projected Dividends Declared per share and Earnings per share, published in The Value Line Investment Survey.
[c] Based on the projected Cash Flow per share and Capital Spending per share, published in The Value Line Investment Survey.

Exhibit OPC (C)-3
Formal Case No. 1176

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Potomac Electric Power Company

Proxy Group

		Credit Ratings[1]		Common Equity Ratios	
Line	Company	S&P	Moody's	MI[1]	Value Line[2]
		(1)	(2)	(3)	(4)
1	Alliant Energy Corporation	A-	Baa2	41.4%	45.0%
2	Ameren Corporation	BBB+	Baa1	40.8%	43.4%
3	American Electric Power Company, Inc.	A-	Baa2	36.2%	42.0%
4	Black Hills Corporation	BBB+	Baa2	38.6%	45.4%
5	CenterPoint Energy, Inc.	BBB+	Baa2	34.3%	37.1%
6	CMS Energy Corporation	BBB+	Baa2	31.0%	33.6%
7	DTE Energy Company	BBB+	Baa2	35.1%	37.0%
8	Duke Energy Corporation	BBB+	Baa2	37.4%	42.0%
9	Entergy Corporation	BBB+	Baa2	32.2%	35.2%
10	Evergy, Inc.	A-	Baa2	43.8%	48.0%
11	Eversource Energy	A-	Baa1	40.0%	43.3%
12	Exelon Corporation	BBB+	Baa2	38.0%	40.2%
13	NextEra Energy, Inc.	A-	Baa1	34.1%	41.5%
14	OGE Energy Corp.	BBB+	Baa1	49.1%	52.4%
15	Pinnacle West Capital Corporation	BBB+	Baa1	40.2%	43.9%
16	Portland General Electric Company	BBB+	A3	41.1%	43.0%
17	PPL Corporation	A-	Baa1	49.3%	51.9%
18	Public Service Enterprise Group Incorporated	BBB+	Baa2	40.1%	45.4%
19	Sempra Energy	BBB+	Baa2	44.4%	50.7%
20	Southern Company	BBB+	Baa2	32.5%	36.5%
21	WEC Energy Group, Inc.	A-	Baa1	39.3%	44.4%
22	Xcel Energy Inc.	A-	Baa1	39.0%	42.2%
23	**Average**	**BBB+**	**Baa2**	**39.0%**	**42.9%**
24	**Median**			**39.1%**	**43.2%**
25	**Potomac Electric Power Company**[3,4]	**A-**	**Baa1**		**50.5%**

Sources:
Note: If credit rating/common equity ratio unavailable for utility, subsidary data used.
[1] S&P Global Market Intelligence, Downloaded on October 13, 2023.
[2] *The Value Line Investment Survey* , July 21, August 11, and September 8 2023.
[3] McKenzie direct testimony at page 25.
[4] Holden direct testimony at 16.

Exhibit OPC (C)-4
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		Zacks		MI		Yahoo! Finance		Average of
Line	**Company**	**Estimated Growth %[1]**	**Number of Estimates**	**Estimated Growth %[2]**	**Number of Estimates**	**Estimated Growth %[3]**	**Number of Estimates**	**Growth Rates**
		(1)	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**
1	Alliant Energy Corporation	6.47%	N/A	6.18%	6	6.80%	N/A	6.48%
2	Ameren Corporation	6.43%	N/A	7.08%	6	5.90%	N/A	6.47%
3	American Electric Power Company, Inc.	5.61%	N/A	5.80%	8	3.70%	N/A	5.04%
4	Black Hills Corporation	2.20%	N/A	3.70%	2	5.40%	N/A	3.77%
5	CenterPoint Energy, Inc.	7.51%	N/A	8.15%	5	- 1.07%	N/A	7.83%
6	CMS Energy Corporation	7.80%	N/A	7.77%	7	5.87%	N/A	7.15%
7	DTE Energy Company	6.00%	N/A	6.80%	6	5.10%	N/A	5.97%
8	Duke Energy Corporation	6.09%	N/A	6.03%	5	6.45%	N/A	6.19%
9	Entergy Corporation	5.83%	N/A	6.76%	4	6.60%	N/A	6.40%
10	Evergy, Inc.	4.82%	N/A	5.75%	5	3.60%	N/A	4.72%
11	Eversource Energy	4.99%	N/A	5.77%	5	6.70%	N/A	5.82%
12	Exelon Corporation	6.30%	N/A	6.74%	7	6.30%	N/A	6.45%
13	NextEra Energy, Inc.	7.93%	N/A	8.56%	8	8.80%	N/A	8.43%
14	OGE Energy Corp.	3.65%	N/A	3.70%	3	-12.34%	N/A	3.67%
15	Pinnacle West Capital Corporation	5.55%	N/A	5.65%	3	7.50%	N/A	6.23%
16	Portland General Electric Company	6.02%	N/A	6.76%	5	5.90%	N/A	6.23%
17	PPL Corporation	7.42%	N/A	6.68%	5	17.21%	N/A	10.44%
18	Public Service Enterprise Group Incorporated	5.46%	N/A	6.21%	5	5.50%	N/A	5.72%
19	Sempra Energy	4.95%	N/A	5.08%	6	4.14%	N/A	4.72%
20	Southern Company	4.00%	N/A	5.59%	6	7.10%	N/A	5.56%
21	WEC Energy Group, Inc.	5.76%	N/A	6.34%	6	5.50%	N/A	5.87%
22	Xcel Energy Inc.	6.49%	N/A	6.03%	5	6.75%	N/A	6.42%
23	**Average**	**5.79%**	**N/A**	**6.23%**	**5**	**6.54%**	**N/A**	**6.16%**
24	**Median**							**6.21%**

Sources:
[1] Zacks, http://www.zacks.com/, downloaded on October 13, 2023.
[2] S&P Global Market Intelligence, https://platform.mi.spglobal.com, downloaded on October 13, 2023.
[3] Yahoo! Finance, http://www.finance.yahoo.com/, downloaded on October 13, 2023.

Exhibit OPC (C)-5
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Line	Company	13-Week AVG Stock Price[1] (1)	Analysts' Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	Alliant Energy Corporation	$51.01	6.48%	$1.81	3.78%	10.26%
2	Ameren Corporation	$80.11	6.47%	$2.52	3.35%	9.82%
3	American Electric Power Company, Inc.	$79.46	5.04%	$3.32	4.39%	9.42%
4	Black Hills Corporation	$55.26	3.77%	$2.50	4.69%	8.46%
5	CenterPoint Energy, Inc.	$28.47	7.83%	$0.76	2.88%	10.71%
6	CMS Energy Corporation	$56.80	7.15%	$1.95	3.68%	10.83%
7	DTE Energy Company	$105.18	5.97%	$3.81	3.84%	9.81%
8	Duke Energy Corporation	$90.96	6.19%	$4.02	4.69%	10.88%
9	Entergy Corporation	$96.55	6.40%	$4.28	4.72%	11.11%
10	Evergy, Inc.	$55.21	4.72%	$2.45	4.65%	9.37%
11	Eversource Energy	$64.43	5.82%	$2.70	4.43%	10.26%
12	Exelon Corporation	$40.21	6.45%	$1.44	3.81%	10.26%
13	NextEra Energy, Inc.	$66.17	8.43%	$1.87	3.06%	11.49%
14	OGE Energy Corp.	$34.54	3.67%	$1.66	4.97%	8.65%
15	Pinnacle West Capital Corporation	$77.90	6.23%	$3.46	4.72%	10.95%
16	Portland General Electric Company	$44.37	6.23%	$1.90	4.55%	10.78%
17	PPL Corporation	$25.36	10.44%	$0.96	4.18%	14.62%
18	Public Service Enterprise Group Incorporated	$60.62	5.72%	$2.28	3.98%	9.70%
19	Sempra Energy	$71.26	4.72%	$2.38	3.50%	8.22%
20	Southern Company	$68.50	5.56%	$2.80	4.32%	9.88%
21	WEC Energy Group, Inc.	$85.44	5.87%	$3.12	3.87%	9.73%
22	Xcel Energy Inc.	$59.07	6.42%	$2.08	3.75%	10.17%
23	**Average**	**$63.49**	**6.16%**	**$2.46**	**4.08%**	**10.24%**
24	**Median**					**10.21%**

Sources:
[1] S&P Global Market Intelligence, Downloaded on October 13, 2023.
[2] Exhibit OPC (C)-4
[3] *The Value Line Investment Survey* , July 21, August 11, and September 8 2023.

Exhibit OPC (C)-6
Formal Case No. 1176

Exhibit OPC (C)-6
Page 1 of 1

Line	Company	Dividends Per Share 2022 (1)	Dividends Per Share Projected (2)	Earnings Per Share 2022 (3)	Earnings Per Share Projected (4)	Payout Ratio 2022 (5)	Payout Ratio Projected (6)
1	Alliant Energy Corporation	$1.71	$2.29	$2.73	$3.80	62.64%	60.26%
2	Ameren Corporation	$2.36	$3.30	$4.14	$5.50	57.00%	60.00%
3	American Electric Power Company, Inc.	$3.17	$4.16	$5.09	$6.80	62.28%	61.18%
4	Black Hills Corporation	$2.41	$3.01	$3.97	$4.50	60.71%	66.89%
5	CenterPoint Energy, Inc.	$0.72	$0.95	$1.59	$1.95	45.28%	48.72%
6	CMS Energy Corporation	$1.84	$2.30	$2.84	$3.75	64.79%	61.33%
7	DTE Energy Company	$3.54	$4.65	$5.52	$8.30	64.13%	56.02%
8	Duke Energy Corporation	$3.98	$4.30	$5.27	$7.00	75.52%	61.43%
9	Entergy Corporation	$4.10	$5.00	$5.37	$6.50	76.35%	76.92%
10	Evergy, Inc.	$2.33	$3.05	$3.26	$4.85	71.47%	62.89%
11	Eversource Energy	$2.55	$3.48	$4.09	$5.60	62.35%	62.14%
12	Exelon Corporation	$1.35	$1.80	$2.26	$3.00	59.73%	60.00%
13	NextEra Energy, Inc.	$1.70	$2.74	$2.90	$4.40	58.62%	62.27%
14	OGE Energy Corp.	$1.64	$1.85	$2.25	$3.15	72.89%	58.73%
15	Pinnacle West Capital Corporation	$3.42	$3.75	$4.26	$5.70	80.28%	65.79%
16	Portland General Electric Company	$1.79	$2.36	$2.74	$3.65	65.33%	64.66%
17	PPL Corporation	$0.88	$1.26	$1.41	$2.10	62.41%	60.00%
18	Public Service Enterprise Group Incorporated	$2.16	$2.82	$3.47	$4.50	62.25%	62.67%
19	Sempra Energy	$4.58	$6.10	$9.21	$12.35	49.73%	49.39%
20	Southern Company	$2.70	$3.10	$3.61	$5.15	74.79%	60.19%
21	WEC Energy Group, Inc.	$2.91	$3.80	$4.46	$5.90	65.25%	64.41%
22	Xcel Energy Inc.	$1.95	$2.66	$3.17	$4.25	61.51%	62.59%
23	**Average**	**$2.45**	**$3.12**	**$3.80**	**$5.12**	**64.33%**	**61.29%**

Source:
The Value Line Investment Survey , July 21, August 11, and September 8 2023.

Exhibit OPC (C)-7
Formal Case No. 1176

Exhibit OPC (C)-7
Page 1 of 2

Line	Company	3 to 5 Year Projections										Sustainable
		Dividends Per Share	Earnings Per Share	Book Value Per Share	Book Value Growth	ROE	Adjustment Factor	Adjusted ROE	Payout Ratio	Retention Rate	Internal Growth Rate	Growth Rate
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Alliant Energy Corporation	$2.29	$3.80	$31.90	5.00%	11.91%	1.02	12.20%	60.26%	39.74%	4.85%	5.33%
2	Ameren Corporation	$3.30	$5.50	$55.00	6.52%	10.00%	1.03	10.32%	60.00%	40.00%	4.13%	5.82%
3	American Electric Power Company, Inc.	$4.16	$6.80	$62.55	6.06%	10.87%	1.03	11.19%	61.18%	38.82%	4.34%	5.31%
4	Black Hills Corporation	$3.01	$4.50	$55.00	3.95%	8.18%	1.02	8.34%	66.89%	33.11%	2.76%	3.08%
5	CenterPoint Energy, Inc.	$0.95	$1.95	$19.50	5.84%	10.00%	1.03	10.28%	48.72%	51.28%	5.27%	5.41%
6	CMS Energy Corporation	$2.30	$3.75	$31.75	6.37%	11.81%	1.03	12.18%	61.33%	38.67%	4.71%	5.56%
7	DTE Energy Company	$4.65	$8.30	$60.75	5.56%	13.66%	1.03	14.03%	56.02%	43.98%	6.17%	6.21%
8	Duke Energy Corporation	$4.30	$7.00	$70.00	2.62%	10.00%	1.01	10.13%	61.43%	38.57%	3.91%	3.91%
9	Entergy Corporation	$5.00	$6.50	$73.90	3.78%	8.80%	1.02	8.96%	76.92%	23.08%	2.07%	3.05%
10	Evergy, Inc.	$3.05	$4.85	$47.50	2.56%	10.21%	1.01	10.34%	62.89%	37.11%	3.84%	3.84%
11	Eversource Energy	$3.48	$5.60	$55.50	4.56%	10.09%	1.02	10.31%	62.14%	37.86%	3.90%	4.20%
12	Exelon Corporation	$1.80	$3.00	$28.75	2.93%	10.43%	1.01	10.59%	60.00%	40.00%	4.23%	4.31%
13	NextEra Energy, Inc.	$2.74	$4.40	$30.00	8.73%	14.67%	1.04	15.28%	62.27%	37.73%	5.76%	7.24%
14	OGE Energy Corp.	$1.85	$3.15	$26.00	3.44%	12.12%	1.02	12.32%	58.73%	41.27%	5.08%	5.08%
15	Pinnacle West Capital Corporation	$3.75	$5.70	$62.00	3.01%	9.19%	1.01	9.33%	65.79%	34.21%	3.19%	3.73%
16	Portland General Electric Company	$2.36	$3.65	$38.70	4.45%	9.43%	1.02	9.64%	64.66%	35.34%	3.41%	4.38%
17	PPL Corporation	$1.26	$2.10	$22.45	3.51%	9.35%	1.02	9.52%	60.00%	40.00%	3.81%	3.82%
18	Public Service Enterprise Group Incorporated	$2.82	$4.50	$34.75	4.70%	12.95%	1.02	13.25%	62.67%	37.33%	4.95%	5.09%
19	Sempra Energy	$6.10	$12.35	$105.65	4.84%	11.69%	1.02	11.97%	49.39%	50.61%	6.06%	6.19%
20	Southern Company	$3.10	$5.15	$32.25	2.92%	15.97%	1.01	16.20%	60.19%	39.81%	6.45%	6.45%
21	WEC Energy Group, Inc.	$3.80	$5.90	$42.00	2.70%	14.05%	1.01	14.23%	64.41%	35.59%	5.07%	5.07%
22	Xcel Energy Inc.	$2.66	$4.25	$38.25	4.74%	11.11%	1.02	11.37%	62.59%	37.41%	4.25%	4.61%
23	**Average**	**$3.12**	**$5.12**	**$46.55**	**4.49%**	**11.20%**	**1.02**	**11.45%**	**61.29%**	**38.71%**	**4.46%**	**4.89%**
24	**Median**											**5.08%**

Sources and Notes:
Cols. (1), (2) and (3): *The Value Line Investment Survey* , July 21, August 11, and September 8 2023.
Col. (4): [Col. (3) / Page 2 Col. (2)] ^ (1/number of years projected) - 1.
Col. (5): Col. (2) / Col. (3).
Col. (6): [2 * (1 + Col. (4))] / (2 + Col. (4)).
Col. (7): Col. (6) * Col. (5).
Col. (8): Col. (1) / Col. (2).
Col. (9): 1 - Col. (8).
Col. (10): Col. (9) * Col. (7).
Col. (11): Col. (10) + Page 2 Col. (9).

Potomac Electric Power Company

Sustainable Growth Rate

Line	Company	13-Week Average Stock Price[1]	2022 Book Value Per Share[2]	Market to Book Ratio	Common Shares Outstanding (in Millions)[2] 2022	3-5 Years	Growth	S Factor[3]	V Factor[4]	S * V
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Alliant Energy Corporation	$51.01	$24.99	2.04	251.14	257.00	0.46%	0.94%	51.01%	0.48%
2	Ameren Corporation	$80.11	$40.11	2.00	262.00	285.00	1.70%	3.39%	49.93%	1.69%
3	American Electric Power Company, Inc.	$79.46	$46.60	1.71	513.87	550.00	1.37%	2.33%	41.35%	0.96%
4	Black Hills Corporation	$55.26	$45.31	1.22	66.10	71.00	1.44%	1.76%	18.01%	0.32%
5	CenterPoint Energy, Inc.	$28.47	$14.68	1.94	629.54	634.00	0.14%	0.27%	48.44%	0.13%
6	CMS Energy Corporation	$56.80	$23.32	2.44	291.27	300.00	0.59%	1.44%	58.94%	0.85%
7	DTE Energy Company	$105.18	$46.35	2.27	205.69	206.00	0.03%	0.07%	55.93%	0.04%
8	Duke Energy Corporation	$90.96	$61.51	1.48	770.00	770.00	0.00%	0.00%	32.38%	0.00%
9	Entergy Corporation	$96.55	$61.40	1.57	211.18	230.00	1.72%	2.71%	36.41%	0.99%
10	Evergy, Inc.	$55.21	$41.86	1.32	229.90	230.00	0.01%	0.01%	24.18%	0.00%
11	Eversource Energy	$64.43	$44.41	1.45	348.44	360.00	0.65%	0.95%	31.08%	0.30%
12	Exelon Corporation	$40.21	$24.89	1.62	994.00	1,000.00	0.12%	0.19%	38.10%	0.07%
13	NextEra Energy, Inc.	$66.17	$19.74	3.35	1,987.00	2,050.00	0.63%	2.10%	70.17%	1.47%
14	OGE Energy Corp.	$34.54	$21.95	1.57	200.20	200.20	0.00%	0.00%	36.45%	0.00%
15	Pinnacle West Capital Corporation	$77.90	$53.45	1.46	113.17	120.00	1.18%	1.72%	31.39%	0.54%
16	Portland General Electric Company	$44.37	$31.13	1.43	89.28	100.00	2.29%	3.27%	29.84%	0.98%
17	PPL Corporation	$25.36	$18.89	1.34	736.49	738.00	0.04%	0.05%	25.50%	0.01%
18	Public Service Enterprise Group Incorporated	$60.62	$27.62	2.19	497.00	500.00	0.12%	0.26%	54.44%	0.14%
19	Sempra Energy	$71.26	$83.43	0.85	314.33	300.00	-0.93%	-0.79%	-17.08%	0.14%
20	Southern Company	$68.50	$27.93	2.45	1,089.00	1,070.00	-0.35%	-0.86%	59.22%	-0.51%
21	WEC Energy Group, Inc.	$85.44	$36.76	2.32	315.43	315.43	0.00%	0.00%	56.97%	0.00%
22	Xcel Energy Inc.	$59.07	$30.34	1.95	549.58	560.00	0.38%	0.73%	48.63%	0.36%
	Average	**$63.49**	**$37.58**	**1.82**	**484.76**	**493.03**	**0.53%**	**0.93%**	**40.06%**	**0.41%**

Sources and Notes:
[1] S&P Global Market Intelligence, Downloaded on October 13, 2023.
[2] *The Value Line Investment Survey* , July 21, August 11, and September 8 2023.
[3] Expected Growth in the Number of Shares, Column (3) * Column (6).
[4] Expected Profit of Stock Investment, [1 - 1 / Column (3)].

Exhibit OPC (C)-8
Formal Case No. 1176

Exhibit OPC (C)-8
Page 1 of 1

Line	Company	13-Week AVG Stock Price[1] (1)	Sustainable Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	Alliant Energy Corporation	$51.01	5.33%	$1.81	3.74%	9.07%
2	Ameren Corporation	$80.11	5.82%	$2.52	3.33%	9.15%
3	American Electric Power Company, Inc.	$79.46	5.31%	$3.32	4.40%	9.71%
4	Black Hills Corporation	$55.26	3.08%	$2.50	4.66%	7.74%
5	CenterPoint Energy, Inc.	$28.47	5.41%	$0.76	2.81%	8.22%
6	CMS Energy Corporation	$56.80	5.56%	$1.95	3.62%	9.18%
7	DTE Energy Company	$105.18	6.21%	$3.81	3.85%	10.06%
8	Duke Energy Corporation	$90.96	3.91%	$4.02	4.59%	8.50%
9	Entergy Corporation	$96.55	3.05%	$4.28	4.57%	7.62%
10	Evergy, Inc.	$55.21	3.84%	$2.45	4.61%	8.45%
11	Eversource Energy	$64.43	4.20%	$2.70	4.37%	8.57%
12	Exelon Corporation	$40.21	4.31%	$1.44	3.74%	8.04%
13	NextEra Energy, Inc.	$66.17	7.24%	$1.87	3.03%	10.27%
14	OGE Energy Corp.	$34.54	5.08%	$1.66	5.04%	10.12%
15	Pinnacle West Capital Corporation	$77.90	3.73%	$3.46	4.61%	8.34%
16	Portland General Electric Company	$44.37	4.38%	$1.90	4.47%	8.85%
17	PPL Corporation	$25.36	3.82%	$0.96	3.93%	7.75%
18	Public Service Enterprise Group Incorporated	$60.62	5.09%	$2.28	3.95%	9.04%
19	Sempra Energy	$71.26	6.19%	$2.38	3.55%	9.74%
20	Southern Company	$68.50	6.45%	$2.80	4.35%	10.80%
21	WEC Energy Group, Inc.	$85.44	5.07%	$3.12	3.84%	8.90%
22	Xcel Energy Inc.	$59.07	4.61%	$2.08	3.68%	8.29%
23	**Average**	**$63.49**	**4.89%**	**$2.46**	**4.03%**	**8.93%**
24	**Median**					**8.88%**

Sources:
[1] S&P Global Market Intelligence, Downloaded on October 13, 2023.
[2] Exhibit OPC (C)-7, page 1.
[3] *The Value Line Investment Survey*, July 21, August 11, and September 8 2023.

Exhibit OPC (C)-9
Formal Case No. 1176

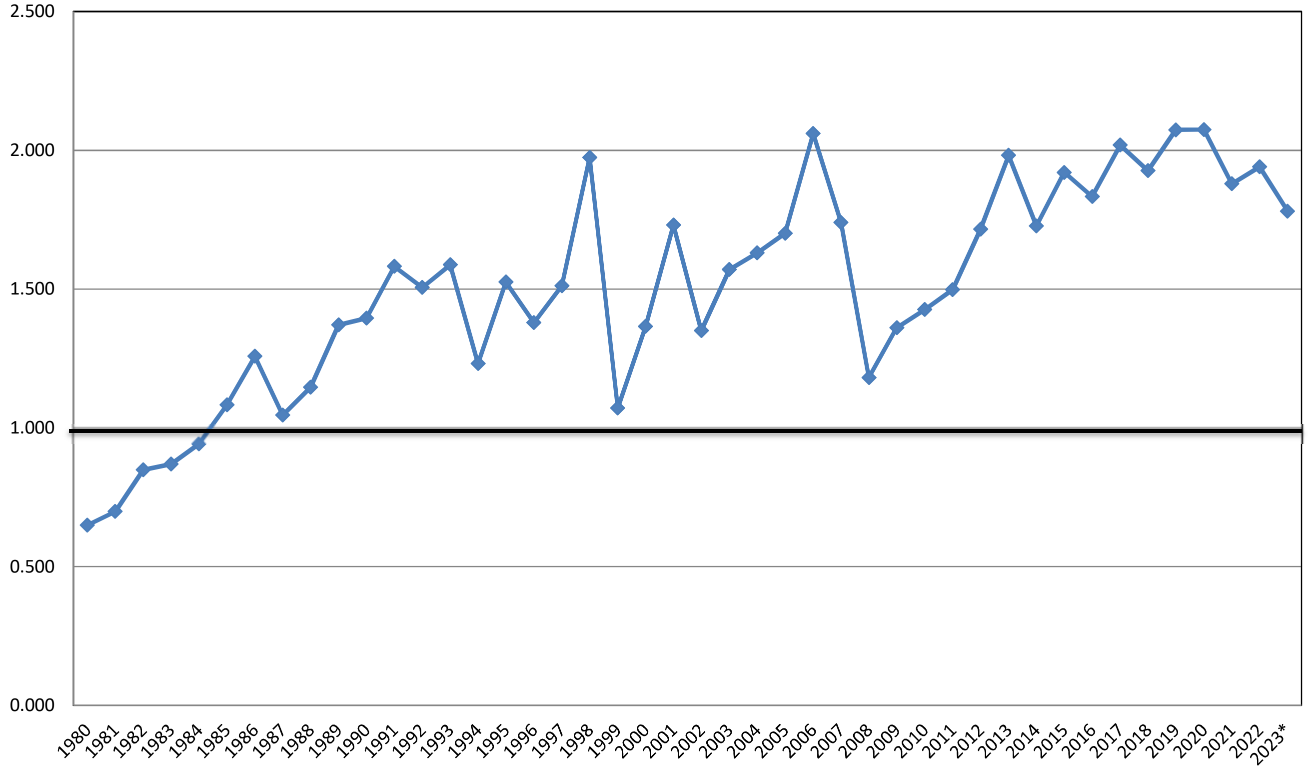
Exhibit OPC (C)-9
Page 1 of 1

Line	Company	13-Week AVG Stock Price[1] (1)	Annualized Dividend[2] (2)	First Stage Growth[3] (3)	Second Stage Growth Year 6 (4)	Year 7 (5)	Year 8 (6)	Year 9 (7)	Year 10 (8)	Third Stage Growth[4] (9)	Multi-Stage Growth DCF (10)
1	Alliant Energy Corporation	$51.01	$1.81	6.48%	6.07%	5.67%	5.26%	4.85%	4.45%	4.04%	8.34%
2	Ameren Corporation	$80.11	$2.52	6.47%	6.06%	5.66%	5.25%	4.85%	4.44%	4.04%	7.86%
3	American Electric Power Company, Inc.	$79.46	$3.32	5.04%	4.87%	4.70%	4.54%	4.37%	4.21%	4.04%	8.66%
4	Black Hills Corporation	$55.26	$2.50	3.77%	3.81%	3.86%	3.90%	3.95%	3.99%	4.04%	8.67%
5	CenterPoint Energy, Inc.	$28.47	$0.76	7.83%	7.20%	6.57%	5.93%	5.30%	4.67%	4.04%	7.57%
6	CMS Energy Corporation	$56.80	$1.95	7.15%	6.63%	6.11%	5.59%	5.08%	4.56%	4.04%	8.38%
7	DTE Energy Company	$105.18	$3.81	5.97%	5.65%	5.32%	5.00%	4.68%	4.36%	4.04%	8.29%
8	Duke Energy Corporation	$90.96	$4.02	6.19%	5.83%	5.47%	5.12%	4.76%	4.40%	4.04%	9.28%
9	Entergy Corporation	$96.55	$4.28	6.40%	6.00%	5.61%	5.22%	4.83%	4.43%	4.04%	9.36%
10	Evergy, Inc.	$55.21	$2.45	4.72%	4.61%	4.50%	4.38%	4.27%	4.15%	4.04%	8.86%
11	Eversource Energy	$64.43	$2.70	5.82%	5.52%	5.23%	4.93%	4.63%	4.34%	4.04%	8.91%
12	Exelon Corporation	$40.21	$1.44	6.45%	6.05%	5.65%	5.24%	4.84%	4.44%	4.04%	8.37%
13	NextEra Energy, Inc.	$66.17	$1.87	8.43%	7.70%	6.97%	6.23%	5.50%	4.77%	4.04%	7.92%
14	OGE Energy Corp.	$34.54	$1.66	3.67%	3.74%	3.80%	3.86%	3.92%	3.98%	4.04%	8.92%
15	Pinnacle West Capital Corporation	$77.90	$3.46	6.23%	5.87%	5.50%	5.14%	4.77%	4.41%	4.04%	9.32%
16	Portland General Electric Company	$44.37	$1.90	6.23%	5.86%	5.50%	5.13%	4.77%	4.40%	4.04%	9.14%
17	PPL Corporation	$25.36	$0.96	10.44%	9.37%	8.31%	7.24%	6.17%	5.11%	4.04%	9.82%
18	Public Service Enterprise Group Incorporate	$60.62	$2.28	5.72%	5.44%	5.16%	4.88%	4.60%	4.32%	4.04%	8.39%
19	Sempra Energy	$71.26	$2.38	4.72%	4.61%	4.50%	4.38%	4.27%	4.15%	4.04%	7.67%
20	Southern Company	$68.50	$2.80	5.56%	5.31%	5.06%	4.80%	4.55%	4.29%	4.04%	8.71%
21	WEC Energy Group, Inc.	$85.44	$3.12	5.87%	5.56%	5.26%	4.95%	4.65%	4.34%	4.04%	8.30%
22	Xcel Energy Inc.	$59.07	$2.08	6.42%	6.03%	5.63%	5.23%	4.83%	4.44%	4.04%	8.29%
23	**Average**	**$63.49**	**$2.46**	**6.16%**	**5.81%**	**5.46%**	**5.10%**	**4.75%**	**4.39%**	**4.04%**	**8.59%**
24	**Median**										**8.53%**

Sources:
[1] S&P Global Market Intelligence, Downloaded on October 13, 2023.
[2] *The Value Line Investment Survey*, July 21, August 11, and September 8 2023.
[3] Exhibit OPC (C)-4
[4] *Blue Chip Economic Indicators October 10, 2023, at page 14.*

Exhibit OPC (C)-10
Formal Case No. 1176

Exhibit OPC (C)-10
Page 1 of 1



Source:
1980 - 2000: Mergent Public Utility Manual.
2001 - 2015: AUS Utility Reports, multiple dates.
2016 - 2022: Value Line Investment Survey, multiple dates.
* Value Line Investment Survey Reports, July 21, August 11, August 25, and September 8, 2023

Exhibit OPC (C)-11
Formal Case No. 1176
Direct Testimony of Christopher C. Walters

Potomac Electric Power Company

Equity Risk Premium - Treasury Bond

Line	Year	Authorized Electric Returns[1] (1)	30 yr. Treasury Bond Yield[2] (2)	Indicated Risk Premium (3)	Rolling 5 - Year Average (4)	Rolling 10 - Year Average (5)
1	1986	13.93%	7.80%	6.13%		
2	1987	12.99%	8.58%	4.41%		
3	1988	12.79%	8.96%	3.83%		
4	1989	12.97%	8.45%	4.52%		
5	1990	12.70%	8.61%	4.09%	4.60%	
6	1991	12.55%	8.14%	4.41%	4.25%	
7	1992	12.09%	7.67%	4.42%	4.26%	
8	1993	11.41%	6.60%	4.81%	4.45%	
9	1994	11.34%	7.37%	3.97%	4.34%	
10	1995	11.55%	6.88%	4.67%	4.46%	4.53%
11	1996	11.39%	6.70%	4.69%	4.51%	4.38%
12	1997	11.40%	6.61%	4.79%	4.59%	4.42%
13	1998	11.66%	5.58%	6.08%	4.84%	4.65%
14	1999	10.77%	5.87%	4.90%	5.03%	4.68%
15	2000	11.43%	5.94%	5.49%	5.19%	4.82%
16	2001	11.09%	5.49%	5.60%	5.37%	4.94%
17	2002	11.16%	5.43%	5.73%	5.56%	5.07%
18	2003	10.97%	4.96%	6.01%	5.55%	5.19%
19	2004	10.75%	5.05%	5.70%	5.71%	5.37%
20	2005	10.54%	4.65%	5.89%	5.79%	5.49%
21	2006	10.34%	4.87%	5.47%	5.76%	5.57%
22	2007	10.31%	4.83%	5.48%	5.71%	5.64%
23	2008	10.37%	4.28%	6.09%	5.73%	5.64%
24	2009	10.52%	4.07%	6.45%	5.88%	5.79%
25	2010	10.29%	4.25%	6.04%	5.90%	5.85%
26	2011	10.19%	3.91%	6.28%	6.07%	5.91%
27	2012	10.01%	2.92%	7.09%	6.39%	6.05%
28	2013	9.81%	3.45%	6.36%	6.44%	6.09%
29	2014	9.75%	3.34%	6.41%	6.44%	6.16%
30	2015	9.60%	2.84%	6.76%	6.58%	6.24%
31	2016	9.60%	2.60%	7.00%	6.72%	6.40%
32	2017	9.68%	2.90%	6.79%	6.66%	6.53%
33	2018	9.55%	3.11%	6.44%	6.68%	6.56%
34	2019	9.64%	2.58%	7.06%	6.81%	6.62%
35	2020	9.39%	1.56%	7.83%	7.02%	6.80%
36	2021	9.39%	2.05%	7.34%	7.09%	6.91%
37	2022	9.52%	3.12%	6.41%	7.01%	6.84%
38	2023[3]	9.64%	3.77%	5.87%	6.90%	6.79%
39	**Average**	**10.87%**	**5.15%**	**5.72%**	**5.71%**	**5.72%**
40	**Minimum**				**4.25%**	**4.38%**
41	**Maximum**				**7.09%**	**6.91%**

Sources:
[1] *Regulatory Research Associates, Inc*., Regulatory Focus, Major Rate Case Decisions, Jan. 1997 p. 5, and Jan. 2011 p. 3.
S&P Global Market Intelligence, RRA Regulatory Focus, Major Rate Case Decisions, January - June 2023
July 31, 2023 at page 4.
2006 - 2023 Authorized Returns exclude limited issue rider cases.
[2] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
The yields from 2002 to 2005 represent the 20-Year Treasury yields obtained from the Federal Reserve Bank
[3] Data represents January - June, 2023.

Potomac Electric Power Company

Equity Risk Premium - Utility Bond

Line	Year	Authorized Electric Returns[1] (1)	Average "A" Rated Utility Bond Yield[2] (2)	Indicated Risk Premium (3)	Rolling 5 - Year Average (4)	Rolling 10 - Year Average (5)
1	1986	13.93%	9.58%	4.35%		
2	1987	12.99%	10.10%	2.89%		
3	1988	12.79%	10.49%	2.30%		
4	1989	12.97%	9.77%	3.20%		
5	1990	12.70%	9.86%	2.84%	3.12%	
6	1991	12.55%	9.36%	3.19%	2.88%	
7	1992	12.09%	8.69%	3.40%	2.99%	
8	1993	11.41%	7.59%	3.82%	3.29%	
9	1994	11.34%	8.31%	3.03%	3.26%	
10	1995	11.55%	7.89%	3.66%	3.42%	3.27%
11	1996	11.39%	7.75%	3.64%	3.51%	3.20%
12	1997	11.40%	7.60%	3.80%	3.59%	3.29%
13	1998	11.66%	7.04%	4.62%	3.75%	3.52%
14	1999	10.77%	7.62%	3.15%	3.77%	3.52%
15	2000	11.43%	8.24%	3.19%	3.68%	3.55%
16	2001	11.09%	7.76%	3.33%	3.62%	3.56%
17	2002	11.16%	7.37%	3.79%	3.61%	3.60%
18	2003	10.97%	6.58%	4.39%	3.57%	3.66%
19	2004	10.75%	6.16%	4.59%	3.86%	3.82%
20	2005	10.54%	5.65%	4.89%	4.20%	3.94%
21	2006	10.34%	6.07%	4.27%	4.39%	4.00%
22	2007	10.31%	6.07%	4.24%	4.48%	4.04%
23	2008	10.37%	6.53%	3.84%	4.37%	3.97%
24	2009	10.52%	6.04%	4.48%	4.34%	4.10%
25	2010	10.29%	5.47%	4.82%	4.33%	4.26%
26	2011	10.19%	5.04%	5.15%	4.51%	4.45%
27	2012	10.01%	4.13%	5.88%	4.83%	4.66%
28	2013	9.81%	4.48%	5.33%	5.13%	4.75%
29	2014	9.75%	4.28%	5.47%	5.33%	4.84%
30	2015	9.60%	4.12%	5.48%	5.46%	4.90%
31	2016	9.60%	3.93%	5.67%	5.57%	5.04%
32	2017	9.68%	4.00%	5.68%	5.53%	5.18%
33	2018	9.55%	4.25%	5.30%	5.52%	5.33%
34	2019	9.64%	3.77%	5.87%	5.60%	5.47%
35	2020	9.39%	3.05%	6.34%	5.77%	5.62%
36	2021	9.39%	3.10%	6.29%	5.90%	5.73%
37	2022	9.52%	4.72%	4.80%	5.72%	5.62%
38	2023[3]	9.64%	5.29%	4.35%	5.53%	5.53%
37	**Average**	**10.87%**	**6.52%**	**4.35%**	**4.37%**	**4.36%**
39	**Minimum**				**2.88%**	**3.20%**
40	**Maximum**				**5.90%**	**5.73%**

Sources:
[1] *Regulatory Research Associates, Inc*., Regulatory Focus, Major Rate Case Decisions, Jan. 1997 p. 5, and Jan. 2011 p. 3.
S&P Global Market Intelligence, RRA Regulatory Focus, Major Rate Case Decisions, January - June 2023
July 31, 2023 at page 4.
2006 - 2023 Authorized Returns exclude limited issue rider cases.
[2] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
The yields from 2002 to 2005 represent the 20-Year Treasury yields obtained from the Federal Reserve Bank
[3] Data represents January - June, 2023.

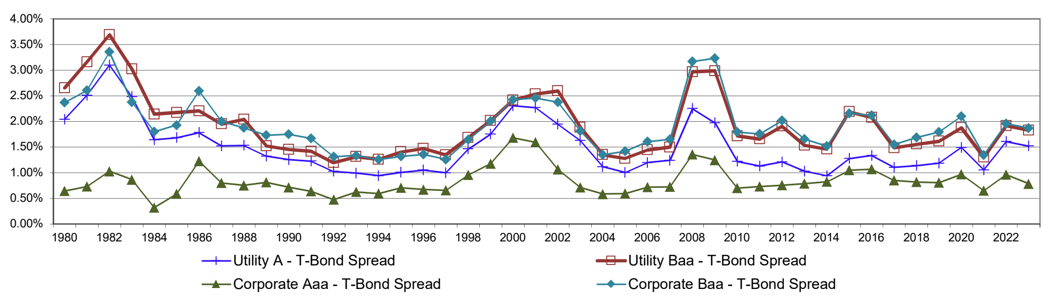
Potomac Electric Power Company

Bond Yield Spreads

			Public Utility Bond				Corporate Bond				Utility to Corporate	
Line	Year	T-Bond Yield[1] (1)	A[2] (2)	Baa[2] (3)	A-T-Bond Spread (4)	Baa-T-Bond Spread (5)	Aaa[3] (6)	Baa[3] (7)	Aaa-T-Bond Spread (8)	Baa-T-Bond Spread (9)	Baa Spread (10)	A-Aaa Spread (11)
1	1980	11.30%	13.34%	13.95%	2.04%	2.65%	11.94%	13.67%	0.64%	2.37%	0.28%	1.40%
2	1981	13.44%	15.95%	16.60%	2.51%	3.16%	14.17%	16.04%	0.73%	2.60%	0.56%	1.78%
3	1982	12.76%	15.86%	16.45%	3.10%	3.69%	13.79%	16.11%	1.03%	3.35%	0.34%	2.07%
4	1983	11.18%	13.66%	14.20%	2.48%	3.02%	12.04%	13.55%	0.86%	2.38%	0.65%	1.62%
5	1984	12.39%	14.03%	14.53%	1.64%	2.14%	12.71%	14.19%	0.32%	1.80%	0.34%	1.32%
6	1985	10.79%	12.47%	12.96%	1.68%	2.17%	11.37%	12.72%	0.58%	1.93%	0.24%	1.10%
7	1986	7.80%	9.58%	10.00%	1.78%	2.20%	9.02%	10.39%	1.22%	2.59%	-0.39%	0.56%
8	1987	8.58%	10.10%	10.53%	1.52%	1.95%	9.38%	10.58%	0.80%	2.00%	-0.05%	0.72%
9	1988	8.96%	10.49%	11.00%	1.53%	2.04%	9.71%	10.83%	0.75%	1.87%	0.17%	0.78%
10	1989	8.45%	9.77%	9.97%	1.32%	1.52%	9.26%	10.18%	0.81%	1.73%	-0.21%	0.51%
11	1990	8.61%	9.86%	10.06%	1.25%	1.45%	9.32%	10.36%	0.71%	1.75%	-0.30%	0.54%
12	1991	8.14%	9.36%	9.55%	1.22%	1.41%	8.77%	9.80%	0.63%	1.67%	-0.25%	0.59%
13	1992	7.67%	8.69%	8.86%	1.02%	1.19%	8.14%	8.98%	0.47%	1.31%	-0.12%	0.55%
14	1993	6.60%	7.59%	7.91%	0.99%	1.31%	7.22%	7.93%	0.62%	1.33%	-0.02%	0.37%
15	1994	7.37%	8.31%	8.63%	0.94%	1.26%	7.96%	8.62%	0.59%	1.25%	0.01%	0.35%
16	1995	6.88%	7.89%	8.29%	1.01%	1.41%	7.59%	8.20%	0.71%	1.32%	0.09%	0.30%
17	1996	6.70%	7.75%	8.17%	1.05%	1.47%	7.37%	8.05%	0.67%	1.35%	0.12%	0.38%
18	1997	6.61%	7.60%	7.95%	0.99%	1.34%	7.26%	7.86%	0.66%	1.26%	0.09%	0.34%
19	1998	5.58%	7.04%	7.26%	1.46%	1.68%	6.53%	7.22%	0.95%	1.64%	0.04%	0.51%
20	1999	5.87%	7.62%	7.88%	1.75%	2.01%	7.04%	7.87%	1.18%	2.01%	0.01%	0.58%
21	2000	5.94%	8.24%	8.36%	2.30%	2.42%	7.62%	8.36%	1.68%	2.42%	-0.01%	0.62%
22	2001	5.49%	7.76%	8.03%	2.27%	2.54%	7.08%	7.95%	1.59%	2.45%	0.08%	0.68%
23	2002	5.43%	7.37%	8.02%	1.94%	2.59%	6.49%	7.80%	1.06%	2.37%	0.22%	0.88%
24	2003	4.96%	6.58%	6.84%	1.62%	1.89%	5.67%	6.77%	0.71%	1.81%	0.08%	0.91%
25	2004	5.05%	6.16%	6.40%	1.11%	1.35%	5.63%	6.39%	0.58%	1.35%	0.00%	0.53%
26	2005	4.65%	5.65%	5.93%	1.00%	1.28%	5.24%	6.06%	0.59%	1.42%	-0.14%	0.41%
27	2006	4.87%	6.07%	6.32%	1.20%	1.44%	5.59%	6.48%	0.71%	1.61%	-0.16%	0.48%
28	2007	4.83%	6.07%	6.33%	1.24%	1.50%	5.56%	6.48%	0.72%	1.65%	-0.15%	0.52%
29	2008	4.28%	6.53%	7.25%	2.25%	2.97%	5.63%	7.45%	1.35%	3.17%	-0.20%	0.90%
30	2009	4.07%	6.04%	7.06%	1.97%	2.99%	5.31%	7.30%	1.24%	3.23%	-0.24%	0.73%
31	2010	4.25%	5.47%	5.96%	1.22%	1.71%	4.95%	6.04%	0.70%	1.79%	-0.08%	0.52%
32	2011	3.91%	5.04%	5.57%	1.13%	1.66%	4.64%	5.67%	0.73%	1.76%	-0.10%	0.40%
33	2012	2.92%	4.13%	4.83%	1.21%	1.90%	3.67%	4.94%	0.75%	2.02%	-0.11%	0.46%
34	2013	3.45%	4.48%	4.98%	1.03%	1.53%	4.24%	5.10%	0.79%	1.65%	-0.12%	0.24%
35	2014	3.34%	4.28%	4.80%	0.94%	1.46%	4.16%	4.86%	0.82%	1.52%	-0.06%	0.12%
36	2015	2.84%	4.12%	5.03%	1.27%	2.19%	3.89%	5.00%	1.05%	2.16%	0.03%	0.23%
37	2016	2.60%	3.93%	4.67%	1.33%	2.08%	3.66%	4.71%	1.07%	2.12%	-0.04%	0.27%
38	2017	2.90%	4.00%	4.38%	1.10%	1.48%	3.74%	4.44%	0.85%	1.55%	-0.06%	0.26%
39	2018	3.11%	4.25%	4.67%	1.14%	1.56%	3.93%	4.80%	0.82%	1.69%	-0.13%	0.32%
40	2019	2.58%	3.77%	4.19%	1.18%	1.61%	3.39%	4.38%	0.81%	1.79%	-0.18%	0.38%
41	2020	1.56%	3.05%	3.44%	1.49%	1.87%	2.53%	3.66%	0.96%	2.10%	-0.22%	0.53%
42	2021	2.05%	3.10%	3.36%	1.05%	1.30%	2.70%	3.39%	0.65%	1.34%	-0.04%	0.40%
43	2022	3.12%	4.72%	5.03%	1.61%	1.91%	4.08%	5.07%	0.96%	1.96%	-0.04%	0.65%
44	2023 [4]	3.77%	5.29%	5.60%	1.52%	1.83%	4.56%	5.64%	0.78%	1.87%	-0.04%	0.74%
45	**Average**	**6.08%**	**7.57%**	**7.99%**	**1.49%**	**1.91%**	**6.92%**	**8.00%**	**0.84%**	**1.91%**	**0.00%**	**0.65%**

Yield Spreads

Treasury Vs. Corporate & Treasury Vs. Utility



Sources:
[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
[2] The utility yields for the period 1980-2000 were obtained from Mergent Public Utility Manual, Mergent Weekly News Reports, 2003.
The utility yields for the period 2001-2009 were obtained from the Mergent Bond Record.
The utility yields for the period 2010-2022 were obtained from http://credittrends.moodys.com/.
[3] The corporate yields for the period 1980-2009 were obtained from the St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
The corporate yields from 2010-2022 were obtained from http://credittrends.moodys.com/.
[4] Data represents January - June, 2023.

Potomac Electric Power Company

13-Week Treasury and Utility Bond Yields

Line	Date	Treasury Bond Yield[1] (1)	"A" Rated Utility Bond Yield[2] (2)	"Baa" Rated Utility Bond Yield[2] (3)
1	10/13/23	4.78%	6.16%	6.43%
2	10/06/23	4.95%	6.32%	6.60%
3	09/29/23	4.73%	6.08%	6.36%
4	09/22/23	4.53%	5.89%	6.17%
5	09/15/23	4.42%	5.82%	6.10%
6	09/08/23	4.33%	5.75%	6.04%
7	09/01/23	4.29%	5.72%	6.01%
8	08/25/23	4.30%	5.73%	6.00%
9	08/18/23	4.38%	5.84%	6.14%
10	08/11/23	4.27%	5.72%	6.02%
11	08/04/23	4.21%	5.64%	5.95%
12	07/28/23	4.03%	5.44%	5.76%
13	07/21/23	3.91%	5.37%	5.69%
14	**Average**	**4.39%**	**5.81%**	**6.10%**
15	**Spread To Treasury**		**1.42%**	**1.71%**

Sources:
[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.
[2] http://credittrends.moodys.com/.

Potomac Electric Power Company

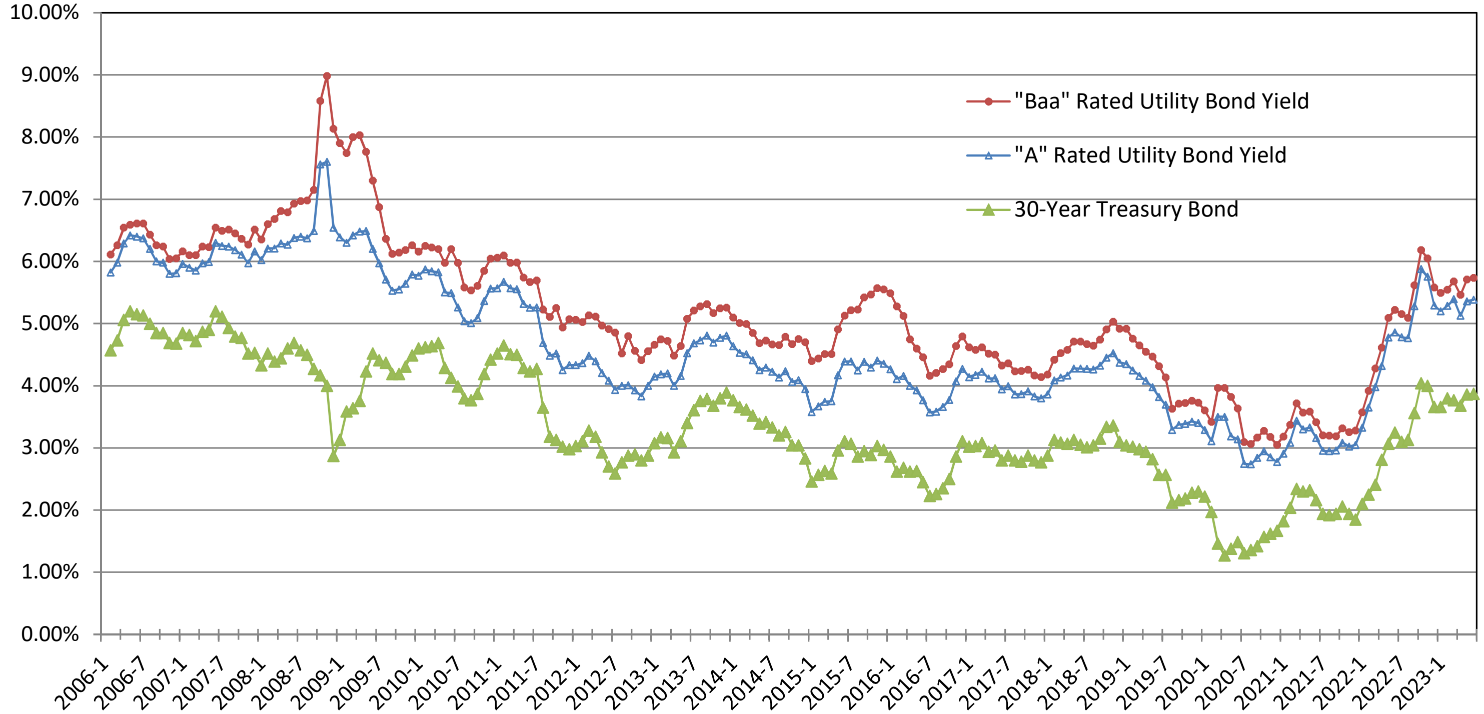
26-Week Treasury and Utility Bond Yields

Line	Date	Treasury Bond Yield[1] (1)	"A" Rated Utility Bond Yield[2] (2)	"Baa" Rated Utility Bond Yield[2] (3)
1	10/13/23	4.78%	6.16%	6.43%
2	10/06/23	4.95%	6.32%	6.60%
3	09/29/23	4.73%	6.08%	6.36%
4	09/22/23	4.53%	5.89%	6.17%
5	09/15/23	4.42%	5.82%	6.10%
6	09/08/23	4.33%	5.75%	6.04%
7	09/01/23	4.29%	5.72%	6.01%
8	08/25/23	4.30%	5.73%	6.00%
9	08/18/23	4.38%	5.84%	6.14%
10	08/11/23	4.27%	5.72%	6.02%
11	08/04/23	4.21%	5.64%	5.95%
12	07/28/23	4.03%	5.44%	5.76%
13	07/21/23	3.91%	5.37%	5.69%
14	07/14/23	3.93%	5.38%	5.69%
15	07/07/23	4.05%	5.53%	5.86%
16	06/30/23	3.85%	5.35%	5.68%
17	06/23/23	3.82%	5.36%	5.69%
18	06/16/23	3.86%	5.37%	5.71%
19	06/09/23	3.89%	5.40%	5.77%
20	06/02/23	3.88%	5.39%	5.77%
21	05/26/23	3.96%	5.50%	5.86%
22	05/19/23	3.95%	5.49%	5.83%
23	05/12/23	3.78%	5.26%	5.61%
24	05/05/23	3.76%	5.24%	5.57%
25	04/28/23	3.67%	5.11%	5.45%
26	04/21/23	3.78%	5.21%	5.54%
27	**Average**	**4.13%**	**5.58%**	**5.90%**
28	**Spread To Treasury**		**1.45%**	**1.77%**

Sources:
[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.
[2] http://credittrends.moodys.com/.

Potomac Electric Power Company

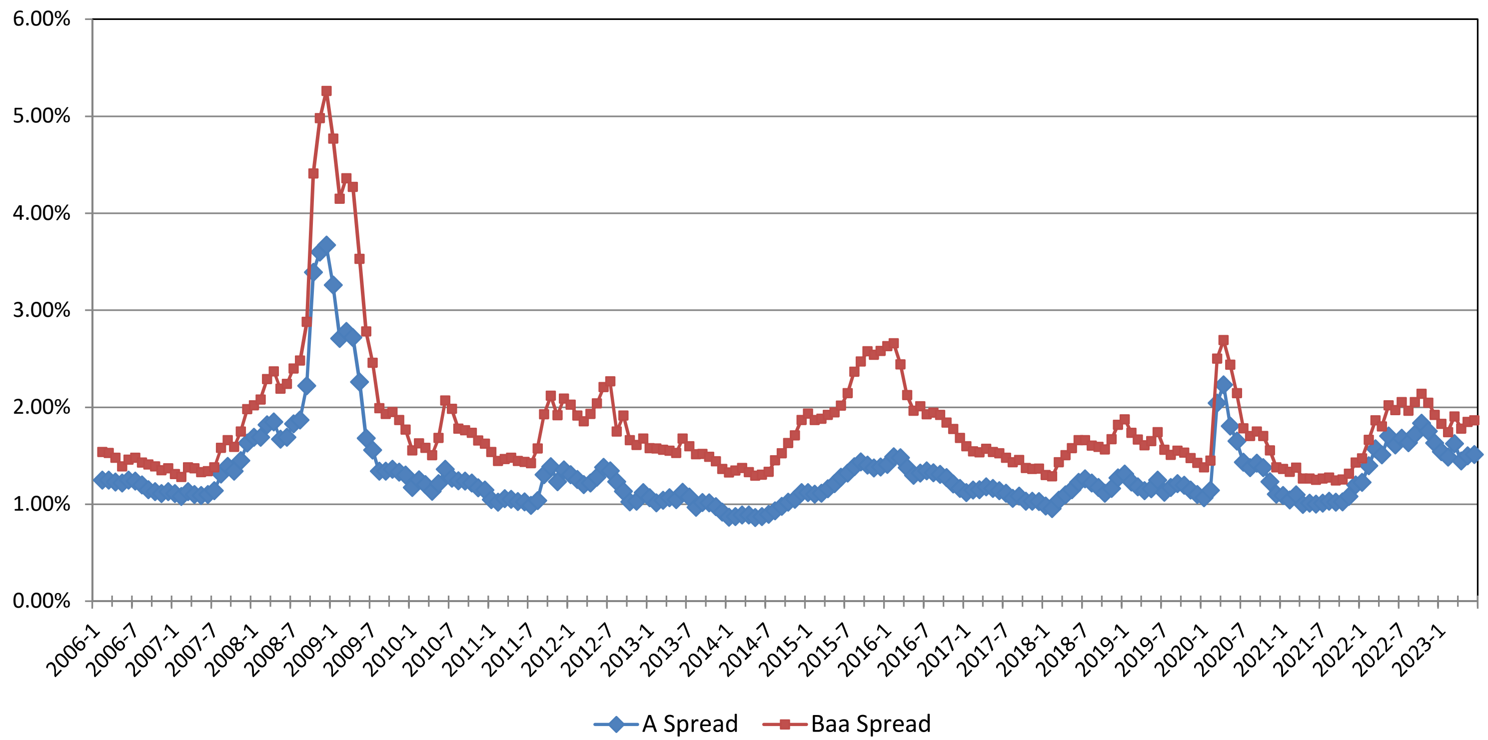
Trends in Bond Yields



Sources:
Mergent Bond Record.
www.moodys.com, Bond Yields and Key Indicators.
St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/

Potomac Electric Power Company

Yield Spread Between Utility Bonds and 30-Year Treasury Bonds



Sources:
Mergent Bond Record.
www.moodys.com, Bond Yields and Key Indicators.
St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/

Potomac Electric Power Company

Beta

Line	Company	Beta[1]	S&P Global Market Intelligence Beta[2]
1	Alliant Energy Corporation	0.85	0.82
2	Ameren Corporation	0.85	0.79
3	American Electric Power Company, Inc.	0.80	0.79
4	Black Hills Corporation	1.00	0.91
5	CenterPoint Energy, Inc.	1.10	0.96
6	CMS Energy Corporation	0.80	0.79
7	DTE Energy Company	0.95	0.85
8	Duke Energy Corporation	0.85	0.77
9	Entergy Corporation	0.95	0.88
10	Evergy, Inc.	0.90	0.82
11	Eversource Energy	0.90	0.83
12	Exelon Corporation	NMF	0.89
13	NextEra Energy, Inc.	0.95	0.84
14	OGE Energy Corp.	1.05	0.92
15	Pinnacle West Capital Corporation	0.90	0.86
16	Portland General Electric Company	0.90	0.79
17	PPL Corporation	1.10	0.95
18	Public Service Enterprise Group Incorporated	0.95	0.90
19	Sempra Energy	1.00	0.86
20	Southern Company	0.90	0.84
21	WEC Energy Group, Inc.	0.80	0.78
22	Xcel Energy Inc.	0.85	0.79
23	**Average**	**0.92**	**0.85**
24	**Median**	**0.90**	**0.84**
25	**Historical Beta[3]**	**0.77**	

Source:
[1] *The Value Line Investment Survey,*
July 21, August 11, and September 8 2023.
[2] S&P Global Market Intelligence, betas for the period 10/13/2018 - 10/13/2023.
[3] Exhibit OPC (C)-15, page 2.

Potomac Electric Power Company

Historical Betas
(Electric Utilities)

Line	Company	Average (1)	2Q23 (2)	1Q23 (3)	4Q22 (4)	3Q22 (5)	2Q22 (6)	1Q22 (7)	4Q21 (8)	3Q21 (9)	2Q21 (10)	1Q21 (11)	4Q20 (12)	3Q20 (13)	2Q20 (14)	1Q20 (15)	4Q19 (16)	3Q19 (17)
1	Alliant Energy Corporation	0.76	0.85	0.85	0.85	0.85	0.80	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.80	0.55	0.60	0.60
2	Ameren Corporation	0.72	0.85	0.85	0.85	0.85	0.80	0.80	0.80	0.85	0.80	0.80	0.85	0.80	0.80	0.50	0.55	0.55
3	American Electric Power Company, Inc.	0.68	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.50	0.55	0.55
4	Black Hills Corporation	0.89	0.95	0.95	0.95	0.95	1.00	1.00	1.00	1.00	1.00	1.00	0.95	1.00	0.65	0.70	0.70	0.75
5	CenterPoint Energy, Inc.	0.94	1.10	1.10	1.10	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.10	1.15	0.70	0.80	0.80
6	CMS Energy Corporation	0.70	0.80	0.80	0.80	0.80	0.75	0.80	0.80	0.80	0.80	0.75	0.80	0.80	0.80	0.50	0.50	0.55
7	DTE Energy Company	0.76	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.90	0.90	0.50	0.55	0.55
8	Duke Energy Corporation	0.67	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.90	0.85	0.85	0.85	0.85	0.85	0.45	0.50	0.50
9	Entergy Corporation	0.76	0.90	0.95	0.95	0.95	0.90	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.60	0.60	0.60
10	Evergy, Inc.	0.95	0.90	0.90	0.90	0.90	0.90	0.95	0.95	0.95	0.95	0.95	1.00	1.00	1.05	NMF	NMF	NMF
11	Eversource Energy	0.75	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.55	0.55	0.60
12	Exelon Corporation	0.77	NMF	NMF	0.95	NMF	1.00	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.90	0.65	0.70	0.70
13	NextEra Energy, Inc.	0.74	0.95	0.95	0.90	0.95	0.90	0.95	0.90	0.95	0.90	0.90	0.90	0.85	0.85	0.50	0.55	0.55
14	OGE Energy Corp.	0.94	1.00	1.00	1.00	1.00	1.00	1.05	1.05	1.05	1.05	1.05	1.10	1.05	1.05	0.70	0.75	0.80
15	Pinnacle West Capital Corporation	0.73	0.90	0.90	0.90	0.90	0.90	0.90	0.95	0.90	0.90	0.90	0.85	0.85	0.45	0.50	0.55	0.55
16	Portland General Electric Company	0.75	0.85	0.85	0.85	0.85	0.85	0.90	0.90	0.90	0.90	0.85	0.85	0.85	0.55	0.55	0.60	0.60
17	PPL Corporation	0.83	1.05	1.05	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.15	1.10	1.05	0.65	0.70	0.65
18	Public Service Enterprise Group Incorporate	0.77	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.95	0.90	0.90	0.90	0.90	0.90	0.60	0.65	0.65
19	Sempra Energy	0.83	0.95	0.95	0.95	0.95	0.95	0.95	1.00	N/A	0.95	1.00	0.95	0.95	0.65	0.70	0.75	0.75
20	Southern Company	0.68	0.90	0.90	0.95	0.90	0.90	0.95	0.95	0.95	0.95	0.95	0.90	0.90	0.90	0.50	0.50	0.50
21	WEC Energy Group, Inc.	0.67	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.45	0.50	0.50
22	Xcel Energy Inc.	0.66	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.75	0.45	0.50	0.50	0.50
23	**Average**	0.77	0.90	0.90	0.91	0.91	0.90	0.92	0.92	0.92	0.92	0.91	0.92	0.90	0.83	0.56	0.60	0.61

Line	Company	2Q19 (18)	1Q19 (19)	4Q18 (20)	3Q18 (21)	2Q18 (22)	1Q18 (23)	4Q17 (24)	3Q17 (25)	2Q17 (26)	1Q17 (27)	4Q16 (28)	3Q16 (29)	2Q16 (30)	1Q16 (31)	4Q15 (32)	3Q15 (33)	2Q15 (34)	1Q15 (35)	4Q14 (36)	3Q14 (37)
1	Alliant Energy Corporation	0.60	0.65	0.60	0.65	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.75	0.75	0.80	0.80	0.80	0.80	0.80	0.80	0.80
2	Ameren Corporation	0.60	0.60	0.55	0.60	0.65	0.65	0.70	0.65	0.65	0.70	0.65	0.70	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
3	American Electric Power Company, Inc.	0.55	0.55	0.55	0.60	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
4	Black Hills Corporation	0.80	0.75	0.80	0.85	0.90	0.90	0.90	0.85	0.85	0.90	0.90	0.90	0.90	0.90	0.95	0.95	0.95	0.90	0.90	0.85
5	CenterPoint Energy, Inc.	0.80	0.80	0.85	0.85	0.90	0.85	0.90	0.90	0.85	0.85	0.85	0.80	0.85	0.85	0.85	0.80	0.80	0.80	0.75	0.75
6	CMS Energy Corporation	0.55	0.55	0.55	0.55	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.70	0.75	0.75	0.70	0.75	0.75	0.70	0.75
7	DTE Energy Company	0.55	0.55	0.55	0.60	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.70	0.70	0.75	0.75	0.75	0.75	0.75	0.75	0.75
8	Duke Energy Corporation	0.50	0.50	0.55	0.55	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.65	0.50	0.60	0.60	0.60	0.60	0.60
9	Entergy Corporation	0.60	0.60	0.60	0.60	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.70	0.70	0.70	0.65	0.70	0.70	0.70	0.70
10	Evergy, Inc.	NMF	NMF	NMF	NMF	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
11	Eversource Energy	0.60	0.60	0.60	0.60	0.65	0.65	0.65	0.65	0.65	0.70	0.70	0.70	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
12	Exelon Corporation	0.70	0.70	0.65	0.65	0.70	0.70	0.70	0.70	0.65	0.70	0.65	0.70	0.65	0.70	0.70	0.65	0.70	0.70	0.70	0.70
13	NextEra Energy, Inc.	0.60	0.60	0.60	0.60	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.70	0.70	0.75	0.70	0.75	0.70	0.70	0.70
14	OGE Energy Corp.	0.80	0.85	0.85	0.90	0.95	0.95	0.95	0.95	0.95	0.95	0.90	0.90	0.95	0.95	0.95	0.90	0.90	0.90	0.90	0.85
15	Pinnacle West Capital Corporation	0.55	0.55	0.60	0.65	0.65	0.70	0.70	0.65	0.70	0.70	0.70	0.70	0.75	0.75	0.75	0.70	0.70	0.70	0.70	0.70
16	Portland General Electric Company	0.60	0.60	0.60	0.65	0.65	0.70	0.70	0.70	0.70	0.70	0.70	0.75	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.75
17	PPL Corporation	0.70	0.70	0.70	0.70	0.75	0.75	0.75	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.65	0.65	0.65	0.60	0.65
18	Public Service Enterprise Group Incorporate	0.65	0.65	0.65	0.65	0.70	0.70	0.70	0.70	0.65	0.70	0.70	0.70	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
19	Sempra Energy	0.75	0.75	0.75	0.75	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.85	0.80	0.80	0.80	0.80	0.75	0.75	0.75
20	Southern Company	0.50	0.50	0.50	0.50	0.55	0.65	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.60	0.60	0.55	0.60	0.55	0.55	0.60
21	WEC Energy Group, Inc.	0.50	0.55	0.50	0.55	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.65	0.65	0.70	0.70	0.70	0.70	0.65	0.65	0.65
22	Xcel Energy Inc.	0.50	0.50	0.55	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.70	0.65
23	**Average**	0.62	0.62	0.63	0.65	0.70	0.70	0.70	0.69	0.69	0.70	0.69	0.71	0.73	0.75	0.75	0.73	0.74	0.73	0.72	0.72

Source: Value Line Software Analyzer

Potomac Electric Power Company

CAPM Return

Line	Description	Kroll Normalized[2] MRP (1)	Risk Premium[3] Derived MRP (2)	Average FERC S&P 500 DCF[4] Derived MRP (3)
	Current Beta			
1	Risk-Free Rate[1,2]	4.58%	4.00%	4.00%
2	Market Risk Premium	5.50%	7.40%	7.85%
3	Beta[6]	0.92	0.92	0.92
4	**CAPM**	**9.64%**	**10.82%**	**11.23%**
	Historical Beta			
5	Risk-Free Rate[1,2]	4.58%	4.00%	4.00%
6	Market Risk Premium	5.50%	7.40%	7.85%
7	Beta[6]	0.77	0.77	0.77
8	**CAPM**	**8.82%**	**9.70%**	**10.05%**
	Current S&P Global Market Intelligence Beta			
9	Risk-Free Rate[1,2]	4.58%	4.00%	4.00%
10	Market Risk Premium	5.50%	7.40%	7.85%
11	Beta[6]	0.85	0.85	0.85
12	**CAPM**	**9.24%**	**10.27%**	**10.65%**

Sources:

[1] *Kroll Recommended U.S. Equity Risk Premium and Corresponding Risk-Free Rates to be Used in Computing Cost of Capital: January 2008 - Present,* October 18, 2022.

[2] *Blue Chip Financial Forecasts,* October 2, 2023 at 2.

[3] *Kroll 2023 SBBI Yearbook*, page 138.

[4] S&P 500 1-Step DCF through October 13, 2023 for Dividend Paying Companies.

[5] S&P 500 1-Step DCF through October 13, 2023 for all Companies.

[6] Exhibit OPC (C)-15, page 1.

Potomac Electric Power Company

Development of the Market Risk Premium

Line	Description	MRP	
	Risk Premium Based Method:		
1	Lg. Co. Stock Real Market Return	8.90%	[1]
2	Projected Consumer Price Index	2.30%	[2]
3	Expected Market Return	11.40%	
4	Risk-Free Rate	4.00%	[2]
5	Market Risk Premium	**7.40%**	
	FERC S&P 500 (Dividend Companies) 1-Step DCF Based Method:		
6	S&P 500 Growth	9.50%	[3]
7	Index Dividend Yield	2.10%	[3]
8	Adjusted Yield	2.20%	
9	Expected Market Return	11.70%	
10	Risk-Free Rate	4.00%	[2]
11	Market Risk Premium	**7.70%**	
	FERC S&P 500 (All Companies) 1-Step DCF Based Method:		
12	Short-Term S&P 500 Growth	10.20%	[4]
13	Index Dividend Yield	1.70%	[4]
14	Adjusted Yield	1.79%	
15	Expected Market Return	11.99%	
16	Risk-Free Rate	4.00%	[2]
17	Market Risk Premium	**8.00%**	
18	Average DCF Based MRP	**7.85%**	

Sources & Note:

[1] *Kroll 2023 SBBI Yearbook,* page 138.

[2] *Blue Chip Financial Forecasts, October 2, 2023 at 2.*

[3] S&P 500 1-Step DCF through October 13, 2023 for Dividend Paying Companies.

[4] S&P 500 1-Step DCF through October 13, 2023 for all Companies.

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In the Matter of	§	
	§	
The Application of the Potomac	§	
Electric Power Company for	§	**Formal Case No. 1176**
Authority to Implement a Multiyear	§	
Rate Plan for Electric Distribution	§	
Service in the District of Columbia	§	

DIRECT TESTIMONY AND SUPPORTING EXHIBITS OF BRIAN C. ANDREWS

Exhibit OPC (D)

On behalf of the
Office of the People's Counsel
for the District of Columbia

January 12, 2024

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EXHIBIT LIST

Exhibit OPC (D)-1	Qualifications of Brian C. Andrews
Exhibit OPC (D)-2	Pepco's Current Depreciation Parameters
Exhibit OPC (D)-3	BCA Depreciation Study
Exhibit OPC (D)-4	Traditional Test Year Impact of OPC's Proposed Depreciation Rates
Exhibit OPC (D)-5	Multi-Year Period Impact of OPC's Proposed Depreciation Rates

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Brian C. Andrews. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017.

Q. WHAT IS YOUR OCCUPATION?

A. I am an Associate with Brubaker & Associates, Inc. ("BAI"), a firm of energy, economic and regulatory consultants specializing in the field of public utility regulation.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND RELEVANT EMPLOYMENT EXPERIENCE.

A. This information is included in Exhibit OPC (D)-1.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing in this proceeding on behalf of the Office of the People's Counsel for the District of Columbia ("OPC").

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA ("COMMISSION") REGARDING DEPRECIATION ISSUES?

A. Yes, I filed depreciation related testimony in Formal Case No. ("FC") 1162. I have also filed depreciation related testimony before the Public Service Commissions in Arizona, Arkansas, California, Colorado, Florida, Illinois, Indiana, Kentucky, Louisiana, Michigan, Missouri, Montana, New Mexico, Oklahoma, and South Carolina.

Q. DO YOU BELONG TO ANY PROFESSIONAL SOCIETIES?

A. Yes. I am a member and a Past President of the Society of Depreciation Professionals ("SDP").

Q. DO YOU HOLD ANY CERTIFICATIONS AS A DEPRECIATION EXPERT?

A. Yes. SDP has awarded me the designation of Certified Depreciation Professional ("CDP"). This certification is based upon my education, experience, and successful completion of the CDP Exam.

Q. WERE YOUR TESTIMONY AND EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes.

II. SUMMARY

Q. WHAT IS THE SCOPE AND PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to present OPC's proposed depreciation rates. I will provide my assessment of Potomac Edison Power Company's ("Pepco" or "Company") depreciation rates. OPC's proposed depreciation rates reflect adjustments to the average service lives ("ASL") assumed for several accounts, the net salvage rate for Account 362, and the use of the Handy-Whitman inflation rates to discount net salvage costs.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. My conclusions and recommendations are as follows:

1. Pepco's proposed depreciation rates are excessive and burden its ratepayers with excessive depreciation expense. As proposed, Pepco's depreciation rates would be an 8.5% increase over the currently approved depreciation rates.

2. The ASLs that Pepco, through its witness, Mr. Ned Allis, is recommending for nine plant accounts should be lengthened. Statistical fitting methods indicate that survivor curves with longer ASLs fit Pepco's historic retirement data better than what has been proposed by Mr. Allis.

3. Pepco's proposed -30% net salvage rate for Account 362 is not supported by the most recent 10 years of retirement history. The -30% includes an excessive amount of net salvage accruals for Account 362. A more reasonable net salvage rate for Account 362 is -25%.

4. Pepco's proposal to use a uniform 2.5% inflation rate based on the Consumer Price Index ("CPI") in order to discount future net salvage costs using the DC Present Value Method should be rejected. The Handy-Whitman inflation rates specific to each Federal Energy Regulatory Commission's ("FERC") account should be utilized instead.

5. The Commission should reject Pepco's depreciation rates that have been presented in Exhibit Pepco (L)-1, as they produce an excessive level of depreciation expense and burden Pepco's ratepayers.

6. The Commission should approve OPC's proposed depreciation rates that have been presented in Exhibit OPC (D)-3.

7. OPC's proposed depreciation rates would reduce the traditional test year depreciation expense by $24.52 million.

8. OPC's proposed depreciation rates would reduce the multi-year test period depreciation expense by $26.37 million, $28.25 million, and $29.87 million in 2024, 2025, and 2026, respectively.

III. BOOK DEPRECIATION CONCEPTS

Q. PLEASE EXPLAIN THE PURPOSE OF BOOK DEPRECIATION ACCOUNTING.

A. Book depreciation is the recognition in a utility's income statement of the consumption or use of assets to provide utility service. Book depreciation is recorded as an expense and is included in the ratemaking formula to calculate the utility's overall revenue requirement.

The basic underlying principle of utility depreciation accounting is intergenerational equity, where the customers/ratepayers who benefit from the generated service of assets pay all the costs for those assets during the benefit period, which is over the life of those assets.[1] This concept of intergenerational equity can be achieved through depreciation by allocating costs to customers in a systematic and rational manner that is consistent with the period of time in which customers receive the service value.[2]

Book depreciation provides for the recovery of the original cost of the utility's assets that are currently providing service. Book depreciation expense is not intended to provide for replacement of the current assets, but provides for capital recovery or return of current investment. Generally, this capital recovery occurs over the ASL of the investment or assets. As a result, it is critical that appropriate ASLs be used to develop the depreciation rates so no generation of ratepayers is disadvantaged.

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[1] Edison Electric Institute, Introduction to Depreciation for Public Utilities and Other Industries, April 2013, page viii.

[2] *Ibid.* at 22.

In addition to capital recovery, depreciation rates also contain a provision for net salvage. Net salvage is simply the scrap or reuse value less the removal cost of the asset being depreciated. Accordingly, a utility will also recover the net salvage costs over the useful life of the asset.

Q. ARE THERE ANY DEFINITIONS OF DEPRECIATION ACCOUNTING THAT ARE UTILIZED FOR RATEMAKING PURPOSES?

A. Yes. One of the most quoted definitions of depreciation accounting is the one contained in the Code of Federal Regulations:

> Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption of prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.[3]

Effectively, depreciation accounting provides for the recovery of the original cost of an asset, adjusted for net salvage, over its useful life.

Q. HOW ARE DEPRECIATION RATES DETERMINED?

A. Depreciation rates are determined using a depreciation system. There are three components, each with a number of variations, used to determine a depreciation system, which is then used to estimate depreciation rates. The three basic components are: methods, procedures, and techniques. The choice of a depreciation system can significantly affect the resulting depreciation rates.

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[3] Electronic Code of Federal Regulations, Title 18, Chapter 1, Subchapter C, Part 101.

Q. PLEASE FURTHER DESCRIBE THE METHODS THAT ARE USED WITHIN A DEPRECIATION SYSTEM.

A. There generally are three types of methods of spreading the depreciation expense over the life of property. These are the Straight Line Method, Accelerated Methods, and Deferred Methods. The Straight Line Method is the method most widely used by utility companies for accounting and ratemaking purposes, as it is easy to apply and does not create intergenerational inequities because it spreads an equal portion of the plant cost across each accounting period. Accelerated Methods result in higher depreciation rates earlier in an asset's life, and lower depreciation rates later. Deferred Methods have increasing rates over an asset's life.

Q. PLEASE FURTHER DESCRIBE THE GROUPING PROCEDURES THAT ARE USED WITHIN A DEPRECIATION SYSTEM.

A. There are four main grouping procedures used within a depreciation system. These four procedures are the Individual Procedure, the Broad Group (more commonly known as the Average Life Group ("ALG")), the Vintage Group, and the Equal Life Group ("ELG").

In the ALG Procedure, all units within a particular account or category are assumed to be part of a single group that exhibits the same life and retirement characteristics. This is the most common utilized procedure.

The Vintage Group and the ELG Procedure assume that sub-groups within a particular account or category may exhibit unique life characteristics. As an example of the Vintage Group Procedure, it may assume that all poles installed in 1985 have a

50-year life, while all poles installed in year 1995 have a 45-year life. With the ELG Procedure, it may assume that all poles that are expected to have a life of 50 years should have one depreciation rate while poles that are expected to only attain life spans of 40 years would have a different depreciation rate. The overall group depreciation rate would be a composite of the ELG depreciation rates.

Q. PLEASE FURTHER DESCRIBE THE TECHNIQUES THAT ARE USED WITHIN A DEPRECIATION SYSTEM.

A. There are two techniques used to calculate depreciation rates: Whole Life and Remaining Life. The Whole Life Technique spreads the original cost less net salvage of the account over the average life of the account. This technique requires that separate amortizations be made to correct for over- and under-accumulations due to changes in an account's ASL.

The Remaining Life Technique spreads the unrecovered cost less net salvage over the remaining life of the account. The Remaining Life Technique is the most common technique used and it has a self-correcting nature that spreads any over- or under-accumulations over the remaining life.

Q. IN YOUR EXPERIENCE, WHAT DEPRECIATION SYSTEM IS MOST COMMONLY UTILIZED TO DETERMINE UTILITY DEPRECIATION RATES FOR RATEMAKING PURPOSES?

A. The most common depreciation system is one that consists of the Straight Line Method, the ALG Procedure, and the Remaining Life Technique.

Q. PLEASE EXPLAIN SURVIVOR CURVES AND THE NOTATION USED TO REFERENCE THEM.

A. The selection of the survivor curve is one of the most important aspects in conducting a depreciation study. A survivor curve is a visual representation of the amount of property existing at each age interval throughout the life of a group of property. From the survivor curve, parameters required to calculate depreciation rates can be determined, such as the ASL of the group of property and the composite remaining life. For assets with an assumed lifespan or retirement date, the survivor curve is used to estimate the interim retirements that will occur between the study date and the estimated year of final retirement. These parameters directly affect the depreciation rate calculations, therefore, informed judgment should be used in their selection.

In this proceeding, as well as the majority of utility regulatory rate case proceedings throughout the U.S. and Canada, the Iowa Curves are the general survivor curves utilized to describe the mortality characteristics of a group of property. There are four types of Iowa Curves: right-moded, left-moded, symmetrical-moded, and origin-moded. Each type describes where the greatest frequency of retirements occur relative to the ASL.

A survivor curve consists of an ASL and Iowa Curve type combination. For example, when describing property with a 50-year ASL that has mortality characteristics of the R2 Iowa Curve, the survivor curve would simply be notated as "50-R2." I present the 50-R2 survivor curve in Figure 1.

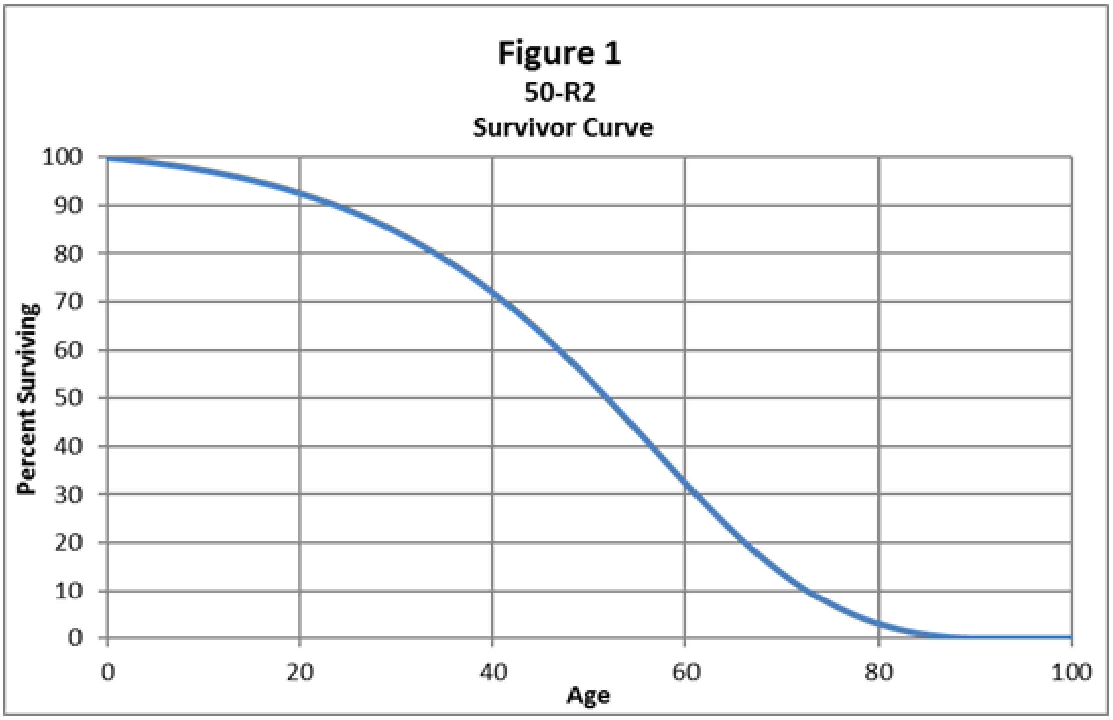

Figure 1
50-R2
Survivor Curve

Q. PLEASE DESCRIBE THE ACTUARIAL LIFE ANALYSIS THAT IS PERFORMED TO EVALUATE HISTORICAL ASSET RETIREMENT DATA.

A. I will first provide the description of actuarial life analysis (retirement rate method) that is contained in the National Association of Regulatory Utility Commissioners' ("NARUC") Public Utility Depreciation Practices Manual ("NARUC Manual"):

> Actuarial analysis is the process of using statistics and probability to describe the retirement history of property. The process may be used as a basis for estimating the probable future life characteristics of a group of property.
>
> Actuarial analysis requires information in greater detail than do other life analysis models (e.g., turnover, simulation) and, as a result, may be impractical to implement for certain accounts (see Chapter VII). However, for accounts for which application of actuarial analysis is practical; **it is a powerful analytical tool and, therefore, is generally considered the preferred approach**.
>
> Actuarial analysis objectively measures how the company has retired its investment. The analyst must then judge whether this historical view

> depicts the future life of the property in service. The analyst takes into consideration various factors, such as changes in technology, services provided, or, capital budgets.
>
> (NARUC Public Utility Depreciation Practices Manual, 1996, Page 111, Emphasis Added).

As explained by the NARUC Manual, when the required data exists, a database that contains the year of installation and the year of retirements for each vintage of property, actuarial life analysis is the preferred method of determining the life, and thus, retirement characteristics of a group of property. In this type of analysis, there are three major steps. The first step is to gather and use available aged data from the Company's continuing plant records to create an observed life table. The observed life table provides the percent surviving for each age interval of property.

The second step is to conduct a fitting analysis to match the actual survivor data from the observed life table to a standard set of mortality or survivor curves. Typically, the observed life table data is matched to Iowa Curves. The fitting process is a mathematical fitting process, which minimizes the Sum of Squared Differences ("SSD") between the actual data and the Iowa Curves.

The third step is to select the best fitting curve while using informed judgment to determine the curve that best represents the property being studied. This includes the use of a visual matching process. Although the mathematical fitting process provides a curve that is theoretically possible, the visual matching process will allow the trained depreciation professional to use informed judgment in the determination of the best fitting survivor curve.

Q. PLEASE PROVIDE FURTHER EXPLANATION OF THE SSD STATISTICAL MEASUREMENT.

A. In the Actuarial Life Analysis section of the NARUC Manual, it describes SSD as follows:

> Generally, the goodness of fit criterion is the least sum of squared deviations. The difference between the observed and projected data is calculated for each data point in the observed data. This difference is squared, and the resulting amounts are summed to provide a single statistic that represents the quality of the fit between the observed and projected curves.
>
> The difference between the observed and projected data points is squared for two reasons: (1) the importance of large differences is increased, and (2) the result is a positive number, hence the squared differences can be summed to generate a measure of the total absolute difference between the two curves. The curves with the least sum of squared deviations are considered the best fits.
>
> (NARUC, Public Utility Depreciation Practices Manual, 1996, Pages 124-125).

IV. <u>ASSESSMENT OF PEPCO'S DEPRECIATION STUDY</u>

Q. HAS PEPCO PROPOSED NEW DEPRECIATION RATES IN THIS PROCEEDING?

A. Yes. Pepco retained Mr. Ned Allis, of Gannett Fleming, to conduct a depreciation study on Pepco's property as of December 31, 2021. As stated previously, this depreciation study has been filed as Exhibit Pepco L-(1).

Q. WHAT DEPRECIATION SYSTEM DID PEPCO UTILIZE IN THE CALCULATION OF DEPRECIATION RATES PRESENTED IN EXHIBIT PEPCO L-(1)?

A. Pepco used a depreciation system consisting of the Straight Line Method, the ALG Group Procedure and the Remaining Life Technique to calculate its proposed depreciation rates.

Q. DO PEPCO'S PROPOSED NEW DEPRECIATION RATES INCREASE DEPRECIATION EXPENSE?

A. Yes. Pepco is proposing an overall depreciation rate of 3.08%. This represents an 8.5% increase over the currently approved rate of 2.84%. This change to the depreciation rate translates to an annualized depreciation expense increase of $10.62 million based on the December 31, 2021 plant balances used in the depreciation study. I show the increase by functional group in Table 1 below.

TABLE 1

Impact of Proposed Depreciation Rates and Expense
as of December 31, 2021
($ Millions)

	Current		Proposed (DC - 2.5%)		Delta (Expense)		Delta
Group	**Amount**	**Rate**	**Amount**	**Rate**	**Amount**	**Percent**	**(Rate)**
Distribution Plant	$ 114.57	2.74%	$ 123.93	2.97%	$ 9.36	8.2%	0.23%
General Plant	$ 10.07	4.60%	$ 11.34	5.18%	$ 1.26	12.5%	0.58%
Total	**$ 124.64**	**2.84%**	**$ 135.26**	**3.08%**	**$ 10.62**	**8.5%**	**0.24%**

Source: Exhibit OPC (D)-2; OPC DR 2-22, Attachment 2

Q. WHAT ARE THE MAJOR DRIVERS TO THIS PROPOSED CHANGE IN DEPRECIATION RATES?

A. The major driver of the increase to the depreciation rates is the proposed increase to net salvage rates. For the 14 distribution accounts, Pepco has proposed to increase the net rates (make more negative) for ten accounts. Accounts 367 and 368 make up the majority of the increase, totaling $9.83 million for the two accounts combined. Pepco proposed no change to the ASLs for these accounts, but the net salvage rate for both have been increased by 10%. Account 367 would move from a -60% to a -70% net salvage rate. Account 368 would move from -40% to -50%. See Exhibit OPC (D)-2, which provides the current and proposed depreciation parameters as provided by Pepco in response to OPC DR 2-22. The increase due to the change to net salvage rates is offset slightly by longer ASLs for seven of the accounts.

For General plant, the increase is largely due to the change to the net salvage rate for Account 390 from -15% to -20%.

Q. WHAT IS YOUR ASSESSMENT OF PEPCO'S DEPRECIATION STUDY?

A. Pepco's depreciation study was conducted using a depreciation system consisting of the Straight Line Method, the ALG Procedure and the Remaining Life Technique to calculate its proposed depreciation rates. I support this Method, Procedure or Technique. It appears the calculations utilized to calculate Pepco's proposed depreciation rates were performed correctly. However, I believe Pepco has overstated its depreciation rates due to a number of factors, thus, proposing an excessive level of depreciation expense to be recovered from its customers. As I will discuss, there are a number of ASL and net salvage rate adjustments that should be made to produce more reasonable deprecation rates. I also take issue with Pepco's proposed present value method for net salvage costs.

V. BCA'S DEPRECIATION STUDY

Q. PLEASE DESCRIBE YOUR DEPRECIATION STUDY.

A. Exhibit OPC (D)-3 contains the BCA Depreciation Study. The depreciation rates calculated in this study were determined using a depreciation system that consists of the Straight Line Method, the ALG Procedure, and the Remaining Life, which is the same system used by Pepco. The BCA Depreciation Study supports OPC's proposed depreciation rates.

There are three main areas of difference between the BCA Depreciation Study and Pepco's depreciation study: (1) the ASLs for nine accounts; (2) the net salvage rate for Account 362; and (3) the use of the Handy-Whitman inflation rates to determine the present value of future net salvage costs.

The adjustments to the ASLs for nine accounts are based on an actuarial analysis (retirement rate method) on Pepco's actual property data. This is the NARUC preferred method of utility property life analysis[4] and is the same method used by Mr. Allis on behalf of Pepco.

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[4] NARUC, Public Utility Depreciation Practices Manual, 1996, page 111.

The net salvage rate adjustment for Account 362 is based on the net salvage analysis that I have conducted based on Pepco's retirement data from 1988-2021. This is the same data set analyzed in Pepco's depreciation study. The analysis for each account is presented and the adjustment is discussed.

The inflation rates to conduct the net salvage present value analysis should be based on the Handy-Whitman indices consistent with past Commission preference. Pepco's use of a single 2.5% inflation rate for all accounts should be rejected.

The adjustments proposed in the BCA Depreciation Study result in a \$22.59 million reduction to Pepco's 2021 Depreciation Study's year depreciation expense. I recommended the Commission approve OPC's proposed depreciation rates that have been presented on page 5 of Exhibit OPC (D)-3.

A. Life Analysis

Q. PLEASE PROVIDE ADDITIONAL DETAIL ON THE PROCESS USED FOR THE LIFE ANALYSIS YOU CONDUCTED ON PEPCO'S PLANT ACCOUNTS.

A. The first step in my analysis was a thorough review of the Pepco depreciation study and of Mr. Allis' workpapers. I conducted my own actuarial analysis based on the observed life tables created by Mr. Allis for his actuarial analysis. An Excel-based model that I created utilizes accepted methodologies to test the fit of the various Iowa Curves to the actual retirement data contained in the observed life tables for the Pepco plant accounts. I then used a statistical and visual analysis to select Iowa Curves and ASLs that resulted in a better statistical fit (lower SSD) than the survivor curves being recommended by

Mr. Allis. Again, the SSD is the sum of the squared differences between the Iowa Curves and the significant data points from the observed life tables. Based on my analysis, I will recommend adjustments to the ASLs of nine accounts.

In Exhibit OPC (D)-3, for each account studied beginning on Page 8, I present four sections of information. The first section contains a description of the plant account per FERC's Uniform System of Accounts. The second section contains a discussion of the proposed adjustment. The third section contains the results of the fitting analysis. This table shows for each Iowa Curve type, the ASL that minimizes the SSD. In addition, the table contains the SSD of the Pepco and BCA proposals, as well as the currently approved curve. For each account to which an adjustment is proposed, the BCA proposal has a lower SSD, which indicates a better statistical fit than both Pepco's proposal and the currently approved curve.

The next section contains a graph that shows the actual Pepco retirement data (blue triangles), the Pepco proposed curve (green long-dashed line), the BCA proposed curve (purple dotted line), the best fit curve (orange short dash-dotted line), and the currently approved curve (red short-dashed line). The best fit curve shown on the graph is the curve determined by the statistical fitting analysis to have the lowest SSD.

Q. PLEASE DISCUSS YOUR ASL ADJUSTMENT FOR ACCOUNT 367 AS AN EXAMPLE.

A. Pages 23-25 of Exhibit OPC (D)-3 is related to Account 367. Account 367 is for underground conductors and devices. The currently approved survivor curve is the 60-R2.5, which has an SSD of 4,114. Pepco is proposing to retain the currently approved curve. However, the 60-R2.5 is no longer an appropriate fit for the data, as it diverges from the significant data points around the 30-year mark. As seen in the fitting analysis results, for all curve types, the ASL is greater than 60 years, indicating that the data supports an increase to the ASL. Additionally, for the R2.5 Iowa Curve type, an ASL of 74 years is the best fit to the data. This also indicates that an increase to the ASL is necessary, however, it would not be prudent to increase the ASL by 14 years. A more gradual movement should be employed. Therefore, my recommendation is the 67-R2.5, which has a much lower SSD of 848 compared to the 60-R2.5. The 67-R2.5 is a much better fit to the actual retirement data, therefore, it will produce a more reasonable deprecation rate for this account.

In Exhibit OPC (D)-3, I provide similar discussions for all of the proposed adjustments.

Q. DO THE SURVIVOR CURVES THAT YOU ARE RECOMMENDING PRODUCE A BETTER FIT TO PEPCO'S DATA THAN THOSE BEING RECOMMENDED BY MR. ALLIS?

A. Yes. For each of the nine accounts where I am proposing a survivor curve that differs from Mr. Allis' recommendation, the SSD is lower. That is, all of my recommendations result in survivor curves that mathematically and statistically fit Pepco's data better than those recommended by Mr. Allis. The SSDs of my recommendations compared to the recommendations of Mr. Allis are shown in Table 2. For each account, the SSD of the OPC proposal is lower than the Pepco proposal.

TABLE 2

Goodness of Fit Statistics

	Pepco		OPC		Delta	
Account	**Curve**	**SSD**	**Curve**	**SSD**	**Curve**	**SSD**
362	50-R2.5	3,495	53-R2	746	3	(2,749)
364	55-R2	10,050	60-R2.5	3,419	5	(6,631)
365	50-R2	1,489	54-R2	495	4	(994)
366	70-R3	5,870	75-R3.5	1,998	5	(3,872)
367	60-R2.5	4,114	67-R2.5	848	7	(3,266)
368	35-R1.5	838	37-R2	272	2	(566)
369.2	55-S4	55,448	60-R4	22,633	5	(32,815)
369.3	60-R2.5	5,573	65-R3	1,483	5	(4,090)
396	25-S3	3,868	27-R3.5	335	2	(3,533)

Source: Exhibit OPC (D) - 3

Q. WHY IS IT IMPORTANT FOR THE SURVIVOR CURVES TO BE A BETTER FIT TO THE ACTUAL RETIREMENT DATA?

A. By selecting a survivor curve that better fits the actual retirement data, a more accurate depreciation rate can be calculated. The actual retirement data is not biased or swayed by forecasts or company personnel opinions. The survivor curve adjustments that I have proposed better reflect Pepco's actual data, resulting in more reasonable depreciation rates. The reduction to the depreciation rates for these nine accounts is necessary because these accounts exhibit ASLs greater than those being proposed by Pepco. The depreciation rates proposed by Pepco would depreciate the assets in these accounts too quickly, which is a burden on current customers.

B. Net Salvage Analysis

Q. PLEASE DISCUSS THE PROCESS USED FOR THE NET SALVAGE YOU CONDUCTED ON PEPCO'S PLANT ACCOUNTS.

A. The net salvage analysis that I have conducted is based on Pepco's retirement data from 1988-2021. This is the same dataset analyzed in Pepco's depreciation study. The analysis for each account is presented in the BCA Depreciation Study and the adjustments are discussed on Pages 62-78. For each account I present the annual retirements, cost of removal, gross salvage and net salvage, net salvage rates, the rolling 3-year, 5-year, and 10-year net salvage rates, as well as the overall average of the 34 years of retirement history. I have analyzed the same 19 accounts and am proposing adjustments to just a single account, Account 362. In general, Pepco's proposed net salvage rates are reasonable and supported by the data.

Q. PLEASE DISCUSS YOUR NET SALVAGE RATE ADJUSTMENT FOR ACCOUNT 362.

A. The currently approved net salvage rate is -30%. Pepco proposes to retain this net salvage rate. The overall average rate is -31%. Over the past 34 years, there has been approximately $51.7 million of retirements, and there is approximately $635.8 million currently in-service in this account. The retirement history reflects approximately 8% of the total account balance. Over the past 10 years, the net salvage rate has never been more negative than -30%. In fact, 8 out of the 10 previous years have shown net salvage rates between -18% and +88%. The five most recent 10-year net salvage rates have all been between -7% and -9%. A -30% net salvage rate, as proposed by Pepco, is excessive and not supported by the recent retirement history. I recommend that the net salvage rate for this account be set at -25%, which will still provide Pepco a substantial amount of net salvage recovery for this account.

C. Net Salvage Present Value Method

Q. WHAT IS THE DC PRESENT VALUE METHOD FOR NET SALVAGE COSTS?

A. The DC Present Value Method for net salvage costs is a method that has been in use in DC and Maryland for at least 13 years. It has also been referred to as the SFAS-143 Method. This is a method of reducing the costs that current customers pay for estimated removal costs for assets that will be retired in the future.

Q. WHY DOES THE COMMISSION PREFER THE SFAS-143 METHOD?

A. It is my understanding that the Commission first approved this method for Pepco in Order No. 15710 in March 2010 in FC 1076. The Commission found that "Fairness and equity require that the Commission adopt a methodology that, to the extent possible, balances the interest of current and future ratepayers. The SFAS-143 Method accomplishes this. Pepco should not be allowed to charge current customers for future inflation, nor should Pepco be allowed to charge current customers in higher-value current dollars for a future cost of removal amount that is calculated in lower value future dollars." The DC Present Value Method recognizes that current dollars are more valuable than future dollars. The traditional method of net salvage recovery results in the same level of nominal dollars provided each year for net salvage costs, ignoring the purchasing power of those dollars.

Q. WHAT INFLATION RATES DOES THE COMMISSION PREFER TO USE FOR THE PRESENT VALUE METHOD?

A. The Commission's preference is to use updated inflation-based discount rates raised on Handy-Whitman Indices as the SFAS-143 discount rates. The Commission clearly stated this preference in its Order No. 17424 in FC 1103.

Q. WHAT ARE THE HANDY-WHITMAN INDICES?

A. The Handy-Whitman Index is a long-standing publication that provides index numbers for construction cost trends in the electric, gas, and water utility industries. Established in 1924, it serves as a valuable resource for monitoring cost fluctuations in these sectors. The index is prepared by Whitman, Requardt and Associates, LLP and covers various aspects of construction, including building, electric, gas, and water utility costs. These index numbers are based on a percentage ratio between the cost of an item at a specific time and its cost at a base period, allowing for insights into cost trends over time and helping utilities, regulatory bodies, engineers, and other stakeholders make informed decisions. The indices track cost trends by FERC account, with 1973 being the base year. These indices are used to create FERC account specific inflation rates for the most-recent 20-year period.

Q. WHAT INFLATION RATE DID PEPCO USE?

A. Rather than use a distinct inflation rate for each FERC account based on the Handy-Whitman Indices, Pepco chose to use a uniform 2.5% inflation rate for all accounts, which is on historical and future growth of the CPI.

Q. DO YOU AGREE THAT A UNIFORM 2.5% INFLATION RATE SHOULD BE USED TO DISCOUNT ALL FUTURE NET SALVAGE COSTS?

A. No. This issue has been brought before the Commissions several times in Pepco's rate cases.[5] The Commission prefers to use inflation rates that are based on the Handy-Whitman Index. I agree this is the better approach. A CPI based inflation rate is based on a very broad basket of goods and services. The Handy-Whitman Indices are related to specific FERC accounts, and as such, are the most appropriate basis for discounting future net salvage costs so that current customers are not paying for future inflation costs.

Q. DID PEPCO PROVIDE THE HANDY-WHITMAN INFLATION RATES?

A. Yes. Pepco provided the Handy-Whitman Inflation rates in Exhibit Pepco (L)-1. These inflation rates range from 2.75% to 5.76%.

Q. DO THE DEPRECIATION RATES BEING PROPOSED BY OPC DISCOUNT FUTURE NET SALVAGE COSTS USING THE HANDY-WHITMAN INDICES.

A. Yes. The depreciation rates being proposed by OPC use the Handy-Whitman Index to determine the discounted level of net salvage costs to include in the deprecation rates.

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[5] FC 1076, Order No. 15710, page 82; FC 1103, Order No. 17424, page 137; and FC 1139, Order No. 18846, page 108.

VI. <u>OPC'S PROPOSED DEPRECIATION RATES</u>

Q. HAVE YOU CALCULATED PEPCO'S DEPRECIATION RATES INCLUDING ALL OF YOUR PROPOSED ADJUSTMENTS TO THE SERVICE LIVES, NET SALVAGE RATE, AND NET SALVAGE INFLATION RATES?

A. Yes. OPC's proposed depreciation rates are presented on Page 5 of Exhibit OPC (D)-3.

Q. WHAT IS THE IMPACT OF OPC'S PROPOSED ADJUSTMENTS ON DEPRECIATION RATES AND EXPENSE AS OF DECEMBER 31, 2021?

A. Page 142 of Exhibit OPC (D)-3 shows that OPC's adjusted overall depreciation rate is 2.56%, compared to 3.08% as proposed by Pepco. When applied to the December 31, 2021 plant balances, this would reduce depreciation expense by $22.59 million. Table 3 below summarizes these results.

TABLE 3

Impact of OPC's Proposed Depreciation Rates and Expense
as of December 31, 2021
($ Millions)

	Pepco		OPC		Delta (Expense)		Delta
Group	**Amount**	**Rate**	**Amount**	**Rate**	**Amount**	**Percent**	**(Rate)**
Distribution Plant	$ 123.93	2.97%	$ 101.40	2.43%	$ (22.53)	-18.2%	-0.54%
General Plant	$ 11.34	5.18%	$ 11.28	5.16%	$ (0.06)	-0.5%	-0.02%
Total	**$ 135.26**	**3.08%**	**$ 112.68**	**2.56%**	**$ (22.59)**	**-16.7%**	**-0.52%**

Source: Exhibit OPC (D) - 3, Table 2

Q. HOW DOES OPC'S DEPRECIATION RATES AFFECT THE DEPRECIATION EXPENSE IN THE TRADITIONAL TEST YEAR?

A. In Exhibit OPC (D)-4, I calculate a decrease to traditional test year depreciation expense of $13.03 million, compared to an increase of $11.49 million proposed by Pepco. This is a $24.52 million reduction to the overall depreciation expense proposed by Pepco. Table 4 below summarizes these results.

TABLE 4

OPC's Proposed Depreciation Rates Impact to Traditional Test Year Depreciation Expense ($ Millions)

Group	Pepco Increase	OPC Increase	Delta
Distribution Plant	$ 10.10	$ (14.37)	$ (24.46)
General Plant	$ 1.39	$ 1.33	$ (0.06)
Total	**$ 11.49**	**$ (13.03)**	**$ (24.52)**

Source: Exhibit OPC (D) - 4

Q. HOW DOES OPC'S DEPRECIATION RATES AFFECT THE DEPRECIATION EXPENSE IN THE MULTI-YEAR TEST PERIOD?

A. In Exhibit OPC (D)-5, I show that OPC's proposed depreciation rates would reduce the total depreciation expense in 2024, 2025, and 2026 by $26.37 million, $28.25 million, and $29.87 million, respectively**.** Table 5 summarized the impacts by year.

TABLE 5

OPC's Proposed Depreciation Rates Impact to Multi-Year Test Period Depreciation Expense
($ Millions)

Group	Pepco Increase 2024	Pepco Increase 2025	Pepco Increase 2026	OPC Increase 2024	OPC Increase 2025	OPC Increase 2026	Delta 2024 Amount	Delta 2025 Amount	Delta 2026 Amount
Distribution Plant	$ 10.20	$ 10.93	$ 11.56	$ (16.14)	$ (17.28)	$ (18.27)	$ (26.34)	$ (28.22)	$ (29.83)
General Plant	$ 1.72	$ 1.92	$ 2.10	$ 1.69	$ 1.88	$ 2.06	$ (0.03)	$ (0.04)	$ (0.04)
Total	**$ 11.92**	**$ 12.85**	**$ 13.66**	**$ (14.45)**	**$ (15.40)**	**$ (16.22)**	**$ (26.37)**	**$ (28.25)**	**$ (29.87)**

Source: Exhibit OPC (D) - 5

VII. CONCLUSION

Q. MR. ANDREWS, WILL YOU PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS?

A. Yes. My conclusions and recommendations are as follows:

1. Pepco's proposed depreciation rates are excessive and burden its ratepayers with excessive depreciation expense. As proposed, Pepco's depreciation rates would be an 8.5% increase over the currently approved depreciation rates.

2. The ASLs that Pepco, through its witness, Mr. Allis, is recommending for nine plant accounts should be lengthened. Statistical fitting methods indicate that survivor curves with longer ASLs fit Pepco's historic retirement data better than what is being proposed by Mr. Allis.

3. Pepco's proposed -30% net salvage rate for Account 362 is not supported by the most recent 10 years of retirement history. -30% includes an excessive amount of net salvage accruals for Account 362. A more reasonable net salvage rate for Account 362 is -25%.

4. Pepco's proposal to use a uniform 2.5% inflation rate based on the CPI in order to discount future net salvage costs using the DC Present Value Method should be rejected. The Handy-Whitman inflation rates specific to each FERC accounts should be utilized instead.

5. The Commission should reject Pepco's depreciation rates that have been presented in Exhibit Pepco (L)-1, as they produce an excessive level of depreciation expense and burden Pepco's ratepayers.

6. The Commission should approve OPC's proposed depreciation rates that have been presented in Exhibit OPC (D)-3.

7. OPC's proposed depreciation rates would reduce the traditional test year's depreciation expense by $24.52 million.

8. OPC's proposed depreciation rates would reduce the multi-year test period depreciation expense by $26.37 million, $28.25 million, and $29.87 million in 2024, 2025, and 2026, respectively.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

485420

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In the Matter of the	)	
	)	
Application of Potomac Electric Power Company	)	**Formal Case No. 1176**
for Authority to Implement a Multiyear Rate	)	
Plan for Electric Distribution Service	)	
in the District of Columbia	)	

AFFIDAVIT

I declare under penalty of perjury that the foregoing testimony was prepared by me or under my direction and is true and correct to the best of my knowledge, information, and belief.

Signature

Date: January 10, 2024

MARIA E. DECKER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis City
My Commission Expires: May 5, 2025
Commission # 13706793

Maria E. Decker

Qualifications of Brian C. Andrews

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Andrews. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I received a Bachelor of Science Degree in Electrical Engineering from the Washington University in St. Louis/University of Missouri - St. Louis Joint Engineering Program. I have also received a Master of Science Degree in Applied Economics from Georgia Southern University.

I have attended training seminars on multiple topics including class cost of service, depreciation, power risk analysis, production cost modeling, cost-estimation for transmission projects, transmission line routing, MISO load serving entity fundamentals and more.

I am a member and a former President of the Society of Depreciation Professionals. I have been awarded the designation of Certified Depreciation Professional ("CDP") by the Society of Depreciation Professionals. I am also a certified Engineer Intern in the State of Missouri.

As an Associate at BAI, and as a Senior Consultant, Consultant, Associate Consultant and Assistant Engineer before that, I have been involved with several regulated and competitive electric service issues. These have included book depreciation, fuel and purchased power cost, transmission planning, transmission line routing, resource planning including renewable portfolio standards compliance, electric price forecasting, class cost of service, power procurement, and rate design. This has involved use of power flow, production cost, cost of service, and various other analyses and models to address these issues, utilizing, but not limited to, various programs such as Strategist, RealTime, PSS/E, MatLab, R Studio, ArcGIS, Excel, and the United States Department of Energy/Bonneville Power Administration's Corona and Field Effects ("CAFÉ") Program. In addition, I have received extensive training on the PLEXOS Integrated Energy Model and the EnCompass Power Planning Software. I have provided testimony on many of these issues before the Public Service Commissions in Arizona, Arkansas, California, Colorado, Florida, Illinois, Indiana, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Missouri, Montana, New Mexico, Oklahoma, South Carolina, Texas, and Washington DC.

BAI was formed in April 1995. BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Detroit, Michigan; Louisville, Kentucky and Phoenix, Arizona.

POTOMAC ELECTRIC POWER COMPANY
WASHINGTON, DC ASSETS

TABLE 2. COMPARISON OF EXISTING AND PROPOSED DEPRECIATION RATES AND ACCRUALS AS OF DECEMBER 31, 2021 BASED ON VARIOUS DEPRECIATION METHODS

			CURRENTLY APPROVED				PROPOSED TRADITIONAL METHOD				DC PRESENT VALUE METHOD			
				NET	CALCULATED ANNUAL			NET	CALCULATED ANNUAL		2.50% INFLATION BASED DISCOUNT		HANDY WHITMAN DISCOUNT	
	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2021	SURVIVOR CURVE	SALVAGE PERCENT	ACCRUAL AMOUNT	ACCRUAL RATE	SURVIVOR CURVE	SALVAGE PERCENT	ACCRUAL AMOUNT	ACCRUAL RATE	ACCRUAL AMOUNT	ACCRUAL RATE	ACCRUAL AMOUNT	ACCRUAL RATE
	(1)	(2)	(3)	(4)	(5)=(2)*(9)	(6)	(7)	(8)	(9)	(10)	(11)	(12)=(11)/(2)	(13)	(14)=(13)/(2)
	ELECTRIC PLANT													
	DISTRIBUTION PLANT													
361.00	STRUCTURES AND IMPROVEMENTS	90,174,871.41	65-R3	(20)	1,587,078	1.76	65-R3	(25)	1,841,608	2.04	1,710,615	1.90	1,643,494	1.82
362.00	STATION EQUIPMENT	635,759,316.59	50-R2.5	(30)	16,148,287	2.54	50-R2.5	(30)	17,732,047	2.79	16,606,206	2.61	15,363,840	2.42
364.00	POLES, TOWERS AND FIXTURES	159,274,142.83	50-R2	(80)	5,877,216	3.69	55-R2	(90)	6,385,720	4.01	5,390,312	3.38	5,179,497	3.25
365.00	OVERHEAD CONDUCTORS AND DEVICES	182,061,444.94	45-S2	(80)	7,209,633	3.96	50-R2	(90)	7,568,602	4.16	6,516,697	3.58	5,782,631	3.18
366.00	UNDERGROUND CONDUIT	990,691,715.33	65-R4	(50)	20,507,319	2.07	70-R3	(60)	24,053,381	2.43	20,217,841	2.04	18,546,535	1.87
367.00	UNDERGROUND CONDUCTORS AND DEVICES	1,050,826,153.31	60-R2.5	(60)	23,013,093	2.19	60-R2.5	(70)	33,723,572	3.21	28,731,294	2.73	26,719,582	2.54
368.00	LINE TRANSFORMERS	657,927,293.40	35-R1.5	(40)	25,988,128	3.95	35-R1.5	(50)	32,023,148	4.87	30,103,214	4.58	26,984,566	4.10
369.10	SERVICES - OVERHEAD	17,496,111.72	50-R1	(60)	685,848	3.92	50-R0.5	(70)	818,041	4.68	715,093	4.09	686,310	3.92
369.20	SERVICES - UNDERGROUND	124,852,375.85	50-S4	(60)	3,595,748	2.88	55-S4	(70)	3,787,596	3.03	3,398,149	2.72	3,099,812	2.48
369.30	SERVICES - UNDERGROUND CABLE	184,629,130.08	55-S1.5	(50)	4,726,506	2.56	60-R2.5	(60)	5,289,784	2.87	4,602,576	2.49	4,157,497	2.25
370.00	METERS	6,453,080.18	30-O1	(2)	228,439	3.54	30-O1	0	239,401	3.71	239,401	3.71	239,401	3.71
370.10	METERS - AMI	65,733,070.88	15-S2.5	0	4,667,048	7.10	15-R4	(5)	5,460,556	8.31	5,448,292	8.29	5,447,397	8.29
371.10	INSTALLATIONS ON CUSTOMERS' PREMISES	1,367,203.12	35-S2	0	9,570	0.70	40-S1.5	0	8,269	0.60	8,269	0.60	8,269	0.60
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	9,777,266.22	35-R2.5	(50)	323,628	3.31	40-S0.5	(50)	241,942	2.47	238,253	2.44	223,943	2.29
	TOTAL DISTRIBUTION PLANT	**4,177,023,175.86**			**114,567,541**	**2.74**			**139,173,667**	**3.33**	**123,926,212**	**2.97**	**114,082,775**	**2.73**
	GENERAL PLANT													
390.00	STRUCTURES AND IMPROVEMENTS													
	BENNING OFFICE BUILDINGS	16,612,758.94	65-R2 *	(15)	441,899	2.66	65-R2 *	(20)	795,490	4.79	782,135	4.71	770,688	4.64
	BENNING WAREHOUSES	3,186,723.28	65-R2 *	(15)	84,767	2.66	65-R2 *	(20)	87,149	2.73	84,697	2.66	82,578	2.59
	CONSOLIDATED CONTROL CENTER	19,911,413.34	65-R2 *	(15)	529,644	2.66	65-R2 *	(20)	666,462	3.35	649,036	3.26	634,571	3.19
	FORESTVILLE SERVICE CENTER	10,496,695.72	65-R2 *	(15)	279,212	2.66	65-R2 *	(20)	407,606	3.88	401,148	3.82	395,047	3.76
	KENILWORTH SERVICE CENTER	5,623,125.57	65-R2 *	(15)	149,575	2.66	65-R2 *	(20)	188,710	3.36	185,063	3.29	181,689	3.23
	ROCKVILLE SERVICE CENTER	11,606,288.62	65-R2 *	(15)	308,727	2.66	65-R2 *	(20)	440,057	3.79	430,495	3.71	422,314	3.64
	TSO BUILDING	5,756,846.44	65-R2 *	(15)	153,132	2.66	65-R2 *	(20)	207,530	3.60	201,197	3.49	196,651	3.42
	OTHER	9,333,984.17	50-R3	(15)	185,746	1.99	50-R3	(20)	232,278	2.49	222,143	2.38	216,553	2.32
	TOTAL STRUCTURES AND IMPROVEMENTS	82,527,836.08			2,132,702	2.58			3,025,282	3.67	2,955,913	3.58	2,900,090	3.51
	OFFICE FURNITURE AND EQUIPMENT													
391.10	FURNITURE	4,208,613.92	15-SQ	0	280,715	6.67	15-SQ	0	221,009	5.25	221,009	5.25	221,009	5.25
391.30	INFORMATION SYSTEMS	14,145,213.20	10-SQ	0	1,414,521	10.00	10-SQ	0	1,718,507	12.15	1,718,507	12.15	1,718,507	12.15
391.50	DATA HANDLING EQUIPMENT	205,088.65	10-SQ	0	20,509	10.00	10-SQ	0	20,739	10.11	20,739	10.11	20,739	10.11
	TOTAL OFFICE FURNITURE AND EQUIPMENT	18,558,915.77			1,715,745	9.24			1,960,255	10.56	1,960,255	10.56	1,960,255	10.56
393.00	STORES EQUIPMENT	68,637.06	25-SQ	0	2,745	4.00	25-SQ	0	7,319	10.66	7,319	10.66	7,319	10.66
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	10,300,042.36	25-SQ	0	412,002	4.00	25-SQ	0	440,442	4.28	440,442	4.28	440,442	4.28
395.00	LABORATORY EQUIPMENT	224,275.98	15-SQ	0	14,959	6.67	15-SQ	0	4,141	1.85	4,141	1.85	4,141	1.85
396.00	POWER OPERATED EQUIPMENT	436,329.69	25-S3	0	8,727	2.00	25-S3	0	5,566	1.28	5,566	1.28	5,566	1.28
397.00	COMMUNICATION EQUIPMENT	25,560,541.00	20-L2.5	0	516,323	2.02	24-L2	0	464,006	1.82	464,006	1.82	464,006	1.82
397.10	COMMUNICATION EQUIPMENT - DISTRIBUTION AUTOMATION	39,883,797.83	15-S2.5	0	2,644,296	6.63	15-R1.5	0	2,614,500	6.56	2,614,500	6.56	2,614,500	6.56
397.30	COMMUNICATION EQUIPMENT - AMORTIZED	33,850,015.37	15-SQ	0	2,257,796	6.67	15-SQ	0	2,507,000	7.41	2,507,000	7.41	2,507,000	7.41
398.00	MISCELLANEOUS EQUIPMENT	7,358,625.85	20-SQ	0	367,931	5.00	20-SQ	0	378,223	5.14	378,223	5.14	378,223	5.14

POTOMAC ELECTRIC POWER COMPANY
WASHINGTON, DC ASSETS

TABLE 2. COMPARISON OF EXISTING AND PROPOSED DEPRECIATION RATES AND ACCRUALS AS OF DECEMBER 31, 2021 BASED ON VARIOUS DEPRECIATION METHODS

			CURRENTLY APPROVED				PROPOSED TRADITIONAL METHOD				DC PRESENT VALUE METHOD			
				NET	CALCULATED ANNUAL			NET	CALCULATED ANNUAL		2.50% INFLATION BASED DISCOUNT		HANDY WHITMAN DISCOUNT	
	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2021	SURVIVOR CURVE	SALVAGE PERCENT	ACCRUAL AMOUNT	ACCRUAL RATE	SURVIVOR CURVE	SALVAGE PERCENT	ACCRUAL AMOUNT	ACCRUAL RATE	ACCRUAL AMOUNT	ACCRUAL RATE	ACCRUAL AMOUNT	ACCRUAL RATE
	(1)	(2)	(3)	(4)	(5)=(2)*(9)	(6)	(7)	(8)	(9)	(10)	(11)	(12)=(11)/(2)	(13)	(14)=(13)/(2)
	TOTAL GENERAL PLANT	218,769,016.99			10,073,226	4.60			11,406,734	5.21	11,337,366	5.18	11,281,542	5.16
	TOTAL DEPRECIABLE PLANT	4,395,792,192.85			124,640,767	2.84			150,580,401	3.43	135,263,578	3.08	125,364,317	2.85
	NONDEPRECIABLE PLANT													
360.10	LAND	38,974,109.52												
360.20	LAND RIGHTS	572,892.46												
389.10	LAND	2,268,980.45												
389.20	LAND RIGHTS	3.52												
	TOTAL NONDEPRECIABLE PLANT	41,815,985.95												
	TOTAL ELECTRIC PLANT	4,437,608,178.80												

* LIFE SPAN MEHTOD IS USED. CURVE SHOWN IS INTERIM SURVIVOR CURVE.

BCA Depreciation Study

Potomac Electric Power Company

Prepared by

Brian C. Andrews

for

the Office of the People's Counsel

for the District of Columbia ("OPC")

January 2024

BRUBAKER & ASSOCIATES, INC.
CHESTERFIELD, MO 63017

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Executive Summary

The contents herein contain the results of the BCA Depreciation Study conducted on behalf of the Office of the People's Counsel for the District of Columbia ("OPC") on all Potomac Electric Power Company ("Pepco") plant accounts. This study contains the depreciation rates for all plants and accounts, however, there are a number of accounts to which no adjustments have been proposed. Silence with regard to any assumption does not indicate agreement with Pepco's position. All plants and accounts have been included to provide a complete set of depreciation rates for all of Pepco's property. The depreciation rates determined as a result of this study are based on the straight line method, average life group procedure, and the remaining life technique, as well as the use of Handy-Whitman inflation rates for the DC Present Value Method.

There are three main areas of difference between this depreciation study and Pepco's 2021 depreciation study: (1) the average service lives and curve types for nine plant accounts; (2) the net salvage rate for Account 362; and (3) the present value discount rates applied to each account.

The adjustments to the average service lives for the plant accounts are based on an actuarial analysis (retirement rate method) on Pepco's actual property data. This is the National Association of Regulatory Utility Commissioners' ("NARUC") preferred method of utility property life analysis and is the same method used by Mr. Allis on behalf of Pepco.

The Account 362 net salvage rate adjustment is based on the net salvage analysis that I have conducted based on Pepco's retirement data from 1988-2021. This is the same data set analyzed in Pepco's depreciation study. The analysis for each account is presented and the adjustment to Account 362 is discussed.

The discount rates applied to each account in this depreciation study are based on the Handy-Whitman Indices utilized to create Table 4 of Pepco's 2021 Depreciation Study (Exhibit PEPCO (L)-1).

The adjustments proposed in this study result in a $22.59 million reduction to Pepco's 2021 study year depreciation expense. The calculation of the depreciation rates with these proposed adjustments are summarized in Table 1.

POTOMAC ELECTRIC POWER COMPANY
WASHINGTON, DC ASSETS
BCA DEPRECIATION STUDY
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2021
DC PRESENT VALUE METHOD - HANDY WHITMAN DISCOUNT RATES

	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK RESERVE (5)	NET SALVAGE ACCRUAL AMOUNT (6)	NET SALVAGE THEORETICAL RESERVE (7)	BOOK RESERVE NO NET SALVAGE (8)=(5)-(7)	NET PLANT (9)=(4)-(8)	COMPOSITE REMAINING LIFE (10)	REM. LIFE ANNUAL ACCRUAL PLANT ONLY (11)=(9)/(10)	TOTAL ANNUAL ACCRUAL AMOUNT (12)=(6)+(11)	TOTAL ANNUAL ACCRUAL RATE (13)=(12)/(4)
	DISTRIBUTION PLANT												
361.00	STRUCTURES AND IMPROVEMENTS	65-R3	(25)	90,174,871.48	32,382,456	230,007	3,867,414	28,515,042	61,659,830	43.6	1,413,438	1,643,445	1.82
362.00	STATION EQUIPMENT	53-R2	(25)	635,759,316.59	191,916,493	1,555,674	17,262,408	174,654,085	461,105,231	40.5	11,380,716	12,936,390	2.03
364.00	POLES, TOWERS AND FIXTURES	60-R2.5	(90)	159,274,142.81	35,788,639	1,520,840	17,472,406	18,316,233	140,957,910	46.0	3,063,485	4,584,326	2.88
365.00	OVERHEAD CONDUCTORS AND DEVICES	54-R2	(90)	182,061,444.95	54,308,413	1,664,543	16,364,683	37,943,730	144,117,715	42.8	3,370,423	5,034,965	2.77
366.00	UNDERGROUND CONDUIT	75-R3.5	(60)	990,691,715.33	346,941,512	3,988,655	62,889,342	284,052,170	706,639,546	56.2	12,576,901	16,565,556	1.67
367.00	UNDERGROUND CONDUCTORS AND DEVICES	67-R2.5	(70)	1,050,826,153.30	273,874,663	5,726,923	72,012,591	201,862,072	848,964,081	52.3	16,230,214	21,957,137	2.09
368.00	LINE TRANSFORMERS	37-R2	(50)	657,927,293.41	198,000,267	5,803,971	51,172,168	146,828,099	511,099,195	25.4	20,090,259	25,894,230	3.94
369.10	SERVICES - OVERHEAD	50-R0.5	(70)	17,496,111.72	(1,662,021)	156,718	1,173,085	(2,835,106)	20,331,218	38.4	529,554	686,272	3.92
369.20	SERVICES - UNDERGROUND	60-R4	(70)	124,852,375.85	77,566,190	992,433	15,758,164	61,808,025	63,044,351	42.2	1,492,768	2,485,201	1.99
369.30	SERVICES - UNDERGROUND CABLE	65-R3	(60)	184,629,130.08	71,997,811	954,266	14,128,858	57,868,953	126,760,177	46.3	2,737,459	3,691,726	2.00
370.00	METERS	30-O1	0	6,453,080.19	2,590,358	-	-	2,590,358	3,862,722	16.1	239,388	239,388	3.71
370.10	METERS - AMI	15-R4	(5)	65,733,070.88	30,403,992	220,206	1,636,034	28,767,958	36,965,112	7.1	5,225,710	5,445,915	8.28
371.10	INSTALLATIONS ON CUSTOMERS' PREMISES	40-S1.5	0	1,367,203.12	1,250,798	-	-	1,250,798	116,405	14.1	8,268	8,268	0.60
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	40-S0.5	(50)	9,777,266.22	7,074,521	100,621	1,166,307	5,908,214	3,869,052	31.4	123,311	223,932	2.29
	TOTAL DISTRIBUTION PLANT			**4,177,023,175.93**	**1,322,434,092**	**22,914,856**	**274,903,461**	**1,047,530,631**	**3,129,492,545**		**78,481,895**	**101,396,751**	**2.43**
	GENERAL PLANT												
390.00	STRUCTURES AND IMPROVEMENTS												
	BENNING OFFICE BUILDINGS	65-R2 *	(20)	16,612,758.96	4,162,811	64,835	1,545,176.12	2,617,635	13,995,124	19.8	705,791	770,626	4.64
	BENNING WAREHOUSES	65-R2 *	(20)	3,186,723.27	2,220,423	13,018.61	313,697.99	1,906,725	1,279,998	18.4	69,568	82,586	2.59
	CONSOLIDATED CONTROL CENTER	65-R2 *	(20)	19,911,413.33	8,658,572	70,596.21	1,639,026.35	7,019,546	12,891,868	22.9	563,880	634,476	3.19
	FORESTVILLE SERVICE CENTER	65-R2 *	(20)	10,496,695.72	6,573,036	48,448.88	1,197,888.39	5,375,148	5,121,548	14.8	346,611	395,060	3.76
	KENILWORTH SERVICE CENTER	65-R2 *	(20)	5,623,125.57	3,828,169	25,345.16	623,769.02	3,204,400	2,418,726	15.5	156,306	181,651	3.23
	ROCKVILLE SERVICE CENTER	65-R2 *	(20)	11,606,288.59	4,552,270	43,316.52	1,020,371.62	3,531,898	8,074,390	21.3	378,995	422,311	3.64
	TSO BUILDING	65-R2 *	(20)	5,756,846.45	686,360	16,095.92	342,623.04	343,737	5,413,109	30.0	180,549	196,645	3.42
	OTHER	50-R3	(20)	9,333,984.18	2,463,567	25,910.82	300,568.35	2,162,999	7,170,986	37.6	190,640	216,551	2.32
	TOTAL STRUCTURES AND IMPROVEMENTS			82,527,836.08	33,145,208	307,567	6,983,121	26,162,087	56,365,749		2,592,340	2,899,907	3.51
	OFFICE FURNITURE AND EQUIPMENT												
391.10	FURNITURE	15-SQ	0	4,208,613.92	2,389,035	-	-	2,389,035	1,819,579	8.2	221,009	221,009	5.25
391.30	INFORMATION SYSTEMS	10-SQ	0	14,145,213.21	2,603,625	-	-	2,603,625	11,541,588	6.7	1,718,508	1,718,508	12.15
391.50	DATA HANDLING EQUIPMENT	10-SQ	0	205,088.65	8,068	-	-	8,068	197,021	9.5	20,739	20,739	10.11
	TOTAL OFFICE FURNITURE AND EQUIPMENT			18,558,915.78	5,000,728	-	-	5,000,728	13,558,188		1,960,256	1,960,256	10.56
393.00	STORES EQUIPMENT	25-SQ	0	68,637.06	42,228	-	-	42,228	26,409	3.6	7,318	7,318	10.66
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	0	10,300,042.36	1,759,422	-	-	1,759,422	8,540,620	19.4	440,441	440,441	4.28
395.00	LABORATORY EQUIPMENT	15-SQ	0	224,275.98	218,064	-	-	218,064	6,212	1.5	4,141	4,141	1.85
396.00	POWER OPERATED EQUIPMENT	27-R3.5	0	436,329.69	374,543	-	-	374,543	61,786	13.8	4,484	4,484	1.03
397.00	COMMUNICATION EQUIPMENT	24-L2	0	25,560,541.00	16,595,241	-	-	16,595,241	8,965,300	19.3	464,096	464,096	1.82
397.10	COMMUNICATION EQUIPMENT - DISTRIBUTION AUTOMATIOI	15-R1.5	0	39,883,797.78	8,445,419	-	-	8,445,419	31,438,379	12.0	2,613,806	2,613,806	6.55
397.30	COMMUNICATION EQUIPMENT - AMORTIZED	15-SQ	0	33,850,015.37	13,442,922	-	-	13,442,922	20,407,093	8.1	2,507,001	2,507,001	7.41
398.00	MISCELLANEOUS EQUIPMENT	20-SQ	0	7,358,625.85	2,259,445	-	-	2,259,445	5,099,181	13.5	378,221	378,221	5.14
	TOTAL GENERAL PLANT			**218,769,016.94**	**81,283,221**	**307,567**	**6,983,121**	**74,300,100**	**144,468,917**		**10,972,104**	**11,279,671**	**5.16**
	TOTAL DEPRECIABLE PLANT			**4,395,792,192.87**	**1,403,717,313**	**23,222,422**	**281,886,582**	**1,121,830,731**	**3,273,961,462**		**89,453,999**	**112,676,421**	**2.56**
	NONDEPRECIABLE PLANT												
360.10	LAND			38,974,109.52									
360.20	LAND RIGHTS			572,892.46	65,099								
389.10	LAND			2,268,980.45									
389.20	LAND RIGHTS			3.52	5								
	TOTAL NONDEPRECIABLE PLANT			**41,815,985.95**	**65,104**								
	TOTAL ELECTRIC PLANT			**4,437,608,178.82**	**1,403,782,417**								

* LIFE SPAN MEHTOD IS USED. CURVE SHOWN IS INTERIM SURVIVOR CURVE.

Life Analysis

An Excel-based model that I created utilizes accepted methodologies to test the fit of the various Iowa Curves to the actual retirement data contained in the observed life tables for Pepco's plant accounts. The data for the observed life tables were contained within Mr. Allis' depreciation study.

In the fitting process, the model determines the average service life that minimizes the sum of squared differences ("SSD") between the Iowa Curve types and the significant data points from the observed life tables for each curve type. Significant data points were determined by dividing the exposures for each vintage by the Age 0 vintage exposures. If that ratio was greater than 1%, the data point was determined to be significant. The Iowa Curve and corresponding average service life that minimizes the SSD produces the "best fit" to Pepco's actual retirement of history.

The analysis provides for each Iowa Curve type, the average service life that best fits the data by minimizing the SSD. The results of this analysis are provided for each account. After the fitting analysis was performed, I created graphs that contain Pepco's retirement data, the best fit line from the fitting analysis, the survivor curve being proposed by Pepco, and my proposed survivor curve ("BCA Proposed"), as well as the currently approved curve. The BCA Proposed survivor curve for each account is typically the curve that lies between the recommendation of Pepco (Allis) and the best fit curve. In some instances the best fit produces an unreasonable average service life; however, the historical retirement pattern should not be ignored in determining the appropriate average service life and retirement dispersion because these are key inputs in developing a fair and equitable depreciation rate. In each instance the proposed average service life and retirement dispersion that I am recommending results in a better statistical fit (lower SSD) compared to the Pepco proposed survivor curve. This life analysis was conducted on all plant accounts.

For each account studied, I present four sections of information. The first section contains a description of the plant account per the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts. The second section contains a discussion of my proposed adjustment. The third section contains the results of the fitting analysis. This table shows the average service life that minimizes the SSD for each Iowa Curve type. Additionally the table contains the SSD of the Pepco and BCA proposals, as well as the currently approved curve. For each account to which I recommended a change, the BCA proposal has a lower SSD, which indicates a better statistical fit.

The last section contains a graph that shows the actual Pepco retirement data (blue triangles), the Pepco proposed curve (green long dashed line), the BCA proposed curve (purple dotted line), the best fit curve (orange dash-dotted line), and the currently approved curve (red short dashed line). The best fit shown on the graph is the curve determined by the fitting analysis which had the lowest SSD. This curve will match the survivor curve at the top of the table in the fitting analysis section.

Account 361 - Structures and Improvements

Account Description

This account is for structures and improvements. Per the FERC Uniform System of Accounts, "This account shall include the cost in place of structures and improvements used in connection with distribution operations." This includes building station control, fencing, yard improvements and other structures for distribution plant.

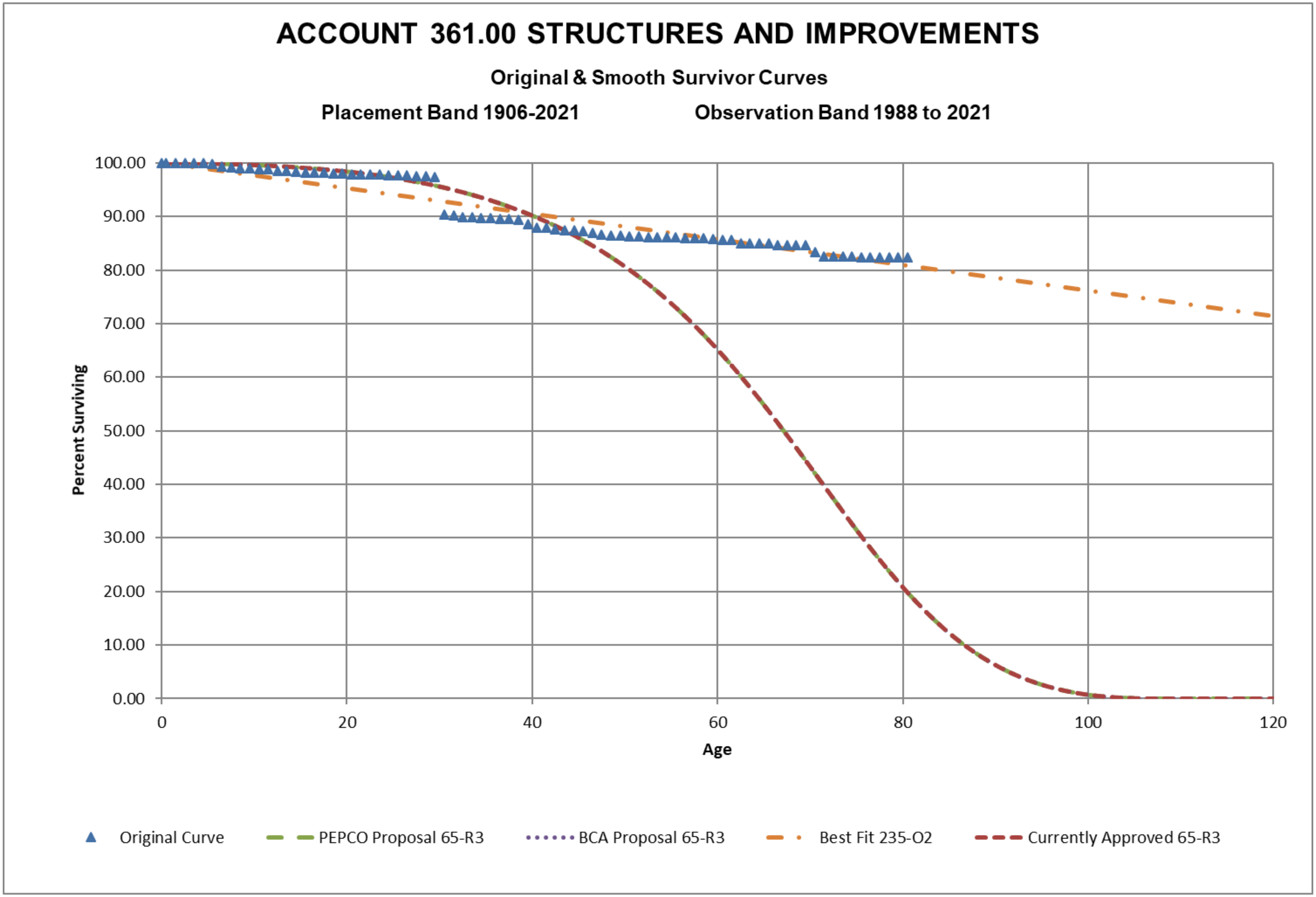
Discussion

The currently approved curve is 65-R3, and Pepco is proposing no change. The best fit is the 235-O2, however, I do not recommend any change from the currently approved curve.

Account 361 Fitting Analysis Results

Iowa Curve	Average Service Life	SSD
O2	234.9	285.9
O3	337.9	286.0
O1	209.7	286.1
O4	464.7	286.2
R0.5	172.0	287.7
R1	141.2	319.1
L0	186.0	335.0
R1.5	122.2	434.4
L0.5	159.2	483.7
S0	137.3	541.1
R2	109.1	750.6
S0.5	123.5	809.5
L1	140.1	862.4
R2.5	100.9	1,160.0
L1.5	125.8	1,170.6
S1	113.4	1,326.6
S1.5	106.3	1,765.9
R3	95.2	1,883.5
L2	115.5	1,894.1
L2.5	107.6	2,289.4
R3.5	91.6	2,514.5
S2	100.7	2,516.4
S2.5	96.9	3,019.6
L3	101.6	3,117.4
R4	88.9	3,424.7
S3	93.8	3,835.6
L4	91.9	4,270.9
S4	88.6	5,478.1
R5	85.5	5,749.0
L5	87.4	5,872.7
S5	85.5	6,894.3
S6	83.6	8,085.7

PEPCO Proposal 65-R3	41,866
Currently Approved 65-R3	41,866
BCA Proposal 65-R3	41,866


ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS
Original & Smooth Survivor Curves
Placement Band 1906-2021
Observation Band 1988 to 2021
Percent Surviving
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0
20
40
60
80
100
120
Age
Original Curve
PEPCO Proposal 65-R3
BCA Proposal 65-R3
Best Fit 235-O2
Currently Approved 65-R3

Account 362 - Station Equipment

Account Description

This account is for Station Equipment. Per the FERC Uniform System of Accounts, “This account shall include the cost installed of station equipment, including transformer banks, etc., which are used for the purpose of changing the characteristics of electricity in connection with its distribution.” This includes much of the equipment located within the fence at a distribution substation, including busses, conduit, control equipment, transformers, switching equipment, insulators, general station equipment, platforms, foundations, etc.

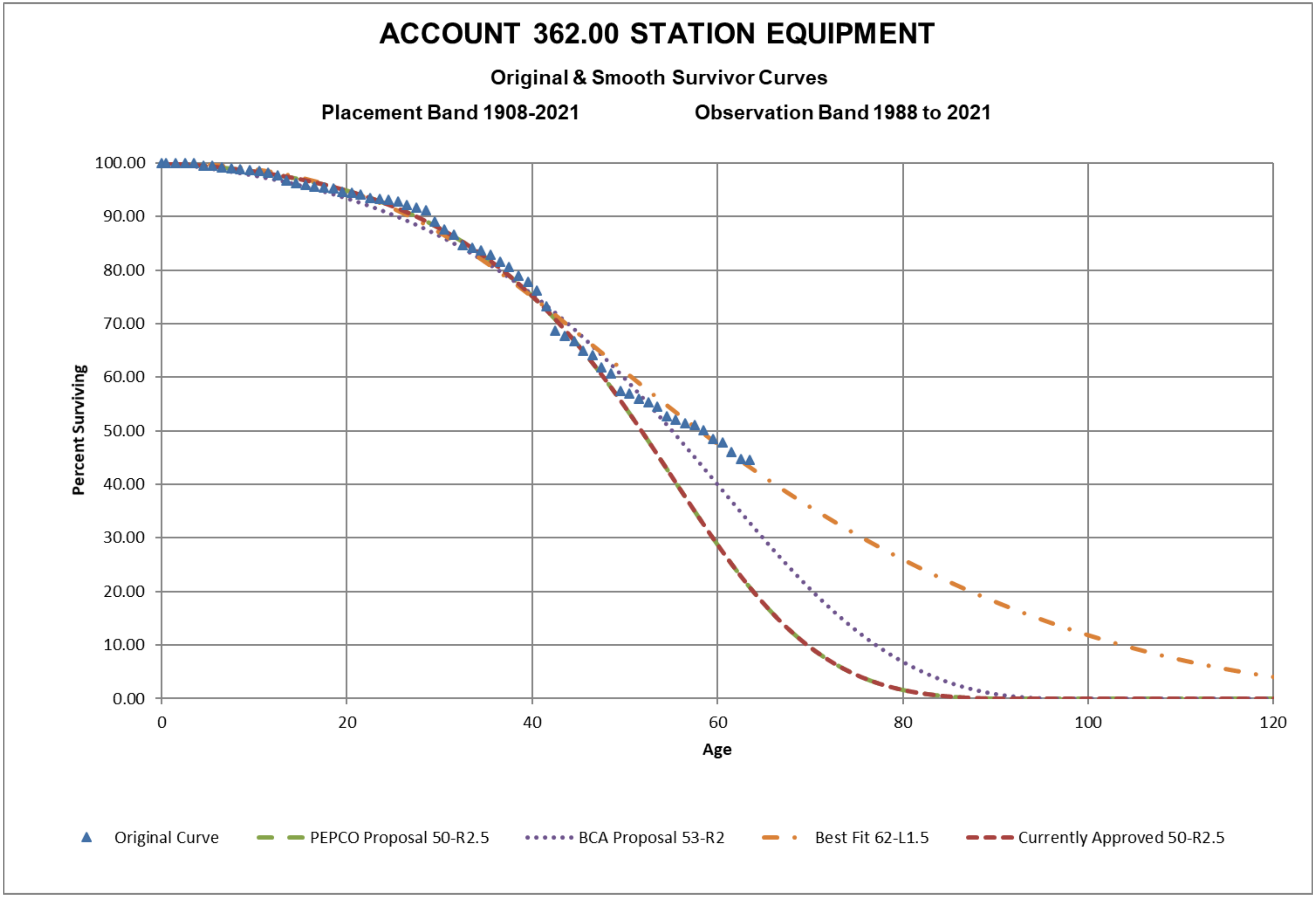
Discussion

The currently approved curve is 50-R2.5 and the best fit curve is the 62-L1.5. Pepco is proposing no change from the currently approved curve. I recommend moving closer to the best fitting curve, to a flatter dispersion and increasing the average service life to 53 years, as a slightly longer ASL is indicated from the best fit curve. The R2 curve is the best fitting R-modal curve. Thus my recommendation for this account is the 53-R2, as it is more appropriate for this account, indicated by the lower SSD of 746 versus the Pepco proposal, which has an SSD of 3,495.

Account 362 Fitting Analysis Results

Iowa Curve	Average Service Life	SSD
L1.5	61.6	157.4
S1	57.1	227.7
L2	59.9	285.2
S0.5	58.3	341.1
R2	54.9	465.9
L1	64.3	521.0
S1.5	56.2	522.0
R1.5	55.8	607.1
S0	60.2	821.3
L2.5	58.3	905.2
R2.5	54.5	1,017.6
L0.5	67.5	1,172.1
S2	55.6	1,228.9
R1	57.6	1,250.7
L0	72.2	2,085.6
L3	57.2	2,098.7
R3	54.4	2,156.8
S2.5	55.2	2,285.1
R0.5	61.7	2,369.9
O2	77.2	3,491.0
O1	68.9	3,492.5
S3	55.0	3,744.1
R3.5	54.6	3,805.0
O3	108.1	4,090.3
O4	146.9	4,404.4
R4	54.8	5,921.6
L4	55.6	6,190.3
S4	55.2	8,971.1
L5	55.6	12,052.7
R5	55.8	13,267.8
S5	56.0	16,099.6
S6	57.1	24,246.8

PEPCO Proposal 50-R2.5	3,495
Currently Approved 50-R2.5	3,495
BCA Proposal 53-R2	746


ACCOUNT 362.00 STATION EQUIPMENT
Original & Smooth Survivor Curves
Placement Band 1908-2021
Observation Band 1988 to 2021
Percent Surviving
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0
20
40
60
80
100
120
Age
Original Curve
PEPCO Proposal 50-R2.5
BCA Proposal 53-R2
Best Fit 62-L1.5
Currently Approved 50-R2.5

Account 364 - Poles, Towers and Fixtures

Account Description

This account is for Poles, Towers, and Fixtures. Per the FERC Uniform System of Accounts, "This account shall include the cost installed of poles, towers, and appurtenant fixtures used for supporting overhead distribution conductors and service wires." This includes the poles, towers, brackets, cross arms, foundations, pole steps, ladders, anchors, etc. required to create a pole or tower structure capable of supporting overhead distribution lines.

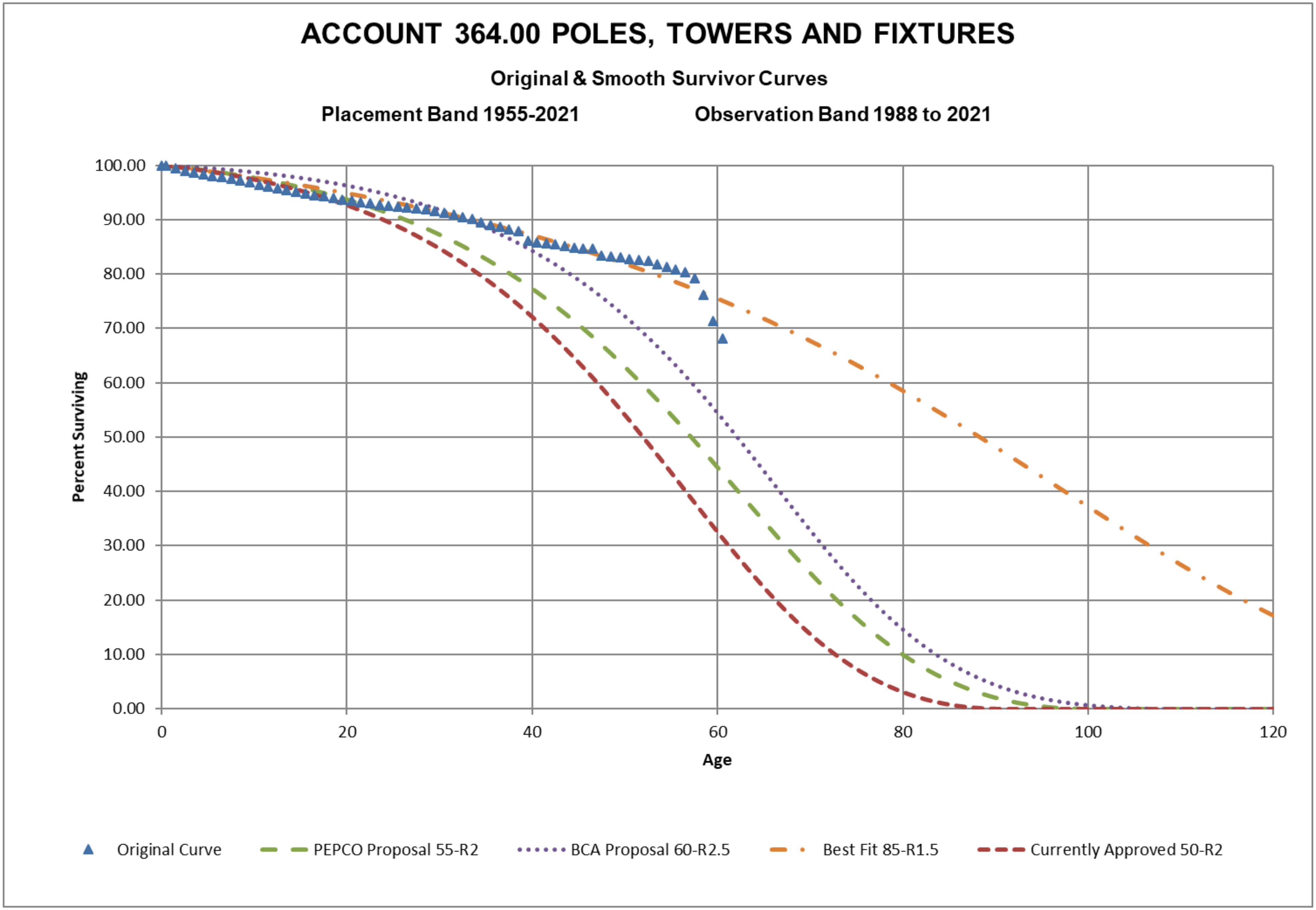
Discussion

For this account, the currently approved curve is 50-R2, which has an SSD of 20,721. Pepco is proposing to retain the same dispersion, but increase the ASL, resulting in the Pepco recommendation of 55-R2 with an SSD of 10,050. Although Pepco's recommendation has a significantly lower SSD than the currently approved curve, the 55-R2 curve still does not properly fit the data. My analysis demonstrates that the best fitting curve is the 85-R1.5, which has an SSD of 134. While this indicates that a longer service life is necessary, it's not feasible to increase the expected life by 35 years. Taking this information into account, my recommendation is the 60-R2.5 curve, which has a much lower SSD than both the currently approved and Pepco proposal at 3,419.

Account 364 Fitting Analysis Results

Iowa Curve	Average Service Life	SSD
R1.5	84.7	133.5
R1	96.7	146.4
L0	128.8	172.5
L0.5	111.1	187.7
R0.5	116.9	197.0
S0	96.1	224.5
O2	158.9	234.1
O1	141.9	234.3
O3	228.4	246.4
R2	76.6	248.2
O4	314.0	252.9
S0.5	87.0	328.1
L1	98.8	344.3
R2.5	71.5	454.5
L1.5	89.0	493.2
S1	80.5	597.0
S1.5	75.7	829.3
R3	67.9	885.9
L2	82.2	896.5
L2.5	76.9	1,135.9
S2	72.1	1,269.0
R3.5	65.7	1,280.8
S2.5	69.5	1,587.1
L3	72.9	1,672.5
R4	64.0	1,880.4
S3	67.5	2,121.1
L4	66.5	2,477.5
S4	64.2	3,359.4
R5	62.2	3,637.5
L5	63.6	3,732.1
S5	62.4	4,589.3
S6	61.3	5,731.0

PEPCO Proposal 55-R2	10,050
Currently Approved 50-R2	20,721
BCA Proposal 60-R2.5	3,419


ACCOUNT 364.00 POLES, TOWERS AND FIXTURES
Original & Smooth Survivor Curves
Placement Band 1955-2021
Observation Band 1988 to 2021
Percent Surviving
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0
20
40
60
80
100
120
Age
Original Curve
PEPCO Proposal 55-R2
BCA Proposal 60-R2.5
Best Fit 85-R1.5
Currently Approved 50-R2

Account 365 - Overhead Conductors and Devices

Account Description

This account is for Overhead Conductors and Devices. Per the FERC Uniform System of Accounts, "This account shall include the cost installed of overhead conductors and devices used for distribution purposes." The items contained within this account include circuit breakers, conductors, ground wires, insulators, lightning arresters, railroad and highway crossing guards, switches, the initial cost of tree trimming including permits, and other line devices.

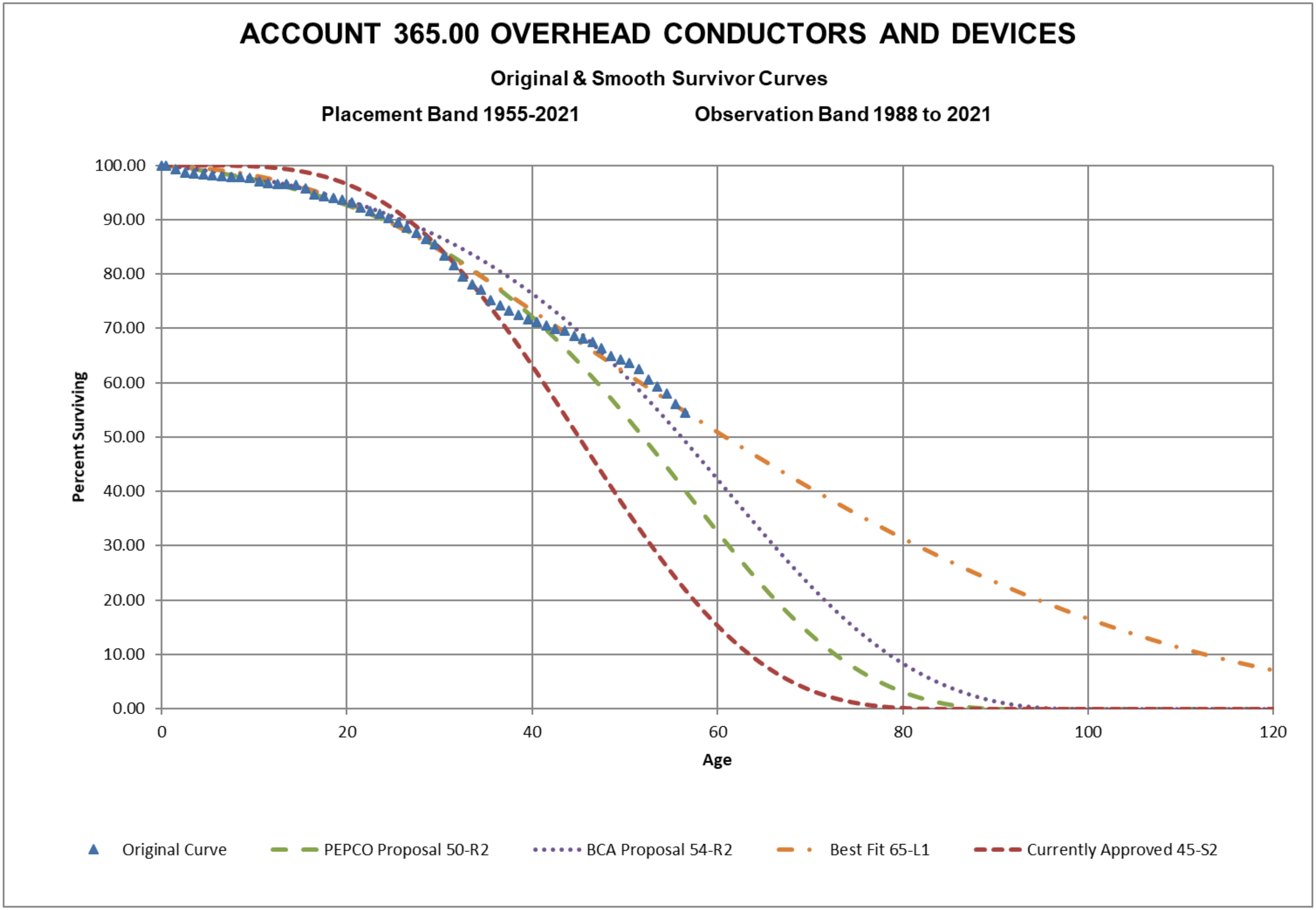
Discussion

The currently approved curve is the 45-S2 with an SSD of 10,423. Pepco proposes to change the S2 dispersion to the R2 dispersion and increase the average service life to 50 years. The fitting analysis shows that a longer life is appropriate for this account, and the 54-R2 is the best fit for the R2 dispersion with an SSD of 495. I recommend the 54-R2 curve for this account, which fits the data better than both the currently approved curve and Pepco's proposed curve.

Account 365 Fitting Analysis Results

Iowa Curve	Average Service Life	SSD
L1	65.0	105.5
S0	61.4	128.1
L0.5	69.4	155.7
S0.5	58.6	187.7
R1.5	56.0	237.6
R1	59.0	327.7
L1.5	61.6	376.3
L0	75.6	405.0
R2	54.1	494.1
S1	56.6	525.2
R0.5	65.0	679.9
O2	83.4	1,035.0
O1	74.4	1,036.2
L2	59.3	1,063.3
S1.5	55.2	1,099.9
R2.5	53.1	1,149.6
O3	117.5	1,200.6
O4	160.0	1,291.3
L2.5	57.4	1,887.9
S2	54.2	2,001.3
R3	52.5	2,239.6
S2.5	53.6	3,013.2
L3	56.0	3,243.2
R3.5	52.3	3,492.9
S3	53.2	4,349.0
R4	52.3	5,093.8
L4	54.0	6,276.5
S4	52.9	8,246.6
L5	53.6	10,231.9
R5	52.8	10,266.0
S5	53.3	12,572.1
S6	54.0	16,846.9

PEPCO Proposal 50-R2	1,489
Currently Approved 45-S2	10,423
BCA Proposal 54-R2	495


ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES
Original & Smooth Survivor Curves
Placement Band 1955-2021
Observation Band 1988 to 2021
Percent Surviving
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0
20
40
60
80
100
120
Age
Original Curve
PEPCO Proposal 50-R2
BCA Proposal 54-R2
Best Fit 65-L1
Currently Approved 45-S2

Account 366 - Underground Conduit

Account Description

This account is for Underground Conduit. Per the FERC Uniform System of Accounts, "This account shall include the cost installed of underground conduit and tunnels used for housing distribution cables or wires." The items contained within this account include conduit, duct banks, excavation, foundations, lighting systems, manholes, inspections, permits, sewer connections, sumps, ventilation equipment, etc.

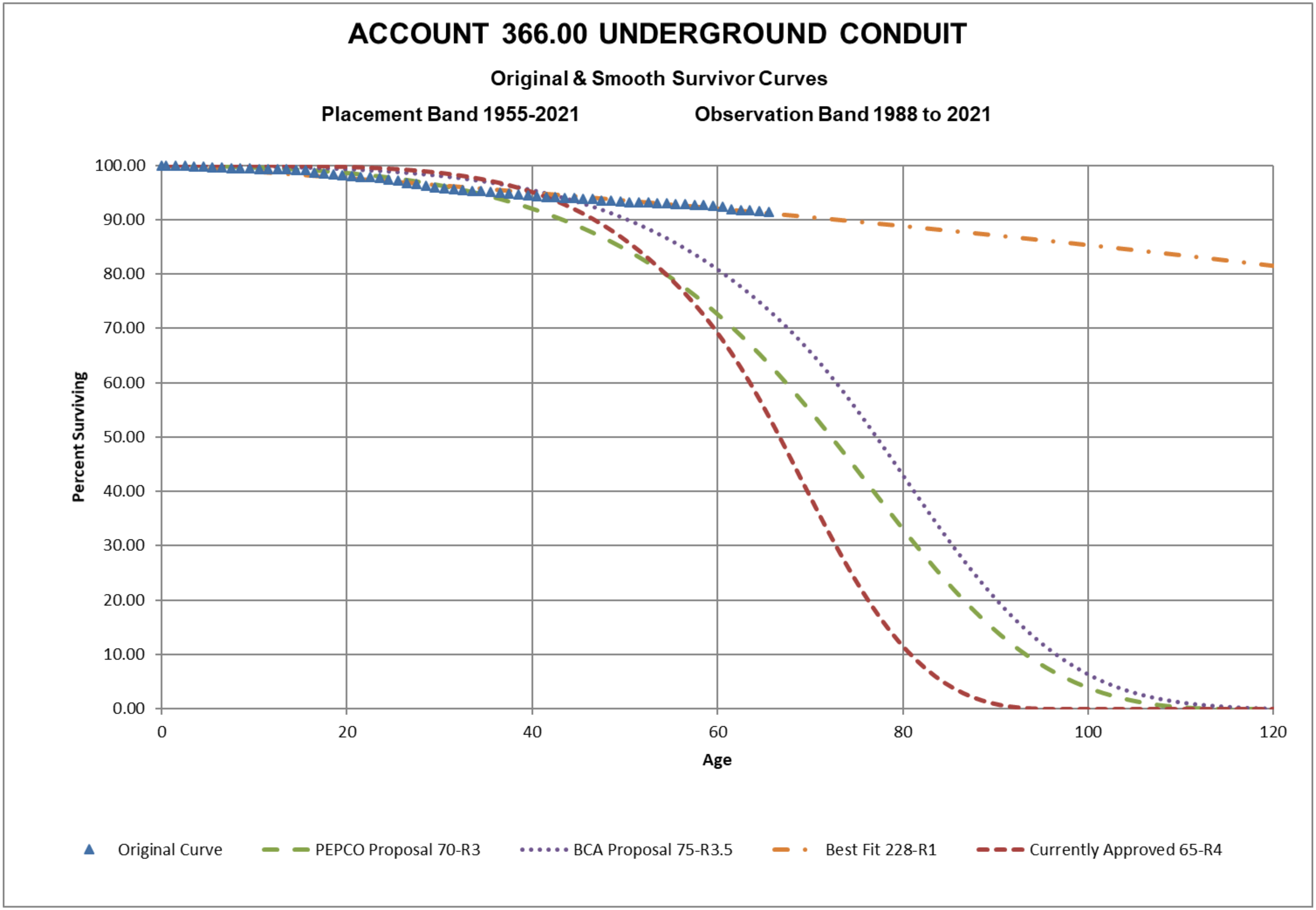
Discussion

The currently approved curve is the 65-R4. Pepco proposes to change to R4 dispersion to the R3 dispersion, and increase the average service life to 70 years. As seen in the fitting analysis results, for all curve types, the ASL is greater than 70 years, indicating that the data supports an increase to the average service life. While the best fit is the 228-R1 curve, which has an SSD of 12.4, I recommend the 75-R3.5 for this account. The 75-R3.5 has an SSD of 1,998, which is much lower than the SSDs of 8,277 and 5,870 for the currently approved and Pepco proposed curves, respectively.

Account 366 Fitting Analysis Results

Iowa Curve	Average Service Life	SSD
R1	228.1	12.4
R0.5	303.1	13.3
O2	432.1	14.2
O1	385.9	14.2
O3	628.0	14.4
O4	868.4	14.4
R1.5	177.4	14.8
L0	277.7	18.7
L0.5	219.3	29.2
R2	137.9	35.5
S0	183.6	47.3
R2.5	116.7	74.9
S0.5	153.5	79.3
L1	172.7	79.9
L1.5	146.4	114.8
S1	129.9	173.3
R3	101.1	185.5
L2	124.1	218.3
S1.5	116.0	228.4
L2.5	111.8	275.5
R3.5	92.9	275.9
S2	104.4	368.6
L3	100.4	404.9
S2.5	97.2	432.4
R4	86.5	459.7
S3	90.9	586.0
L4	86.2	619.0
S4	81.0	860.3
R5	76.8	862.6
L5	78.3	897.8
S5	75.1	1,086.7
S6	71.3	1,267.9

PEPCO Proposal 70-R3	5,870
Currently Approved 65-R4	8,277
BCA Proposal 75-R3.5	1,998


ACCOUNT 366.00 UNDERGROUND CONDUIT
Original & Smooth Survivor Curves
Placement Band 1955-2021
Observation Band 1988 to 2021
Percent Surviving
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0
20
40
60
80
100
120
Age
Original Curve
PEPCO Proposal 70-R3
BCA Proposal 75-R3.5
Best Fit 228-R1
Currently Approved 65-R4

Account 367 - Underground Conductors and Devices

Account Description

This account is for Underground Conductors and Devices. Per the FERC Uniform System of Accounts, "This account shall include the cost installed of underground conductors and devices used for distribution purposes." The items contained within this account include, circuit breakers, armored conductors, insulators, insulating materials, splicing, fireproofing, inspections, permits, cable racking, lightning arresters, switches, and other line devices.

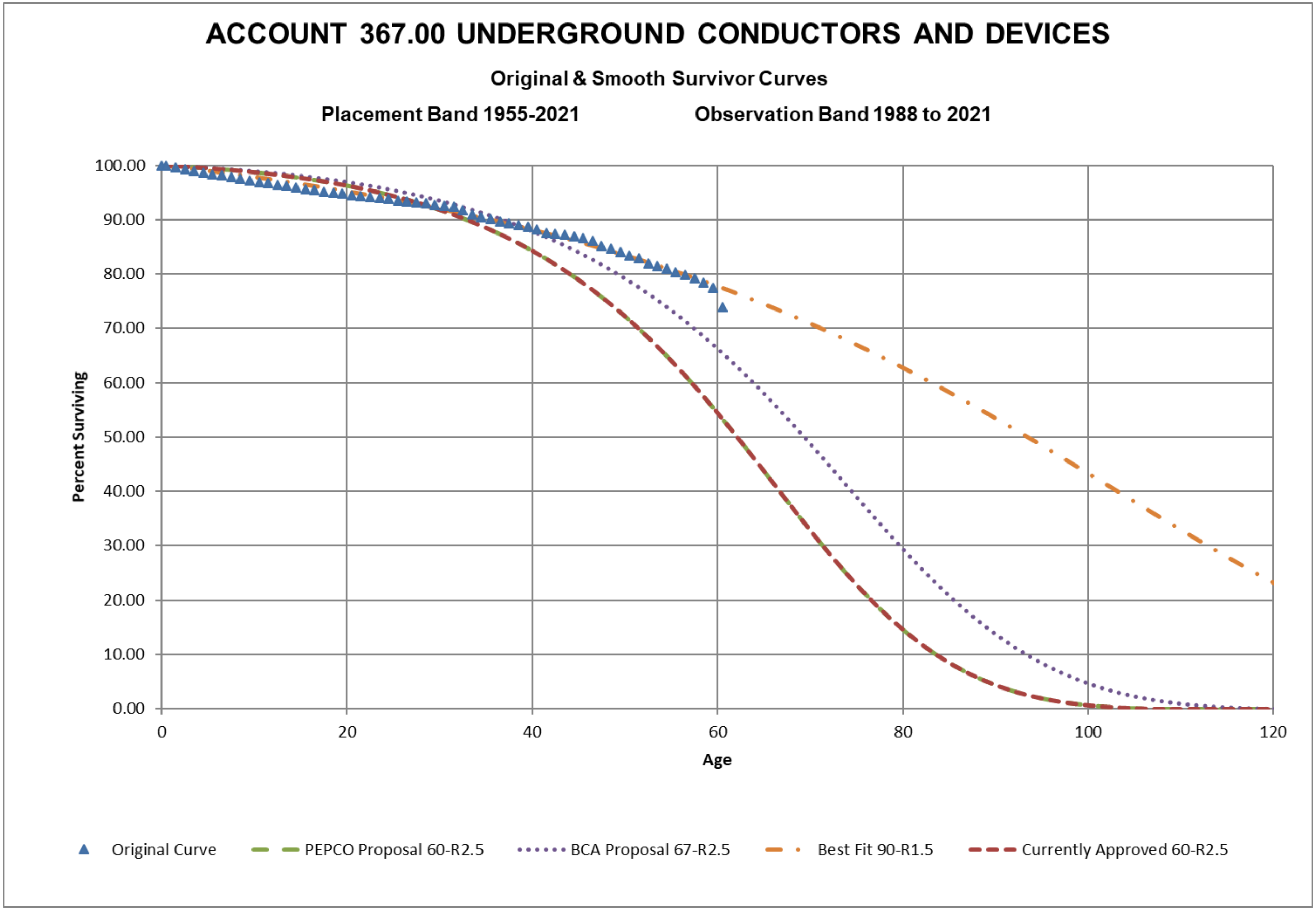
Discussion

The currently approved survivor curve is the 60-R2.5, which has an SSD of 4,114. Pepco is proposing to retain the currently approved curve. However, the 60-R2.5 is no longer an appropriate fit for the data, as it diverges from the significant data points around the 30 year mark. As seen in the fitting analysis results, for all curve types, the ASL is greater than 60 years, indicating that the data supports an increase to the ASL. Additionally, for the R2.5 Iowa Curve type, an ASL of 74 years is the best fit to the data. This also indicates that an increase to the ASL is necessary, however, it would not be prudent to increase the ASL by 14 years. A more gradual movement should be employed. Therefore, my recommendation is the 67-R2.5, which has a much lower SSD of 848 compared to the 60-R2.5. The 67-R2.5 is a much better fit to the actual retirement data, therefore, it will produce a more reasonable deprecation rate for this account.

Account 367 Fitting Analysis Results

Iowa Curve	Average Service Life	SSD
R1.5	89.8	28.3
L0.5	118.0	55.0
L0	138.5	63.8
R1	104.2	65.3
S0	101.8	79.4
R2	80.1	80.6
R0.5	127.8	121.5
S0.5	91.3	142.7
L1	103.7	150.4
O2	175.2	156.8
O1	156.4	157.1
O3	252.3	167.4
O4	347.4	172.9
R2.5	74.1	222.2
L1.5	92.7	256.0
S1	83.7	341.5
S1.5	78.3	518.8
R3	69.9	556.0
L2	84.9	567.6
L2.5	79.0	759.7
S2	74.2	875.1
R3.5	67.2	875.8
S2.5	71.2	1,136.3
L3	74.6	1,204.4
R4	65.3	1,380.7
S3	68.9	1,589.9
L4	67.5	1,901.9
S4	65.1	2,682.3
R5	63.0	2,941.9
L5	64.4	3,028.8
S5	63.0	3,835.4
S6	61.9	4,955.7

PEPCO Proposal 60-R2.5	4,114
Currently Approved 60-R2.5	4,114
BCA Proposal 67-R2.5	848


ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES
Original & Smooth Survivor Curves
Placement Band 1955-2021
Observation Band 1988 to 2021
Percent Surviving
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0
20
40
60
80
100
120
Age
Original Curve
PEPCO Proposal 60-R2.5
BCA Proposal 67-R2.5
Best Fit 90-R1.5
Currently Approved 60-R2.5

Account 368 - Line Transformers

Account Description

This Account is for Line Transformers. Per the FERC Uniform System of Accounts, "This account shall include the cost installed of overhead and underground distribution line transformers and pole type and underground voltage regulators owned by the utility, for use in transforming electricity to the voltage at which it is to be used by the customer, whether actually in service or held in reserve." This includes labor of first installation, transformer cut-out boxes, transformer lightning arresters, transformers, lines and network, capacitors, network protectors, etc.

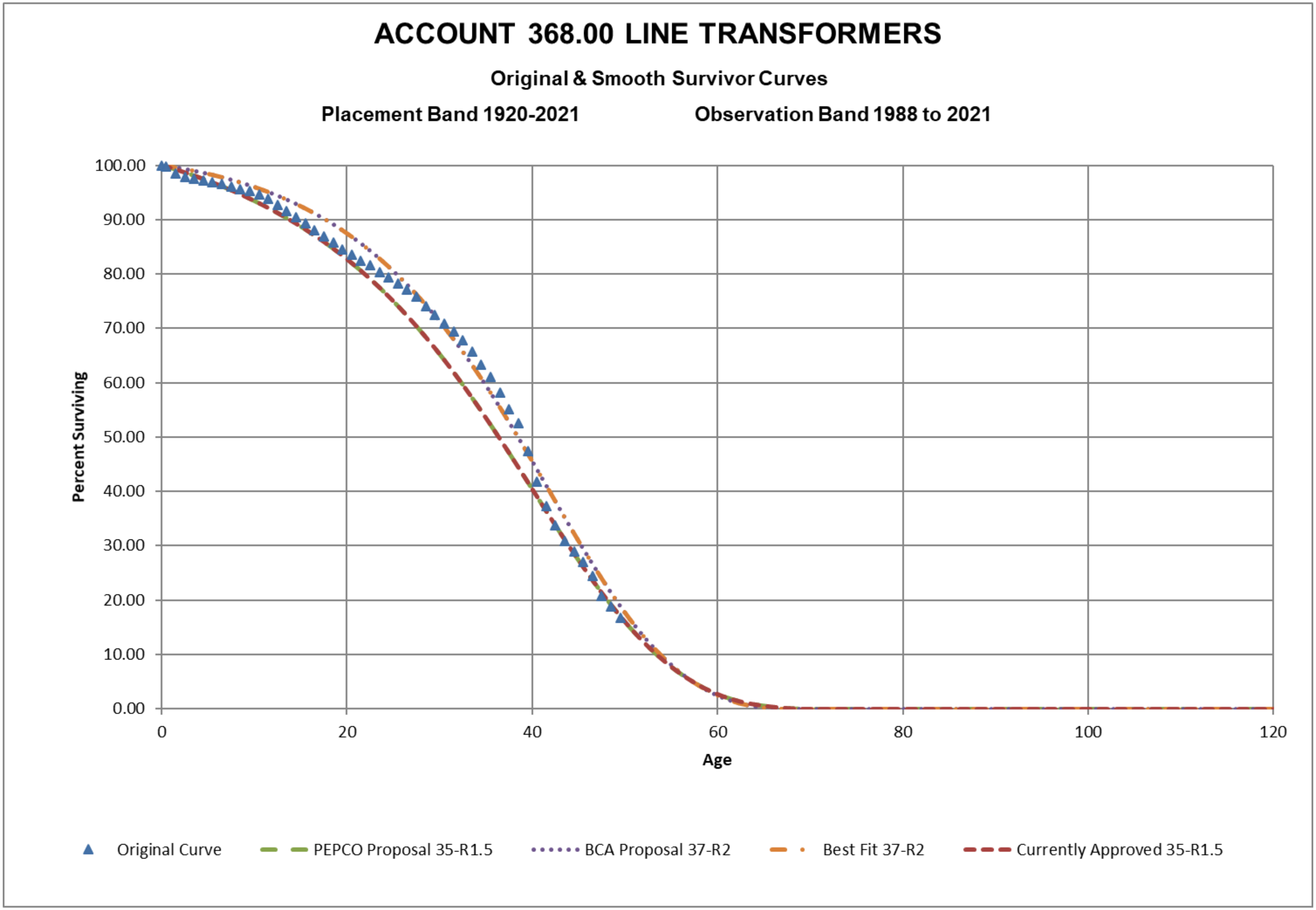
Discussion

The currently approved curve is the 35-R1.5. Pepco proposes no change. As Mr. Allis notes in Pepco's 2021 Depreciation Study (page III-4), the outlook for the assets in this account "has not changed significantly since the previous depreciation study" and the retirements are usually due to "failure and capacity." However, the current curve diverges from the significant data for the 20 year – 40 year time frame. The fitting analysis shows that the best fit to the significant data points is the 37-R2, with an SSD of 272, which more consistently matches the data. I recommend the 37-R2, since it is a better fit to the data and is only slightly different from the current curve in ASL and dispersion.

Account 368 Fitting Analysis Results

Iowa Curve	Average Service Life	SSD
R2	36.6	242.1
R1.5	36.5	448.9
R2.5	37.0	563.0
S1	37.4	722.7
S1.5	37.5	745.7
S0.5	37.5	981.0
S2	37.6	1,202.1
L2	39.5	1,231.1
R1	36.4	1,267.0
L2.5	39.1	1,280.3
L1.5	39.7	1,332.4
R3	37.3	1,491.4
S0	37.6	1,677.0
S2.5	37.8	1,859.9
L3	38.9	1,924.6
L1	40.1	1,996.3
R3.5	37.6	2,718.3
L0.5	41.1	2,735.8
R0.5	37.1	2,774.8
S3	37.9	2,908.7
L0	42.5	3,816.0
L4	38.5	4,215.1
R4	38.0	4,430.9
O1	38.8	4,816.2
O2	43.6	4,882.0
S4	38.4	6,528.8
O3	59.3	6,723.3
O4	79.5	7,611.9
L5	38.7	8,088.8
R5	38.6	9,750.7
S5	38.8	11,320.9
S6	38.9	16,499.3

PEPCO Proposal 35-R1.5	838
Currently Approved 35-R1.5	838
BCA Proposal 37-R2	272


ACCOUNT 368.00 LINE TRANSFORMERS
Original & Smooth Survivor Curves
Placement Band 1920-2021
Observation Band 1988 to 2021
Percent Surviving
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0
20
40
60
80
100
120
Age
Original Curve
PEPCO Proposal 35-R1.5
BCA Proposal 37-R2
Best Fit 37-R2
Currently Approved 35-R1.5

Account 369.1 – Services - Overhead

Account Description

This account is for Services. Per the FERC Uniform System of Accounts for Account 369, "This account shall include the cost installed of overhead and underground conductors leading from a point where wires leave the last pole of the overhead system or the distribution box or manhole, or the top of the pole of the distribution line, to the point of connection with the customer's outlet or wiring. Conduit used for underground service conductors shall be included herein." The items contained within this account include brackets, cables and wires, conduit, insulators, inspection, overhead to underground connections, permits, pavement, suspension wire, service switch, and protection of street openings. This subaccount is for overhead components only.

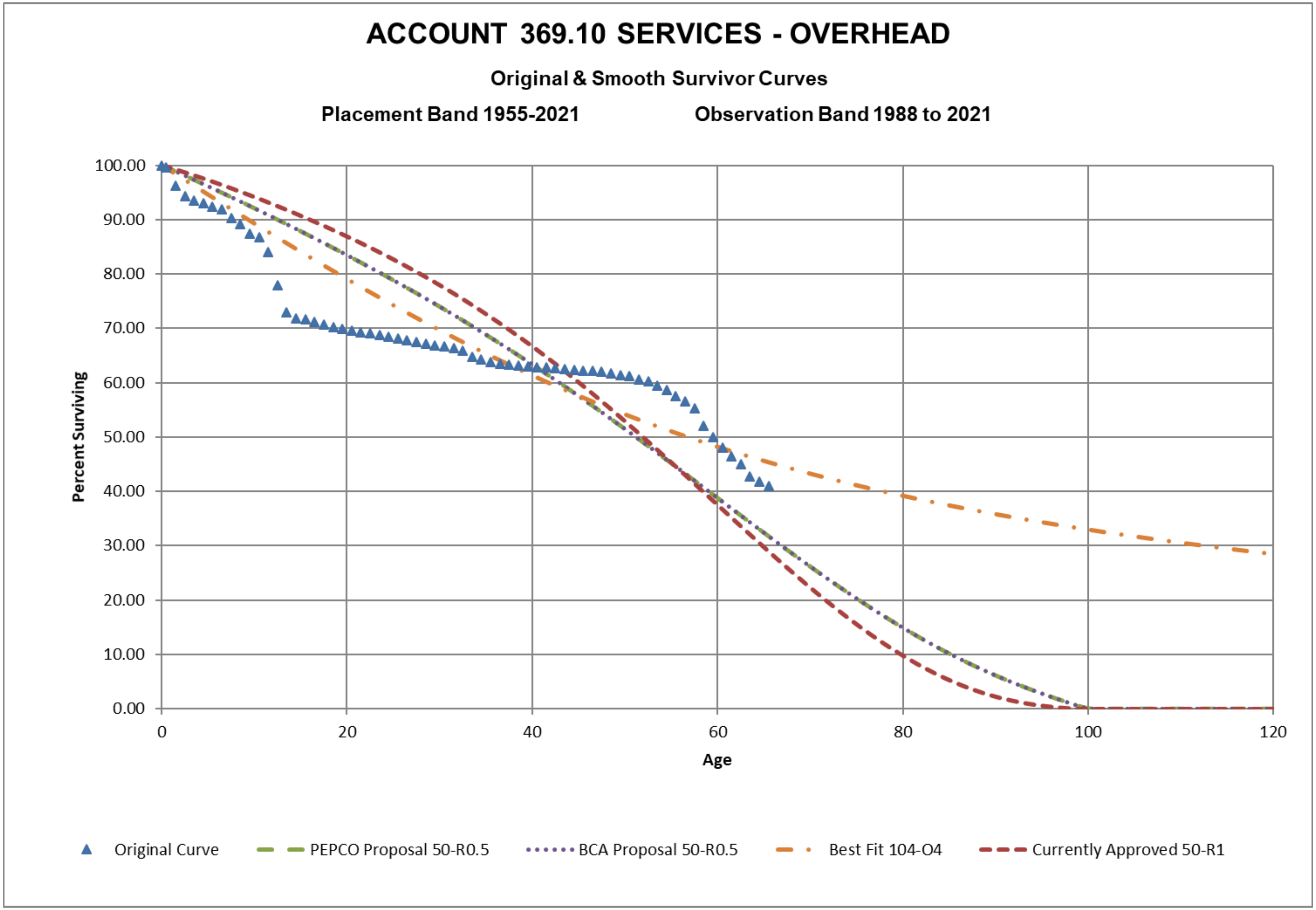
Discussion

The currently approved curve is the 50-R1 which has an SSD of 8,091. Pepco is proposing to retain the current ASL but change the dispersion to the R0.5 curve. Pepco's proposed 50-R0.5 has an SSD of 5,646. I believe that the 50-R0.5 is appropriate for this account.

Account 369.1 Fitting Analysis Results

Iowa Curve	Average Service Life	SSD
O4	103.6	2,171.2
O3	79.8	2,502.4
O2	61.9	3,276.5
O1	55.3	3,279.9
R0.5	53.8	4,969.8
L0	59.3	5,111.5
L0.5	57.6	7,160.3
R1	52.9	7,534.1
S0	53.7	8,617.3
L1	56.2	9,752.0
R1.5	53.0	10,613.1
S0.5	53.6	11,438.7
L1.5	55.9	13,001.5
R2	53.1	14,397.3
S1	53.6	14,815.4
L2	55.7	17,028.8
S1.5	53.9	18,119.1
R2.5	53.7	18,440.4
L2.5	55.7	20,579.7
S2	54.1	21,930.4
R3	54.2	23,093.9
L3	55.7	24,950.9
S2.5	54.6	25,275.9
R3.5	55.0	27,192.4
S3	55.0	29,035.5
R4	55.6	31,698.9
L4	56.2	33,202.2
S4	56.4	37,777.5
L5	57.2	41,421.0
R5	57.4	42,483.8
S5	57.8	45,973.4
S6	59.1	53,718.3

PEPCO Proposal 50-R0.5	5,646
Currently Approved 50-R1	8,091
BCA Proposal 50-R0.5	5,646


ACCOUNT 369.10 SERVICES - OVERHEAD
Original & Smooth Survivor Curves
Placement Band 1955-2021
Observation Band 1988 to 2021
Percent Surviving
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0
20
40
60
80
100
120
Age
Original Curve
PEPCO Proposal 50-R0.5
BCA Proposal 50-R0.5
Best Fit 104-O4
Currently Approved 50-R1

Account 369.2 – Services - Underground

Account Description

This account is for Services. Per the FERC Uniform System of Accounts for Account 369, "This account shall include the cost installed of overhead and underground conductors leading from a point where wires leave the last pole of the overhead system or the distribution box or manhole, or the top of the pole of the distribution line, to the point of connection with the customer's outlet or wiring. Conduit used for underground service conductors shall be included herein." The items contained within this account include brackets, cables and wires, conduit, insulators, inspection, overhead to underground connections, permits, pavement, suspension wire, service switch, and protection of street openings. This subaccount is for underground components only.

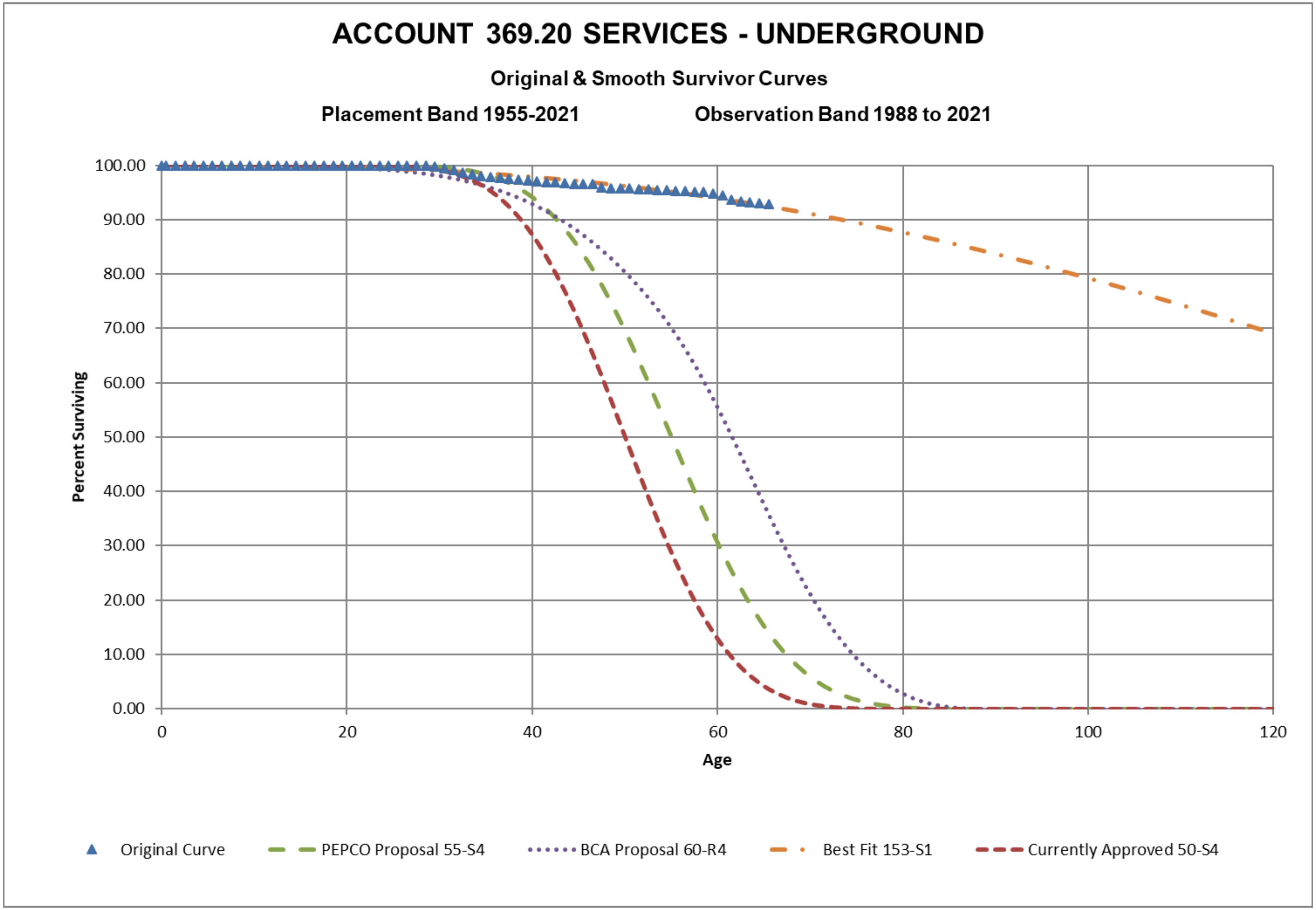
Discussion

The currently approved curve is the 50-S4 which has an SSD of 96,934. Pepco is proposing to increase the ASL to 55-S4, which has an SSD of 55,448. Clearly, the currently approved curve is no longer appropriate for this account, and Pepco's proposal is a significantly better match to the data. However, the fitting analysis indicates that a longer average life is necessary, so I propose to the 60-R4 for this account, which has an SSD of 22,633 and is a much better overall fit than both the currently approved and Pepco's proposed curves.

Account 369.2 Fitting Analysis Results

Iowa Curve	Average Service Life	SSD
S1	153.3	13.9
L1.5	177.3	15.8
L2	141.8	16.2
R3	116.7	17.2
S0.5	192.9	17.6
S1.5	133.2	19.5
L1	215.7	22.0
S0	241.7	24.0
L2.5	125.4	24.5
R3.5	103.5	26.3
R2.5	145.2	28.5
L0.5	299.9	37.8
L0	394.7	42.0
R2	184.7	43.8
S2	115.6	47.0
L3	109.1	50.1
S2.5	105.9	62.3
R1.5	264.9	64.3
R4	93.2	68.0
R1	359.6	72.3
R0.5	499.7	78.8
O2	725.1	81.1
O1	648.0	81.2
O3	1,057.7	81.5
O4	1,465.0	81.7
S3	97.0	112.9
L4	91.6	125.4
R5	79.4	220.1
S4	84.0	222.5
L5	80.9	240.8
S5	76.6	328.9
S6	72.1	425.8

PEPCO Proposal 55-S4	55,448
Currently Approved 50-S4	96,934
BCA Proposal 60-R4	22,633


ACCOUNT 369.20 SERVICES - UNDERGROUND
Original & Smooth Survivor Curves
Placement Band 1955-2021
Observation Band 1988 to 2021
Percent Surviving
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0
20
40
60
80
100
120
Age
Original Curve
PEPCO Proposal 55-S4
BCA Proposal 60-R4
Best Fit 153-S1
Currently Approved 50-S4

Account 369.3 – Services – Underground Cable

Account Description

This account is for Services. Per the FERC Uniform System of Accounts for Account 369, "This account shall include the cost installed of overhead and underground conductors leading from a point where wires leave the last pole of the overhead system or the distribution box or manhole, or the top of the pole of the distribution line, to the point of connection with the customer's outlet or wiring. Conduit used for underground service conductors shall be included herein." The items contained within this account include brackets, cables and wires, conduit, insulators, inspection, overhead to underground connections, permits, pavement, suspension wire, service switch, and protection of street openings. This subaccount is for underground cable.

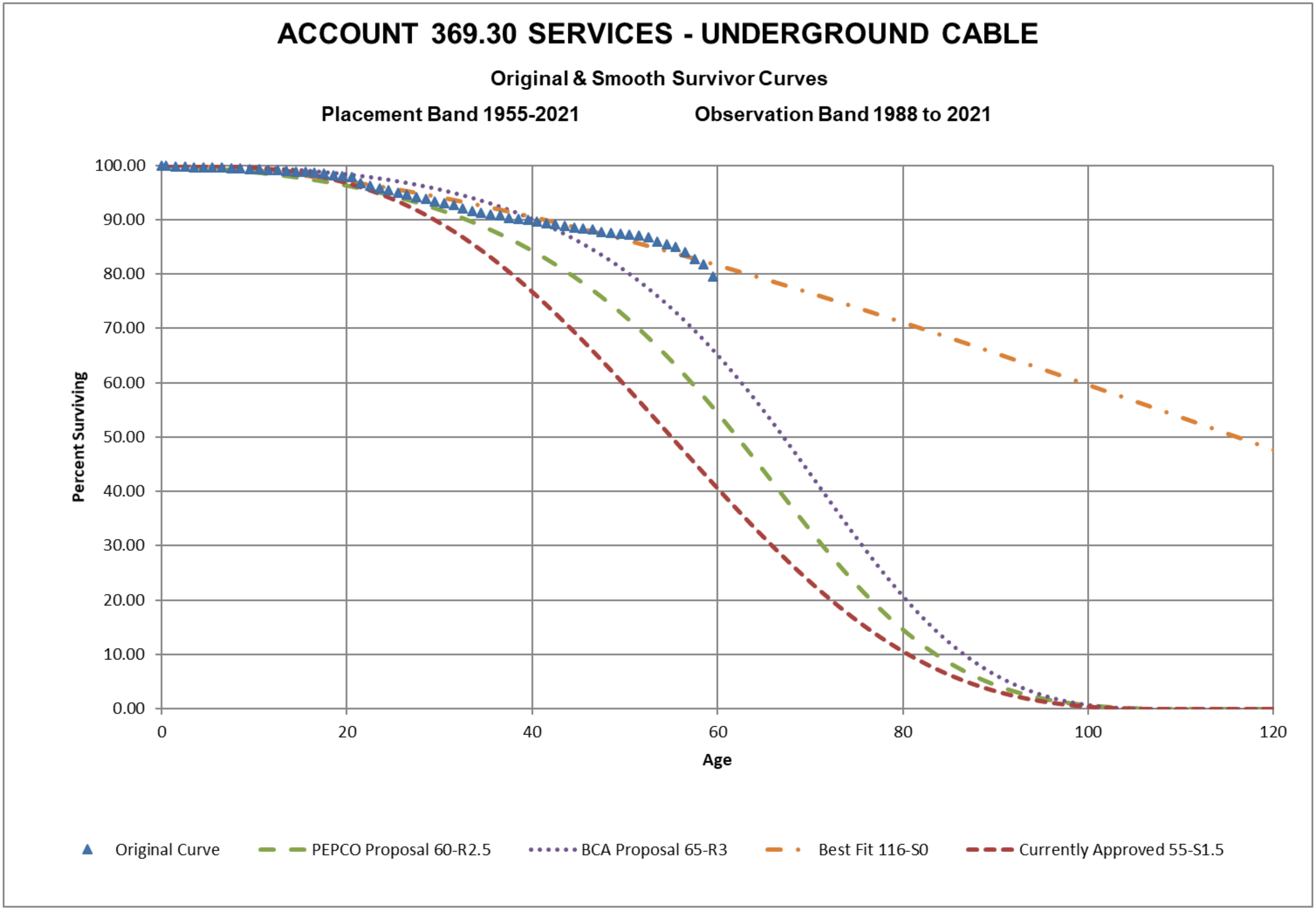
Discussion

The currently approved curve is the 55-S1.5 which has an SSD of 17,009. Pepco is proposing to change both the service life and dispersion, recommending the 60-R2.5, which has an SSD of 5,573. I agree with Pepco's recommendation to increase the average service life and change the dispersion to an R curve. However, Pepco's proposed curve diverges from the data early on, around age 30. I propose the 65-R3 curve, which has a much lower SSD of 1,483 and more closely follows the slope and curvature of the significant data points between age 40 and age 60.

Account 369.3 Fitting Analysis Results

Iowa Curve	Average Service Life	SSD
S0	116.1	39.7
L0.5	135.4	40.3
L0	163.4	49.3
R2	89.1	58.4
R1.5	103.9	59.5
S0.5	101.8	74.3
L1	115.4	86.7
R1	125.1	95.4
R2.5	80.4	126.1
R0.5	158.3	136.5
L1.5	101.5	146.7
O2	220.5	158.8
O1	196.9	159.1
O3	319.0	164.1
O4	440.0	166.9
S1	91.2	199.4
S1.5	84.1	320.5
R3	74.3	324.5
L2	91.1	354.0
L2.5	83.8	476.2
R3.5	70.7	534.6
S2	78.7	579.2
S2.5	74.8	754.9
L3	78.1	774.9
R4	67.9	890.8
S3	71.8	1,085.4
L4	69.5	1,229.0
S4	66.7	1,807.9
R5	64.0	1,908.0
L5	65.5	1,968.7
S5	63.8	2,493.6
S6	62.0	3,114.9

PEPCO Proposal 60-R2.5	5,573
Currently Approved 55-S1.5	17,009
BCA Proposal 65-R3	1,483


ACCOUNT 369.30 SERVICES - UNDERGROUND CABLE
Original & Smooth Survivor Curves
Placement Band 1955-2021
Observation Band 1988 to 2021
Percent Surviving
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0
20
40
60
80
100
120
Age
Original Curve
PEPCO Proposal 60-R2.5
BCA Proposal 65-R3
Best Fit 116-S0
Currently Approved 55-S1.5

Account 370 - Meters

Account Description

This account is for meters. Per the FERC Uniform System of Accounts, "This account shall include the cost installed of meters or devices and appurtenances thereto, for use in measuring the electricity delivered to its users, whether actually in service or held in reserve." This includes labor of first installation, alternating current, watt-hour meters, current limiting device, demand indicators, demand meters, maximum demand meters, meter fittings, connections, and shelves, meter switches and cut-outs, instrument transformers, etc.

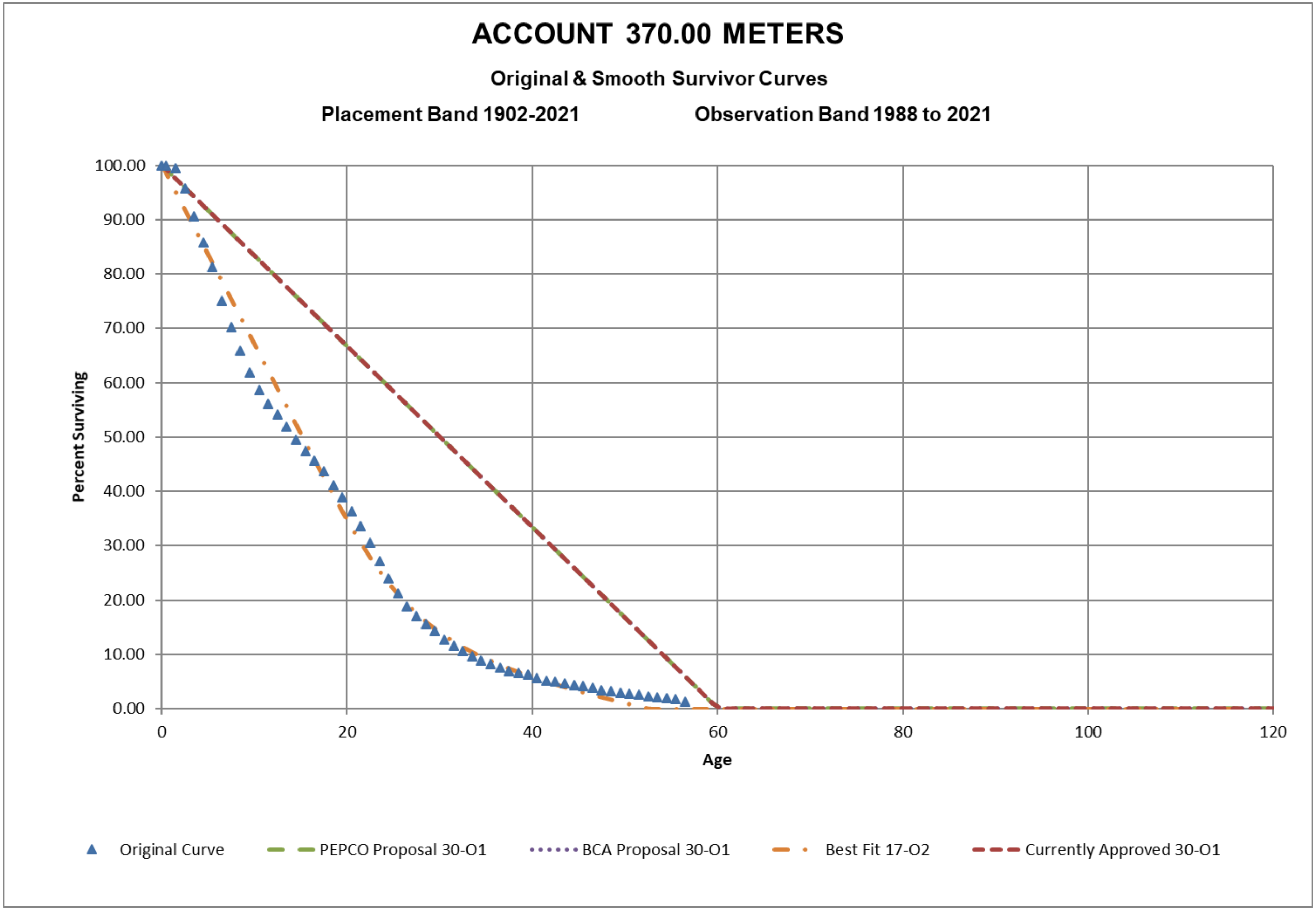
Discussion

The currently approved curve is the 30-O1. Pepco is not proposing any change to this curve. Although the best fitting curve is the 17-O2 curve, I am not recommending a change from the currently approved curve.

Account 370 Fitting Analysis Results

Iowa Curve	Average Service Life	SSD
O2	16.9	371.9
L0	16.7	681.9
L0.5	16.7	1,360.8
O3	17.5	1,445.4
O1	16.1	1,485.9
L1	16.7	2,347.5
R0.5	16.4	2,423.3
S0	16.5	3,383.2
L1.5	16.7	3,668.2
R1	16.5	4,022.8
O4	18.8	4,539.0
S0.5	16.6	4,660.9
L2	16.6	5,327.1
R1.5	16.6	5,632.7
S1	16.6	6,253.6
L2.5	16.6	7,228.7
R2	16.6	7,682.5
S1.5	16.6	7,944.1
L3	16.5	9,490.3
R2.5	16.6	9,768.5
S2	16.6	9,913.2
S2.5	16.5	11,727.0
R3	16.6	12,244.8
S3	16.5	13,764.0
R3.5	16.5	14,309.7
L4	16.3	14,913.5
R4	16.3	16,641.7
S4	16.2	18,506.3
L5	16.0	19,607.0
R5	15.9	21,543.1
S5	15.7	22,644.9
S6	15.2	25,981.2

PEPCO Proposal 30-O1	36,342
Currently Approved 30-O1	36,342
BCA Proposal 30-O1	36,342


ACCOUNT 370.00 METERS
Original & Smooth Survivor Curves
Placement Band 1902-2021
Observation Band 1988 to 2021
Percent Surviving
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0
20
40
60
80
100
120
Age
Original Curve
PEPCO Proposal 30-O1
BCA Proposal 30-O1
Best Fit 17-O2
Currently Approved 30-O1

Account 370.1 – Meters - AMI

Account Description

This account is for meters. Per the FERC Uniform System of Accounts, "This account shall include the cost installed of meters or devices and appurtenances thereto, for use in measuring the electricity delivered to its users, whether actually in service or held in reserve." This includes labor of first installation, alternating current, watt-hour meters, current limiting device, demand indicators, demand meters, maximum demand meters, meter fittings, connections, and shelves, meter switches and cut-outs, instrument transformers, etc. This subaccount is for AMI meters.

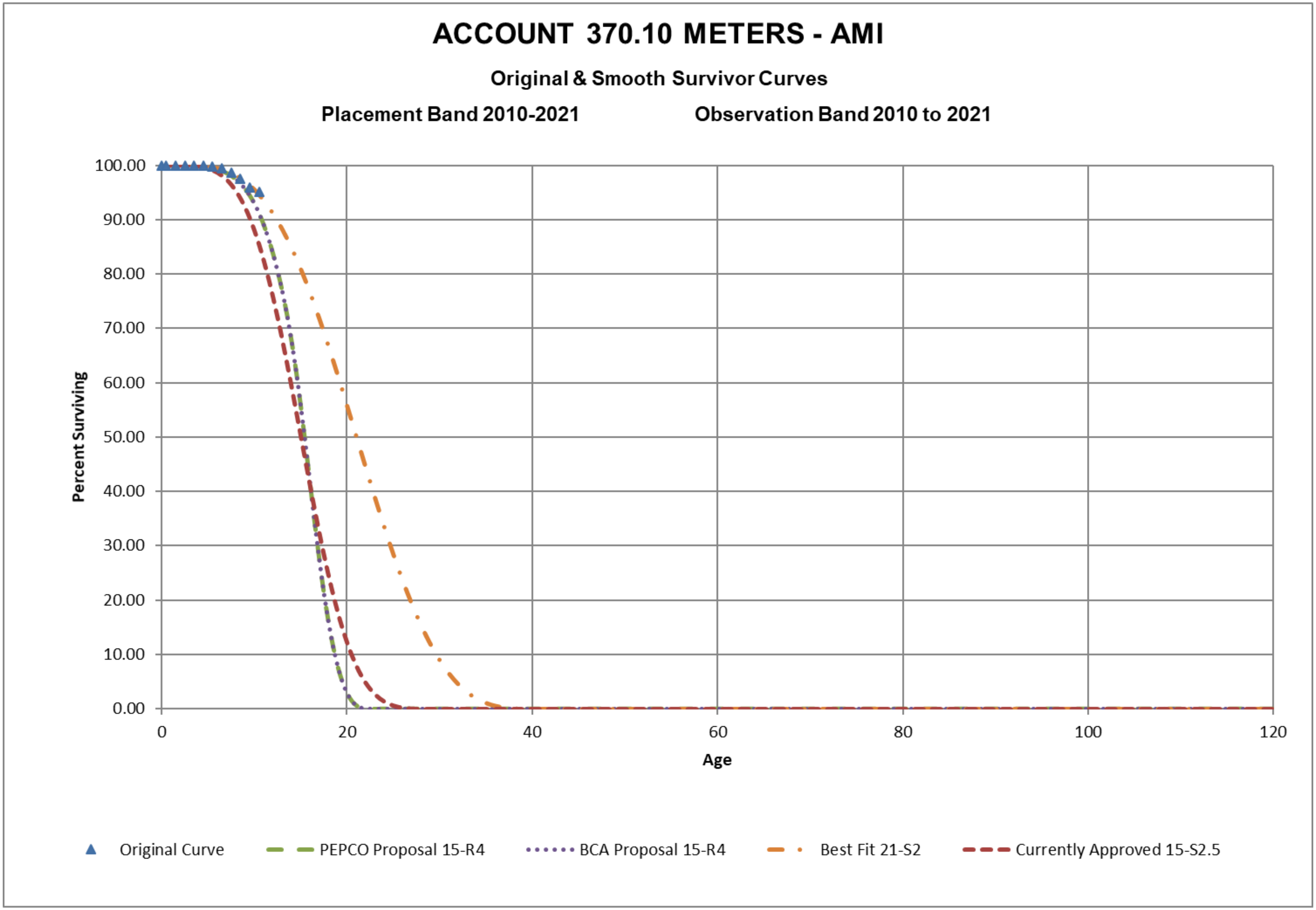
Discussion

The currently approved curve is the 15-S2.5. Pepco is proposing to update the dispersion curve to 15-R4, which has an SSD of 21. I agree with Pepco's proposal and recommend the 15-R4 curve.

Account 370.1 Fitting Analysis Results

Iowa Curve	Average Service Life	SSD
S2	21.2	0.4
L3	19.8	0.5
S2.5	19.2	0.7
R4	16.7	0.8
L2.5	23.6	1.0
S1.5	25.4	1.1
R3.5	19.4	1.4
L2	27.3	1.6
S1	30.0	1.7
S3	17.2	2.4
R3	22.7	2.7
L4	16.2	2.9
L1.5	35.9	3.8
S0.5	40.3	4.5
L1	45.1	5.5
S0	52.3	5.6
R2.5	31.1	6.9
L0.5	68.3	7.8
L0	91.7	8.1
R5	13.6	8.3
S4	14.4	8.8
R2	42.6	9.0
L5	13.9	10.2
R1.5	66.8	10.9
R1	93.5	11.5
R0.5	133.4	11.9
O2	195.3	12.1
O1	174.6	12.1
O3	285.3	12.1
O4	395.4	12.1
S5	12.9	16.6
S6	12.0	22.6

PEPCO Proposal 15-R4	21
Currently Approved 15-S2.5	152
BCA Proposal 15-R4	21


ACCOUNT 370.10 METERS - AMI
Original & Smooth Survivor Curves
Placement Band 2010-2021
Observation Band 2010 to 2021
Percent Surviving
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0
20
40
60
80
100
120
Age
Original Curve
PEPCO Proposal 15-R4
BCA Proposal 15-R4
Best Fit 21-S2
Currently Approved 15-S2.5

Account 371.1 – Installations of Customers' Premises

Account Description

This account is for Installation on Customers' Premises. Per the FERC Uniform System of Accounts, "This account shall include the cost installed of equipment on the customer's side of a meter when the utility incurs such cost and when the utility retains title to and assumes full responsibility for maintenance and replacement of such property." This includes the cost of cable vaults, commercial lamp equipment, foundations, frequency changer sets, motor generator sets, motors, switchboards panels, and wire and cable connections.

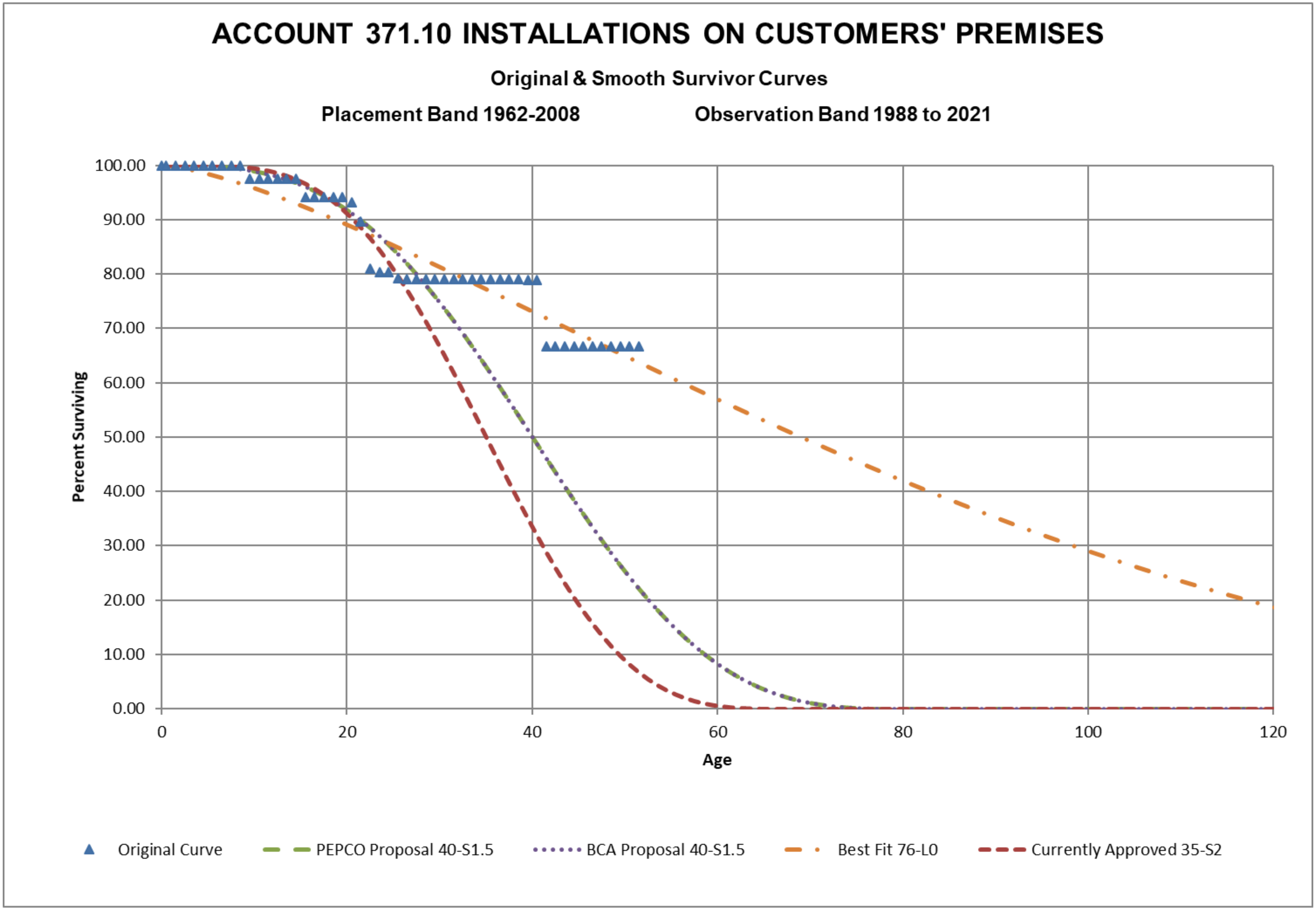
Discussion

The currently approved curve is the 35-S2 which has an SSD of 40, 125. Pepco is proposing to lengthen the average service life and change the curve type to the 40-S1.5. This is a much better fit to the data with an SSD of 16,903. This change in service life and curve type is supported by the fitting analysis, which shows that the best fitting ASL for each curve type is greater than 49 years. I support Pepco's proposal and recommend the 40-S1.5 curve.

Account 371.1 Fitting Analysis Results

Iowa Curve	Average Service Life	SSD
L0	76.3	577.5
L0.5	69.3	641.3
R1	59.1	682.5
S0	61.1	684.4
R0.5	66.3	726.0
O2	85.9	825.9
O1	76.7	826.6
R1.5	55.4	837.6
O3	121.4	873.1
O4	165.5	900.6
L1	64.4	904.8
S0.5	57.8	979.0
R2	52.9	1,282.9
L1.5	60.6	1,380.3
S1	55.4	1,526.0
R2.5	51.5	1,972.5
S1.5	53.7	2,188.8
L2	58.0	2,274.2
L2.5	55.8	3,025.5
R3	50.5	3,026.1
S2	52.5	3,148.4
S2.5	51.7	4,037.9
R3.5	50.1	4,090.9
L3	54.2	4,264.0
S3	51.1	5,216.0
R4	49.7	5,450.4
L4	51.6	6,615.4
S4	50.3	8,146.2
R5	49.8	9,433.8
L5	50.8	9,549.8
S5	50.2	11,217.0
S6	50.5	14,331.5

PEPCO Proposal 40-S1.5	16,903
Currently Approved 35-S2	40,125
BCA Proposal 40-S1.5	16,903


ACCOUNT 371.10 INSTALLATIONS ON CUSTOMERS' PREMISES
Original & Smooth Survivor Curves
Placement Band 1962-2008
Observation Band 1988 to 2021
Percent Surviving
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0
20
40
60
80
100
120
Age
Original Curve
PEPCO Proposal 40-S1.5
BCA Proposal 40-S1.5
Best Fit 76-L0
Currently Approved 35-S2

Account 373 - Street Lighting and Signal Systems

Account Description

This account is for street lighting and signal systems. Per the FERC Uniform System of Accounts, "This account shall include the cost installed of equipment used wholly for Public Street and highway lighting or traffic, fire alarm, police, and other signal systems." This includes automatic control equipment, conductors, lamps, municipal inspection, lamp posts, permits, series contactors, switches, etc.

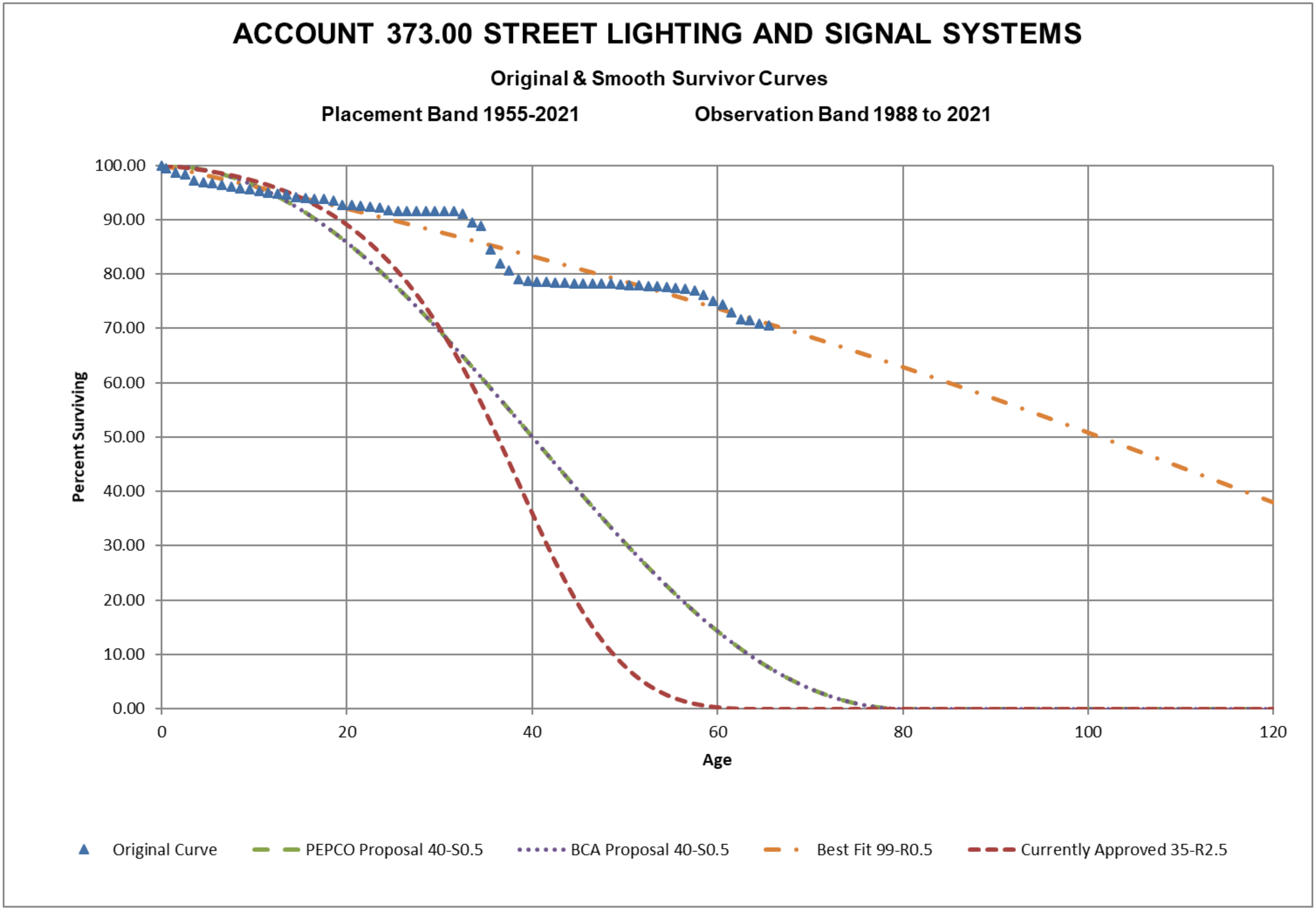
Discussion

The currently approved curve is the 35-R2.5. The fitting analysis shows that the 99-R0.5 is the best fit and that lower moded curves fit the data better. Pepco proposed the 40-S0.5, which is a better fit to the data than the currently approved curve. I recommend Pepco's proposal, the 40-S0.5 curve.

Account 373 Fitting Analysis Results

Iowa Curve	Average Service Life	SSD
R0.5	98.7	308.8
O2	130.4	330.8
O1	116.4	331.1
L0	112.3	344.1
O3	185.5	344.2
O4	253.7	352.6
R1	85.7	353.0
L0.5	100.2	506.1
R1.5	78.4	557.1
S0	87.6	593.7
L1	91.6	912.7
S0.5	81.5	946.3
R2	73.5	1,058.3
L1.5	84.8	1,413.7
S1	77.2	1,581.5
R2.5	70.4	1,726.8
S1.5	74.0	2,227.5
L2	80.2	2,387.1
R3	68.3	2,787.4
L2.5	76.4	3,081.9
S2	71.6	3,207.2
R3.5	67.0	3,759.3
S2.5	70.0	4,044.0
L3	73.6	4,340.2
R4	66.1	5,054.1
S3	68.7	5,215.3
L4	68.9	6,314.6
S4	66.8	7,990.8
R5	65.5	8,794.0
L5	67.0	8,971.2
S5	66.0	10,532.4
S6	65.6	12,734.6

PEPCO Proposal 40-S0.5	77,144
Currently Approved 35-R2.5	132,999
BCA Proposal 40-S0.5	77,144


ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS
Original & Smooth Survivor Curves
Placement Band 1955-2021
Observation Band 1988 to 2021
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Percent Surviving
0
20
40
60
80
100
120
Age
Original Curve
PEPCO Proposal 40-S0.5
BCA Proposal 40-S0.5
Best Fit 99-R0.5
Currently Approved 35-R2.5

Account 390 – Structures and Improvements

Account Description

This account is for Structures and Improvements. Per the FERC Uniform System of Accounts, "This account shall include the cost in place of structures and improvements used for utility purposes, the cost of which is not properly includible in other structures and improvements accounts." This account includes the Company's office buildings, service centers, and other buildings.

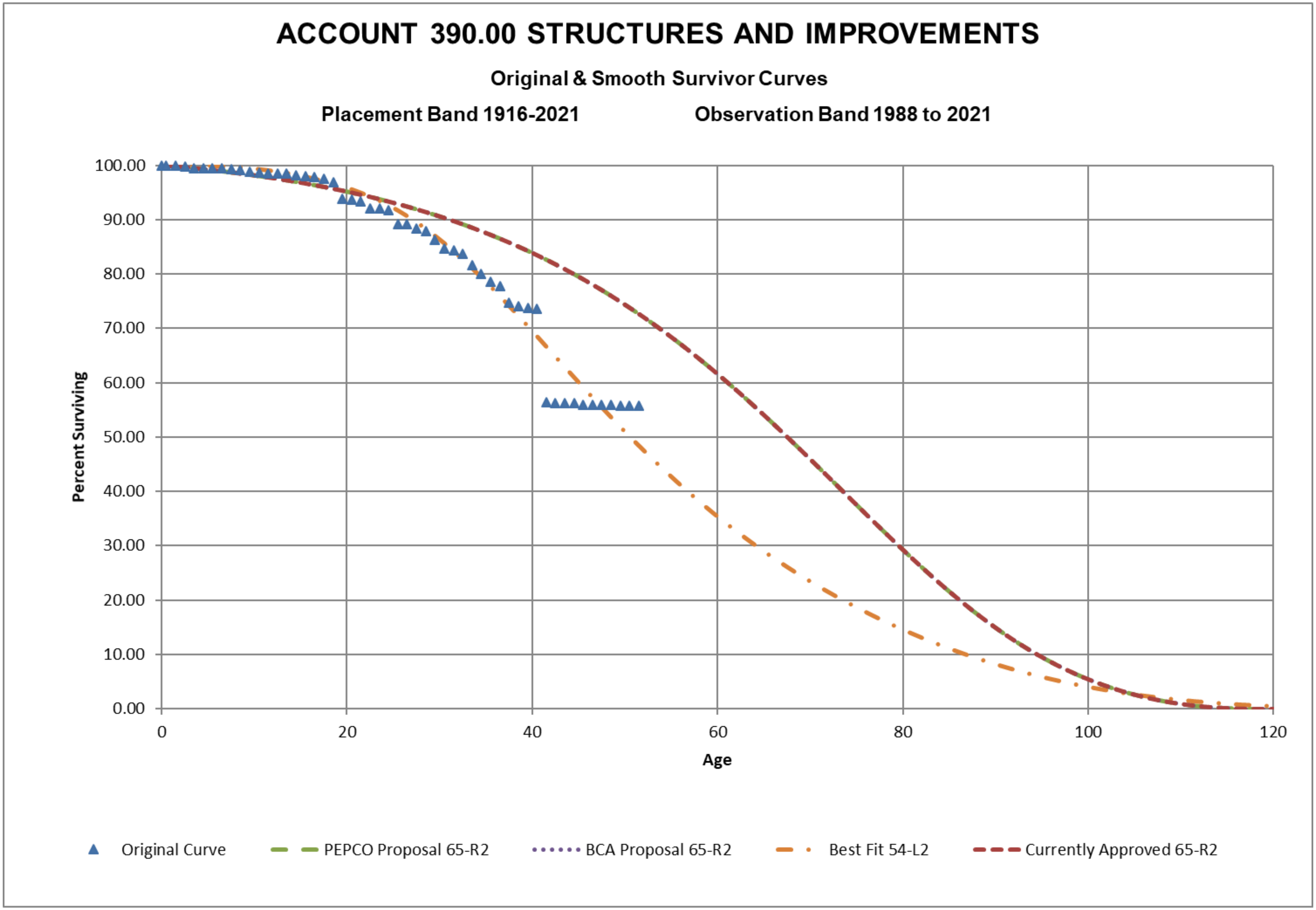
Discussion

The currently approved curve is the 65-R2, with an SSD of 6,267. Pepco is not proposing any change to this curve. Although the best fitting curve is the 54-L2 curve, I am not recommending a change from the currently approved curve.

Account 390 Fitting Analysis Results

Iowa Curve	Average Service Life	SSD
L2	53.8	443.2
S1	51.4	481.9
L1.5	56.1	497.7
S1.5	49.9	508.7
R2	48.8	638.9
L2.5	51.8	686.7
R2.5	47.8	687.4
S0.5	53.3	715.1
S2	48.9	788.0
L1	59.7	820.1
R1.5	50.6	1,017.4
R3	47.1	1,104.5
S0	56.1	1,142.9
S2.5	48.2	1,276.3
L3	50.3	1,284.4
L0.5	63.9	1,349.1
R1	53.5	1,642.6
R3.5	47.0	1,877.8
L0	70.0	1,999.4
S3	47.8	2,032.2
R0.5	59.6	2,450.9
R4	46.9	2,974.1
O2	77.6	3,065.2
O1	69.2	3,066.9
O3	110.2	3,318.8
L4	48.1	3,439.9
O4	150.8	3,451.0
S4	47.3	4,884.5
L5	47.7	6,843.0
R5	47.3	7,177.2
S5	47.5	9,086.9
S6	48.2	14,373.0

PEPCO Proposal 65-R2	6,267
Currently Approved 65-R2	6,267
BCA Proposal 65-R2	6,267


ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS
Original & Smooth Survivor Curves
Placement Band 1916-2021
Observation Band 1988 to 2021
Percent Surviving
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0
20
40
60
80
100
120
Age
Original Curve
PEPCO Proposal 65-R2
BCA Proposal 65-R2
Best Fit 54-L2
Currently Approved 65-R2

Account 396 - Power Operated Equipment

Account Description

This account is for Power Operated Equipment. Per the FERC Uniform System of Accounts, "This account shall include the cost of power operated equipment used in construction or repair work exclusive of equipment includible in other accounts. Include, also, the tools and accessories acquired for use with such equipment and the vehicle on which such equipment is mounted." This includes back filling machines, boring machines, bulldozers, cranes and hoists, diggers, engines, pile drivers, pipe cleaning machines, tractors, trenchers, and other power operated equipment.

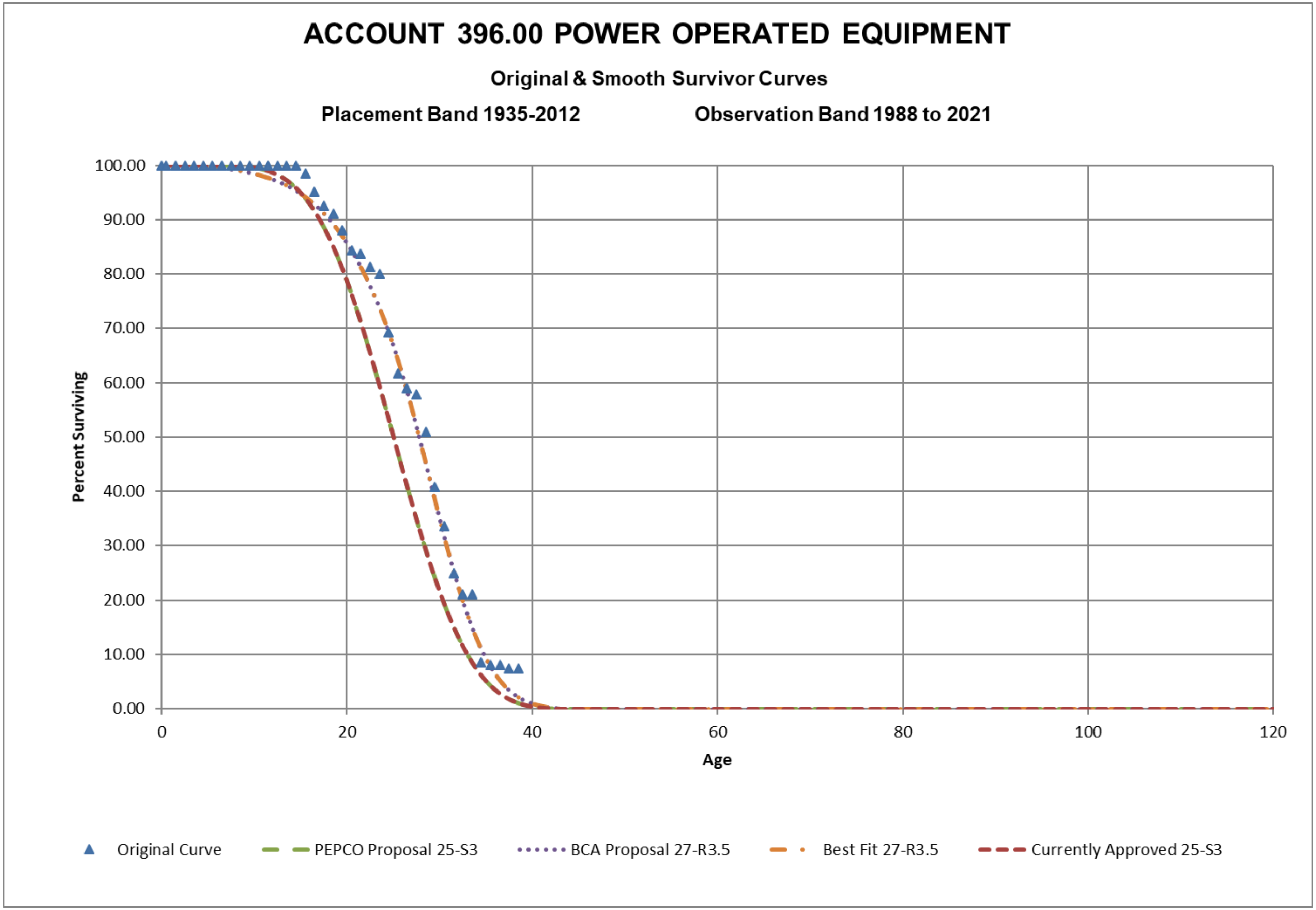
Discussion

The currently approved curve is the 25-S3 with an SSD of 3,868; Pepco is not proposing any change to this curve. The best fitting curve is the 27-R3.5, which has an SSD of 335. I recommend the 27-R3.5 for this account, as it has a much better fit than the currently approved curve.

Account 396 Fitting Analysis Results

Iowa Curve	Average Service Life	SSD
R3.5	27.5	233.3
S3	27.8	307.7
R4	27.6	311.2
L4	28.2	330.2
R3	27.2	555.6
S4	28.0	640.3
S2.5	27.7	707.8
L5	28.2	1,199.0
R2.5	27.0	1,395.7
S2	27.6	1,436.9
L3	28.7	1,493.7
R5	28.1	1,873.0
S1.5	27.5	2,505.0
S5	28.2	2,549.5
L2.5	28.9	2,599.6
R2	26.7	2,751.3
S1	27.4	3,937.4
L2	29.2	4,161.6
R1.5	26.5	4,582.6
S6	28.3	5,435.9
S0.5	27.4	5,625.4
L1.5	29.3	5,916.8
R1	26.3	6,940.8
S0	27.3	7,680.6
L1	29.5	8,114.4
L0.5	30.1	10,007.3
R0.5	26.7	10,079.5
L0	30.9	12,166.4
O1	27.7	13,722.7
O2	31.3	13,918.0
O3	43.5	17,092.8
O4	59.2	18,497.1

PEPCO Proposal 25-S3	3,868
Currently Approved 25-S3	3,868
BCA Proposal 27-R3.5	335


ACCOUNT 396.00 POWER OPERATED EQUIPMENT
Original & Smooth Survivor Curves
Placement Band 1935-2012
Observation Band 1988 to 2021
Percent Surviving
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0
20
40
60
80
100
120
Age
Original Curve
PEPCO Proposal 25-S3
BCA Proposal 27-R3.5
Best Fit 27-R3.5
Currently Approved 25-S3

Account 397 - Communication Equipment

Account Description

This account is for Communication Equipment. Per the FERC Uniform System of Accounts, "This account shall include the cost installed of telephone, telegraph, and wireless equipment for general use in connection with utility operations." This includes antennae, booths, cables, distributing boards, extension cords, loading coils, operators' desks, radio transmitting and receiving sets, remote control equipment and lines, etc.

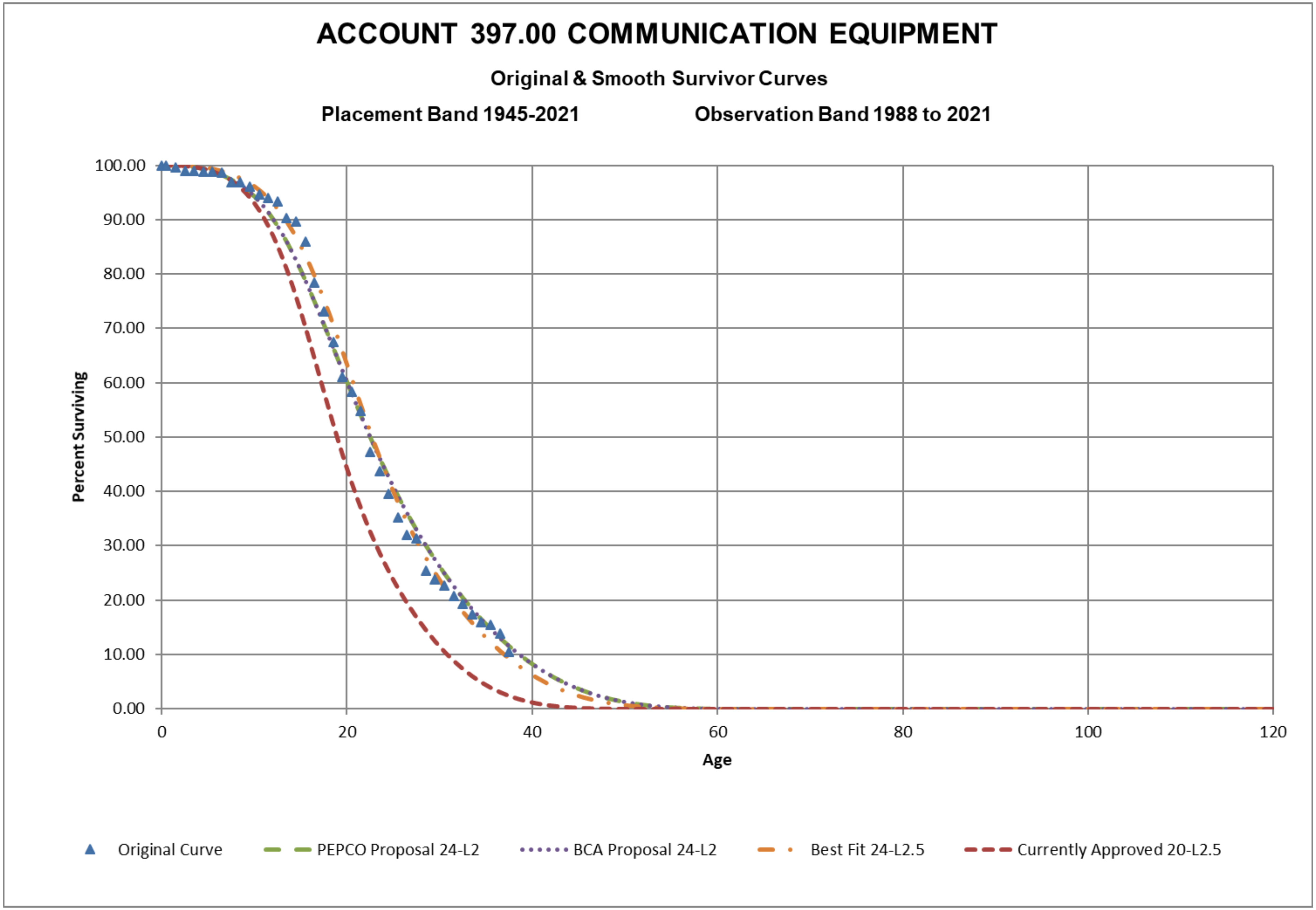
Discussion

The currently approved curve is the 20-L2.5, with an SSD of 4,551. Pepco is proposing to increase the life and change the curve type in the form of the 24-L2 curve, which has an SSD of 285. This is the second best fitting curve in the fitting analysis, with the 24-L2.5 being the best fit with an SSD of 125. Since both curves are extremely close to each other, I approve of Pepco's proposal and recommend the 24-L2 curve.

Account 397 Fitting Analysis Results

Iowa Curve	Average Service Life	SSD
L2.5	23.7	124.8
L2	23.9	281.6
L3	23.6	425.3
S1.5	23.2	588.6
S1	23.2	609.2
L1.5	23.9	863.6
S2	23.3	945.0
S0.5	23.0	978.9
R2	22.8	1,139.0
R1.5	22.7	1,189.3
R2.5	22.9	1,502.7
S2.5	23.3	1,547.7
S0	22.8	1,738.8
R1	22.5	1,800.5
L1	23.9	1,870.1
R3	23.0	2,402.2
S3	23.2	2,465.6
L0.5	24.1	2,944.8
L4	23.3	2,948.5
R0.5	22.3	3,054.9
R3.5	23.0	3,361.3
L0	24.4	4,325.5
R4	22.9	4,700.7
O1	22.2	5,078.8
O2	24.8	5,447.0
S4	23.0	5,495.3
L5	23.0	6,349.9
R5	22.8	8,215.1
O3	31.8	8,645.5
S5	22.7	9,101.9
O4	41.9	10,419.0
S6	22.5	12,688.8

PEPCO Proposal 24-L2	285
Currently Approved 20-L2.5	4,551
BCA Proposal 24-L2	285


ACCOUNT 397.00 COMMUNICATION EQUIPMENT
Original & Smooth Survivor Curves
Placement Band 1945-2021
Observation Band 1988 to 2021
Percent Surviving
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0
20
40
60
80
100
120
Age
Original Curve
PEPCO Proposal 24-L2
BCA Proposal 24-L2
Best Fit 24-L2.5
Currently Approved 20-L2.5

Account 397.1 - Communication Equipment - Distribution

Account Description

This account is for Communication Equipment. Per the FERC Uniform System of Accounts, “This account shall include the cost installed of telephone, telegraph, and wireless equipment for general use in connection with utility operations.” This includes antennae, booths, cables, distributing boards, extension cords, loading coils, operators’ desks, radio transmitting and receiving sets, remote control equipment and lines, etc. This subaccount is for distribution equipment.

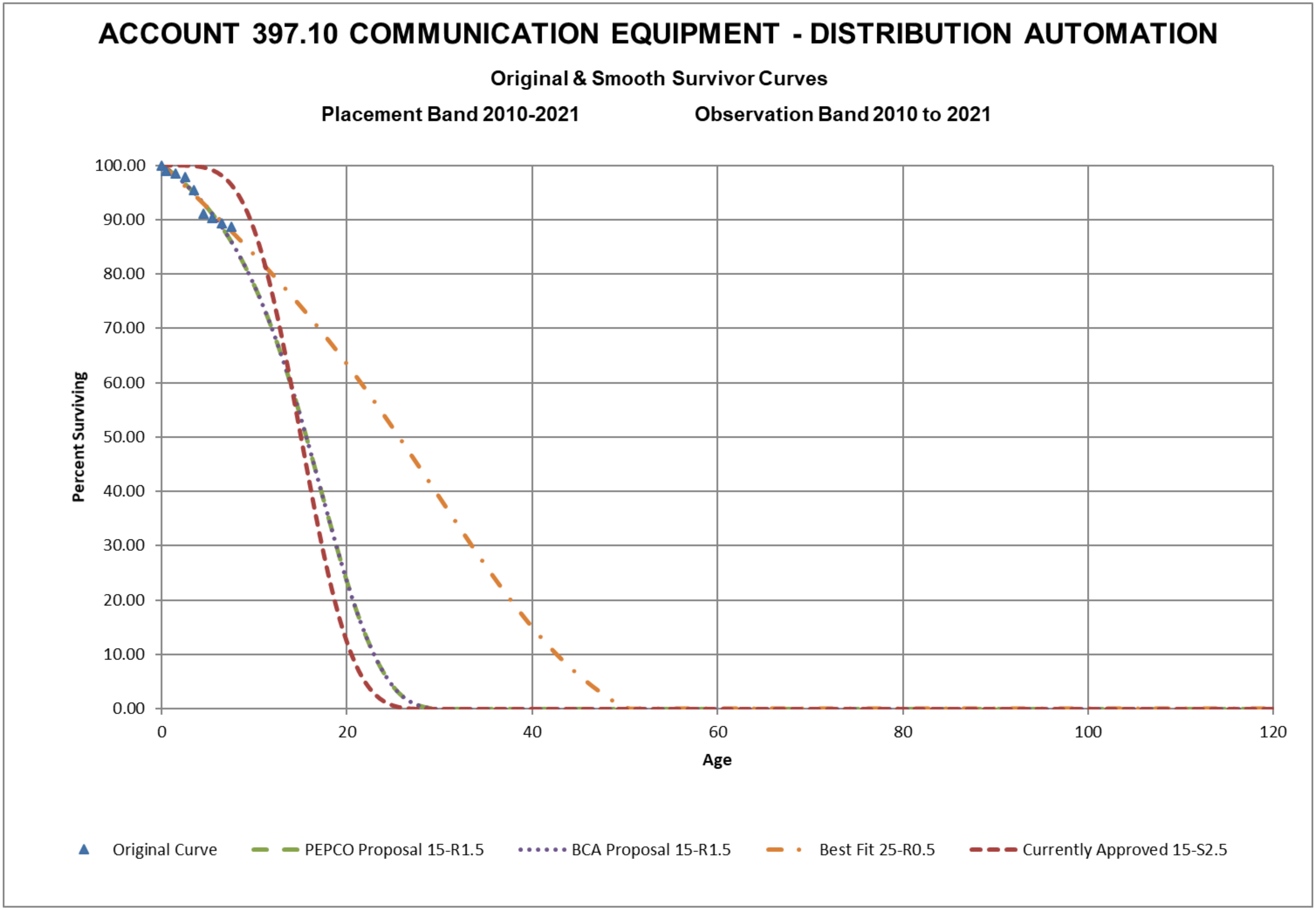
Discussion

The currently approved curve is the 15-S2.5, with an SSD of 314. Pepco is proposing to retain the current ASL and change the curve type to the 15-R1.5 curve, which has an SSD of 15. I believe Pepco’s proposal is reasonable and recommend the 15-R1.5 curve.

Account 397.1 Fitting Analysis Results

Iowa Curve	Average Service Life	SSD
R0.5	25.0	9.8
R1	19.5	9.9
O2	35.0	10.0
O1	31.2	10.1
O3	50.6	10.1
O4	69.9	10.1
L0	25.0	11.3
R1.5	15.9	12.0
L0.5	20.4	15.6
S0	17.4	19.0
R2	13.3	21.1
S0.5	15.1	28.9
L1	17.0	30.9
R2.5	11.8	35.2
L1.5	14.8	41.5
S1	13.3	52.3
R3	10.7	65.7
S1.5	12.1	69.4
L2	13.1	72.3
L2.5	12.0	87.8
R3.5	10.0	92.2
S2	11.2	104.7
L3	11.0	123.0
S2.5	10.6	124.6
R4	9.5	136.9
S3	10.1	163.5
L4	9.7	173.2
S4	9.2	234.4
R5	8.8	236.8
L5	8.9	243.0
S5	8.7	285.9
S6	8.2	312.1

PEPCO Proposal 15-R1.5	15
Currently Approved 15-S2.5	314
BCA Proposal 15-R1.5	15


ACCOUNT 397.10 COMMUNICATION EQUIPMENT - DISTRIBUTION AUTOMATION
Original & Smooth Survivor Curves
Placement Band 2010-2021
Observation Band 2010 to 2021
Percent Surviving
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0
20
40
60
80
100
120
Age
Original Curve
PEPCO Proposal 15-R1.5
BCA Proposal 15-R1.5
Best Fit 25-R0.5
Currently Approved 15-S2.5

Net Salvage Analysis

The D&G net salvage rate adjustments are based on the net salvage analysis that I have conducted based on Pepco's retirement data from 1988-2021. This is the same data set analyzed in Pepco's depreciation study. The analysis for each account is presented and the adjustments will be discussed. For each account, I present the annual retirements, cost of removal, gross salvage, net salvage, net salvage rates, and the rolling 3-year, 5-year, and 10-year net salvage rates. I also present the overall average of the 34 years of retirement history. I have analyzed the same 16 accounts as Mr. Allis and am proposing an adjustment to only one account, Account 362, relative to Pepco's proposals.

Account 362

The currently approved net salvage rate is -30%. Pepco proposes to retain this net salvage rate. The overall average rate is -31%. Over the past 34 years, there has been approximately $51.7 million of retirements, and there is approximately $635.8 million currently in service in this account. The retirement history reflects approximately 8% of the total account balance. Over the past 10 years, the net salvage rate has never been more negative than -30%. In fact, 8 out of the 10 previous years have shown net salvage rates between -18% and +88%. The five most recent 10 year net salvage rates have all been between -7% and -9%. A -30% net salvage rate, as proposed by Pepco, is excessive and not supported by the recent retirement history. I recommend that the net salvage rate for this account be set at -25%, which will still provide Pepco a substantial amount of net salvage recovery for this account.

BCA Mass Property Net Salvage Analysis
of PEPCO Electric Plant Accounts
Account 361.0 - Structures and Improvements

					Average Net Salvage Rates			
Year	**Retirements**	**Cost of Removal**	**Gross Salvage**	**Net Salvage**	1-Year	3-Year	5-Year	10-Year
1988	$ 11,218	$ 25,792	$ (1,811)	$ (27,603)	-246%			
1989	$ 0	$ 725,866	$ 176,018	$ (549,848)	-916413533%			
1990	$ 31,326	$ 77,068	$ (58)	$ (77,126)	-246%	-1539%		
1991	$ -	$ 105,829	$ (25,562)	$ (131,391)		-2421%		
1992	$ 108,928	$ 113,403	$ (8,274)	$ (121,677)	-112%	-235%	-599%	
1993	$ 202,369	$ 44,426	$ -	$ (44,426)	-22%	-96%	-270%	
1994	$ 17,001	$ 37,329	$ -	$ (37,329)	-220%	-62%	-115%	
1995	$ 5,867	$ 3,692,718	$ 4,422,127	$ 729,409	12432%	288%	118%	
1996	$ 1,961	$ (26,285)	$ -	$ 26,285	1340%	2893%	164%	
1997	$ 105,947	$ 52,716	$ -	$ (52,716)	-50%	618%	186%	-59%
1998	$ 12,411	$ 35,727	$ -	$ (35,727)	-288%	-52%	440%	-61%
1999	$ 82,870	$ 12,700	$ (293)	$ (12,993)	-16%	-50%	313%	43%
2000	$ 24,957	$ 26,633	$ -	$ (26,633)	-107%	-63%	-45%	52%
2001	$ 13,325	$ 32,527	$ 4,116,428	$ 4,083,900	30647%	3338%	1652%	783%
2002	$ 63,598	$ 2,812,783	$ 1,189,748	$ (1,623,035)	-2552%	2389%	1210%	567%
2003	$ 11,238	$ 113,912	$ 60,593	$ (53,318)	-474%	2731%	1208%	884%
2004	$ -	$ -	$ -	$ -		-2240%	2105%	942%
2005	$ 1,700,049	$ 1,774,764	$ -	$ (1,774,764)	-104%	-107%	35%	26%
2006	$ 63,594	$ 61,512	$ -	$ (61,512)	-97%	-104%	-191%	21%
2007	$ 258,583	$ 128,727	$ -	$ (128,727)	-50%	-97%	-99%	16%
2008	$ 63,438	$ 86,551	$ -	$ (86,551)	-136%	-72%	-98%	14%
2009	$ -	$ 226,447	$ -	$ (226,447)		-137%	-109%	5%
2010	$ 11,194	$ 37,860	$ -	$ (37,860)	-338%	-470%	-136%	4%
2011	$ 36,700	$ 15,972	$ -	$ (15,972)	-44%	-585%	-134%	-181%
2012	$ 54,069	$ 56,745	$ -	$ (56,745)	-105%	-108%	-256%	-111%
2013	$ 41,688	$ 80,987	$ -	$ (80,987)	-194%	-116%	-291%	-111%
2014	$ 65,377	$ 47,567	$ -	$ (47,567)	-73%	-115%	-114%	-110%
2015	$ 139,754	$ 127,044	$ -	$ (127,044)	-91%	-104%	-97%	-118%
2016	$ 84,524	$ 28,825	$ -	$ (28,825)	-34%	-70%	-89%	-111%
2017	$ 215,332	$ 15,270	$ -	$ (15,270)	-7%	-39%	-55%	-102%
2018	$ -	$ -	$ -	$ -		-15%	-43%	-98%
2019	$ 41,927	$ 10,706	$ -	$ (10,706)	-26%	-10%	-38%	-61%
2020	$ 134,854	$ 95,973	$ -	$ (95,973)	-71%	-60%	-32%	-59%
2021	$ 331,482	$ 279,640	$ -	$ (279,640)	-84%	-76%	-55%	-67%
Total	**$ 3,935,579**	**$ 10,957,734**	**$ 9,928,917**	**$ (1,028,816)**	**-26%**			

BCA Mass Property Net Salvage Analysis
of PEPCO Electric Plant Accounts
Account 362.0 - Station Equipment

					Average Net Salvage Rates			
Year	**Retirements**	**Cost of Removal**	**Gross Salvage**	**Net Salvage**	1-Year	3-Year	5-Year	10-Year
1988	$ 864,381	$ 358,460	$ 33,368	$ (325,091)	-38%			
1989	$ 42,421	$ 124,196	$ 437,795	$ 313,599	739%			
1990	$ 1,472,006	$ 296,687	$ 82,827	$ (213,859)	-15%	-9%		
1991	$ 621,800	$ 322,489	$ 11,260	$ (311,229)	-50%	-10%		
1992	$ 1,568,830	$ 741,987	$ 155,424	$ (586,563)	-37%	-30%	-25%	
1993	$ 3,235,359	$ 1,064,277	$ 45,136	$ (1,019,141)	-32%	-35%	-26%	
1994	$ 228,497	$ 554,659	$ 10,439	$ (544,220)	-238%	-43%	-38%	
1995	$ 268,425	$ 369,425	$ 6,904	$ (362,521)	-135%	-52%	-48%	
1996	$ 1,898,308	$ 1,144,894	$ (4,186)	$ (1,149,080)	-61%	-86%	-51%	
1997	$ 1,238,994	$ 1,168,539	$ 106,801	$ (1,061,738)	-86%	-76%	-60%	-46%
1998	$ 381,474	$ 1,249,946	$ 2,591	$ (1,247,355)	-327%	-98%	-109%	-56%
1999	$ 628,105	$ 404,249	$ 2,311	$ (401,938)	-64%	-121%	-96%	-60%
2000	$ 300,800	$ 600,391	$ (46,607)	$ (646,998)	-215%	-175%	-101%	-71%
2001	$ 352,221	$ 1,026,779	$ -	$ (1,026,779)	-292%	-162%	-151%	-80%
2002	$ 1,807,668	$ 2,019,865	$ 884,800	$ (1,135,065)	-63%	-114%	-128%	-83%
2003	$ 2,319,758	$ 407,510	$ 383,895	$ (23,615)	-1%	-49%	-60%	-81%
2004	$ -	$ -	$ (300,000)	$ (300,000)		-35%	-66%	-80%
2005	$ 901,880	$ 1,382,213	$ -	$ (1,382,213)	-153%	-53%	-72%	-85%
2006	$ 1,714,804	$ 1,656,877	$ 5,574,839	$ 3,917,962	228%	85%	16%	-34%
2007	$ 5,106,677	$ 5,754,069	$ 315,000	$ (5,439,069)	-107%	-38%	-32%	-57%
2008	$ 132,555	$ (2,645)	$ -	$ 2,645	2%	-22%	-41%	-49%
2009	$ 595,828	$ 51,112	$ -	$ (51,112)	-9%	-94%	-35%	-46%
2010	$ 326,675	$ 465,974	$ -	$ (465,974)	-143%	-49%	-26%	-45%
2011	$ 145,863	$ 161,421	$ -	$ (161,421)	-111%	-64%	-97%	-39%
2012	$ 2,233,830	$ 471,657	$ 120,727	$ (350,930)	-16%	-36%	-30%	-32%
2013	$ 2,250,632	$ 178,451	$ 43,425	$ (135,026)	-6%	-14%	-21%	-33%
2014	$ 1,720,791	$ 194,778	$ 1,701,367	$ 1,506,588	88%	16%	6%	-17%
2015	$ 4,126,042	$ 716,744	$ 36,049	$ (680,695)	-16%	9%	2%	-10%
2016	$ 2,619,111	$ 515,847	$ 36,225	$ (479,622)	-18%	4%	-1%	-32%
2017	$ 3,088,277	$ 310,040	$ -	$ (310,040)	-10%	-15%	-1%	-7%
2018	$ 2,324,742	$ 191,321	$ -	$ (191,321)	-8%	-12%	-1%	-7%
2019	$ 2,201,352	$ 280,509	$ -	$ (280,509)	-13%	-10%	-14%	-7%
2020	$ 2,852,362	$ 763,145	$ 68	$ (763,077)	-27%	-17%	-15%	-8%
2021	$ 2,098,415	$ 634,279	$ -	$ (634,279)	-30%	-23%	-17%	-9%
Total	**$ 51,668,883**	**$ 25,580,144**	**$ 9,640,457**	**$ (15,939,686)**	**-31%**			

BCA Mass Property Net Salvage Analysis
of PEPCO Electric Plant Accounts
Account 364.0 - Poles, Towers, and Fixtures

					Average Net Salvage Rates			
Year	Retirements	Cost of Removal	Gross Salvage	Net Salvage	1-Year	3-Year	5-Year	10-Year
1988	$ 181,986	$ 199,853	$ 103,092	$ (96,762)	-53%			
1989	$ 237,403	$ 338,553	$ 91,522	$ (247,031)	-104%			
1990	$ 352,140	$ 175,482	$ 140,349	$ (35,133)	-10%	-49%		
1991	$ 103,433	$ 140,672	$ 106,930	$ (33,741)	-33%	-46%		
1992	$ 167,461	$ 119,434	$ 724,391	$ 604,957	361%	86%	18%	
1993	$ 147,543	$ 101,464	$ 17,135	$ (84,329)	-57%	116%	20%	
1994	$ 165,082	$ 176,526	$ 23,086	$ (153,441)	-93%	76%	32%	
1995	$ 300,101	$ 200,562	$ 36,000	$ (164,562)	-55%	-66%	19%	
1996	$ 48,708	$ 185,000	$ 144,000	$ (41,000)	-84%	-70%	19%	
1997	$ 123,612	$ 293,960	$ 175,150	$ (118,810)	-96%	-69%	-72%	-20%
1998	$ 163,066	$ 276,881	$ 168,819	$ (108,062)	-66%	-80%	-73%	-21%
1999	$ 59,948	$ 211,416	$ 137,301	$ (74,115)	-124%	-87%	-73%	-13%
2000	$ 15,168	$ 4,906,482	$ 2,586,413	$ (2,320,069)	-15295%	-1051%	-648%	-193%
2001	$ 462,885	$ 536,701	$ -	$ (536,701)	-116%	-545%	-383%	-181%
2002	$ 12,414	$ 148,883	$ 24,773	$ (124,110)	-1000%	-608%	-443%	-249%
2003	$ 1,544,868	$ 1,793,000	$ 88,583	$ (1,704,418)	-110%	-117%	-227%	-185%
2004	$ 36,268	$ 81,218	$ -	$ (81,218)	-224%	-120%	-230%	-191%
2005	$ 152,624	$ 260,544	$ -	$ (260,544)	-171%	-118%	-123%	-205%
2006	$ 2,265,017	$ 2,190,880	$ -	$ (2,190,880)	-97%	-103%	-109%	-155%
2007	$ 1,165,067	$ 279,645	$ -	$ (279,645)	-24%	-76%	-87%	-131%
2008	$ 35,035	$ 312,754	$ -	$ (312,754)	-893%	-80%	-86%	-137%
2009	$ 91,108	$ 355,859	$ -	$ (355,859)	-391%	-73%	-92%	-141%
2010	$ 57,534	$ 488,872	$ -	$ (488,872)	-850%	-630%	-100%	-109%
2011	$ 70,060	$ 205,393	$ -	$ (205,393)	-293%	-480%	-116%	-111%
2012	$ 39,348	$ 545,112	$ -	$ (545,112)	-1385%	-742%	-651%	-118%
2013	$ 122,253	$ 1,042,964	$ 40,653	$ (1,002,310)	-820%	-757%	-683%	-142%
2014	$ 108,439	$ 1,629,283	$ 77,755	$ (1,551,528)	-1431%	-1148%	-954%	-175%
2015	$ 122,345	$ 1,316,912	$ 84,252	$ (1,232,660)	-1008%	-1073%	-981%	-200%
2016	$ 155,633	$ 12,037,292	$ 137,259	$ (11,900,033)	-7646%	-3800%	-2962%	-909%
2017	$ 246,318	$ 3,503,315	$ 126,415	$ (3,376,900)	-1371%	-3149%	-2525%	-2001%
2018	$ 261,268	$ 194,751	$ (32,276)	$ (227,027)	-87%	-2338%	-2046%	-1639%
2019	$ 217,444	$ 3,295,526	$ 30,212	$ (3,265,314)	-1502%	-947%	-1994%	-1699%
2020	$ 109,355	$ 810,909	$ 43,148	$ (767,761)	-702%	-724%	-1973%	-1657%
2021	$ 84,952	$ 231,615	$ 5,630	$ (225,985)	-266%	-1034%	-855%	-1642%
Total	**$ 9,425,885**	**$ 38,587,714**	**$ 5,080,591**	**$ (33,507,123)**	**-355%**			

BCA Mass Property Net Salvage Analysis
of PEPCO Electric Plant Accounts
Account 365.0 - Overhead Conductors and Devices

					Average Net Salvage Rates			
Year	**Retirements**	**Cost of Removal**	**Gross Salvage**	**Net Salvage**	1-Year	3-Year	5-Year	10-Year
1988	$ 152,359	$ 167,466	$ 86,385	$ (81,081)	-53%			
1989	$ 163,486	$ 309,294	$ 76,690	$ (232,603)	-142%			
1990	$ 50,052	$ 147,044	$ 80,631	$ (66,413)	-133%	-104%		
1991	$ 63,450	$ 127,695	$ 89,539	$ (38,156)	-60%	-122%		
1992	$ 73,247	$ 111,088	$ 718,655	$ 607,567	829%	269%	38%	
1993	$ 54,709	$ 85,017	$ 14,348	$ (70,669)	-129%	261%	49%	
1994	$ 69,031	$ 248,964	$ 60,416	$ (188,548)	-273%	177%	79%	
1995	$ 92,672	$ 273,086	$ 54,000	$ (219,086)	-236%	-221%	26%	
1996	$ 19,044	$ 362,387	$ 240,769	$ (121,618)	-639%	-293%	2%	
1997	$ 51,003	$ 761,200	$ 298,550	$ (462,650)	-907%	-494%	-371%	-111%
1998	$ 89,859	$ 787,782	$ 288,688	$ (499,094)	-555%	-678%	-464%	-178%
1999	$ 60,852	$ 927,719	$ 241,706	$ (686,013)	-1127%	-817%	-634%	-280%
2000	$ 6,695	$ 1,385,929	$ 292,451	$ (1,093,477)	-16334%	-1448%	-1259%	-477%
2001	$ 3,763	$ 2,357,146	$ -	$ (2,357,146)	-62642%	-5801%	-2403%	-977%
2002	$ 79,490	$ 582,841	$ 48,433	$ (534,408)	-672%	-4430%	-2148%	-1182%
2003	$ 722,800	$ 3,679,764	$ 39,727	$ (3,640,037)	-504%	-810%	-951%	-820%
2004	$ 17,143	$ 41,873	$ -	$ (41,873)	-244%	-515%	-924%	-845%
2005	$ 48,075	$ 56,612	$ -	$ (56,612)	-118%	-474%	-761%	-864%
2006	$ 2,262,303	$ 2,188,254	$ -	$ (2,188,254)	-97%	-98%	-206%	-346%
2007	$ 1,022,636	$ 331,646	$ 33,241	$ (298,405)	-29%	-76%	-153%	-264%
2008	$ 88,255	$ 229,382	$ -	$ (229,382)	-260%	-81%	-82%	-258%
2009	$ 174,224	$ 507,725	$ -	$ (507,725)	-291%	-81%	-91%	-247%
2010	$ 214,904	$ 650,910	$ -	$ (650,910)	-303%	-291%	-103%	-227%
2011	$ 164,649	$ 307,558	$ 680,280	$ 372,722	226%	-142%	-79%	-162%
2012	$ 316,792	$ 645,047	$ 874,863	$ 229,816	73%	-7%	-82%	-139%
2013	$ 520,786	$ 1,012,219	$ 972,736	$ (39,483)	-8%	56%	-43%	-71%
2014	$ 599,965	$ 2,222,630	$ 698,794	$ (1,523,837)	-254%	-93%	-89%	-90%
2015	$ 703,665	$ 1,683,169	$ 269,747	$ (1,413,421)	-201%	-163%	-103%	-103%
2016	$ 382,709	$ 9,235,975	$ 165,926	$ (9,070,049)	-2370%	-712%	-468%	-313%
2017	$ 819,216	$ 2,561,736	$ 366,248	$ (2,195,488)	-268%	-665%	-471%	-377%
2018	$ 309,795	$ 254,986	$ (8,981)	$ (263,966)	-85%	-763%	-514%	-358%
2019	$ 765,980	$ 1,485,855	$ 257,891	$ (1,227,964)	-160%	-195%	-475%	-329%
2020	$ 2,683,422	$ 1,074,587	$ 1,200,586	$ 125,998	5%	-36%	-255%	-206%
2021	$ 1,433,162	$ 1,015,321	$ 291,057	$ (724,264)	-51%	-37%	-71%	-189%
Total	**$ 14,280,192**	**$ 37,819,906**	**$ 8,433,378**	**$ (29,386,528)**	**-206%**			

BCA Mass Property Net Salvage Analysis
of PEPCO Electric Plant Accounts
Account 366.0 - Underground Conduit

Year	Retirements	Cost of Removal	Gross Salvage	Net Salvage	Average Net Salvage Rates 1-Year	3-Year	5-Year	10-Year
1988	$ 452,478	$ 496,079	$ 366,436	$ (129,643)	-29%			
1989	$ 445,166	$ 448,171	$ 2,005,418	$ 1,557,247	350%			
1990	$ 116,383	$ 583,466	$ 428,150	$ (155,315)	-133%	125%		
1991	$ 61,975	$ 872,460	$ 705,160	$ (167,300)	-270%	198%		
1992	$ 71,763	$ 762,968	$ 192,514	$ (570,454)	-795%	-357%	47%	
1993	$ 37,668	$ 686,301	$ 93,069	$ (593,232)	-1575%	-777%	10%	
1994	$ 122,133	$ 683,094	$ 35,151	$ (647,944)	-531%	-782%	-521%	
1995	$ 422,712	$ 338,240	$ -	$ (338,240)	-80%	-271%	-324%	
1996	$ 248,247	$ 344,611	$ -	$ (344,611)	-139%	-168%	-276%	
1997	$ 70,003	$ 444,720	$ -	$ (444,720)	-635%	-152%	-263%	-90%
1998	$ 75,187	$ 408,393	$ -	$ (408,393)	-543%	-304%	-233%	-126%
1999	$ 58,297	$ 447,066	$ -	$ (447,066)	-767%	-639%	-227%	-321%
2000	$ 37,653	$ 617,618	$ -	$ (617,618)	-1640%	-861%	-462%	-380%
2001	$ 526,453	$ 1,137,372	$ -	$ (1,137,372)	-216%	-354%	-398%	-332%
2002	$ 80,298	$ 195,957	$ (89,098)	$ (285,055)	-355%	-317%	-372%	-314%
2003	$ 604,278	$ 1,365,439	$ 2,076	$ (1,363,363)	-226%	-230%	-295%	-269%
2004	$ 28,141	$ 44,388	$ -	$ (44,388)	-158%	-238%	-270%	-252%
2005	$ 184,951	$ 248,422	$ -	$ (248,422)	-134%	-203%	-216%	-279%
2006	$ 282,216	$ 272,979	$ -	$ (272,979)	-97%	-114%	-188%	-271%
2007	$ 122,019	$ 38,252	$ -	$ (38,252)	-31%	-95%	-161%	-243%
2008	$ 392,577	$ 361,738	$ -	$ (361,738)	-92%	-84%	-96%	-208%
2009	$ 326,633	$ 225,911	$ -	$ (225,911)	-69%	-74%	-88%	-178%
2010	$ 1,004,112	$ 462,749	$ -	$ (462,749)	-46%	-61%	-64%	-125%
2011	$ 84,948	$ 116,310	$ 3,042	$ (113,268)	-133%	-57%	-62%	-110%
2012	$ 34,797	$ 977,972	$ 20,202	$ (957,770)	-2752%	-136%	-115%	-133%
2013	$ 30,513	$ 696,880	$ 342,436	$ (354,444)	-1162%	-949%	-143%	-124%
2014	$ 13,274	$ 525,821	$ 10,075	$ (515,746)	-3886%	-2326%	-206%	-143%
2015	$ 75,352	$ 1,774,705	$ 24,337	$ (1,750,368)	-2323%	-2200%	-1545%	-214%
2016	$ 94,835	$ 2,614,719	$ 275,763	$ (2,338,956)	-2466%	-2510%	-2379%	-327%
2017	$ 48,080	$ 1,690,977	$ 427,914	$ (1,263,062)	-2627%	-2452%	-2375%	-396%
2018	$ 7,628	$ 101,870	$ (14,326)	$ (116,197)	-1523%	-2470%	-2502%	-471%
2019	$ 14,336,634	$ 1,532,598	$ -	$ (1,532,598)	-11%	-20%	-48%	-60%
2020	$ 133,367	$ 9,649,461	$ 26,185	$ (9,623,275)	-7216%	-78%	-102%	-125%
2021	$ 134,922	$ 4,716,811	$ 45,381	$ (4,671,431)	-3462%	-108%	-117%	-155%
Total	**$ 20,765,692**	**$ 35,884,518**	**$ 4,899,885**	**$ (30,984,632)**	**-149%**			

BCA Mass Property Net Salvage Analysis
of PEPCO Electric Plant Accounts
Account 367.0 - Underground Conductors and Devices

Year	Retirements	Cost of Removal	Gross Salvage	Net Salvage	Average Net Salvage Rates 1-Year	3-Year	5-Year	10-Year
1988	$ 1,982,637	$ 2,174,690	$ 1,121,786	$ (1,052,905)	-53%			
1989	$ 2,100,299	$ 1,983,789	$ 1,051,703	$ (932,086)	-44%			
1990	$ 1,282,533	$ 1,945,794	$ 1,767,079	$ (178,716)	-14%	-40%		
1991	$ 779,959	$ 1,771,949	$ 1,173,203	$ (598,746)	-77%	-41%		
1992	$ 1,837,558	$ 1,473,897	$ 385,130	$ (1,088,767)	-59%	-48%	-48%	
1993	$ 442,086	$ 1,253,017	$ 186,201	$ (1,066,816)	-241%	-90%	-60%	
1994	$ 1,048,771	$ 1,361,174	$ 128,644	$ (1,232,529)	-118%	-102%	-77%	
1995	$ 590,628	$ 639,394	$ 61,287	$ (578,107)	-98%	-138%	-97%	
1996	$ 861,093	$ 664,557	$ 102,000	$ (562,557)	-65%	-95%	-95%	
1997	$ 1,554,657	$ 434,719	$ 157,350	$ (277,369)	-18%	-47%	-83%	-61%
1998	$ 100,446	$ 258,058	$ 129,098	$ (128,960)	-128%	-39%	-67%	-63%
1999	$ 853,514	$ 296,576	$ 110,783	$ (185,794)	-22%	-24%	-44%	-63%
2000	$ 850,474	$ 1,171,536	$ 99,873	$ (1,071,663)	-126%	-77%	-53%	-76%
2001	$ 1,718,804	$ 753,550	$ -	$ (753,550)	-44%	-59%	-48%	-70%
2002	$ 926,889	$ 323,142	$ (126,726)	$ (449,868)	-49%	-65%	-58%	-70%
2003	$ 6,066,747	$ 1,330,206	$ 10,378	$ (1,319,827)	-22%	-29%	-36%	-45%
2004	$ 798,360	$ 1,195,697	$ -	$ (1,195,697)	-150%	-38%	-46%	-46%
2005	$ 1,694,117	$ 2,044,589	$ -	$ (2,044,589)	-121%	-53%	-51%	-52%
2006	$ 3,126,547	$ 3,024,210	$ -	$ (3,024,210)	-97%	-111%	-64%	-59%
2007	$ 2,106,309	$ 629,765	$ -	$ (629,765)	-30%	-82%	-60%	-59%
2008	$ 2,540,325	$ 2,006,664	$ -	$ (2,006,664)	-79%	-73%	-87%	-61%
2009	$ 2,409,858	$ 2,812,902	$ -	$ (2,812,902)	-117%	-77%	-89%	-69%
2010	$ 1,973,618	$ 3,447,585	$ -	$ (3,447,585)	-175%	-119%	-98%	-76%
2011	$ 639,121	$ 744,819	$ 371,391	$ (373,428)	-58%	-132%	-96%	-78%
2012	$ 4,879	$ 2,798,793	$ 205,250	$ (2,593,543)	-53155%	-245%	-148%	-91%
2013	$ 105,989	$ 4,127,725	$ 624,182	$ (3,503,543)	-3306%	-863%	-248%	-140%
2014	$ 82,245	$ 1,738,872	$ 189,657	$ (1,549,215)	-1884%	-3959%	-409%	-150%
2015	$ 212,278	$ 8,592,687	$ 313,563	$ (8,279,125)	-3900%	-3329%	-1560%	-214%
2016	$ 855,570	$ 22,898,553	$ 1,769,410	$ (21,129,143)	-2470%	-2692%	-2939%	-424%
2017	$ 455,100	$ 14,331,308	$ 1,054,081	$ (13,277,227)	-2917%	-2803%	-2790%	-636%
2018	$ 411,073	$ 2,216,253	$ (151,363)	$ (2,367,616)	-576%	-2136%	-2311%	-830%
2019	$ 3,439,573	$ 8,572,836	$ 2,871,550	$ (5,701,286)	-166%	-496%	-945%	-761%
2020	$ 3,030,498	$ 5,395,071	$ 649,170	$ (4,745,901)	-157%	-186%	-576%	-688%
2021	$ 2,107,078	$ 4,931,299	$ 278,547	$ (4,652,752)	-221%	-176%	-326%	-633%
Total	**$ 48,989,630**	**$ 109,345,677**	**$ 14,533,226**	**$ (94,812,451)**	**-194%**			

BCA Mass Property Net Salvage Analysis
of PEPCO Electric Plant Accounts
Account 368.0 - Line Transformers

Year	Retirements	Cost of Removal	Gross Salvage	Net Salvage	Average Net Salvage Rates 1-Year	3-Year	5-Year	10-Year
1988	$ 3,631,362	$ 6,422,719	$ 568,900	$ (5,853,819)	-161%			
1989	$ 2,584,770	$ 1,569,780	$ 507,697	$ (1,062,083)	-41%			
1990	$ 3,224,456	$ 2,052,041	$ 917,836	$ (1,134,205)	-35%	-85%		
1991	$ 1,817,523	$ 2,507,854	$ 812,789	$ (1,695,064)	-93%	-51%		
1992	$ 3,748,960	$ 1,083,154	$ 1,670,003	$ 586,849	16%	-26%	-61%	
1993	$ 2,501,243	$ 3,250,689	$ 569,422	$ (2,681,267)	-107%	-47%	-43%	
1994	$ 1,938,680	$ 4,248,832	$ 1,046,885	$ (3,201,947)	-165%	-65%	-61%	
1995	$ 1,723,729	$ 1,756,267	$ 279,533	$ (1,476,734)	-86%	-119%	-72%	
1996	$ 2,374,687	$ 3,264,715	$ 867,790	$ (2,396,925)	-101%	-117%	-75%	
1997	$ 977,222	$ 2,104,693	$ 277,626	$ (1,827,067)	-187%	-112%	-122%	-85%
1998	$ 2,580,593	$ 1,901,824	$ 501,779	$ (1,400,044)	-54%	-95%	-107%	-69%
1999	$ 2,575,453	$ 1,611,795	$ 848,080	$ (763,715)	-30%	-65%	-77%	-68%
2000	$ 1,356,431	$ 1,474,951	$ 95,564	$ (1,379,387)	-102%	-54%	-79%	-75%
2001	$ 5,078,570	$ 4,095,190	$ -	$ (4,095,190)	-81%	-69%	-75%	-75%
2002	$ 2,942,108	$ 2,084,212	$ 487,706	$ (1,596,506)	-54%	-75%	-64%	-87%
2003	$ 20,742,253	$ 2,916,500	$ 1,110,993	$ (1,805,507)	-9%	-26%	-29%	-47%
2004	$ 1,309,842	$ 2,243,931	$ -	$ (2,243,931)	-171%	-23%	-35%	-46%
2005	$ 2,095,104	$ 2,937,068	$ (326,989)	$ (3,264,057)	-156%	-30%	-40%	-49%
2006	$ 6,463,476	$ 6,251,916	$ 229,017	$ (6,022,899)	-93%	-117%	-45%	-53%
2007	$ 6,261,803	$ 2,072,325	$ 252,495	$ (1,819,830)	-29%	-75%	-41%	-47%
2008	$ 3,627,785	$ 665,954	$ -	$ (665,954)	-18%	-52%	-71%	-45%
2009	$ 2,210,286	$ 805,028	$ 625,270	$ (179,758)	-8%	-22%	-58%	-44%
2010	$ 2,156,610	$ 1,059,866	$ 382,491	$ (677,376)	-31%	-19%	-45%	-42%
2011	$ 1,721,678	$ 341,842	$ -	$ (341,842)	-20%	-20%	-23%	-38%
2012	$ 2,049,207	$ 1,420,037	$ -	$ (1,420,037)	-69%	-41%	-28%	-38%
2013	$ 1,754,747	$ 2,363,409	$ 2,386,946	$ 23,538	1%	-31%	-26%	-56%
2014	$ 2,062,943	$ 2,035,743	$ 219,443	$ (1,816,301)	-88%	-55%	-43%	-53%
2015	$ 5,092,817	$ 5,121,338	$ 546,079	$ (4,575,260)	-90%	-71%	-64%	-52%
2016	$ 7,699,190	$ 15,126,149	$ 573,442	$ (14,552,707)	-189%	-141%	-120%	-75%
2017	$ 5,042,797	$ 5,825,061	$ 127,825	$ (5,697,236)	-113%	-139%	-123%	-89%
2018	$ 3,374,408	$ 816,010	$ (37,110)	$ (853,120)	-25%	-131%	-118%	-91%
2019	$ 7,593,078	$ 1,996,160	$ 13,679	$ (1,982,481)	-26%	-53%	-96%	-83%
2020	$ 10,420,741	$ 3,276,856	$ 375,748	$ (2,901,109)	-28%	-27%	-76%	-73%
2021	$ 3,358,471	$ 2,308,839	$ 51,416	$ (2,257,422)	-67%	-33%	-46%	-74%
Total	**$ 134,093,024**	**$ 99,012,749**	**$ 15,982,355**	**$ (83,030,395)**	**-62%**			

BCA Mass Property Net Salvage Analysis
of PEPCO Electric Plant Accounts
Account 369.1 - Services - Overhead

					Average Net Salvage Rates			
Year	**Retirements**	**Cost of Removal**	**Gross Salvage**	**Net Salvage**	1-Year	3-Year	5-Year	10-Year
1988	$ 20,324	$ 22,118	$ 11,409	$ (10,709)	-53%			
1989	$ 160,698	$ 27,091	$ 8,623	$ (18,468)	-11%			
1990	$ 16,017	$ 19,419	$ 13,244	$ (6,175)	-39%	-18%		
1991	$ 59,618	$ 15,536	$ 35,057	$ 19,521	33%	-2%		
1992	$ 35,611	$ 13,210	$ 3,915	$ (9,296)	-26%	4%	-9%	
1993	$ 8,335	$ 11,220	$ 1,890	$ (9,329)	-112%	1%	-8%	
1994	$ 7,511	$ 53,504	$ 70,414	$ 16,910	225%	-3%	9%	
1995	$ 10,242	$ 97,000	$ 34,000	$ (63,000)	-615%	-212%	-37%	
1996	$ 6,362	$ 76,000	$ -	$ (76,000)	-1195%	-506%	-207%	
1997	$ 10,222	$ 74,600	$ 20,244	$ (54,356)	-532%	-721%	-435%	-63%
1998	$ 7,922	$ 65,622	$ -	$ (65,622)	-828%	-800%	-573%	-82%
1999	$ 2,606	$ 59,035	$ -	$ (59,035)	-2265%	-863%	-851%	-186%
2000	$ 636	$ 9,311	$ 197,413	$ 188,102	29579%	568%	-241%	-75%
2001	$ 15,026	$ 149,626	$ -	$ (149,626)	-996%	-113%	-386%	-269%
2002	$ 1,987	$ 34,546	$ -	$ (34,546)	-1738%	22%	-428%	-433%
2003	$ 5,419	$ -	$ 15,602	$ 15,602	288%	-751%	-154%	-414%
2004	$ 9,550	$ 10,598	$ -	$ (10,598)	-111%	-174%	27%	-442%
2005	$ 18,456	$ 19,732	$ -	$ (19,732)	-107%	-44%	-394%	-340%
2006	$ 209,753	$ 202,887	$ -	$ (202,887)	-97%	-98%	-103%	-139%
2007	$ 383,111	$ 568,074	$ -	$ (568,074)	-148%	-129%	-125%	-138%
2008	$ 178,080	$ 109,638	$ -	$ (109,638)	-62%	-114%	-114%	-115%
2009	$ 98,338	$ 118,972	$ -	$ (118,972)	-121%	-121%	-115%	-110%
2010	$ 92,335	$ 126,031	$ -	$ (126,031)	-136%	-96%	-117%	-131%
2011	$ 132,877	$ 99,753	$ 496,214	$ 396,461	298%	47%	-59%	-69%
2012	$ 43,804	$ 166,674	$ 391,150	$ 224,476	512%	184%	49%	-44%
2013	$ 113,352	$ 384,521	$ 441,971	$ 57,450	51%	234%	90%	-37%
2014	$ 44,794	$ 739,310	$ 376,834	$ (362,476)	-809%	-40%	44%	-63%
2015	$ 60,305	$ 558,130	$ 99,280	$ (458,850)	-761%	-350%	-36%	-93%
2016	$ 11,549	$ 2,160,211	$ 59,412	$ (2,100,799)	-18191%	-2505%	-964%	-273%
2017	$ 26,314	$ 609,571	$ 288,861	$ (320,710)	-1219%	-2934%	-1243%	-364%
2018	$ 35,225	$ 448,803	$ (13,273)	$ (462,077)	-1312%	-3945%	-2079%	-497%
2019	$ 132,997	$ 374,896	$ -	$ (374,896)	-282%	-595%	-1395%	-509%
2020	$ 971,424	$ 547,658	$ -	$ (547,658)	-56%	-121%	-323%	-251%
2021	$ 369,271	$ 611,642	$ -	$ (611,642)	-166%	-104%	-151%	-274%
Total	**$ 3,300,071**	**$ 8,584,941**	**$ 2,552,260**	**$ (6,032,681)**	**-183%**			

BCA Mass Property Net Salvage Analysis
of PEPCO Electric Plant Accounts
Account 369.2 - Services - Underground

Year	Retirements	Cost of Removal	Gross Salvage	Net Salvage	Average Net Salvage Rates 1-Year	3-Year	5-Year	10-Year
1988	$ 40,906	$ 45,026	$ 23,226	$ (21,800)	-53%			
1989	$ 65,645	$ 40,678	$ 18,851	$ (21,827)	-33%			
1990	$ 18,356	$ 39,534	$ 21,681	$ (17,853)	-97%	-49%		
1991	$ 50,730	$ 31,637	$ 24,069	$ (7,568)	-15%	-35%		
1992	$ 21,824	$ 26,901	$ 7,972	$ (18,930)	-87%	-49%	-45%	
1993	$ 20,358	$ 22,852	$ 3,856	$ (18,997)	-93%	-49%	-48%	
1994	$ 51,749	$ 34,816	$ 20,952	$ (13,864)	-27%	-55%	-47%	
1995	$ 25,948	$ 47,000	$ -	$ (47,000)	-181%	-81%	-62%	
1996	$ 23,868	$ 50,000	$ 286,000	$ 236,000	989%	172%	95%	
1997	$ 9,921	$ 46,160	$ 298,550	$ 252,390	2544%	739%	310%	97%
1998	$ 14,659	$ 53,407	$ 287,984	$ 234,577	1600%	1492%	525%	190%
1999	$ 14,926	$ 28,310	$ 247,266	$ 218,956	1467%	1787%	1002%	324%
2000	$ 2,316	$ 11,380	$ 545,717	$ 534,337	23070%	3097%	2247%	580%
2001	$ 881	$ 71,560	$ -	$ (71,560)	-8123%	3762%	2737%	700%
2002	$ 17,911	$ 21,310	$ 135,730	$ 114,420	639%	2735%	2033%	788%
2003	$ 205,932	$ -	$ 34,672	$ 34,672	17%	35%	343%	406%
2004	$ 44,780	$ 32,955	$ -	$ (32,955)	-74%	43%	213%	408%
2005	$ 97,691	$ 63,065	$ -	$ (63,065)	-65%	-18%	-5%	337%
2006	$ 90,764	$ 87,794	$ -	$ (87,794)	-97%	-79%	-8%	227%
2007	$ 86,041	$ 17,419	$ -	$ (17,419)	-20%	-61%	-32%	150%
2008	$ 31,447	$ 34,017	$ -	$ (34,017)	-108%	-67%	-67%	100%
2009	$ 15,216	$ 18,732	$ -	$ (18,732)	-123%	-53%	-69%	60%
2010	$ 14,400	$ 25,785	$ -	$ (25,785)	-179%	-129%	-77%	-33%
2011	$ 7,442	$ 3,864	$ 11,414	$ 7,550	101%	-100%	-57%	-20%
2012	$ 2,206	$ 36,662	$ 6,429	$ (30,233)	-1371%	-202%	-143%	-45%
2013	$ 2,760	$ 28,048	$ 4,928	$ (23,120)	-838%	-369%	-215%	-83%
2014	$ 14,944	$ 41,670	$ 12,058	$ (29,612)	-198%	-417%	-242%	-89%
2015	$ 5,740	$ 44,423	$ 2,492	$ (41,931)	-730%	-404%	-355%	-111%
2016	$ 19,946	$ 287,755	$ 105,591	$ (182,164)	-913%	-624%	-673%	-198%
2017	$ 5,916	$ 167,420	$ 3,502	$ (163,918)	-2771%	-1228%	-894%	-452%
2018	$ 2,800	$ 90,690	$ (2,675)	$ (93,365)	-3335%	-1533%	-1036%	-658%
2019	$ 8,188	$ 29,021	$ 52,269	$ 23,247	284%	-1385%	-1076%	-663%
2020	$ 6,163	$ 376,850	$ 395	$ (376,455)	-6108%	-2604%	-1843%	-1196%
2021	$ 1,938	$ 5,973	$ -	$ (5,973)	-308%	-2205%	-2465%	-1308%
Total	**$ 1,044,310**	**$ 1,962,714**	**$ 2,152,925**	**$ 190,212**	**18%**			

BCA Mass Property Net Salvage Analysis
of PEPCO Electric Plant Accounts
Account 369.3 - Services - Underground Cable

					Average Net Salvage Rates			
Year	Retirements	Cost of Removal	Gross Salvage	Net Salvage	1-Year	3-Year	5-Year	10-Year
1988	$ 193,687	$ 212,492	$ 109,611	$ (102,881)	-53%			
1989	$ 156,796	$ 191,972	$ 86,873	$ (105,099)	-67%			
1990	$ 105,617	$ 186,580	$ 102,310	$ (84,270)	-80%	-64%		
1991	$ 65,446	$ 149,342	$ 113,615	$ (35,727)	-55%	-69%		
1992	$ 108,620	$ 126,988	$ 37,629	$ (89,358)	-82%	-75%	-66%	
1993	$ 160,981	$ 107,875	$ 18,204	$ (89,672)	-56%	-64%	-68%	
1994	$ 111,777	$ 194,007	$ 63,335	$ (130,672)	-117%	-81%	-78%	
1995	$ 39,447	$ 210,000	$ 65,000	$ (145,000)	-368%	-117%	-101%	
1996	$ 76,947	$ 278,000	$ 383,000	$ 105,000	136%	-75%	-70%	
1997	$ 62,908	$ 236,520	$ 422,950	$ 186,430	296%	82%	-16%	-45%
1998	$ 41,469	$ 220,092	$ 405,918	$ 185,826	448%	263%	61%	-22%
1999	$ 94,174	$ 175,087	$ 344,190	$ 169,103	180%	273%	159%	8%
2000	$ 34,734	$ 50,051	$ 767,312	$ 717,261	2065%	629%	440%	110%
2001	$ 101,067	$ 444,540	$ -	$ (444,540)	-440%	192%	243%	56%
2002	$ 53,061	$ 53,778	$ 213,059	$ 159,281	300%	229%	243%	92%
2003	$ 1,601,736	$ -	$ 62,409	$ 62,409	4%	-13%	35%	39%
2004	$ 208,929	$ 211,329	$ -	$ (211,329)	-101%	1%	14%	34%
2005	$ 517,618	$ 434,387	$ -	$ (434,387)	-84%	-25%	-35%	18%
2006	$ 1,198,341	$ 1,159,118	$ -	$ (1,159,118)	-97%	-94%	-44%	-20%
2007	$ 897,410	$ 212,079	$ -	$ (212,079)	-24%	-69%	-44%	-25%
2008	$ 285,504	$ 765,227	$ -	$ (765,227)	-268%	-90%	-90%	-42%
2009	$ 134,056	$ 731,655	$ -	$ (731,655)	-546%	-130%	-109%	-60%
2010	$ 151,022	$ 752,132	$ -	$ (752,132)	-498%	-394%	-136%	-87%
2011	$ 98,356	$ 503,530	$ 439,008	$ (64,522)	-66%	-404%	-161%	-80%
2012	$ 51,302	$ 774,010	$ 283,855	$ (490,155)	-955%	-435%	-389%	-92%
2013	$ 26,459	$ 736,114	$ 61,519	$ (674,594)	-2550%	-698%	-588%	-154%
2014	$ 64,573	$ 836,467	$ 108,316	$ (728,151)	-1128%	-1330%	-692%	-176%
2015	$ 92,920	$ 2,143,162	$ 78,866	$ (2,064,295)	-2222%	-1885%	-1206%	-255%
2016	$ 257,755	$ 6,335,390	$ 263,437	$ (6,071,953)	-2356%	-2135%	-2034%	-610%
2017	$ 148,516	$ 2,216,618	$ 255,689	$ (1,960,929)	-1320%	-2023%	-1948%	-1091%
2018	$ 129,332	$ 291,313	$ (10,566)	$ (301,879)	-233%	-1556%	-1605%	-1199%
2019	$ 275,139	$ 1,234,150	$ -	$ (1,234,150)	-449%	-632%	-1287%	-1107%
2020	$ 165,917	$ 1,284,889	$ 51,310	$ (1,233,579)	-743%	-486%	-1106%	-1131%
2021	$ 139,153	$ 698,680	$ 621	$ (698,059)	-502%	-546%	-633%	-1144%
Total	**$ 7,850,770**	**$ 24,157,574**	**$ 4,727,472**	**$ (19,430,102)**	**-247%**			

BCA Mass Property Net Salvage Analysis
of PEPCO Electric Plant Accounts
Account 370.0 - Meters

					Average Net Salvage Rates			
Year	**Retirements**	**Cost of Removal**	**Gross Salvage**	**Net Salvage**	1-Year	3-Year	5-Year	10-Year
1988	$ 846,465	$ 51,736	$ -	$ (51,736)	-6%			
1989	$ 670,626	$ 31,650	$ -	$ (31,650)	-5%			
1990	$ -	$ -	$ -	$ -		-5%		
1991	$ -	$ -	$ -	$ -		-5%		
1992	$ 2,162,955	$ 129,777	$ -	$ (129,777)	-6%	-6%	-6%	
1993	$ 1,022,330	$ -	$ -	$ -	0%	-4%	-4%	
1994	$ 866,929	$ 81,491	$ -	$ (81,491)	-9%	-5%	-5%	
1995	$ 857,271	$ -	$ -	$ -	0%	-3%	-4%	
1996	$ 676,159	$ 87,901	$ -	$ (87,901)	-13%	-7%	-5%	
1997	$ 1,137,574	$ 147,885	$ -	$ (147,885)	-13%	-9%	-7%	-6%
1998	$ 1,444,391	$ 187,771	$ -	$ (187,771)	-13%	-13%	-10%	-8%
1999	$ 1,079,523	$ 93,393	$ -	$ (93,393)	-9%	-12%	-10%	-8%
2000	$ -	$ -	$ -	$ -		-11%	-12%	-8%
2001	$ 2,554,865	$ 237,449	$ -	$ (237,449)	-9%	-9%	-11%	-8%
2002	$ 666,129	$ -	$ -	$ -	0%	-7%	-9%	-8%
2003	$ 312,834	$ 28,341	$ -	$ (28,341)	-9%	-8%	-8%	-9%
2004	$ 446,422	$ -	$ -	$ -	0%	-2%	-7%	-9%
2005	$ 461,055	$ -	$ -	$ -	0%	-2%	-6%	-9%
2006	$ 993,268	$ -	$ -	$ -	0%	0%	-1%	-8%
2007	$ 1,401,593	$ 220,102	$ -	$ (220,102)	-16%	-8%	-7%	-8%
2008	$ 453,327	$ -	$ -	$ -	0%	-8%	-6%	-7%
2009	$ 338,158	$ -	$ -	$ -	0%	-10%	-6%	-6%
2010	$ 637,158	$ 16,411	$ -	$ (16,411)	-3%	-1%	-6%	-6%
2011	$ 56,671,825	$ 149,356	$ 39,017	$ (110,339)	0%	0%	-1%	-1%
2012	$ 6,227,664	$ 43,212	$ 45,748	$ 2,536	0%	0%	0%	-1%
2013	$ 1,018,782	$ 3,443	$ -	$ (3,443)	0%	0%	0%	-1%
2014	$ 2,549,433	$ 26,037	$ 229	$ (25,808)	-1%	0%	0%	-1%
2015	$ 174,999	$ -	$ 24,883	$ 24,883	14%	0%	0%	0%
2016	$ 256,303	$ -	$ -	$ -	0%	0%	0%	-1%
2017	$ 47,031	$ -	$ -	$ -	0%	5%	0%	0%
2018	$ 397	$ -	$ -	$ -	0%	0%	0%	0%
2019	$ 1,907	$ -	$ -	$ -	0%	0%	5%	0%
2020	$ 1,167	$ -	$ -	$ -	0%	0%	0%	0%
2021	$ -	$ -	$ -	$ -		0%	0%	0%
Total	**$ 85,978,538**	**$ 1,535,955**	**$ 109,877**	**$ (1,426,078)**	**-2%**			

BCA Mass Property Net Salvage Analysis
of PEPCO Electric Plant Accounts
Account 370.1 - Meters - AMI

					Average Net Salvage Rates			
Year	**Retirements**	**Cost of Removal**	**Gross Salvage**	**Net Salvage**	1-Year	3-Year	5-Year	10-Year
1988	$ -	$ -	$ -	$ -				
1989	$ -	$ -	$ -	$ -				
1990	$ -	$ -	$ -	$ -				
1991	$ -	$ -	$ -	$ -				
1992	$ -	$ -	$ -	$ -				
1993	$ -	$ -	$ -	$ -				
1994	$ -	$ -	$ -	$ -				
1995	$ -	$ -	$ -	$ -				
1996	$ -	$ -	$ -	$ -				
1997	$ -	$ -	$ -	$ -				
1998	$ -	$ -	$ -	$ -				
1999	$ -	$ -	$ -	$ -				
2000	$ -	$ -	$ -	$ -				
2001	$ -	$ -	$ -	$ -				
2002	$ -	$ -	$ -	$ -				
2003	$ -	$ -	$ -	$ -				
2004	$ -	$ -	$ -	$ -				
2005	$ -	$ -	$ -	$ -				
2006	$ -	$ -	$ -	$ -				
2007	$ -	$ -	$ -	$ -				
2008	$ -	$ -	$ -	$ -				
2009	$ -	$ -	$ -	$ -				
2010	$ -	$ -	$ -	$ -				
2011	$ -	$ -	$ -	$ -				
2012	$ -	$ -	$ -	$ -				
2013	$ -	$ -	$ -	$ -				
2014	$ 12,414	$ -	$ -	$ -	0%	0%	0%	0%
2015	$ 10,033	$ -	$ -	$ -	0%	0%	0%	0%
2016	$ 37,769	$ -	$ -	$ -	0%	0%	0%	0%
2017	$ 223,779	$ -	$ 13,438	$ 13,438	6%	5%	5%	5%
2018	$ 442,184	$ -	$ -	$ -	0%	2%	2%	2%
2019	$ 427,758	$ 1,385,847	$ -	$ (1,385,847)	-324%	-125%	-120%	-119%
2020	$ 773,984	$ 740,815	$ -	$ (740,815)	-96%	-129%	-111%	-110%
2021	$ 245,643	$ 281,284	$ -	$ (281,284)	-115%	-166%	-113%	-110%
Total	**$ 2,173,563**	**$ 2,407,945**	**$ 13,438**	**$ (2,394,506)**	**-110%**			

BCA Mass Property Net Salvage Analysis
of PEPCO Electric Plant Accounts
Account 371.1 - Installations on Customers' Premises

								Average Net Salvage Rates			
Year	**Retirements**		**Cost of Removal**		**Gross Salvage**		**Net Salvage**	1-Year	3-Year	5-Year	10-Year
1988	$	31,200	$	7,413	$	7	$ (7,406)	-24%			
1989	$	-	$	-	$	-	$ -				
1990	$	-	$	5,448	$	-	$ (5,448)		-41%		
1991	$	-	$	-	$	-	$ -				
1992	$	-	$	-	$	-	$ -			-41%	
1993	$	-	$	61,340	$	-	$ (61,340)				
1994	$	9,963	$	14,724	$	-	$ (14,724)	-148%	-763%	-818%	
1995	$	-	$	-	$	-	$ -		-763%	-763%	
1996	$	-	$	-	$	-	$ -		-148%	-763%	
1997	$	-	$	-	$	-	$ -			-763%	-216%
1998	$	15,604	$	15,905	$	-	$ (15,905)	-102%	-102%	-120%	-381%
1999	$	-	$	-	$	-	$ -		-102%	-102%	-381%
2000	$	-	$	-	$	-	$ -		-102%	-102%	-360%
2001	$	15,574	$	-	$	-	$ -	0%	0%	-51%	-224%
2002	$	-	$	-	$	-	$ -		0%	-51%	-224%
2003	$	3	$	-	$	-	$ -	0%	0%	0%	-74%
2004	$	-	$	-	$	-	$ -		0%	0%	-51%
2005	$	-	$	-	$	-	$ -		0%	0%	-51%
2006	$	9,316	$	9,011	$	-	$ (9,011)	-97%	-97%	-97%	-62%
2007	$	-	$	-	$	-	$ -		-97%	-97%	-62%
2008	$	-	$	-	$	-	$ -		-97%	-97%	-36%
2009	$	17,128	$	-	$	-	$ -	0%	0%	-34%	-21%
2010	$	482,899	$	197,114	$	82,586	$ (114,528)	-24%	-23%	-24%	-24%
2011	$	-	$	-	$	-	$ -		-23%	-23%	-24%
2012	$	-	$	-	$	-	$ -		-24%	-23%	-24%
2013	$	-	$	-	$	-	$ -			-23%	-24%
2014	$	-	$	-	$	-	$ -			-24%	-24%
2015	$	-	$	-	$	-	$ -				-24%
2016	$	-	$	-	$	-	$ -				-23%
2017	$	-	$	-	$	-	$ -				-23%
2018	$	-	$	-	$	-	$ -				-23%
2019	$	-	$	-	$	-	$ -				-24%
2020	$	-	$	-	$	-	$ -				
2021	$	-	$	-	$	-	$ -				
Total	**$**	**581,687**	**$**	**310,956**	**$**	**82,593**	**$ (228,364)**	**-39%**			

BCA Mass Property Net Salvage Analysis
of PEPCO Electric Plant Accounts
Account 373.0 - Street Lighting and Signal Systems

Year	Retirements	Cost of Removal	Gross Salvage	Net Salvage	Average Net Salvage Rates 1-Year	3-Year	5-Year	10-Year
1988	$ 80,069	$ 88,473	$ -	$ (88,473)	-110%			
1989	$ 60,624	$ 42,385	$ 22,988	$ (19,397)	-32%			
1990	$ 8,595	$ 1,038	$ 4,915	$ 3,877	45%	-70%		
1991	$ 33,977	$ -	$ -	$ -	0%	-15%		
1992	$ 35,945	$ -	$ -	$ -	0%	5%	-47%	
1993	$ 24,583	$ 14,657	$ -	$ (14,657)	-60%	-16%	-18%	
1994	$ 22,956	$ -	$ 28,715	$ 28,715	125%	17%	14%	
1995	$ 14,407	$ -	$ -	$ -	0%	23%	11%	
1996	$ -	$ -	$ -	$ -		77%	14%	
1997	$ -	$ -	$ -	$ -		0%	23%	-32%
1998	$ 6	$ -	$ -	$ -	0%	0%	77%	-1%
1999	$ -	$ -	$ -	$ -		0%	0%	13%
2000	$ -	$ 180,101	$ -	$ (180,101)		-3037117%	-3037117%	-126%
2001	$ 2,501	$ -	$ -	$ -	0%	-7201%	-7184%	-165%
2002	$ -	$ -	$ -	$ -		-7201%	-7184%	-258%
2003	$ 31,695	$ 17,338	$ -	$ (17,338)	-55%	-51%	-577%	-236%
2004	$ 5,630	$ 7,654	$ -	$ (7,654)	-136%	-67%	-515%	-378%
2005	$ 18,730	$ 20,208	$ -	$ (20,208)	-108%	-81%	-77%	-385%
2006	$ 262,102	$ 253,523	$ -	$ (253,523)	-97%	-98%	-94%	-149%
2007	$ 275,339	$ 98,880	$ -	$ (98,880)	-36%	-67%	-67%	-97%
2008	$ 25,192	$ 32,541	$ -	$ (32,541)	-129%	-68%	-70%	-98%
2009	$ 12,723	$ 28,814	$ -	$ (28,814)	-226%	-51%	-73%	-101%
2010	$ 23,571	$ 34,959	$ -	$ (34,959)	-148%	-157%	-75%	-75%
2011	$ 15,963	$ 13,288	$ 10,029	$ (3,259)	-20%	-128%	-56%	-74%
2012	$ 4,209	$ 10,089	$ 2,734	$ (7,356)	-175%	-104%	-131%	-75%
2013	$ 22,402	$ 38,754	$ 7,157	$ (31,596)	-141%	-99%	-134%	-78%
2014	$ 16,876	$ 26,967	$ 16,671	$ (10,295)	-61%	-113%	-105%	-77%
2015	$ 7,762	$ 20,208	$ 1,212	$ (18,996)	-245%	-129%	-106%	-78%
2016	$ 35,051	$ 87,159	$ 3,553	$ (83,605)	-239%	-189%	-176%	-80%
2017	$ 70,775	$ 80,140	$ 37,002	$ (43,138)	-61%	-128%	-123%	-126%
2018	$ 4,272	$ 18,968	$ (9,016)	$ (27,983)	-655%	-141%	-137%	-136%
2019	$ 1,770	$ 20,302	$ -	$ (20,302)	-1147%	-119%	-162%	-139%
2020	$ 881	$ 11,634	$ -	$ (11,634)	-1320%	-866%	-166%	-143%
2021	$ 209	$ 1,866	$ 13	$ (1,853)	-885%	-1181%	-135%	-156%
Total	**$ 1,118,815**	**$ 1,149,943**	**$ 125,973**	**$ (1,023,970)**	**-92%**			

BCA Mass Property Net Salvage Analysis
of PEPCO Electric Plant Accounts
Account 390.0 - Structures And Improvements

					Average Net Salvage Rates			
Year	**Retirements**	**Cost of Removal**	**Gross Salvage**	**Net Salvage**	1-Year	3-Year	5-Year	10-Year
1988	$ 70,279	$ 264,631	$ 1,501	$ (263,130)	-374%			
1989	$ (231,607)	$ 36,773	$ 16,393	$ (20,380)	9%			
1990	$ 120,964	$ 64,690	$ 10,171	$ (54,519)	-45%	837%		
1991	$ 9,185	$ 34,967	$ (175)	$ (35,142)	-383%	108%		
1992	$ 1,230	$ 4,819	$ 90,207	$ 85,387	6942%	-3%	961%	
1993	$ 4,875	$ 4,024	$ 110,341	$ 106,317	2181%	1024%	-86%	
1994	$ 269,589	$ 18,163	$ -	$ (18,163)	-7%	63%	21%	
1995	$ 8,543	$ 523,138	$ 130,631	$ (392,507)	-4594%	-108%	-87%	
1996	$ 23,800	$ 128,693	$ (323)	$ (129,016)	-542%	-179%	-113%	
1997	$ 189,621	$ 166,995	$ 393,970	$ 226,975	120%	-133%	-42%	-106%
1998	$ -	$ 10,701	$ (126)	$ (10,827)		41%	-66%	-61%
1999	$ 113,149	$ 105,123	$ (6,700)	$ (111,823)	-99%	34%	-124%	-45%
2000	$ 88,851	$ 54,091	$ -	$ (54,091)	-61%	-87%	-19%	-47%
2001	$ 787,656	$ 3,838,486	$ (652)	$ (3,839,138)	-487%	-405%	-321%	-278%
2002	$ 100,152	$ 200,965	$ 17,163	$ (183,803)	-184%	-417%	-385%	-278%
2003	$ 97,856	$ 181,035	$ (987)	$ (182,021)	-186%	-427%	-368%	-280%
2004	$ -	$ -	$ -	$ -		-185%	-396%	-332%
2005	$ 315,532	$ -	$ -	$ -	0%	-44%	-323%	-250%
2006	$ 214,035	$ 13,026	$ 162,351	$ 149,325	70%	28%	-30%	-210%
2007	$ 390,588	$ 159,329	$ -	$ (159,329)	-41%	-1%	-19%	-208%
2008	$ 3,773	$ 1,821	$ -	$ (1,821)	-48%	-2%	-1%	-208%
2009	$ 34,142	$ -	$ -	$ -	0%	-38%	-1%	-210%
2010	$ 663,320	$ 26,016	$ -	$ (26,016)	-4%	-4%	-3%	-163%
2011	$ -	$ -	$ -	$ -		-4%	-17%	-22%
2012	$ 686,704	$ 131,510	$ -	$ (131,510)	-19%	-12%	-11%	-15%
2013	$ 683,068	$ 195,507	$ -	$ (195,507)	-29%	-24%	-17%	-12%
2014	$ 748,535	$ 156,663	$ -	$ (156,663)	-21%	-23%	-18%	-14%
2015	$ 682,502	$ 141,940	$ -	$ (141,940)	-21%	-23%	-22%	-16%
2016	$ 2,178,145	$ 162,853	$ -	$ (162,853)	-7%	-13%	-16%	-16%
2017	$ 1,540,834	$ 1,630,438	$ -	$ (1,630,438)	-106%	-44%	-39%	-34%
2018	$ 55,898	$ 21,138	$ -	$ (21,138)	-38%	-48%	-41%	-34%
2019	$ 452,401	$ 128,927	$ -	$ (128,927)	-28%	-87%	-42%	-34%
2020	$ -	$ -	$ -	$ -		-30%	-46%	-37%
2021	$ 599,853	$ 216,539	$ -	$ (216,539)	-36%	-33%	-75%	-37%
Total	**$ 10,903,470**	**$ 8,623,000**	**$ 923,764**	**$ (7,699,236)**	**-71%**			

BCA Mass Property Net Salvage Analysis
of PEPCO Electric Plant Accounts
Account 396.0 - Power Operated Equipment

					Average Net Salvage Rates			
Year	Retirements	Cost of Removal	Gross Salvage	Net Salvage	1-Year	3-Year	5-Year	10-Year
1988	$ (1,401)	$ 452	$ -	$ (452)	32%			
1989	$ 56,427	$ -	$ -	$ -	0%			
1990	$ -	$ -	$ -	$ -		-1%		
1991	$ -	$ -	$ -	$ -		0%		
1992	$ -	$ -	$ -	$ -			-1%	
1993	$ -	$ -	$ 1,643	$ 1,643			3%	
1994	$ -	$ -	$ -	$ -				
1995	$ -	$ -	$ -	$ -				
1996	$ -	$ -	$ -	$ -				
1997	$ -	$ -	$ -	$ -				2%
1998	$ -	$ -	$ -	$ -				3%
1999	$ -	$ -	$ -	$ -				
2000	$ -	$ -	$ -	$ -				
2001	$ -	$ -	$ -	$ -				
2002	$ -	$ -	$ -	$ -				
2003	$ 173,249	$ -	$ -	$ -	0%	0%	0%	0%
2004	$ -	$ -	$ -	$ -		0%	0%	0%
2005	$ -	$ -	$ -	$ -		0%	0%	0%
2006	$ -	$ -	$ -	$ -			0%	0%
2007	$ -	$ -	$ -	$ -			0%	0%
2008	$ -	$ -	$ -	$ -				0%
2009	$ -	$ -	$ -	$ -				0%
2010	$ -	$ -	$ -	$ -				0%
2011	$ -	$ -	$ -	$ -				0%
2012	$ -	$ -	$ -	$ -				0%
2013	$ -	$ -	$ -	$ -				
2014	$ -	$ -	$ -	$ -				
2015	$ -	$ -	$ -	$ -				
2016	$ -	$ -	$ -	$ -				
2017	$ -	$ -	$ -	$ -				
2018	$ -	$ -	$ -	$ -				
2019	$ -	$ -	$ -	$ -				
2020	$ -	$ -	$ -	$ -				
2021	$ -	$ -	$ -	$ -				
Total	**$ 228,274**	**$ 452**	**$ 1,643**	**$ 1,191**	**1%**			

Present Value Net Salvage Calculations

The detailed calculations of the discounted Net Salvage Accrual and Net Salvage Theoretical Reserve seen in Table 1 are presented below. These calculations use the Handy Whitman discount factors Mr. Allis utilized to create Table 4 in Pepco's 2021 Depreciation Study (Exhibit PEPCO (L)-1).

Account 361 - Structures and Improvements
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 3.64%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 3.64%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.03640)^e)	g=f/e	h	i=1/(1+0.03640)^(h-1)-1/(1+0.03640)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
1935	52.57	-25%	13	65	1	0	5.82	0.0296	0	0	1	0.7142	9	11
1936	376,859.72	-25%	94,215	65	9,222	142	6.08	0.0293	2,759	2,901	8,360	0.7068	66,587	74,947
1937	14,315.16	-25%	3,579	65	350	5	6.34	0.0290	104	109	316	0.6992	2,502	2,818
1938	5,188.61	-25%	1,297	65	127	2	6.61	0.0287	37	39	114	0.6917	897	1,011
1939	2,130.19	-25%	533	65	52	1	6.88	0.0285	15	16	47	0.6841	364	411
1940	228,923.26	-25%	57,231	65	5,602	86	7.15	0.0282	1,613	1,699	4,986	0.6765	38,714	43,700
1941	22,951.11	-25%	5,738	65	562	9	7.43	0.0279	160	169	497	0.6687	3,837	4,334
1942	46,287.31	-25%	11,572	65	1,133	17	7.72	0.0276	320	337	998	0.6609	7,647	8,645
1943	195,698.22	-25%	48,925	65	4,789	74	8.02	0.0273	1,337	1,411	4,198	0.6529	31,942	36,140
1944	1,706.52	-25%	427	65	42	1	8.32	0.0270	12	12	36	0.6448	275	311
1945	33,141.68	-25%	8,285	65	811	12	8.64	0.0267	221	234	703	0.6365	5,274	5,977
1946	26,394.63	-25%	6,599	65	646	10	8.96	0.0264	174	184	557	0.6280	4,144	4,701
1947	3,547.89	-25%	887	65	87	1	9.29	0.0261	23	24	74	0.6194	549	624
1948	42,785.29	-25%	10,696	65	1,047	16	9.64	0.0258	276	292	892	0.6106	6,531	7,422
1949	12,443.81	-25%	3,111	65	305	5	10.00	0.0255	79	84	258	0.6015	1,871	2,129
1950	84,788.97	-25%	21,197	65	2,075	32	10.37	0.0251	533	564	1,744	0.5923	12,555	14,299
1951	3,199.27	-25%	800	65	78	1	10.75	0.0248	20	21	65	0.5829	466	532
1952	35,644.46	-25%	8,911	65	872	13	11.15	0.0244	218	231	723	0.5733	5,109	5,831
1953	28,645.65	-25%	7,161	65	701	11	11.56	0.0241	172	183	576	0.5635	4,035	4,612
1954	245,044.86	-25%	61,261	65	5,997	92	11.99	0.0237	1,452	1,545	4,890	0.5535	33,907	38,797
1955	77,523.40	-25%	19,381	65	1,897	29	12.43	0.0233	452	482	1,534	0.5433	10,530	12,064
1956	917.36	-25%	229	65	22	0	12.89	0.0230	5	6	18	0.5330	122	140
1957	948,972.97	-25%	237,243	65	23,223	357	13.35	0.0226	5,357	5,714	18,451	0.5225	123,950	142,401
1958	3,655.94	-25%	914	65	89	1	13.84	0.0222	20	22	70	0.5118	468	538
1959	510,797.28	-25%	127,699	65	12,500	192	14.34	0.0218	2,784	2,976	9,743	0.5010	63,981	73,724
1960	117,312.17	-25%	29,328	65	2,871	44	14.85	0.0214	628	672	2,215	0.4901	14,375	16,589
1961	14,157.33	-25%	3,539	65	346	5	15.38	0.0210	74	80	264	0.4791	1,696	1,960
1962	540,926.77	-25%	135,232	65	13,237	204	15.92	0.0206	2,786	2,989	9,995	0.4680	63,295	73,289
1963	6,701.92	-25%	1,675	65	164	3	16.48	0.0202	34	36	122	0.4569	766	888
1964	1,020,549.45	-25%	255,137	65	24,974	384	17.05	0.0198	5,048	5,432	18,423	0.4457	113,713	132,137
1965	1,098,132.58	-25%	274,533	65	26,873	413	17.63	0.0194	5,320	5,733	19,583	0.4345	119,277	138,859
1966	422,308.35	-25%	105,577	65	10,334	159	18.23	0.0190	2,003	2,162	7,436	0.4232	44,681	52,117
1967	234,651.22	-25%	58,663	65	5,742	88	18.84	0.0186	1,089	1,177	4,078	0.4120	24,167	28,245
1968	1,256,056.07	-25%	314,014	65	30,737	473	19.47	0.0181	5,699	6,172	21,533	0.4007	125,830	147,363
1969	125,092.79	-25%	31,273	65	3,061	47	20.10	0.0177	555	602	2,115	0.3895	12,181	14,296
1970	140,674.65	-25%	35,169	65	3,443	53	20.75	0.0173	610	663	2,344	0.3783	13,306	15,650
1971	159,343.99	-25%	39,836	65	3,899	60	21.41	0.0169	674	734	2,615	0.3672	14,630	17,245
1972	332,952.88	-25%	83,238	65	8,148	125	22.08	0.0165	1,376	1,501	5,380	0.3562	29,652	35,032
1973	1,412,676.84	-25%	353,169	65	34,570	532	22.76	0.0161	5,697	6,229	22,464	0.3453	121,943	144,407
1974	2,566,632.46	-25%	641,658	65	62,809	966	23.45	0.0157	10,098	11,064	40,145	0.3344	214,600	254,746
1975	1,126,369.14	-25%	281,592	65	27,564	424	24.16	0.0153	4,321	4,745	17,319	0.3237	91,151	108,471
1976	85,400.29	-25%	21,350	65	2,090	32	24.87	0.0150	319	352	1,290	0.3131	6,685	7,975
1977	13,534.37	-25%	3,384	65	331	5	25.59	0.0146	49	54	201	0.3026	1,024	1,225
1978	1,925,491.00	-25%	481,373	65	47,119	725	26.33	0.0142	6,836	7,561	28,034	0.2922	140,678	168,712
1979	53,470.44	-25%	13,368	65	1,308	20	27.07	0.0138	185	205	764	0.2820	3,770	4,533
1980	52,870.08	-25%	13,218	65	1,294	20	27.82	0.0135	178	198	740	0.2720	3,595	4,335
1981	26,810.19	-25%	6,703	65	656	10	28.58	0.0131	88	98	368	0.2620	1,756	2,124
1982	11,768.58	-25%	2,942	65	288	4	29.35	0.0127	37	42	158	0.2523	742	900
1983	6,701,184.36	-25%	1,675,296	65	163,987	2,523	30.13	0.0124	20,767	23,290	87,977	0.2427	406,539	494,516
1984	1,633,518.99	-25%	408,380	65	39,974	615	30.91	0.0121	4,922	5,537	20,962	0.2332	95,246	116,208
1985	108,344.52	-25%	27,086	65	2,651	41	31.71	0.0117	317	358	1,358	0.2240	6,066	7,424
1986	52,209.42	-25%	13,052	65	1,278	20	32.51	0.0114	149	168	639	0.2149	2,804	3,443
1987	1,442,225.95	-25%	360,556	65	35,293	543	33.32	0.0111	3,987	4,530	17,201	0.2059	74,248	91,449
1988	2,514,918.63	-25%	628,730	65	61,544	947	34.14	0.0107	6,752	7,699	29,219	0.1972	123,963	153,182
1989	113,263.82	-25%	28,316	65	2,772	43	34.97	0.0104	295	338	1,281	0.1886	5,340	6,621
1990	822,561.28	-25%	205,640	65	20,129	310	35.80	0.0101	2,081	2,391	9,043	0.1802	37,049	46,092
1991	5,301,837.04	-25%	1,325,459	65	129,743	1,996	36.64	0.0098	13,018	15,014	56,607	0.1719	227,890	284,497
1992	9,566.60	-25%	2,392	65	234	4	37.49	0.0095	23	26	99	0.1639	392	491
1993	85,382.64	-25%	21,346	65	2,089	32	38.34	0.0092	197	229	857	0.1560	3,330	4,187
1994	260,315.27	-25%	65,079	65	6,370	98	39.21	0.0090	583	681	2,528	0.1483	9,650	12,178
1995	557,166.63	-25%	139,292	65	13,635	210	40.08	0.0087	1,210	1,420	5,228	0.1407	19,604	24,832
1996	129,049.47	-25%	32,262	65	3,158	49	40.95	0.0084	272	320	1,168	0.1334	4,303	5,472
1997	1,687,572.27	-25%	421,893	65	41,297	635	41.84	0.0082	3,441	4,077	14,718	0.1262	53,242	67,959
1998	90,904.67	-25%	22,726	65	2,225	34	42.72	0.0079	180	214	762	0.1192	2,709	3,471
1999	262,892.93	-25%	65,723	65	6,433	99	43.62	0.0077	503	602	2,116	0.1123	7,384	9,500
2000	336,968.47	-25%	84,242	65	8,246	127	44.52	0.0074	624	751	2,598	0.1057	8,903	11,501
2001	679,815.22	-25%	169,954	65	16,636	256	45.43	0.0072	1,219	1,475	5,009	0.0992	16,856	21,865
2002	7,141,525.61	-25%	1,785,381	65	174,763	2,689	46.34	0.0069	12,396	15,084	50,167	0.0929	165,780	215,947
2003	77,311.80	-25%	19,328	65	1,892	29	47.26	0.0067	130	159	516	0.0867	1,675	2,192
2005	719,715.88	-25%	179,929	65	17,612	271	49.11	0.0063	1,131	1,402	4,305	0.0749	13,469	17,773
2006	202,889.02	-25%	50,722	65	4,965	76	50.05	0.0061	308	385	1,142	0.0692	3,509	4,651
2007	13,015,714.89	-25%	3,253,929	65	318,513	4,900	50.99	0.0059	19,135	24,035	68,670	0.0637	207,169	275,839
2008	142,526.95	-25%	35,632	65	3,488	54	51.93	0.0057	203	256	701	0.0583	2,078	2,779
2009	212,880.10	-25%	53,220	65	5,209	80	52.88	0.0055	293	373	972	0.0531	2,826	3,798
2010	144,828.34	-25%	36,207	65	3,544	55	53.83	0.0053	192	247	609	0.0481	1,740	2,349
2011	305,196.32	-25%	76,299	65	7,469	115	54.78	0.0051	392	507	1,174	0.0432	3,293	4,467
2012	536,821.11	-25%	134,205	65	13,137	202	55.74	0.0050	666	868	1,871	0.0384	5,154	7,024
2013	346,150.64	-25%	86,538	65	8,471	130	56.71	0.0048	415	545	1,081	0.0338	2,924	4,005
2014	92,732.61	-25%	23,183	65	2,269	35	57.67	0.0046	107	142	256	0.0293	680	936

Account 361 - Structures and Improvements
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 3.64%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 3.64%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.03640)^e)	g=f/e	h	i=1/(1+0.03640)^(h-1)-1/(1+0.03640)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
2015	935,524.11	-25%	233,881	65	22,894	352	58.64	0.0045	1,046	1,398	2,240	0.0250	5,844	8,084
2016	2,291,916.39	-25%	572,979	65	56,086	863	59.61	0.0043	2,475	3,338	4,649	0.0208	11,914	16,562
2017	7,601,638.29	-25%	1,900,410	65	186,023	2,862	60.59	0.0042	7,929	10,791	12,631	0.0167	31,796	44,427
2018	34,386.62	-25%	8,597	65	841	13	61.56	0.0040	35	48	44	0.0128	110	154
2019	4,979,378.62	-25%	1,244,845	65	121,852	1,875	62.54	0.0039	4,843	6,717	4,606	0.0090	11,189	15,796
2020	8,341,959.69	-25%	2,085,490	65	204,139	3,141	63.52	0.0038	7,833	10,974	4,634	0.0053	11,059	15,694
2021	4,566,576.59	-25%	1,141,644	65	111,750	1,719	64.51	0.0036	4,140	5,859	847	0.0017	1,985	2,832
	90,174,871.48		22,543,718		2,206,705	33,949			196,058	230,007	687,923		3,179,491	3,867,414

Account 362 - Station Equipment
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 4.88%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 4.88%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.04880)^e)	g=f/e	h	i=1/(1+0.04880)^(h-1)-1/(1+0.04880)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
1934	10,379.66	-25%	2,595	53	208	4	2.93	0.0424	110	114	196	0.7895	2,049	2,245
1936	38,475.59	-25%	9,619	53	770	15	3.50	0.0413	397	412	719	0.7665	7,373	8,092
1937	53,124.24	-25%	13,281	53	1,063	20	3.78	0.0408	541	561	987	0.7550	10,028	11,015
1938	16,240.43	-25%	4,060	53	325	6	4.07	0.0402	163	169	300	0.7437	3,020	3,320
1939	9,572.41	-25%	2,393	53	192	4	4.36	0.0396	95	98	176	0.7325	1,753	1,929
1940	203,179.64	-25%	50,795	53	4,065	77	4.65	0.0391	1,986	2,063	3,709	0.7213	36,639	40,348
1941	187,011.00	-25%	46,753	53	3,742	71	4.94	0.0386	1,803	1,874	3,393	0.7103	33,210	36,603
1942	216,583.44	-25%	54,146	53	4,334	82	5.23	0.0380	2,060	2,141	3,906	0.6995	37,873	41,779
1943	166,331.88	-25%	41,583	53	3,328	63	5.52	0.0375	1,560	1,623	2,982	0.6888	28,642	31,624
1944	10,219.03	-25%	2,555	53	204	4	5.81	0.0370	95	98	182	0.6782	1,733	1,915
1945	63,936.52	-25%	15,984	53	1,279	24	6.10	0.0365	583	607	1,132	0.6677	10,673	11,805
1946	40,718.83	-25%	10,180	53	815	15	6.40	0.0360	366	382	716	0.6573	6,691	7,408
1947	4,277.55	-25%	1,069	53	86	2	6.69	0.0355	38	40	75	0.6470	692	767
1948	47,442.83	-25%	11,861	53	949	18	6.99	0.0350	415	433	824	0.6367	7,551	8,375
1949	118,111.52	-25%	29,528	53	2,363	45	7.29	0.0345	1,018	1,063	2,038	0.6264	18,496	20,534
1950	47,419.39	-25%	11,855	53	949	18	7.60	0.0340	403	421	813	0.6162	7,304	8,117
1951	6,628.94	-25%	1,657	53	133	3	7.91	0.0335	55	58	113	0.6059	1,004	1,117
1952	50,808.14	-25%	12,702	53	1,017	19	8.23	0.0330	419	438	859	0.5957	7,566	8,425
1953	168,047.78	-25%	42,012	53	3,362	63	8.55	0.0325	1,364	1,428	2,820	0.5854	24,593	27,413
1954	679,825.05	-25%	169,956	53	13,603	257	8.88	0.0320	5,433	5,690	11,324	0.5750	97,729	109,053
1955	240,394.55	-25%	60,099	53	4,810	91	9.21	0.0315	1,891	1,981	3,974	0.5646	33,933	37,907
1956	4,545.43	-25%	1,136	53	91	2	9.56	0.0309	35	37	75	0.5542	630	704
1957	1,967,509.27	-25%	491,877	53	39,368	743	9.91	0.0304	14,970	15,712	32,007	0.5436	267,386	299,393
1958	140,721.83	-25%	35,180	53	2,816	53	10.27	0.0299	1,052	1,106	2,270	0.5330	18,750	21,020
1959	1,664,148.88	-25%	416,037	53	33,298	628	10.64	0.0294	12,228	12,857	26,613	0.5223	217,281	243,894
1960	625,027.05	-25%	156,257	53	12,506	236	11.02	0.0289	4,511	4,747	9,906	0.5115	79,923	89,829
1961	557,672.93	-25%	139,418	53	11,159	211	11.41	0.0283	3,951	4,161	8,756	0.5006	69,795	78,551
1962	729,623.89	-25%	182,406	53	14,599	275	11.81	0.0278	5,071	5,347	11,346	0.4897	89,320	100,666
1963	291,358.05	-25%	72,840	53	5,830	110	12.22	0.0273	1,986	2,096	4,486	0.4787	34,866	39,351
1964	2,005,140.54	-25%	501,285	53	40,121	757	12.64	0.0267	13,396	14,153	30,554	0.4676	234,392	264,946
1965	1,117,298.58	-25%	279,325	53	22,356	422	13.07	0.0262	7,313	7,735	16,843	0.4565	127,499	144,343
1966	316,689.09	-25%	79,172	53	6,337	120	13.51	0.0256	2,030	2,149	4,721	0.4453	35,253	39,975
1967	1,010,361.43	-25%	252,590	53	20,216	381	13.96	0.0251	6,337	6,718	14,890	0.4341	109,638	124,528
1968	1,308,259.31	-25%	327,065	53	26,177	494	14.43	0.0245	8,026	8,520	19,051	0.4228	138,286	157,337
1969	829,001.23	-25%	207,250	53	16,588	313	14.90	0.0240	4,972	5,285	11,923	0.4115	85,293	97,216
1970	1,530,292.06	-25%	382,573	53	30,620	578	15.39	0.0234	8,967	9,545	21,728	0.4003	153,133	174,861
1971	319,189.39	-25%	79,797	53	6,387	121	15.89	0.0229	1,827	1,947	4,472	0.3890	31,042	35,514
1972	431,815.46	-25%	107,954	53	8,640	163	16.40	0.0223	2,412	2,575	5,967	0.3778	40,781	46,748
1973	3,498,548.53	-25%	874,637	53	70,003	1,321	16.92	0.0218	19,061	20,382	47,656	0.3665	320,596	368,252
1974	2,923,623.11	-25%	730,906	53	58,499	1,104	17.45	0.0212	15,530	16,634	39,238	0.3554	259,748	298,986
1975	1,916,570.48	-25%	479,143	53	38,349	724	17.99	0.0207	9,921	10,645	25,330	0.3443	164,949	190,279
1976	2,271,281.27	-25%	567,820	53	45,446	857	18.55	0.0202	11,451	12,308	29,543	0.3332	189,205	218,748
1977	1,851,176.91	-25%	462,794	53	37,040	699	19.11	0.0196	9,085	9,784	23,684	0.3222	149,133	172,817
1978	2,695,984.63	-25%	673,996	53	53,944	1,018	19.69	0.0191	12,874	13,891	33,906	0.3114	209,859	243,765
1979	2,074,555.88	-25%	518,639	53	41,510	783	20.27	0.0186	9,633	10,417	25,632	0.3006	155,894	181,526
1980	2,623,670.69	-25%	655,918	53	52,497	991	20.87	0.0181	11,842	12,832	31,825	0.2899	190,158	221,983
1981	1,274,604.65	-25%	318,651	53	25,504	481	21.48	0.0175	5,589	6,070	15,169	0.2794	89,019	104,188
1982	4,288,979.69	-25%	1,072,245	53	85,819	1,619	22.09	0.0170	18,261	19,880	50,043	0.2689	288,374	338,417
1983	11,674,494.88	-25%	2,918,624	53	233,596	4,407	22.72	0.0165	48,241	52,648	133,449	0.2587	754,945	888,394
1984	7,136,895.19	-25%	1,784,224	53	142,803	2,694	23.36	0.0160	28,609	31,303	79,863	0.2485	443,441	523,304
1985	2,020,893.05	-25%	505,223	53	40,436	763	24.01	0.0155	7,855	8,618	22,120	0.2386	120,525	142,645
1986	4,329,550.93	-25%	1,082,388	53	86,631	1,635	24.66	0.0151	16,310	17,944	46,317	0.2287	247,590	293,907
1987	3,223,647.71	-25%	805,912	53	64,502	1,217	25.33	0.0146	11,764	12,981	33,676	0.2191	176,571	210,246
1988	4,876,812.99	-25%	1,219,203	53	97,581	1,841	26.01	0.0141	17,234	19,075	49,701	0.2096	255,566	305,268
1989	7,956,555.56	-25%	1,989,139	53	159,204	3,004	26.69	0.0137	27,214	30,218	79,031	0.2003	398,467	477,498
1990	19,903,322.84	-25%	4,975,831	53	398,248	7,514	27.38	0.0132	65,864	73,378	192,485	0.1912	951,418	1,143,903
1991	11,142,048.92	-25%	2,785,512	53	222,943	4,206	28.09	0.0128	35,657	39,864	104,799	0.1823	507,740	612,539
1992	39,121,607.14	-25%	9,780,402	53	782,789	14,770	28.80	0.0124	121,029	135,798	357,467	0.1735	1,697,303	2,054,771
1993	3,050,770.28	-25%	762,693	53	61,043	1,152	29.52	0.0120	9,120	10,272	27,047	0.1650	125,842	152,889
1994	1,775,403.74	-25%	443,851	53	35,524	670	30.24	0.0116	5,126	5,797	15,252	0.1566	69,527	84,779
1995	1,562,027.54	-25%	390,507	53	31,255	590	30.98	0.0112	4,355	4,945	12,985	0.1485	57,986	70,971
1996	1,053,327.39	-25%	263,332	53	21,076	398	31.72	0.0108	2,834	3,232	8,461	0.1405	37,006	45,467
1997	2,785,681.28	-25%	696,420	53	55,739	1,052	32.48	0.0104	7,232	8,284	21,584	0.1328	92,459	114,043
1998	15,420,740.80	-25%	3,855,185	53	308,555	5,822	33.24	0.0100	38,612	44,433	115,060	0.1252	482,664	597,725
1999	6,046,528.13	-25%	1,511,632	53	120,986	2,283	34.00	0.0097	14,596	16,879	43,364	0.1178	178,114	221,478
2000	2,549,882.23	-25%	637,471	53	51,021	963	34.78	0.0093	5,932	6,895	17,541	0.1107	70,541	88,082
2001	3,421,509.17	-25%	855,377	53	68,461	1,292	35.56	0.0090	7,669	8,961	22,527	0.1037	88,688	111,215
2002	4,145,228.02	-25%	1,036,307	53	82,942	1,565	36.35	0.0086	8,948	10,513	26,056	0.0969	100,420	126,476
2003	11,920,154.15	-25%	2,980,039	53	238,512	4,500	37.15	0.0083	24,774	29,274	71,346	0.0903	269,145	340,491
2004	16,162.82	-25%	4,041	53	323	6	37.95	0.0080	32	38	92	0.0839	339	431
2005	12,477,592.80	-25%	3,119,398	53	249,666	4,711	38.76	0.0077	24,013	28,724	67,080	0.0777	242,402	309,482
2006	9,708,943.61	-25%	2,427,236	53	194,267	3,665	39.58	0.0074	17,971	21,637	49,202	0.0717	173,999	223,201
2007	26,389,239.80	-25%	6,597,310	53	528,026	9,963	40.40	0.0071	46,967	56,930	125,527	0.0658	434,420	559,948
2008	5,915,794.25	-25%	1,478,949	53	118,370	2,233	41.23	0.0068	10,121	12,354	26,287	0.0602	89,022	115,309
2009	14,486,870.59	-25%	3,621,718	53	289,870	5,469	42.07	0.0066	23,816	29,285	59,799	0.0547	198,164	257,963
2010	19,250,893.45	-25%	4,812,723	53	385,193	7,268	42.91	0.0063	30,403	37,671	73,342	0.0494	237,819	311,161
2011	9,927,266.73	-25%	2,481,817	53	198,636	3,748	43.76	0.0061	15,057	18,805	34,641	0.0443	109,910	144,551
2012	26,210,949.40	-25%	6,552,737	53	524,458	9,895	44.61	0.0058	38,169	48,065	83,009	0.0393	257,698	340,707

Account 362 - Station Equipment
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 4.88%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 4.88%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.04880)^e)	g=f/e	h	i=1/(1+0.04880)^(h-1)-1/(1+0.04880)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
2013	22,094,740.23	-25%	5,523,685	53	442,096	8,341	45.47	0.0056	30,883	39,224	62,797	0.0345	190,751	253,549
2014	28,742,412.98	-25%	7,185,603	53	575,110	10,851	46.34	0.0054	38,551	49,402	72,294	0.0299	214,864	287,157
2015	22,258,433.25	-25%	5,564,608	53	445,372	8,403	47.21	0.0051	28,640	37,043	48,662	0.0254	141,510	190,172
2016	26,028,442.92	-25%	6,507,111	53	520,806	9,827	48.09	0.0049	32,120	41,947	48,288	0.0211	137,397	185,685
2017	84,677,962.69	-25%	21,169,491	53	1,694,332	31,969	48.97	0.0047	100,195	132,163	128,887	0.0170	358,838	487,725
2018	10,730,739.47	-25%	2,682,685	53	214,713	4,051	49.86	0.0045	12,171	16,223	12,738	0.0129	34,700	47,438
2019	45,433,311.20	-25%	11,358,328	53	909,081	17,152	50.75	0.0043	49,388	66,540	38,625	0.0091	102,964	141,589
2020	35,510,375.88	-25%	8,877,594	53	710,531	13,406	51.65	0.0042	36,986	50,392	18,163	0.0053	47,379	65,542
2021	28,135,723.90	-25%	7,033,931	53	562,971	10,622	52.55	0.0040	28,072	38,694	4,807	0.0017	12,270	17,077
	635,759,316.59		158,939,829		12,720,986	240,019			1,315,655	1,555,674	3,023,245		14,239,163	17,262,408

Account 364 - Poles, Towers and Fixtures
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 2.96%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 2.96%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.02960)^e)	g=f/e	h	i=1/(1+0.02960)^(h-1)-1/(1+0.02960)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
1955	610,240.48	-90%	549,216	60	95,418	1,590	11.66	0.0211	11,569	13,159	76,870	0.5379	295,410	372,280
1956	112,937.94	-90%	101,644	60	17,659	294	12.04	0.0208	2,118	2,412	14,117	0.5302	53,889	68,006
1957	146,882.66	-90%	132,194	60	22,967	383	12.42	0.0206	2,723	3,106	18,211	0.5223	69,042	87,253
1958	125,327.10	-90%	112,794	60	19,596	327	12.82	0.0204	2,297	2,623	15,408	0.5142	57,997	73,405
1959	159,881.75	-90%	143,894	60	24,999	417	13.24	0.0201	2,895	3,311	19,483	0.5059	72,796	92,279
1960	210,265.30	-90%	189,239	60	32,877	548	13.67	0.0199	3,760	4,307	25,387	0.4974	94,134	119,521
1961	253,420.72	-90%	228,079	60	39,625	660	14.11	0.0196	4,473	5,133	30,305	0.4888	111,484	141,789
1962	186,144.49	-90%	167,530	60	29,106	485	14.57	0.0194	3,242	3,727	22,037	0.4800	80,413	102,450
1963	275,198.38	-90%	247,679	60	43,030	717	15.05	0.0191	4,727	5,444	32,240	0.4710	116,661	148,901
1964	344,826.19	-90%	310,344	60	53,918	899	15.53	0.0188	5,839	6,738	39,959	0.4619	143,352	183,311
1965	300,672.66	-90%	270,605	60	47,014	784	16.04	0.0185	5,017	5,801	34,449	0.4527	122,495	156,944
1966	421,116.34	-90%	379,005	60	65,846	1,097	16.55	0.0183	6,922	8,020	47,681	0.4433	168,011	215,693
1967	303,507.23	-90%	273,157	60	47,457	791	17.08	0.0180	4,912	5,703	33,946	0.4338	118,503	152,449
1968	159,107.77	-90%	143,197	60	24,878	415	17.63	0.0177	2,535	2,949	17,570	0.4243	60,753	78,322
1969	295,941.45	-90%	266,347	60	46,274	771	18.18	0.0174	4,638	5,410	32,249	0.4146	110,428	142,678
1970	157,401.67	-90%	141,662	60	24,612	410	18.76	0.0171	2,426	2,836	16,918	0.4049	57,358	74,276
1971	197,905.38	-90%	178,115	60	30,945	516	19.34	0.0168	2,999	3,515	20,971	0.3951	70,377	91,348
1972	109,233.52	-90%	98,310	60	17,080	285	19.94	0.0165	1,627	1,911	11,405	0.3853	37,880	49,285
1973	398,019.28	-90%	358,217	60	62,235	1,037	20.54	0.0163	5,823	6,861	40,926	0.3755	134,504	175,430
1974	645,061.96	-90%	580,556	60	100,863	1,681	21.16	0.0160	9,269	10,950	65,285	0.3656	212,270	277,555
1975	422,277.52	-90%	380,050	60	66,028	1,100	21.80	0.0157	5,957	7,057	42,042	0.3558	135,213	177,256
1976	498,689.99	-90%	448,821	60	77,976	1,300	22.44	0.0154	6,904	8,204	48,815	0.3459	155,267	204,082
1977	355,222.35	-90%	319,700	60	55,543	926	23.09	0.0151	4,825	5,751	34,166	0.3361	107,459	141,625
1978	266,530.48	-90%	239,877	60	41,675	695	23.76	0.0148	3,551	4,245	25,174	0.3263	78,280	103,454
1979	636,153.47	-90%	572,538	60	99,470	1,658	24.43	0.0145	8,310	9,967	58,966	0.3166	181,261	240,228
1980	382,637.54	-90%	344,374	60	59,830	997	25.12	0.0142	4,899	5,896	34,785	0.3069	105,687	140,472
1981	265,368.43	-90%	238,832	60	41,493	692	25.81	0.0139	3,330	4,021	23,644	0.2973	70,994	94,638
1982	370,086.48	-90%	333,078	60	57,867	964	26.51	0.0137	4,549	5,514	32,295	0.2877	95,823	128,118
1983	299,820.17	-90%	269,838	60	46,880	781	27.23	0.0134	3,610	4,391	25,606	0.2782	75,066	100,673
1984	477,194.74	-90%	429,475	60	74,615	1,244	27.95	0.0131	5,625	6,869	39,857	0.2688	115,429	155,286
1985	524,860.80	-90%	472,375	60	82,068	1,368	28.68	0.0128	6,057	7,425	42,839	0.2594	122,552	165,391
1986	828,564.48	-90%	745,708	60	129,556	2,159	29.42	0.0125	9,357	11,517	66,031	0.2502	186,572	252,603
1987	814,746.66	-90%	733,272	60	127,395	2,123	30.17	0.0123	9,003	11,126	63,341	0.2410	176,750	240,091
1988	1,269,586.84	-90%	1,142,628	60	198,515	3,309	30.92	0.0120	13,723	17,031	96,201	0.2320	265,086	361,287
1989	2,284,292.53	-90%	2,055,863	60	357,176	5,953	31.69	0.0117	24,146	30,099	168,539	0.2231	458,565	627,103
1990	1,138,008.79	-90%	1,024,208	60	177,941	2,966	32.46	0.0115	11,761	14,727	81,673	0.2142	219,395	301,068
1991	363,925.20	-90%	327,533	60	56,904	948	33.24	0.0112	3,677	4,625	25,379	0.2055	67,303	92,682
1992	1,692,923.98	-90%	1,523,632	60	264,709	4,412	34.03	0.0110	16,714	21,126	114,582	0.1969	299,957	414,540
1993	2,473,217.02	-90%	2,225,895	60	386,716	6,445	34.82	0.0107	23,858	30,303	162,268	0.1884	419,291	581,559
1994	1,940,104.97	-90%	1,746,094	60	303,358	5,056	35.63	0.0105	18,282	23,338	123,233	0.1800	314,282	437,515
1995	3,179,466.45	-90%	2,861,520	60	497,147	8,286	36.44	0.0102	29,262	37,547	195,247	0.1717	491,423	686,670
1996	1,406,403.85	-90%	1,265,763	60	219,908	3,665	37.25	0.0100	12,639	16,304	83,370	0.1636	207,074	290,444
1997	2,141,546.64	-90%	1,927,392	60	334,856	5,581	38.08	0.0097	18,788	24,369	122,351	0.1556	299,877	422,228
1998	1,202,827.68	-90%	1,082,545	60	188,076	3,135	38.91	0.0095	10,300	13,435	66,116	0.1477	159,894	226,010
1999	1,688,314.48	-90%	1,519,483	60	263,988	4,400	39.75	0.0093	14,108	18,508	89,116	0.1399	212,641	301,757
2000	3,216,107.68	-90%	2,894,497	60	502,876	8,381	40.59	0.0091	26,222	34,603	162,690	0.1323	382,997	545,687
2001	2,561,830.99	-90%	2,305,648	60	400,572	6,676	41.44	0.0088	20,376	27,052	123,915	0.1248	287,790	411,704
2002	2,658,476.36	-90%	2,392,629	60	415,684	6,928	42.30	0.0086	20,622	27,551	122,655	0.1175	281,020	403,675
2003	3,568,351.65	-90%	3,211,516	60	557,954	9,299	43.16	0.0084	26,993	36,292	156,614	0.1102	353,967	510,581
2004	907,278.05	-90%	816,550	60	141,864	2,364	44.03	0.0082	6,691	9,056	37,767	0.1031	84,199	121,966
2005	2,161,455.71	-90%	1,945,310	60	337,969	5,633	44.90	0.0080	15,540	21,173	85,050	0.0961	187,030	272,080
2006	2,162,584.40	-90%	1,946,326	60	338,145	5,636	45.78	0.0078	15,154	20,790	80,138	0.0893	173,826	253,964
2007	1,590,374.66	-90%	1,431,337	60	248,674	4,145	46.67	0.0076	10,861	15,005	55,266	0.0826	118,236	173,503
2008	3,339,283.49	-90%	3,005,355	60	522,136	8,702	47.56	0.0074	22,219	30,921	108,292	0.0760	228,505	336,797
2009	2,652,809.42	-90%	2,387,528	60	414,798	6,913	48.45	0.0072	17,196	24,110	79,841	0.0696	166,160	246,001
2010	2,793,063.56	-90%	2,513,757	60	436,728	7,279	49.35	0.0070	17,636	24,915	77,509	0.0633	159,089	236,598
2011	4,847,097.86	-90%	4,362,388	60	757,901	12,632	50.26	0.0068	29,809	42,440	123,079	0.0571	249,147	372,226
2012	12,345,830.90	-90%	11,111,248	60	1,930,416	32,174	51.17	0.0067	73,937	106,111	284,238	0.0511	567,461	851,699
2013	17,254,479.89	-90%	15,529,032	60	2,697,940	44,966	52.08	0.0065	100,616	145,582	356,157	0.0452	701,249	1,057,406
2014	14,893,752.34	-90%	13,404,377	60	2,328,813	38,814	53.00	0.0063	84,555	123,368	271,794	0.0394	527,769	799,564
2015	9,888,725.76	-90%	8,899,853	60	1,546,218	25,770	53.92	0.0061	54,651	80,421	156,702	0.0337	300,091	456,793
2016	6,452,726.06	-90%	5,807,453	60	1,008,959	16,816	54.85	0.0060	34,711	51,527	86,680	0.0282	163,709	250,389
2017	6,290,732.43	-90%	5,661,659	60	983,630	16,394	55.78	0.0058	32,934	49,328	69,263	0.0228	129,013	198,276
2018	3,404,037.39	-90%	3,063,634	60	532,261	8,871	56.71	0.0057	17,343	26,214	29,202	0.0175	53,645	82,848
2019	4,722,097.73	-90%	4,249,888	60	738,355	12,306	57.64	0.0055	23,410	35,716	28,986	0.0124	52,515	81,501
2020	7,821,007.49	-90%	7,038,907	60	1,222,906	20,382	58.58	0.0054	37,724	58,106	28,848	0.0073	51,547	80,395
2021	11,406,175.14	-90%	10,265,558	60	1,783,489	29,725	59.53	0.0052	53,524	83,249	14,045	0.0024	24,753	38,798
	159,274,142.81		143,346,729		24,904,381	415,073			1,105,767	1,520,840	5,019,786		12,452,621	17,472,406

Account 365 - Overhead Conductors and Devices
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 3.95%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 3.95%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.03950)^e)	g=f/e	h	i=1/(1+0.03950)^(h-1)-1/(1+0.03950)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
1955	684,480.88	-90%	616,033	54	76,047	1,408	9.82	0.0270	16,633	18,041	62,217	0.5601	345,047	407,264
1956	21,839.57	-90%	19,656	54	2,426	45	10.17	0.0266	523	568	1,969	0.5508	10,826	12,796
1957	26,376.49	-90%	23,739	54	2,930	54	10.54	0.0263	623	678	2,359	0.5414	12,852	15,211
1958	38,668.42	-90%	34,802	54	4,296	80	10.91	0.0259	901	980	3,428	0.5319	18,511	21,939
1959	55,258.04	-90%	49,732	54	6,139	114	11.29	0.0255	1,269	1,382	4,856	0.5223	25,975	30,831
1960	73,813.87	-90%	66,432	54	8,201	152	11.68	0.0251	1,669	1,821	6,427	0.5126	34,053	40,480
1961	100,294.52	-90%	90,265	54	11,143	206	12.08	0.0247	2,233	2,439	8,650	0.5028	45,386	54,036
1962	96,187.35	-90%	86,569	54	10,687	198	12.49	0.0243	2,108	2,306	8,215	0.4929	42,671	50,886
1963	93,801.67	-90%	84,422	54	10,422	193	12.91	0.0240	2,022	2,215	7,929	0.4829	40,770	48,700
1964	120,643.46	-90%	108,579	54	13,404	248	13.34	0.0236	2,558	2,806	10,091	0.4729	51,345	61,436
1965	121,511.37	-90%	109,360	54	13,500	250	13.79	0.0232	2,532	2,782	10,053	0.4627	50,606	60,659
1966	109,832.10	-90%	98,849	54	12,203	226	14.24	0.0228	2,249	2,475	8,984	0.4525	44,732	53,717
1967	158,517.56	-90%	142,666	54	17,612	326	14.71	0.0223	3,188	3,514	12,816	0.4423	63,096	75,912
1968	119,963.82	-90%	107,967	54	13,328	247	15.18	0.0219	2,369	2,615	9,581	0.4319	46,636	56,217
1969	144,072.58	-90%	129,665	54	16,007	296	15.67	0.0215	2,791	3,088	11,363	0.4216	54,662	66,025
1970	111,465.41	-90%	100,319	54	12,384	229	16.16	0.0211	2,118	2,348	8,677	0.4112	41,247	49,924
1971	85,634.36	-90%	77,071	54	9,514	176	16.67	0.0207	1,596	1,772	6,576	0.4007	30,884	37,461
1972	104,784.42	-90%	94,306	54	11,642	216	17.19	0.0203	1,914	2,129	7,935	0.3903	36,806	44,741
1973	454,168.32	-90%	408,751	54	50,459	934	17.72	0.0199	8,126	9,060	33,897	0.3798	155,256	189,154
1974	830,728.47	-90%	747,656	54	92,295	1,709	18.27	0.0195	14,554	16,264	61,077	0.3694	276,170	337,247
1975	460,757.24	-90%	414,682	54	51,191	948	18.82	0.0191	7,902	8,850	33,352	0.3589	148,848	182,200
1976	438,007.04	-90%	394,206	54	48,663	901	19.38	0.0186	7,349	8,250	31,198	0.3485	137,394	168,592
1977	397,338.92	-90%	357,605	54	44,145	817	19.95	0.0182	6,520	7,338	27,832	0.3382	120,927	148,759
1978	256,838.16	-90%	231,154	54	28,535	528	20.54	0.0178	4,120	4,649	17,682	0.3278	75,780	93,461
1979	420,758.22	-90%	378,682	54	46,747	866	21.13	0.0174	6,596	7,462	28,452	0.3176	120,252	148,704
1980	537,881.49	-90%	484,093	54	59,759	1,107	21.74	0.0170	8,237	9,344	35,703	0.3073	148,784	184,487
1981	321,087.58	-90%	288,979	54	35,673	661	22.35	0.0166	4,802	5,462	20,907	0.2972	85,887	106,794
1982	471,453.47	-90%	424,308	54	52,379	970	22.98	0.0162	6,882	7,852	30,091	0.2871	121,837	151,928
1983	413,272.43	-90%	371,945	54	45,915	850	23.61	0.0158	5,886	6,736	25,838	0.2772	103,091	128,929
1984	447,357.27	-90%	402,622	54	49,702	920	24.26	0.0154	6,214	7,135	27,375	0.2673	107,617	134,992
1985	712,396.12	-90%	641,157	54	79,148	1,466	24.91	0.0150	9,648	11,114	42,636	0.2575	165,110	207,746
1986	996,387.29	-90%	896,749	54	110,700	2,050	25.57	0.0147	13,152	15,202	58,273	0.2479	222,266	280,539
1987	1,099,190.90	-90%	989,272	54	122,122	2,262	26.25	0.0143	14,136	16,398	62,766	0.2383	235,759	298,524
1988	1,040,941.24	-90%	936,847	54	115,650	2,142	26.93	0.0139	13,039	15,180	57,981	0.2289	214,440	272,421
1989	2,094,499.56	-90%	1,885,050	54	232,702	4,309	27.62	0.0136	25,543	29,852	113,690	0.2196	413,950	527,640
1990	990,424.11	-90%	891,382	54	110,038	2,038	28.32	0.0132	11,756	13,793	52,336	0.2104	187,574	239,910
1991	600,496.20	-90%	540,447	54	66,716	1,235	29.02	0.0128	6,935	8,170	30,857	0.2014	108,849	139,706
1992	2,175,027.32	-90%	1,957,525	54	241,649	4,475	29.74	0.0125	24,431	28,906	108,564	0.1925	376,867	485,431
1993	3,328,809.32	-90%	2,995,928	54	369,836	6,849	30.46	0.0121	36,357	43,206	161,195	0.1838	550,599	711,794
1994	3,717,576.21	-90%	3,345,819	54	413,028	7,649	31.20	0.0118	39,468	47,117	174,422	0.1752	586,162	760,584
1995	3,538,476.34	-90%	3,184,629	54	393,130	7,280	31.94	0.0115	36,505	43,785	160,632	0.1668	531,048	691,680
1996	1,695,308.00	-90%	1,525,777	54	188,351	3,488	32.68	0.0111	16,990	20,478	74,350	0.1585	241,780	316,131
1997	2,278,747.16	-90%	2,050,872	54	253,172	4,688	33.44	0.0108	22,178	26,867	96,394	0.1503	308,305	404,700
1998	1,144,449.88	-90%	1,030,005	54	127,150	2,355	34.20	0.0105	10,814	13,169	46,615	0.1424	146,626	193,242
1999	1,729,109.41	-90%	1,556,198	54	192,107	3,558	34.97	0.0102	15,858	19,416	67,688	0.1345	209,367	277,055
2000	3,393,475.45	-90%	3,054,128	54	377,020	6,982	35.75	0.0099	30,199	37,181	127,411	0.1269	387,508	514,919
2001	1,943,467.14	-90%	1,749,120	54	215,922	3,999	36.54	0.0096	16,777	20,776	69,831	0.1194	208,816	278,647
2002	3,113,931.43	-90%	2,802,538	54	345,962	6,407	37.33	0.0093	26,069	32,476	106,814	0.1120	314,018	420,833
2003	4,723,981.00	-90%	4,251,583	54	524,841	9,719	38.13	0.0090	38,343	48,062	154,275	0.1049	445,859	600,134
2004	266,660.90	-90%	239,995	54	29,626	549	38.93	0.0087	2,098	2,646	8,267	0.0979	23,484	31,751
2005	3,492,202.34	-90%	3,142,982	54	387,989	7,185	39.74	0.0085	26,623	33,808	102,422	0.0910	286,000	388,422
2006	3,526,484.12	-90%	3,173,836	54	391,798	7,256	40.56	0.0082	26,045	33,300	97,488	0.0843	267,561	365,049
2007	2,206,103.01	-90%	1,985,493	54	245,101	4,539	41.39	0.0079	15,780	20,319	57,241	0.0778	154,404	211,645
2008	3,744,106.95	-90%	3,369,696	54	415,976	7,703	42.22	0.0077	25,933	33,636	90,744	0.0714	240,562	331,306
2009	4,065,552.59	-90%	3,658,997	54	451,689	8,365	43.06	0.0075	27,260	35,625	91,525	0.0652	238,444	329,969
2010	3,220,972.93	-90%	2,898,876	54	357,855	6,627	43.90	0.0072	20,903	27,530	66,920	0.0591	171,325	238,246
2011	6,178,851.21	-90%	5,560,966	54	686,480	12,713	44.75	0.0070	38,799	51,512	117,570	0.0532	295,780	413,350
2012	14,574,278.57	-90%	13,116,851	54	1,619,224	29,986	45.61	0.0067	88,534	118,520	251,665	0.0474	622,141	873,807
2013	13,891,259.95	-90%	12,502,134	54	1,543,340	28,580	46.47	0.0065	81,616	110,197	215,261	0.0418	522,897	738,158
2014	9,765,209.07	-90%	8,788,688	54	1,084,929	20,091	47.33	0.0063	55,480	75,571	133,911	0.0364	319,625	453,536
2015	7,193,323.49	-90%	6,473,991	54	799,189	14,800	48.21	0.0061	39,510	54,310	85,735	0.0311	201,074	286,809
2016	8,417,415.82	-90%	7,575,674	54	935,187	17,318	49.08	0.0059	44,689	62,007	85,129	0.0259	196,172	281,301
2017	8,365,250.58	-90%	7,528,726	54	929,392	17,211	49.97	0.0057	42,918	60,129	69,406	0.0209	157,151	226,557
2018	3,879,136.82	-90%	3,491,223	54	430,978	7,981	50.86	0.0055	19,229	27,210	25,098	0.0160	55,836	80,935
2019	10,011,832.57	-90%	9,010,649	54	1,112,329	20,599	51.75	0.0053	47,943	68,541	46,391	0.0113	101,408	147,800
2020	15,392,719.88	-90%	13,853,448	54	1,710,154	31,670	52.65	0.0051	71,191	102,861	42,908	0.0067	92,160	135,068
2021	15,836,595.54	-90%	14,252,936	54	1,759,469	32,583	53.55	0.0050	70,728	103,311	14,745	0.0022	31,117	45,862
	182,061,444.95		163,855,300		20,227,296	374,580			1,289,963	1,664,543	3,934,688		12,429,995	16,364,683

Account 366 - Underground Conduit
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 3.53%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 3.53%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.03530)^e)	g=f/e	h	i=1/(1+0.03530)^(h-1)-1/(1+0.03530)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
1955	15,550,638.19	-60%	9,330,383	75	691,725	9,223	17.58	0.0192	178,998	188,221	529,608	0.4693	4,379,040	4,908,647
1956	691,217.16	-60%	414,730	75	30,747	410	18.19	0.0188	7,789	8,199	23,290	0.4579	189,905	213,195
1957	1,417,377.30	-60%	850,426	75	63,048	841	18.81	0.0184	15,629	16,470	47,231	0.4465	379,712	426,943
1958	1,584,290.31	-60%	950,574	75	70,473	940	19.45	0.0180	17,087	18,027	52,194	0.4351	413,588	465,782
1959	1,767,534.87	-60%	1,060,521	75	78,624	1,048	20.10	0.0176	18,640	19,688	57,551	0.4238	449,418	506,970
1960	1,870,008.77	-60%	1,122,005	75	83,182	1,109	20.76	0.0172	19,276	20,385	60,159	0.4125	462,877	523,035
1961	1,773,082.78	-60%	1,063,850	75	78,870	1,052	21.43	0.0168	17,857	18,909	56,337	0.4014	427,007	483,343
1962	1,699,759.35	-60%	1,019,856	75	75,609	1,008	22.11	0.0164	16,721	17,729	53,324	0.3903	398,075	451,398
1963	2,276,609.52	-60%	1,365,966	75	101,268	1,350	22.79	0.0160	21,868	23,218	70,493	0.3794	518,229	588,721
1964	3,720,465.53	-60%	2,232,279	75	165,494	2,207	23.49	0.0156	34,881	37,088	113,658	0.3685	822,649	936,307
1965	3,444,724.38	-60%	2,066,835	75	153,229	2,043	24.20	0.0152	31,513	33,556	103,788	0.3578	739,492	843,281
1966	3,998,926.41	-60%	2,399,356	75	177,881	2,372	24.92	0.0149	35,685	38,056	118,787	0.3472	833,018	951,805
1967	3,603,468.45	-60%	2,162,081	75	160,290	2,137	25.64	0.0145	31,354	33,491	105,484	0.3367	727,918	833,402
1968	808,760.06	-60%	485,256	75	35,975	480	26.38	0.0141	6,859	7,339	23,321	0.3263	158,343	181,664
1969	6,480,198.66	-60%	3,888,119	75	288,253	3,843	27.13	0.0138	53,558	57,402	183,997	0.3161	1,228,976	1,412,973
1970	3,821,883.23	-60%	2,293,130	75	170,005	2,267	27.88	0.0134	30,769	33,036	106,802	0.3060	701,641	808,443
1971	2,641,579.67	-60%	1,584,948	75	117,503	1,567	28.65	0.0131	20,710	22,277	72,620	0.2960	469,179	541,799
1972	3,000,166.82	-60%	1,800,100	75	133,454	1,779	29.42	0.0127	22,899	24,678	81,102	0.2862	515,231	596,334
1973	7,128,152.47	-60%	4,276,891	75	317,075	4,228	30.20	0.0124	52,946	57,173	189,379	0.2766	1,182,802	1,372,181
1974	7,054,287.19	-60%	4,232,572	75	313,789	4,184	31.00	0.0120	50,977	55,161	184,104	0.2671	1,130,326	1,314,430
1975	10,605,235.36	-60%	6,363,141	75	471,743	6,290	31.80	0.0117	74,541	80,831	271,747	0.2577	1,639,901	1,911,647
1976	5,071,774.04	-60%	3,043,064	75	225,603	3,008	32.61	0.0114	34,661	37,669	127,523	0.2485	756,290	883,813
1977	4,879,149.32	-60%	2,927,490	75	217,035	2,894	33.42	0.0111	32,413	35,306	120,316	0.2395	701,167	821,483
1978	6,501,831.32	-60%	3,901,099	75	289,215	3,856	34.25	0.0108	41,974	45,831	157,151	0.2307	899,863	1,057,014
1979	8,676,661.26	-60%	5,205,997	75	385,956	5,146	35.08	0.0105	54,418	59,564	205,427	0.2220	1,155,632	1,361,059
1980	8,407,888.16	-60%	5,044,733	75	374,000	4,987	35.92	0.0102	51,217	56,204	194,872	0.2135	1,076,906	1,271,778
1981	6,773,730.10	-60%	4,064,238	75	301,310	4,017	36.77	0.0099	40,067	44,085	153,593	0.2051	833,737	987,329
1982	17,665,358.02	-60%	10,599,215	75	785,792	10,477	37.62	0.0096	101,436	111,913	391,592	0.1970	2,087,737	2,479,329
1983	11,248,708.34	-60%	6,749,225	75	500,366	6,672	38.49	0.0093	62,688	69,359	243,601	0.1890	1,275,488	1,519,089
1984	7,524,840.77	-60%	4,514,904	75	334,721	4,463	39.35	0.0090	40,691	45,154	159,082	0.1812	817,987	977,069
1985	13,562,533.92	-60%	8,137,520	75	603,290	8,044	40.23	0.0087	71,143	79,187	279,675	0.1735	1,412,105	1,691,780
1986	11,360,954.78	-60%	6,816,573	75	505,359	6,738	41.11	0.0085	57,799	64,537	228,334	0.1661	1,132,010	1,360,343
1987	13,435,558.24	-60%	8,061,335	75	597,642	7,969	42.00	0.0082	66,281	74,250	262,956	0.1588	1,280,006	1,542,962
1988	18,864,826.29	-60%	11,318,896	75	839,147	11,189	42.90	0.0080	90,222	101,410	359,209	0.1517	1,716,712	2,075,921
1989	14,637,737.87	-60%	8,782,643	75	651,117	8,682	43.79	0.0077	67,855	76,536	270,910	0.1447	1,271,107	1,542,018
1990	9,464,455.83	-60%	5,678,673	75	420,999	5,613	44.70	0.0075	42,517	48,131	170,085	0.1380	783,460	953,545
1991	9,982,102.81	-60%	5,989,262	75	444,025	5,920	45.61	0.0073	43,448	49,368	173,994	0.1314	786,786	960,780
1992	13,201,725.04	-60%	7,921,035	75	587,240	7,830	46.53	0.0070	55,665	63,495	222,945	0.1249	989,664	1,212,609
1993	19,593,827.74	-60%	11,756,297	75	871,574	11,621	47.45	0.0068	80,021	91,642	320,197	0.1187	1,395,308	1,715,505
1994	18,970,555.69	-60%	11,382,333	75	843,850	11,251	48.37	0.0066	75,028	86,279	299,599	0.1126	1,281,576	1,581,175
1995	15,546,206.20	-60%	9,327,724	75	691,528	9,220	49.30	0.0064	59,533	68,753	236,946	0.1067	994,955	1,231,901
1996	8,530,303.20	-60%	5,118,182	75	379,446	5,059	50.24	0.0062	31,625	36,684	125,289	0.1009	516,443	641,732
1997	8,355,779.09	-60%	5,013,467	75	371,683	4,956	51.17	0.0060	29,986	34,941	118,076	0.0953	477,770	595,846
1998	5,158,284.24	-60%	3,094,971	75	229,451	3,059	52.12	0.0058	17,916	20,975	70,009	0.0898	278,079	348,088
1999	6,056,313.08	-60%	3,633,788	75	269,397	3,592	53.06	0.0056	20,356	23,948	78,802	0.0846	307,263	386,065
2000	9,617,181.81	-60%	5,770,309	75	427,792	5,704	54.01	0.0054	31,277	36,981	119,717	0.0794	458,244	577,961
2001	19,590,336.73	-60%	11,754,202	75	871,419	11,619	54.96	0.0052	61,640	73,259	232,795	0.0744	874,770	1,107,565
2002	10,900,114.74	-60%	6,540,069	75	484,860	6,465	55.92	0.0051	33,178	39,643	123,349	0.0696	455,040	578,389
2003	42,046,512.02	-60%	25,227,907	75	1,870,317	24,938	56.88	0.0049	123,795	148,733	451,893	0.0649	1,636,637	2,088,530
2004	4,829,445.69	-60%	2,897,667	75	214,824	2,864	57.84	0.0047	13,752	16,617	49,149	0.0603	174,763	223,912
2005	18,810,378.48	-60%	11,286,227	75	836,725	11,156	58.81	0.0046	51,802	62,958	180,672	0.0559	630,758	811,430
2006	8,933,009.00	-60%	5,359,805	75	397,359	5,298	59.77	0.0044	23,789	29,087	80,675	0.0516	276,544	357,219
2007	8,171,618.72	-60%	4,902,971	75	363,491	4,847	60.74	0.0043	21,041	25,888	69,100	0.0474	232,584	301,683
2008	39,894,534.93	-60%	23,936,721	75	1,774,592	23,661	61.71	0.0041	99,321	122,982	314,358	0.0434	1,039,027	1,353,386
2009	24,629,423.49	-60%	14,777,654	75	1,095,568	14,608	62.69	0.0040	59,279	73,887	179,843	0.0395	583,733	763,575
2010	15,122,420.80	-60%	9,073,452	75	672,677	8,969	63.66	0.0039	35,185	44,155	101,668	0.0357	324,079	425,747
2011	24,413,155.60	-60%	14,647,893	75	1,085,948	14,479	64.64	0.0037	54,907	69,387	149,967	0.0321	469,496	619,463
2012	24,010,961.32	-60%	14,406,577	75	1,068,058	14,241	65.62	0.0036	52,198	66,439	133,542	0.0285	410,632	544,174
2013	26,812,645.09	-60%	16,087,587	75	1,192,683	15,902	66.60	0.0035	56,338	72,240	133,520	0.0251	403,284	536,804
2014	39,402,498.56	-60%	23,641,499	75	1,752,706	23,369	67.59	0.0034	80,014	103,384	173,235	0.0217	513,989	687,223
2015	31,948,161.31	-60%	19,168,897	75	1,421,121	18,948	68.57	0.0033	62,698	81,647	121,806	0.0185	355,037	476,843
2016	40,649,041.12	-60%	24,389,425	75	1,808,154	24,109	69.56	0.0032	77,092	101,201	131,214	0.0154	375,757	506,972
2017	51,046,724.04	-60%	30,628,034	75	2,270,665	30,276	70.54	0.0031	93,553	123,829	134,899	0.0124	379,565	514,464
2018	69,193,012.64	-60%	41,515,808	75	3,077,850	41,038	71.53	0.0030	122,534	163,572	142,282	0.0095	393,378	535,659
2019	33,916,464.62	-60%	20,349,879	75	1,508,675	20,116	72.52	0.0029	58,036	78,152	49,839	0.0067	135,410	185,250
2020	54,204,827.09	-60%	32,522,896	75	2,411,144	32,149	73.51	0.0028	89,620	121,769	47,817	0.0039	127,678	175,495
2021	44,139,775.71	-60%	26,483,865	75	1,963,430	26,179	74.50	0.0027	70,512	96,691	12,985	0.0013	34,078	47,063
	990,691,715.33		594,415,029		44,068,040	587,574			3,401,081	3,988,655	10,609,483		52,279,860	62,889,342

Account 367 - Underground Conductors and Devices
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 3.42%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 3.42%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.03420)^e)	g=f/e	h	i=1/(1+0.03420)^(h-1)-1/(1+0.03420)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
1955	4,428,405.97	-70%	3,099,884	67	325,718	4,861	16.24	0.0198	61,395	66,257	246,748	0.4740	1,469,467	1,716,215
1956	906,739.11	-70%	634,717	67	66,692	995	16.72	0.0195	12,373	13,368	50,053	0.4649	295,092	345,146
1957	716,738.21	-70%	501,717	67	52,718	787	17.20	0.0192	9,622	10,409	39,183	0.4557	228,633	267,816
1958	1,005,496.96	-70%	703,848	67	73,956	1,104	17.70	0.0189	13,275	14,379	54,420	0.4464	314,194	368,614
1959	875,927.33	-70%	613,149	67	64,426	962	18.21	0.0185	11,367	12,329	46,916	0.4370	267,948	314,864
1960	984,218.44	-70%	688,953	67	72,391	1,080	18.73	0.0182	12,550	13,630	52,151	0.4276	294,562	346,714
1961	1,070,642.97	-70%	749,450	67	78,748	1,175	19.27	0.0179	13,408	14,583	56,101	0.4180	313,301	369,402
1962	679,412.83	-70%	475,589	67	49,972	746	19.82	0.0176	8,353	9,099	35,192	0.4085	194,275	229,467
1963	1,508,789.73	-70%	1,056,153	67	110,974	1,656	20.38	0.0172	18,204	19,860	77,225	0.3989	421,309	498,534
1964	1,645,048.33	-70%	1,151,534	67	120,997	1,806	20.95	0.0169	19,470	21,276	83,167	0.3893	448,311	531,478
1965	1,803,457.44	-70%	1,262,420	67	132,648	1,980	21.53	0.0166	20,931	22,910	90,020	0.3797	479,357	569,377
1966	1,637,230.50	-70%	1,146,061	67	120,422	1,797	22.13	0.0163	18,625	20,423	80,655	0.3701	424,182	504,838
1967	1,620,792.33	-70%	1,134,555	67	119,212	1,779	22.73	0.0159	18,067	19,846	78,768	0.3605	409,054	487,822
1968	1,476,377.09	-70%	1,033,464	67	108,590	1,621	23.35	0.0156	16,120	17,740	70,751	0.3510	362,745	433,496
1969	3,536,701.42	-70%	2,475,691	67	260,131	3,883	23.97	0.0153	37,810	41,692	167,053	0.3415	845,410	1,012,463
1970	3,179,475.85	-70%	2,225,633	67	233,857	3,490	24.61	0.0149	33,271	36,761	147,959	0.3320	738,977	886,936
1971	1,768,250.05	-70%	1,237,775	67	130,058	1,941	25.26	0.0146	18,105	20,046	81,031	0.3226	399,335	480,366
1972	1,508,354.49	-70%	1,055,848	67	110,942	1,656	25.91	0.0143	15,107	16,763	68,035	0.3133	330,790	398,825
1973	4,197,211.67	-70%	2,938,048	67	308,713	4,608	26.58	0.0140	41,107	45,715	186,247	0.3040	893,242	1,079,489
1974	4,998,408.71	-70%	3,498,886	67	367,643	5,487	27.25	0.0137	47,856	53,343	218,099	0.2949	1,031,652	1,249,751
1975	5,767,663.07	-70%	4,037,364	67	424,223	6,332	27.94	0.0134	53,965	60,296	247,332	0.2858	1,153,694	1,401,026
1976	5,979,053.36	-70%	4,185,337	67	439,771	6,564	28.63	0.0131	54,656	61,220	251,855	0.2768	1,158,357	1,410,212
1977	5,096,545.29	-70%	3,567,582	67	374,861	5,595	29.33	0.0128	45,502	51,097	210,756	0.2679	955,621	1,166,377
1978	6,757,640.65	-70%	4,730,348	67	497,038	7,418	30.04	0.0125	58,912	66,330	274,188	0.2591	1,225,525	1,499,713
1979	7,103,509.51	-70%	4,972,457	67	522,477	7,798	30.76	0.0122	60,450	68,248	282,622	0.2504	1,245,052	1,527,674
1980	6,849,866.80	-70%	4,794,907	67	503,821	7,520	31.48	0.0119	56,887	64,407	267,079	0.2418	1,159,547	1,426,626
1981	5,649,145.31	-70%	3,954,402	67	415,506	6,202	32.22	0.0116	45,772	51,974	215,712	0.2334	922,855	1,138,568
1982	10,376,674.00	-70%	7,263,672	67	763,225	11,391	32.96	0.0113	82,009	93,400	387,798	0.2251	1,634,692	2,022,490
1983	12,884,519.24	-70%	9,019,163	67	947,682	14,145	33.71	0.0110	99,296	113,440	470,925	0.2168	1,955,696	2,426,621
1984	8,116,685.04	-70%	5,681,680	67	596,998	8,910	34.46	0.0107	60,983	69,893	289,932	0.2088	1,186,129	1,476,061
1985	5,524,972.92	-70%	3,867,481	67	406,373	6,065	35.23	0.0105	40,458	46,523	192,722	0.2008	776,616	969,338
1986	6,788,494.15	-70%	4,751,946	67	499,307	7,452	36.00	0.0102	48,440	55,892	231,059	0.1930	917,071	1,148,130
1987	7,188,159.54	-70%	5,031,712	67	528,703	7,891	36.77	0.0099	49,968	57,859	238,524	0.1853	932,338	1,170,861
1988	13,690,848.70	-70%	9,583,594	67	1,006,989	15,030	37.56	0.0097	92,695	107,724	442,522	0.1777	1,703,380	2,145,902
1989	12,776,440.66	-70%	8,943,508	67	939,732	14,026	38.35	0.0094	84,231	98,257	401,862	0.1703	1,523,163	1,925,025
1990	6,616,086.02	-70%	4,631,260	67	486,626	7,263	39.15	0.0092	42,464	49,727	202,307	0.1630	755,003	957,310
1991	13,880,953.77	-70%	9,716,668	67	1,020,971	15,238	39.95	0.0089	86,712	101,951	412,186	0.1559	1,514,476	1,926,662
1992	8,538,713.20	-70%	5,977,099	67	628,039	9,374	40.76	0.0087	51,907	61,280	245,958	0.1489	889,698	1,135,655
1993	18,712,929.30	-70%	13,099,051	67	1,376,373	20,543	41.58	0.0084	110,670	131,213	522,227	0.1420	1,859,582	2,381,808
1994	10,143,327.54	-70%	7,100,329	67	746,062	11,135	42.40	0.0082	58,351	69,486	273,908	0.1352	960,102	1,234,010
1995	23,197,604.89	-70%	16,238,323	67	1,706,230	25,466	43.23	0.0080	129,774	155,240	605,285	0.1286	2,088,332	2,693,617
1996	11,055,584.19	-70%	7,738,909	67	813,160	12,137	44.07	0.0078	60,135	72,272	278,331	0.1221	945,174	1,223,505
1997	6,726,890.74	-70%	4,708,824	67	494,776	7,385	44.91	0.0076	35,569	42,954	163,139	0.1158	545,248	708,386
1998	9,253,272.02	-70%	6,477,290	67	680,596	10,158	45.76	0.0073	47,554	57,712	215,806	0.1096	709,858	925,664
1999	7,040,999.11	-70%	4,928,699	67	517,879	7,730	46.61	0.0071	35,161	42,891	157,616	0.1035	510,220	667,836
2000	11,108,909.22	-70%	7,776,236	67	817,082	12,195	47.47	0.0069	53,897	66,093	238,215	0.0976	758,867	997,082
2001	17,685,508.91	-70%	12,379,856	67	1,300,804	19,415	48.33	0.0067	83,348	102,763	362,466	0.0918	1,136,276	1,498,742
2002	13,713,751.12	-70%	9,599,626	67	1,008,673	15,055	49.20	0.0065	62,769	77,824	267,986	0.0861	826,688	1,094,674
2003	27,164,571.04	-70%	19,015,200	67	1,998,008	29,821	50.07	0.0063	120,733	150,554	504,763	0.0806	1,532,195	2,036,958
2004	6,757,706.60	-70%	4,730,395	67	497,043	7,419	50.95	0.0062	29,160	36,579	119,051	0.0752	355,594	474,645
2005	31,231,399.31	-70%	21,861,980	67	2,297,131	34,286	51.84	0.0060	130,819	165,105	519,898	0.0699	1,527,992	2,047,890
2006	21,828,956.99	-70%	15,280,270	67	1,605,563	23,964	52.72	0.0058	88,744	112,707	342,087	0.0647	989,280	1,331,367
2007	24,968,380.95	-70%	17,477,867	67	1,836,474	27,410	53.62	0.0056	98,503	125,913	366,799	0.0597	1,043,719	1,410,518
2008	23,409,261.32	-70%	16,386,483	67	1,721,797	25,698	54.52	0.0055	89,606	115,305	320,834	0.0548	898,275	1,219,110
2009	28,333,126.49	-70%	19,833,189	67	2,083,957	31,104	55.42	0.0053	105,213	136,317	360,255	0.0500	992,445	1,352,700
2010	22,758,003.82	-70%	15,930,603	67	1,673,896	24,984	56.32	0.0051	81,974	106,958	266,734	0.0454	723,016	989,750
2011	23,446,814.58	-70%	16,412,770	67	1,724,559	25,740	57.23	0.0050	81,910	107,650	251,385	0.0409	670,477	921,861
2012	41,929,412.33	-70%	29,350,589	67	3,083,991	46,030	58.15	0.0048	142,045	188,074	407,475	0.0364	1,069,362	1,476,838
2013	31,582,473.78	-70%	22,107,732	67	2,322,953	34,671	59.07	0.0047	103,741	138,411	275,102	0.0321	710,396	985,498
2014	36,919,977.63	-70%	25,843,984	67	2,715,537	40,530	59.99	0.0045	117,573	158,104	284,256	0.0279	722,282	1,006,538
2015	33,021,872.88	-70%	23,115,311	67	2,428,824	36,251	60.91	0.0044	101,939	138,190	220,707	0.0239	551,837	772,543
2016	50,121,974.01	-70%	35,085,382	67	3,686,570	55,023	61.84	0.0043	149,972	204,995	283,925	0.0199	698,564	982,489
2017	51,412,293.80	-70%	35,988,606	67	3,781,475	56,440	62.77	0.0041	149,089	205,528	238,662	0.0161	577,838	816,500
2018	44,256,189.43	-70%	30,979,333	67	3,255,130	48,584	63.71	0.0040	124,366	172,950	160,032	0.0123	381,293	541,325
2019	73,390,120.54	-70%	51,373,084	67	5,397,988	80,567	64.64	0.0039	199,836	280,403	189,856	0.0087	445,169	635,025
2020	100,880,646.23	-70%	70,616,452	67	7,419,970	110,746	65.58	0.0038	266,138	376,883	156,802	0.0051	361,833	518,635
2021	59,640,543.85	-70%	41,748,381	67	4,386,679	65,473	66.53	0.0037	152,428	217,901	30,941	0.0017	70,270	101,211
	1,050,826,153.30		735,578,307		77,290,332	1,153,587			4,573,336	5,726,923	15,579,655		56,432,936	72,012,591

Account 368 - Line Transformers
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 5.76%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 5.76%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.05760)^e)	g=f/e	h	i=1/(1+0.05760)^(h-1)-1/(1+0.05760)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
1955	299,780.01	-50%	149,890	37	18,875	510	0.68	0.0555	8,312	8,822	18,528	0.8368	125,423	143,951
1956	52,535.69	-50%	26,268	37	3,308	89	0.91	0.0548	1,438	1,528	3,227	0.8246	21,661	24,887
1957	7,808.27	-50%	3,904	37	492	13	1.15	0.0540	211	224	476	0.8118	3,169	3,646
1958	9,577.86	-50%	4,789	37	603	16	1.41	0.0532	255	271	580	0.7983	3,823	4,403
1959	69,100.14	-50%	34,550	37	4,351	118	1.68	0.0524	1,812	1,929	4,154	0.7845	27,105	31,258
1960	60,446.81	-50%	30,223	37	3,806	103	1.95	0.0516	1,561	1,664	3,606	0.7707	23,295	26,900
1961	31,776.68	-50%	15,888	37	2,001	54	2.23	0.0509	808	862	1,880	0.7569	12,026	13,906
1962	66,912.35	-50%	33,456	37	4,213	114	2.51	0.0501	1,675	1,788	3,927	0.7430	24,859	28,787
1963	84,163.31	-50%	42,082	37	5,299	143	2.79	0.0493	2,073	2,216	4,899	0.7293	30,689	35,588
1964	110,891.17	-50%	55,446	37	6,982	189	3.08	0.0485	2,688	2,876	6,401	0.7157	39,681	46,082
1965	52,694.93	-50%	26,347	37	3,318	90	3.37	0.0477	1,257	1,346	3,016	0.7022	18,500	21,516
1966	149,091.21	-50%	74,546	37	9,387	254	3.66	0.0469	3,498	3,752	8,459	0.6888	51,349	59,808
1967	178,338.10	-50%	89,169	37	11,228	303	3.95	0.0462	4,118	4,421	10,031	0.6758	60,256	70,287
1968	98,636.77	-50%	49,318	37	6,210	168	4.24	0.0454	2,240	2,408	5,499	0.6628	32,687	38,186
1969	676,421.12	-50%	338,211	37	42,589	1,151	4.53	0.0447	15,113	16,264	37,371	0.6499	219,794	257,165
1970	353,841.28	-50%	176,921	37	22,278	602	4.83	0.0439	7,775	8,378	19,370	0.6371	112,712	132,082
1971	360,849.67	-50%	180,425	37	22,720	614	5.13	0.0432	7,797	8,411	19,569	0.6243	112,638	132,207
1972	285,329.85	-50%	142,665	37	17,965	486	5.44	0.0425	6,059	6,545	15,324	0.6115	87,234	102,558
1973	399,501.93	-50%	199,751	37	25,153	680	5.75	0.0417	8,336	9,016	21,241	0.5986	119,565	140,806
1974	487,170.93	-50%	243,585	37	30,673	829	6.08	0.0410	9,983	10,812	25,634	0.5856	142,637	168,271
1975	550,815.95	-50%	275,408	37	34,680	937	6.41	0.0402	11,078	12,015	28,671	0.5724	157,647	186,318
1976	497,025.79	-50%	248,513	37	31,294	846	6.76	0.0395	9,805	10,651	25,580	0.5591	138,935	164,515
1977	479,583.62	-50%	239,792	37	30,195	816	7.11	0.0387	9,274	10,090	24,391	0.5455	130,816	155,207
1978	916,114.43	-50%	458,057	37	57,680	1,559	7.48	0.0379	17,353	18,912	46,017	0.5318	243,591	289,608
1979	1,711,688.03	-50%	855,844	37	107,771	2,913	7.86	0.0371	31,735	34,648	84,864	0.5178	443,185	528,049
1980	2,323,488.83	-50%	1,161,744	37	146,291	3,954	8.26	0.0363	42,130	46,084	113,625	0.5037	585,135	698,760
1981	2,720,233.67	-50%	1,360,117	37	171,271	4,629	8.67	0.0354	48,198	52,827	131,118	0.4893	665,499	796,617
1982	3,471,605.25	-50%	1,735,803	37	218,578	5,908	9.10	0.0346	60,056	65,963	164,809	0.4747	824,057	988,866
1983	3,328,573.38	-50%	1,664,287	37	209,573	5,664	9.55	0.0337	56,169	61,834	155,508	0.4600	765,592	921,100
1984	2,397,572.47	-50%	1,198,786	37	150,955	4,080	10.00	0.0329	39,431	43,511	110,138	0.4451	533,617	643,755
1985	4,646,041.23	-50%	2,323,021	37	292,523	7,906	10.48	0.0320	74,403	82,309	209,669	0.4301	999,200	1,208,870
1986	6,164,724.76	-50%	3,082,362	37	388,142	10,490	10.97	0.0312	96,045	106,535	273,052	0.4150	1,279,305	1,552,357
1987	7,622,649.93	-50%	3,811,325	37	479,935	12,971	11.48	0.0303	115,429	128,401	331,040	0.3999	1,524,047	1,855,087
1988	8,143,679.51	-50%	4,071,840	37	512,740	13,858	12.00	0.0294	119,755	133,613	346,410	0.3847	1,566,338	1,912,749
1989	9,054,991.96	-50%	4,527,496	37	570,118	15,409	12.54	0.0285	129,192	144,601	376,860	0.3695	1,672,798	2,049,658
1990	9,851,506.21	-50%	4,925,753	37	620,268	16,764	13.10	0.0277	136,253	153,017	400,702	0.3543	1,745,231	2,145,932
1991	5,679,096.71	-50%	2,839,548	37	357,566	9,664	13.67	0.0268	76,072	85,736	225,471	0.3392	963,135	1,188,606
1992	5,702,892.90	-50%	2,851,446	37	359,064	9,704	14.26	0.0259	73,924	83,628	220,727	0.3242	924,337	1,145,064
1993	4,676,370.30	-50%	2,338,185	37	294,432	7,958	14.86	0.0251	58,611	66,568	176,212	0.3093	723,114	899,326
1994	4,109,704.89	-50%	2,054,852	37	258,754	6,993	15.47	0.0242	49,761	56,754	150,548	0.2945	605,146	755,694
1995	6,379,514.68	-50%	3,189,757	37	401,665	10,856	16.10	0.0234	74,563	85,419	226,850	0.2799	892,833	1,119,684
1996	5,583,637.69	-50%	2,791,819	37	351,555	9,501	16.75	0.0225	62,947	72,449	192,425	0.2655	741,276	933,701
1997	5,194,453.43	-50%	2,597,227	37	327,052	8,839	17.41	0.0217	56,439	65,278	173,191	0.2513	652,792	825,983
1998	6,691,591.45	-50%	3,345,796	37	421,314	11,387	18.08	0.0209	70,020	81,407	215,455	0.2374	794,315	1,009,770
1999	8,629,428.51	-50%	4,314,714	37	543,324	14,684	18.76	0.0201	86,900	101,584	267,792	0.2237	965,352	1,233,144
2000	6,746,469.47	-50%	3,373,235	37	424,769	11,480	19.46	0.0194	65,334	76,814	201,348	0.2103	709,504	910,852
2001	12,271,405.50	-50%	6,135,703	37	772,629	20,882	20.17	0.0186	114,204	135,085	351,404	0.1972	1,210,073	1,561,477
2002	10,001,206.54	-50%	5,000,603	37	629,693	17,019	20.89	0.0179	89,386	106,404	274,100	0.1844	922,139	1,196,238
2003	9,065,409.34	-50%	4,532,705	37	570,774	15,426	21.63	0.0172	77,759	93,185	237,129	0.1719	779,202	1,016,331
2004	6,729,025.82	-50%	3,364,513	37	423,671	11,451	22.37	0.0165	55,357	66,808	167,474	0.1597	537,388	704,862
2005	19,338,291.19	-50%	9,669,146	37	1,217,572	32,907	23.13	0.0158	152,484	185,392	456,385	0.1479	1,429,728	1,886,112
2006	19,665,157.64	-50%	9,832,579	37	1,238,152	33,464	23.90	0.0151	148,536	181,999	438,405	0.1363	1,340,594	1,778,999
2007	23,488,715.13	-50%	11,744,358	37	1,478,890	39,970	24.68	0.0145	169,847	209,817	492,526	0.1252	1,469,836	1,962,363
2008	22,310,670.78	-50%	11,155,335	37	1,404,718	37,965	25.47	0.0138	154,355	192,320	437,869	0.1143	1,275,052	1,712,920
2009	21,292,735.22	-50%	10,646,368	37	1,340,627	36,233	26.27	0.0132	140,866	177,099	388,941	0.1038	1,104,964	1,493,904
2010	15,882,559.02	-50%	7,941,280	37	999,993	27,027	27.07	0.0126	100,421	127,448	268,257	0.0936	743,425	1,011,682
2011	17,215,095.90	-50%	8,607,548	37	1,083,892	29,294	27.89	0.0121	103,969	133,264	266,785	0.0838	721,129	987,913
2012	25,596,450.39	-50%	12,798,225	37	1,611,597	43,557	28.72	0.0115	147,586	191,142	360,620	0.0743	950,653	1,311,273
2013	31,139,374.66	-50%	15,569,687	37	1,960,589	52,989	29.56	0.0110	171,326	224,315	394,375	0.0651	1,013,822	1,408,197
2014	30,315,036.61	-50%	15,157,518	37	1,908,687	51,586	30.40	0.0105	159,075	210,661	340,306	0.0563	853,033	1,193,338
2015	27,500,318.33	-50%	13,750,159	37	1,731,468	46,796	31.26	0.0100	137,563	184,360	268,728	0.0478	656,784	925,512
2016	30,684,191.78	-50%	15,342,096	37	1,931,930	52,214	32.12	0.0095	146,253	198,468	254,813	0.0396	607,190	862,002
2017	37,387,440.62	-50%	18,693,720	37	2,353,978	63,621	32.99	0.0091	169,724	233,345	255,091	0.0317	592,614	847,705
2018	48,420,130.55	-50%	24,210,065	37	3,048,615	82,395	33.87	0.0086	209,257	291,652	257,991	0.0241	584,311	842,302
2019	37,580,399.26	-50%	18,790,200	37	2,366,127	63,949	34.75	0.0082	154,549	218,499	143,581	0.0169	317,024	460,604
2020	41,956,079.91	-50%	20,978,040	37	2,641,627	71,395	35.65	0.0078	164,130	235,525	96,558	0.0099	207,848	304,405
2021	42,979,276.10	-50%	21,489,638	37	2,706,050	73,136	36.55	0.0074	159,866	233,002	33,068	0.0032	69,394	102,462
	657,927,293.41		328,963,647		41,424,240	1,119,574			4,684,397	5,803,971	11,270,070		39,902,099	51,172,168

Account 369.1 - Overhead Services
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 3.23%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 3.23%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.03230)^e)	g=f/e	h	i=1/(1+0.03230)^(h-1)-1/(1+0.03230)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
1955	398,732.11	-70%	279,112	50	56,949	1,139	14.26	0.0205	5,730	6,869	40,711	0.4316	120,455	161,166
1956	30,420.48	-70%	21,294	50	4,345	87	14.67	0.0203	431	518	3,070	0.4232	9,012	12,082
1957	27,658.40	-70%	19,361	50	3,950	79	15.09	0.0200	387	466	2,758	0.4149	8,034	10,792
1958	27,870.77	-70%	19,510	50	3,981	80	15.51	0.0197	385	464	2,746	0.4067	7,934	10,680
1959	30,985.87	-70%	21,690	50	4,426	89	15.94	0.0195	422	511	3,015	0.3985	8,643	11,658
1960	30,193.92	-70%	21,136	50	4,312	86	16.37	0.0192	406	492	2,901	0.3903	8,250	11,151
1961	32,842.62	-70%	22,990	50	4,691	94	16.80	0.0189	435	529	3,115	0.3822	8,787	11,902
1962	47,419.20	-70%	33,193	50	6,773	135	17.23	0.0187	620	755	4,438	0.3741	12,419	16,857
1963	31,493.90	-70%	22,046	50	4,498	90	17.67	0.0184	406	496	2,908	0.3661	8,071	10,979
1964	51,184.78	-70%	35,829	50	7,310	146	18.12	0.0182	651	797	4,661	0.3581	12,831	17,492
1965	65,926.94	-70%	46,149	50	9,416	188	18.57	0.0179	826	1,014	5,919	0.3502	16,159	22,079
1966	57,991.20	-70%	40,594	50	8,283	166	19.02	0.0176	716	882	5,132	0.3422	13,893	19,025
1967	44,927.38	-70%	31,449	50	6,417	128	19.48	0.0174	547	675	3,917	0.3344	10,515	14,432
1968	79,835.37	-70%	55,885	50	11,402	228	19.94	0.0171	958	1,186	6,855	0.3265	18,247	25,103
1969	8,845.26	-70%	6,192	50	1,263	25	20.40	0.0169	105	130	748	0.3187	1,973	2,721
1970	85,179.58	-70%	59,626	50	12,166	243	20.87	0.0166	992	1,235	7,087	0.3110	18,541	25,628
1971	38,134.38	-70%	26,694	50	5,447	109	21.35	0.0164	437	546	3,121	0.3032	8,095	11,216
1972	5,863.29	-70%	4,104	50	837	17	21.83	0.0161	66	83	472	0.2956	1,213	1,685
1973	36,625.76	-70%	25,638	50	5,231	105	22.31	0.0159	407	512	2,897	0.2879	7,382	10,279
1974	39,967.13	-70%	27,977	50	5,708	114	22.80	0.0156	438	552	3,105	0.2803	7,843	10,948
1975	37,920.93	-70%	26,545	50	5,416	108	23.30	0.0154	409	517	2,893	0.2728	7,242	10,134
1976	42,109.99	-70%	29,477	50	6,014	120	23.79	0.0152	447	567	3,152	0.2653	7,821	10,973
1977	69,518.44	-70%	48,663	50	9,929	199	24.30	0.0149	726	925	5,104	0.2579	12,549	17,653
1978	79,519.60	-70%	55,664	50	11,357	227	24.80	0.0147	817	1,044	5,723	0.2505	13,943	19,666
1979	65,698.36	-70%	45,989	50	9,383	188	25.32	0.0144	664	852	4,632	0.2431	11,182	15,814
1980	84,257.71	-70%	58,980	50	12,034	241	25.83	0.0142	838	1,079	5,817	0.2359	13,911	19,728
1981	64,589.24	-70%	45,212	50	9,225	184	26.35	0.0140	632	816	4,363	0.2286	10,337	14,700
1982	88,978.68	-70%	62,285	50	12,708	254	26.88	0.0137	856	1,110	5,876	0.2215	13,794	19,671
1983	63,036.77	-70%	44,126	50	9,003	180	27.41	0.0135	596	776	4,068	0.2144	9,459	13,526
1984	102,031.83	-70%	71,422	50	14,573	291	27.94	0.0133	949	1,240	6,428	0.2073	14,807	21,235
1985	29,278.94	-70%	20,495	50	4,182	84	28.48	0.0131	268	351	1,800	0.2003	4,106	5,905
1986	74,526.34	-70%	52,168	50	10,644	213	29.03	0.0128	670	883	4,465	0.1934	10,090	14,555
1987	76,530.48	-70%	53,571	50	10,930	219	29.57	0.0126	676	894	4,466	0.1866	9,994	14,460
1988	99,407.17	-70%	69,585	50	14,198	284	30.12	0.0124	863	1,147	5,644	0.1798	12,510	18,154
1989	81,253.94	-70%	56,878	50	11,605	232	30.68	0.0122	693	925	4,485	0.1731	9,844	14,328
1991	7,383.10	-70%	5,168	50	1,054	21	31.80	0.0118	61	82	384	0.1599	826	1,210
1992	182,372.83	-70%	127,661	50	26,047	521	32.37	0.0115	1,474	1,995	9,187	0.1534	19,580	28,767
1993	21,506.61	-70%	15,055	50	3,072	61	32.93	0.0113	171	232	1,048	0.1470	2,213	3,261
1994	26,830.06	-70%	18,781	50	3,832	77	33.51	0.0111	209	286	1,264	0.1406	2,641	3,906
1995	31,365.27	-70%	21,956	50	4,480	90	34.08	0.0109	240	330	1,426	0.1344	2,951	4,377
1996	19,166.83	-70%	13,417	50	2,737	55	34.66	0.0107	144	199	840	0.1282	1,721	2,560
1997	19,721.44	-70%	13,805	50	2,817	56	35.24	0.0105	145	202	831	0.1222	1,686	2,518
1998	26,898.01	-70%	18,829	50	3,842	77	35.82	0.0103	195	272	1,089	0.1162	2,187	3,277
1999	57,081.22	-70%	39,957	50	8,153	163	36.41	0.0102	406	569	2,216	0.1103	4,406	6,622
2000	79,655.05	-70%	55,759	50	11,377	228	37.00	0.0100	556	783	2,959	0.1044	5,824	8,783
2001	51,013.56	-70%	35,709	50	7,286	146	37.59	0.0098	349	495	1,809	0.0987	3,525	5,334
2002	82,973.05	-70%	58,081	50	11,851	237	38.18	0.0096	557	794	2,802	0.0931	5,406	8,208
2003	2.25	-70%	2	50	0	0	38.77	0.0094	0	0	0	0.0875	0	0
2004	121,437.18	-70%	85,006	50	17,344	347	39.37	0.0092	786	1,132	3,689	0.0821	6,977	10,666
2005	479,645.10	-70%	335,752	50	68,505	1,370	39.96	0.0091	3,045	4,415	13,754	0.0767	25,752	39,506
2006	75,295.90	-70%	52,707	50	10,754	215	40.56	0.0089	469	684	2,031	0.0714	3,764	5,795
2007	118,128.34	-70%	82,690	50	16,872	337	41.16	0.0087	722	1,059	2,984	0.0662	5,476	8,460
2008	125,668.64	-70%	87,968	50	17,949	359	41.76	0.0086	753	1,112	2,959	0.0611	5,377	8,335
2009	89,590.17	-70%	62,713	50	12,796	256	42.36	0.0084	527	783	1,955	0.0561	3,518	5,474
2010	120,110.22	-70%	84,077	50	17,155	343	42.96	0.0082	693	1,036	2,415	0.0512	4,302	6,717
2011	257,266.15	-70%	180,086	50	36,744	735	43.57	0.0081	1,456	2,191	4,729	0.0463	8,340	13,069
2012	1,280,758.71	-70%	896,531	50	182,923	3,658	44.17	0.0079	7,111	10,770	21,328	0.0415	37,245	58,573
2013	2,954,667.17	-70%	2,068,267	50	421,998	8,440	44.78	0.0078	16,092	24,532	44,081	0.0369	76,217	120,298
2014	1,655,643.19	-70%	1,158,950	50	236,466	4,729	45.39	0.0076	8,845	13,574	21,823	0.0322	37,360	59,184
2015	1,170,532.34	-70%	819,373	50	167,180	3,344	46.00	0.0075	6,133	9,477	13,390	0.0277	22,696	36,086
2016	709,175.93	-70%	496,423	50	101,287	2,026	46.61	0.0073	3,644	5,670	6,874	0.0232	11,536	18,410
2017	980,625.86	-70%	686,438	50	140,057	2,801	47.22	0.0072	4,942	7,743	7,786	0.0188	12,939	20,725
2018	1,006,218.41	-70%	704,353	50	143,712	2,874	47.83	0.0071	4,973	7,847	6,223	0.0145	10,239	16,462
2019	447,879.13	-70%	313,515	50	63,968	1,279	48.45	0.0069	2,170	3,450	1,981	0.0103	3,228	5,209
2020	1,262,911.47	-70%	884,038	50	180,374	3,607	49.07	0.0068	6,001	9,608	3,356	0.0061	5,414	8,769
2021	1,803,831.77	-70%	1,262,682	50	257,631	5,153	49.69	0.0067	8,404	13,556	1,597	0.0020	2,551	4,147
	17,496,111.72		12,247,278		2,498,867	49,977			106,740	156,718	367,299		805,785	1,173,085

Account 369.2 - Underground Services
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 3.87%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 3.87%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.03870)^e)	g=f/e	h	i=1/(1+0.03870)^(h-1)-1/(1+0.03870)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
1955	1,443,802.66	-70%	1,010,662	60	103,561	1,726	6.25	0.0305	30,846	32,572	92,768	0.6862	693,500	786,269
1956	27,156.21	-70%	19,009	60	1,948	32	6.59	0.0301	573	605	1,734	0.6762	12,854	14,588
1957	38,726.07	-70%	27,108	60	2,778	46	6.94	0.0297	806	852	2,456	0.6658	18,050	20,506
1958	51,915.07	-70%	36,341	60	3,724	62	7.31	0.0293	1,065	1,127	3,270	0.6551	23,806	27,076
1959	74,090.14	-70%	51,863	60	5,314	89	7.70	0.0289	1,498	1,587	4,632	0.6439	33,394	38,026
1960	91,017.19	-70%	63,712	60	6,529	109	8.12	0.0284	1,812	1,920	5,645	0.6322	40,281	45,926
1961	132,002.36	-70%	92,402	60	9,468	158	8.56	0.0280	2,584	2,742	8,118	0.6201	57,297	65,415
1962	227,310.38	-70%	159,117	60	16,305	272	9.02	0.0275	4,372	4,643	13,853	0.6074	96,656	110,508
1963	174,185.51	-70%	121,930	60	12,494	208	9.52	0.0270	3,288	3,496	10,513	0.5943	72,463	82,976
1964	347,749.36	-70%	243,425	60	24,943	416	10.03	0.0264	6,436	6,852	20,772	0.5807	141,360	162,132
1965	490,688.43	-70%	343,482	60	35,196	587	10.58	0.0259	8,895	9,481	28,990	0.5667	194,645	223,634
1966	477,514.69	-70%	334,260	60	34,251	571	11.15	0.0253	8,470	9,040	27,884	0.5523	184,601	212,485
1967	399,343.29	-70%	279,540	60	28,644	477	11.75	0.0248	6,924	7,402	23,034	0.5376	150,277	173,311
1968	826,217.36	-70%	578,352	60	59,263	988	12.37	0.0242	13,992	14,980	47,043	0.5227	302,295	349,338
1969	90,346.26	-70%	63,242	60	6,480	108	13.01	0.0236	1,493	1,601	5,075	0.5077	32,105	37,180
1970	911,879.75	-70%	638,316	60	65,408	1,090	13.67	0.0230	14,701	15,791	50,506	0.4926	314,454	364,960
1971	190,508.86	-70%	133,356	60	13,665	228	14.34	0.0225	2,994	3,222	10,399	0.4777	63,699	74,098
1972	425,070.86	-70%	297,550	60	30,490	508	15.02	0.0219	6,509	7,017	22,855	0.4628	137,706	160,561
1973	567,920.93	-70%	397,545	60	40,736	679	15.72	0.0213	8,471	9,149	30,065	0.4481	178,141	208,205
1974	652,757.83	-70%	456,930	60	46,821	780	16.42	0.0207	9,479	10,259	34,005	0.4335	198,102	232,107
1975	643,732.66	-70%	450,613	60	46,174	770	17.14	0.0202	9,096	9,866	32,983	0.4191	188,868	221,851
1976	1,039,839.53	-70%	727,888	60	74,586	1,243	17.87	0.0196	14,292	15,535	52,371	0.4049	294,715	347,086
1977	1,113,923.45	-70%	779,746	60	79,900	1,332	18.61	0.0191	14,885	16,217	55,114	0.3908	304,721	359,836
1978	1,138,111.10	-70%	796,678	60	81,635	1,361	19.37	0.0185	14,778	16,139	55,284	0.3769	300,233	355,517
1979	1,266,612.69	-70%	886,629	60	90,852	1,514	20.13	0.0180	15,975	17,489	60,365	0.3631	321,939	382,304
1980	1,660,871.05	-70%	1,162,610	60	119,131	1,986	20.91	0.0175	20,336	22,322	77,606	0.3495	406,355	483,962
1981	1,128,065.23	-70%	789,646	60	80,914	1,349	21.71	0.0170	13,403	14,751	51,641	0.3361	265,414	317,055
1982	1,323,752.95	-70%	926,627	60	94,950	1,583	22.51	0.0165	15,255	16,837	59,327	0.3229	299,230	358,556
1983	1,689,053.06	-70%	1,182,337	60	121,153	2,019	23.33	0.0160	18,870	20,889	74,048	0.3099	366,441	440,489
1984	1,553,118.43	-70%	1,087,183	60	111,402	1,857	24.16	0.0155	16,813	18,670	66,549	0.2971	323,049	389,598
1985	1,969,293.27	-70%	1,378,505	60	141,254	2,354	25.00	0.0150	20,649	23,003	82,403	0.2846	392,310	474,713
1986	1,660,302.34	-70%	1,162,212	60	119,091	1,985	25.85	0.0145	16,855	18,840	67,782	0.2723	316,433	384,214
1987	1,655,454.37	-70%	1,158,818	60	118,743	1,979	26.71	0.0140	16,264	18,243	65,875	0.2602	301,505	367,380
1988	1,938,222.24	-70%	1,356,756	60	139,025	2,317	27.59	0.0136	18,420	20,738	75,104	0.2484	336,956	412,059
1989	1,482,247.23	-70%	1,037,573	60	106,319	1,772	28.47	0.0131	13,622	15,394	55,869	0.2368	245,671	301,540
1990	1,365,967.16	-70%	956,177	60	97,978	1,633	29.36	0.0127	12,135	13,768	50,027	0.2255	215,577	265,604
1991	666,890.79	-70%	466,824	60	47,835	797	30.27	0.0123	5,725	6,522	23,705	0.2144	100,092	123,797
1992	1,291,686.69	-70%	904,181	60	92,650	1,544	31.18	0.0118	10,711	12,255	44,506	0.2036	184,120	228,626
1993	2,801,283.96	-70%	1,960,899	60	200,931	3,349	32.10	0.0114	22,432	25,781	93,439	0.1931	378,700	472,139
1994	3,797,059.87	-70%	2,657,942	60	272,356	4,539	33.03	0.0110	29,354	33,893	122,445	0.1829	486,137	608,582
1995	323,213.23	-70%	226,249	60	23,184	386	33.96	0.0107	2,412	2,798	10,062	0.1730	39,130	49,192
1996	1,311,229.10	-70%	917,860	60	94,052	1,568	34.90	0.0103	9,440	11,007	39,343	0.1633	149,870	189,213
1997	1,718,642.04	-70%	1,203,049	60	123,275	2,055	35.85	0.0099	11,936	13,990	49,621	0.1539	185,140	234,761
1998	1,789,547.76	-70%	1,252,683	60	128,361	2,139	36.80	0.0096	11,986	14,126	49,630	0.1448	181,365	230,995
1999	2,633,018.15	-70%	1,843,113	60	188,862	3,148	37.76	0.0092	17,006	20,153	70,004	0.1359	250,560	320,564
2000	2,058,105.57	-70%	1,440,674	60	147,624	2,460	38.72	0.0089	12,815	15,276	52,349	0.1274	183,516	235,865
2001	6,743,314.22	-70%	4,720,320	60	483,686	8,061	39.69	0.0086	40,474	48,535	163,720	0.1191	562,149	725,869
2002	3,980,055.19	-70%	2,786,039	60	285,482	4,758	40.66	0.0083	23,023	27,781	92,008	0.1111	309,435	401,443
2003	3,286,142.77	-70%	2,300,300	60	235,709	3,928	41.64	0.0080	18,318	22,247	72,135	0.1033	237,628	309,764
2004	810,516.19	-70%	567,361	60	58,137	969	42.62	0.0077	4,353	5,322	16,844	0.0958	54,354	71,198
2005	3,491,893.52	-70%	2,444,325	60	250,467	4,174	43.60	0.0074	18,069	22,244	68,472	0.0885	216,441	284,913
2006	4,297,142.14	-70%	3,007,999	60	308,226	5,137	44.58	0.0071	21,421	26,558	79,207	0.0815	245,283	324,490
2007	3,260,338.24	-70%	2,282,237	60	233,858	3,898	45.57	0.0069	15,655	19,553	56,253	0.0748	170,668	226,921
2008	2,841,831.19	-70%	1,989,282	60	203,840	3,397	46.56	0.0066	13,143	16,540	45,675	0.0683	135,777	181,452
2009	2,296,863.83	-70%	1,607,805	60	164,750	2,746	47.55	0.0064	10,231	12,977	34,198	0.0620	99,612	133,810
2010	2,144,774.72	-70%	1,501,342	60	153,841	2,564	48.54	0.0061	9,201	11,765	29,392	0.0559	83,898	113,290
2011	3,180,568.83	-70%	2,226,398	60	228,137	3,802	49.53	0.0059	13,139	16,941	39,811	0.0500	111,373	151,184
2012	3,596,657.60	-70%	2,517,660	60	257,982	4,300	50.52	0.0057	14,308	18,607	40,745	0.0444	111,723	152,469
2013	4,169,519.70	-70%	2,918,664	60	299,072	4,985	51.52	0.0055	15,971	20,956	42,274	0.0389	113,623	155,897
2014	3,629,946.08	-70%	2,540,962	60	260,370	4,339	52.51	0.0053	13,389	17,728	32,483	0.0337	85,590	118,072
2015	4,684,568.09	-70%	3,279,198	60	336,016	5,600	53.51	0.0051	16,637	22,237	36,341	0.0286	93,882	130,223
2016	5,883,125.87	-70%	4,118,188	60	421,986	7,033	54.51	0.0049	20,117	27,150	38,624	0.0238	97,840	136,465
2017	5,418,293.94	-70%	3,792,806	60	388,645	6,477	55.51	0.0047	17,839	24,316	29,109	0.0191	72,311	101,420
2018	4,331,970.21	-70%	3,032,379	60	310,725	5,179	56.50	0.0045	13,732	18,911	18,105	0.0145	44,110	62,215
2019	1,025,910.51	-70%	718,137	60	73,587	1,226	57.50	0.0044	3,131	4,358	3,063	0.0102	7,320	10,383
2020	1,954,995.85	-70%	1,368,497	60	140,228	2,337	58.50	0.0042	5,745	8,082	3,502	0.0060	8,210	11,712
2021	5,164,500.03	-70%	3,615,150	60	370,440	6,174	59.50	0.0040	14,611	20,785	3,084	0.0020	7,093	10,177
	124,852,375.85		87,396,663		8,955,441	149,257			843,176	992,433	2,926,114		12,832,050	15,758,164

Account 369.3 - Underground Cable
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 3.87%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 3.87%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.03870)^e)	g=f/e	h	i=1/(1+0.03870)^(h-1)-1/(1+0.03870)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
1955	280,708.56	-60%	168,425	65	14,274	220	12.43	0.0241	4,066	4,285	11,544	0.5390	90,783	102,327
1956	95,108.07	-60%	57,065	65	4,836	74	12.89	0.0237	1,354	1,428	3,878	0.5283	30,149	34,027
1957	117,519.78	-60%	70,512	65	5,976	92	13.35	0.0233	1,643	1,735	4,748	0.5175	36,490	41,238
1958	136,890.87	-60%	82,135	65	6,961	107	13.84	0.0229	1,879	1,987	5,479	0.5065	41,603	47,082
1959	170,669.01	-60%	102,401	65	8,679	134	14.34	0.0225	2,299	2,433	6,764	0.4954	50,733	57,497
1960	185,175.35	-60%	111,105	65	9,416	145	14.85	0.0220	2,446	2,591	7,265	0.4842	53,800	61,064
1961	220,478.35	-60%	132,287	65	11,211	172	15.38	0.0216	2,855	3,028	8,559	0.4729	62,563	71,122
1962	346,044.60	-60%	207,627	65	17,596	271	15.92	0.0211	4,390	4,660	13,286	0.4616	95,831	109,117
1963	244,938.74	-60%	146,963	65	12,455	192	16.48	0.0207	3,042	3,234	9,298	0.4501	66,155	75,453
1964	438,806.32	-60%	263,284	65	22,313	343	17.05	0.0203	5,333	5,676	16,461	0.4387	115,494	131,955
1965	590,167.68	-60%	354,101	65	30,010	462	17.63	0.0198	7,016	7,477	21,869	0.4272	151,271	173,140
1966	551,158.14	-60%	330,695	65	28,027	431	18.23	0.0194	6,405	6,836	20,166	0.4157	137,470	157,636
1967	450,528.45	-60%	270,317	65	22,909	352	18.84	0.0189	5,115	5,468	16,269	0.4042	109,273	125,542
1968	936,599.12	-60%	561,959	65	47,626	733	19.47	0.0185	10,386	11,118	33,364	0.3928	220,734	254,098
1969	97,721.61	-60%	58,633	65	4,969	76	20.10	0.0180	1,058	1,134	3,432	0.3814	22,363	25,795
1970	992,942.46	-60%	595,765	65	50,491	777	20.75	0.0176	10,487	11,263	34,374	0.3701	220,479	254,852
1971	509,851.84	-60%	305,911	65	25,926	399	21.41	0.0172	5,251	5,650	17,387	0.3588	109,769	127,156
1972	587,846.71	-60%	352,708	65	29,892	460	22.08	0.0167	5,902	6,362	19,738	0.3477	122,627	142,365
1973	884,407.50	-60%	530,645	65	44,972	692	22.76	0.0163	8,653	9,345	29,224	0.3366	178,620	207,844
1974	989,334.72	-60%	593,601	65	50,308	774	23.45	0.0159	9,429	10,202	32,155	0.3257	193,323	225,478
1975	1,174,583.40	-60%	704,750	65	59,728	919	24.16	0.0155	10,899	11,818	37,529	0.3149	221,892	259,421
1976	1,198,580.02	-60%	719,148	65	60,948	938	24.87	0.0151	10,824	11,762	37,628	0.3042	218,754	256,382
1977	1,183,830.62	-60%	710,298	65	60,198	926	25.59	0.0146	10,401	11,327	36,494	0.2936	208,570	245,064
1978	1,377,170.40	-60%	826,302	65	70,029	1,077	26.33	0.0142	11,768	12,846	41,665	0.2833	234,059	275,725
1979	1,833,110.03	-60%	1,099,866	65	93,214	1,434	27.07	0.0138	15,229	16,663	54,394	0.2730	300,292	354,686
1980	2,425,853.23	-60%	1,455,512	65	123,355	1,898	27.82	0.0135	19,586	21,484	70,557	0.2630	382,750	453,307
1981	1,824,706.61	-60%	1,094,824	65	92,787	1,427	28.58	0.0131	14,313	15,741	51,986	0.2531	277,063	329,050
1982	2,034,260.64	-60%	1,220,556	65	103,443	1,591	29.35	0.0127	15,498	17,089	56,733	0.2433	297,020	353,754
1983	2,509,032.33	-60%	1,505,419	65	127,585	1,963	30.13	0.0123	18,559	20,522	68,448	0.2338	351,968	420,416
1984	1,785,823.91	-60%	1,071,494	65	90,810	1,397	30.91	0.0120	12,821	14,218	47,620	0.2244	240,477	288,097
1985	2,432,402.85	-60%	1,459,442	65	123,688	1,903	31.71	0.0116	16,944	18,847	63,350	0.2152	314,144	377,495
1986	2,341,820.80	-60%	1,405,092	65	119,082	1,832	32.51	0.0113	15,823	17,655	59,520	0.2062	289,791	349,312
1987	2,219,307.31	-60%	1,331,584	65	112,852	1,736	33.32	0.0109	14,541	16,278	55,000	0.1974	262,894	317,894
1988	1,815,326.18	-60%	1,089,196	65	92,310	1,420	34.14	0.0106	11,530	12,951	43,826	0.1888	205,634	249,459
1989	3,237,153.48	-60%	1,942,292	65	164,610	2,532	34.97	0.0103	19,927	22,459	76,062	0.1804	350,300	426,362
1990	2,204,564.47	-60%	1,322,739	65	112,103	1,725	35.80	0.0099	13,148	14,872	50,360	0.1721	227,627	277,987
1991	1,022,251.46	-60%	613,351	65	51,982	800	36.64	0.0096	5,905	6,705	22,680	0.1640	100,601	123,281
1992	1,950,526.08	-60%	1,170,316	65	99,185	1,526	37.49	0.0093	10,910	12,436	41,980	0.1561	182,722	224,702
1993	4,175,335.65	-60%	2,505,201	65	212,317	3,266	38.34	0.0090	22,608	25,874	87,070	0.1484	371,863	458,933
1994	2,185,562.08	-60%	1,311,337	65	111,136	1,710	39.21	0.0087	11,453	13,162	44,101	0.1409	184,796	228,897
1995	2,436,491.78	-60%	1,461,895	65	123,896	1,906	40.08	0.0084	12,353	14,259	47,507	0.1336	195,298	242,806
1996	1,722,292.77	-60%	1,033,376	65	87,579	1,347	40.95	0.0082	8,446	9,794	32,401	0.1264	130,669	163,070
1997	3,354,488.06	-60%	2,012,693	65	170,576	2,624	41.84	0.0079	15,908	18,532	60,790	0.1195	240,488	301,279
1998	3,494,363.03	-60%	2,096,618	65	177,689	2,734	42.72	0.0076	16,022	18,755	60,896	0.1127	236,306	297,202
1999	2,698,966.33	-60%	1,619,380	65	137,243	2,111	43.62	0.0074	11,961	14,072	45,143	0.1061	171,824	216,966
2000	4,617,068.20	-60%	2,770,241	65	234,779	3,612	44.52	0.0071	19,773	23,385	73,970	0.0997	276,151	350,121
2001	8,456,007.64	-60%	5,073,605	65	429,990	6,615	45.43	0.0069	34,987	41,602	129,469	0.0934	474,061	603,530
2002	4,531,739.83	-60%	2,719,044	65	230,440	3,545	46.34	0.0067	18,112	21,657	66,150	0.0874	237,558	303,708
2003	5,168,261.33	-60%	3,100,957	65	262,807	4,043	47.26	0.0064	19,947	23,990	71,724	0.0815	252,614	324,337
2004	1,722,399.98	-60%	1,033,440	65	87,584	1,347	48.18	0.0062	6,418	7,766	22,658	0.0757	78,267	100,926
2005	7,317,422.33	-60%	4,390,453	65	372,092	5,724	49.11	0.0060	26,323	32,047	90,943	0.0702	308,086	399,029
2006	6,153,124.89	-60%	3,691,875	65	312,888	4,814	50.05	0.0058	21,363	26,177	71,977	0.0648	239,139	311,117
2007	6,240,209.20	-60%	3,744,126	65	317,316	4,882	50.99	0.0056	20,907	25,789	68,412	0.0595	222,915	291,327
2008	5,222,132.35	-60%	3,133,279	65	265,546	4,085	51.93	0.0054	16,881	20,966	53,397	0.0545	170,643	224,040
2009	4,912,321.96	-60%	2,947,393	65	249,793	3,843	52.88	0.0052	15,318	19,161	46,588	0.0495	146,018	192,606
2010	4,638,728.25	-60%	2,783,237	65	235,880	3,629	53.83	0.0050	13,951	17,580	40,540	0.0448	124,622	165,162
2011	4,501,285.27	-60%	2,700,771	65	228,891	3,521	54.78	0.0048	13,056	16,577	35,975	0.0402	108,469	144,444
2012	5,316,097.91	-60%	3,189,659	65	270,325	4,159	55.74	0.0047	14,868	19,027	38,498	0.0357	113,853	152,350
2013	5,959,837.02	-60%	3,575,902	65	303,059	4,662	56.71	0.0045	16,070	20,732	38,672	0.0314	112,183	150,855
2014	5,957,116.48	-60%	3,574,270	65	302,921	4,660	57.67	0.0043	15,484	20,144	34,152	0.0272	97,185	131,337
2015	6,317,961.76	-60%	3,790,777	65	321,270	4,943	58.64	0.0042	15,829	20,771	31,431	0.0231	87,740	119,171
2016	5,607,530.73	-60%	3,364,518	65	285,144	4,387	59.61	0.0040	13,540	17,927	23,634	0.0192	64,723	88,357
2017	5,191,552.04	-60%	3,114,931	65	263,991	4,061	60.59	0.0039	12,080	16,142	17,925	0.0155	48,162	66,087
2018	2,783,760.56	-60%	1,670,256	65	141,555	2,178	61.56	0.0037	6,242	8,419	7,483	0.0118	19,728	27,212
2019	1,745,620.57	-60%	1,047,372	65	88,765	1,366	62.54	0.0036	3,771	5,137	3,356	0.0083	8,680	12,036
2020	10,760,152.97	-60%	6,456,092	65	547,156	8,418	63.52	0.0035	22,395	30,813	12,422	0.0049	31,533	43,954
2021	8,044,097.41	-60%	4,826,458	65	409,044	6,293	64.51	0.0033	16,129	22,422	3,099	0.0016	7,721	10,820
	184,629,130.08		110,777,478		9,388,429	144,437			809,829	954,266	2,591,471		11,537,387	14,128,858

Account 370.00 Meters and Meter Relays
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 2.75%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 2.75%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.02750)^e)	g=f/e	h	i=1/(1+0.02750)^(h-1)-1/(1+0.02750)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
1955	75,456.01	0%	0	30	0	0	0.00	0.0275	-	0	-	0.5569	-	-
1956	16,858.22	0%	0	30	0	0	0.00	0.0275	-	0	-	0.5569	-	-
1957	15,991.41	0%	0	30	0	0	0.00	0.0275	-	0	-	0.5569	-	-
1958	15,904.43	0%	0	30	0	0	0.00	0.0275	-	0	-	0.5569	-	-
1959	25,123.59	0%	0	30	0	0	0.00	0.0275	-	0	-	0.5569	-	-
1960	28,407.92	0%	0	30	0	0	0.00	0.0275	-	0	-	0.5569	-	-
1961	33,584.28	0%	0	30	0	0	0.00	0.0275	-	0	-	0.5569	-	-
1962	36,128.42	0%	0	30	0	0	0.50	0.0271	-	0	-	0.5434	-	-
1963	44,067.72	0%	0	30	0	0	0.83	0.0269	-	0	-	0.5345	-	-
1964	40,962.59	0%	0	30	0	0	1.30	0.0265	-	0	-	0.5222	-	-
1965	45,935.08	0%	0	30	0	0	1.79	0.0262	-	0	-	0.5096	-	-
1966	43,926.21	0%	0	30	0	0	2.28	0.0259	-	0	-	0.4969	-	-
1967	36,149.10	0%	0	30	0	0	2.77	0.0255	-	0	-	0.4844	-	-
1968	31,944.36	0%	0	30	0	0	3.27	0.0252	-	0	-	0.4720	-	-
1969	28,962.07	0%	0	30	0	0	3.77	0.0248	-	0	-	0.4597	-	-
1970	32,245.35	0%	0	30	0	0	4.26	0.0245	-	0	-	0.4476	-	-
1971	23,807.17	0%	0	30	0	0	4.76	0.0242	-	0	-	0.4356	-	-
1972	41,677.11	0%	0	30	0	0	5.26	0.0238	-	0	-	0.4238	-	-
1973	65,648.22	0%	0	30	0	0	5.76	0.0235	-	0	-	0.4122	-	-
1974	77,652.67	0%	0	30	0	0	6.26	0.0232	-	0	-	0.4007	-	-
1975	89,776.58	0%	0	30	0	0	6.76	0.0229	-	0	-	0.3893	-	-
1976	75,199.40	0%	0	30	0	0	7.26	0.0226	-	0	-	0.3781	-	-
1977	53,708.28	0%	0	30	0	0	7.76	0.0223	-	0	-	0.3671	-	-
1978	60,706.37	0%	0	30	0	0	8.26	0.0220	-	0	-	0.3562	-	-
1979	56,449.50	0%	0	30	0	0	8.76	0.0217	-	0	-	0.3454	-	-
1980	67,654.72	0%	0	30	0	0	9.26	0.0214	-	0	-	0.3348	-	-
1981	67,649.40	0%	0	30	0	0	9.76	0.0211	-	0	-	0.3243	-	-
1982	84,580.11	0%	0	30	0	0	10.26	0.0208	-	0	-	0.3140	-	-
1983	60,214.96	0%	0	30	0	0	10.76	0.0205	-	0	-	0.3038	-	-
1984	57,346.99	0%	0	30	0	0	11.26	0.0203	-	0	-	0.2937	-	-
1985	81,407.29	0%	0	30	0	0	11.76	0.0200	-	0	-	0.2838	-	-
1986	118,703.72	0%	0	30	0	0	12.26	0.0197	-	0	-	0.2740	-	-
1987	102,055.49	0%	0	30	0	0	12.75	0.0195	-	0	-	0.2644	-	-
1988	79,569.36	0%	0	30	0	0	13.25	0.0192	-	0	-	0.2548	-	-
1989	83,662.01	0%	0	30	0	0	13.75	0.0189	-	0	-	0.2454	-	-
1990	78,123.95	0%	0	30	0	0	14.25	0.0187	-	0	-	0.2361	-	-
1991	95,629.28	0%	0	30	0	0	14.75	0.0184	-	0	-	0.2270	-	-
1992	81,275.72	0%	0	30	0	0	15.25	0.0182	-	0	-	0.2180	-	-
1993	87,359.67	0%	0	30	0	0	15.75	0.0179	-	0	-	0.2091	-	-
1994	91,027.64	0%	0	30	0	0	16.25	0.0177	-	0	-	0.2003	-	-
1995	137,593.03	0%	0	30	0	0	16.75	0.0175	-	0	-	0.1916	-	-
1996	165,605.65	0%	0	30	0	0	17.25	0.0172	-	0	-	0.1831	-	-
1997	156,851.94	0%	0	30	0	0	17.75	0.0170	-	0	-	0.1746	-	-
1998	201,205.90	0%	0	30	0	0	18.25	0.0168	-	0	-	0.1663	-	-
1999	246,617.61	0%	0	30	0	0	18.75	0.0165	-	0	-	0.1581	-	-
2000	320,257.08	0%	0	30	0	0	19.25	0.0163	-	0	-	0.1500	-	-
2001	294,802.62	0%	0	30	0	0	19.75	0.0161	-	0	-	0.1420	-	-
2002	551,436.36	0%	0	30	0	0	20.25	0.0159	-	0	-	0.1341	-	-
2003	130,859.89	0%	0	30	0	0	20.75	0.0157	-	0	-	0.1264	-	-
2004	92,390.14	0%	0	30	0	0	21.25	0.0155	-	0	-	0.1187	-	-
2005	222,746.57	0%	0	30	0	0	21.75	0.0152	-	0	-	0.1111	-	-
2006	168,006.69	0%	0	30	0	0	22.25	0.0150	-	0	-	0.1036	-	-
2007	208,636.93	0%	0	30	0	0	22.75	0.0148	-	0	-	0.0963	-	-
2008	200,070.17	0%	0	30	0	0	23.25	0.0146	-	0	-	0.0890	-	-
2009	220,294.94	0%	0	30	0	0	23.75	0.0144	-	0	-	0.0818	-	-
2010	207,254.19	0%	0	30	0	0	24.25	0.0142	-	0	-	0.0748	-	-
2011	144,006.89	0%	0	30	0	0	24.75	0.0141	-	0	-	0.0678	-	-
2013	39,831.99	0%	0	30	0	0	25.75	0.0137	-	0	-	0.0541	-	-
2014	32,021.43	0%	0	30	0	0	26.25	0.0135	-	0	-	0.0474	-	-
2015	94,716.79	0%	0	30	0	0	26.75	0.0133	-	0	-	0.0408	-	-
2016	85,492.46	0%	0	30	0	0	27.25	0.0131	-	0	-	0.0343	-	-
2017	37,515.83	0%	0	30	0	0	27.75	0.0130	-	0	-	0.0279	-	-
2019	26,399.63	0%	0	30	0	0	28.75	0.0126	-	0	-	0.0153	-	-
2020	36,109.18	0%	0	30	0	0	29.25	0.0124	-	0	-	0.0091	-	-
2021	99,823.90	0%	0	30	0	0	29.75	0.0123	-	0	-	0.0030	-	-
	6,453,080.19		0		0	0			0	0	-		-	0

Account 370.1 Meters - AMI
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Amount	Average Service Life	Discounted Removal Cost 2.75%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 2.75%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.02750)^e)	g=f/e	h	i=1/(1+0.02750)^(h-1)-1/(1+0.02750)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
2010	1,165,612.77	-5%	58,281	15	38,797	2,586	4.38	0.0244	1,423	4,010	27,466	0.2223	12,953	40,419
2011	31,704,416.30	-5%	1,585,221	15	1,055,267	70,351	5.13	0.0239	37,926	108,277	694,098	0.2043	323,860	1,017,958
2012	4,891,873.70	-5%	244,594	15	162,824	10,855	5.94	0.0234	5,726	16,581	98,372	0.1855	45,380	143,752
2013	7,195,275.97	-5%	359,764	15	239,491	15,966	6.79	0.0229	8,229	24,195	131,102	0.1661	59,758	190,860
2014	1,111,033.60	-5%	55,552	15	36,980	2,465	7.68	0.0223	1,240	3,706	18,043	0.1462	8,122	26,165
2015	2,877,884.95	-5%	143,894	15	95,789	6,386	8.61	0.0218	3,133	9,519	40,819	0.1260	18,138	58,957
2016	3,373,189.47	-5%	168,659	15	112,275	7,485	9.56	0.0212	3,579	11,064	40,714	0.1058	17,852	58,566
2017	1,929,722.33	-5%	96,486	15	64,230	4,282	10.53	0.0207	1,994	6,276	19,133	0.0858	8,277	27,410
2019	6,918,916.56	-5%	345,946	15	230,293	15,353	12.51	0.0196	6,776	22,129	38,280	0.0466	16,116	54,396
2020	3,316,925.82	-5%	165,846	15	110,402	7,360	13.50	0.0191	3,162	10,522	11,022	0.0276	4,578	15,600
2021	1,248,219.41	-5%	62,411	15	41,546	2,770	14.50	0.0186	1,158	3,928	1,383	0.0091	567	1,950
	65,733,070.88		3,286,654		2,187,895	145,860			74,346	220,206	1,120,432		515,602	1,636,034

Account 371.1 - Installations on Customers' Premises
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 3.56%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 3.56%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.03560)^e)	g=f/e	h	i=1/(1+0.03560)^(h-1)-1/(1+0.03560)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
1962	1,119.87	0%	0	40	0	0	5.29	0.0296	-	0	-	0.5844	-	-
1966	1,722.79	0%	0	40	0	0	6.37	0.0285	-	0	-	0.5534	-	-
1969	275,602.57	0%	0	40	0	0	7.23	0.0276	-	0	-	0.5296	-	-
1970	118,404.48	0%	0	40	0	0	7.53	0.0274	-	0	-	0.5216	-	-
1971	126,375.19	0%	0	40	0	0	7.84	0.0271	-	0	-	0.5134	-	-
1972	97,247.33	0%	0	40	0	0	8.15	0.0268	-	0	-	0.5052	-	-
1973	37,572.55	0%	0	40	0	0	8.47	0.0265	-	0	-	0.4969	-	-
1974	85,887.00	0%	0	40	0	0	8.79	0.0262	-	0	-	0.4885	-	-
1975	90,579.91	0%	0	40	0	0	9.12	0.0259	-	0	-	0.4800	-	-
1976	135,707.15	0%	0	40	0	0	9.46	0.0256	-	0	-	0.4714	-	-
1977	11,239.00	0%	0	40	0	0	9.81	0.0253	-	0	-	0.4627	-	-
1979	1,976.61	0%	0	40	0	0	10.53	0.0246	-	0	-	0.4450	-	-
1980	189,523.31	0%	0	40	0	0	10.91	0.0243	-	0	-	0.4359	-	-
1983	1,883.21	0%	0	40	0	0	12.10	0.0233	-	0	-	0.4081	-	-
1985	43,720.14	0%	0	40	0	0	12.95	0.0226	-	0	-	0.3889	-	-
1987	8,863.85	0%	0	40	0	0	13.85	0.0219	-	0	-	0.3691	-	-
1988	5,238.28	0%	0	40	0	0	14.32	0.0216	-	0	-	0.3591	-	-
1996	24,217.06	0%	0	40	0	0	18.64	0.0185	-	0	-	0.2741	-	-
1998	72,071.39	0%	0	40	0	0	19.89	0.0178	-	0	-	0.2518	-	-
2008	38,251.43	0%	0	40	0	0	27.32	0.0137	-	0	-	0.1378	-	-
	1,367,203.12		0		0	0			0	0	-		-	0

Account 373 - Street Lighting and Signal Systems
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 3.64%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 3.64%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.03640)^e)	g=f/e	h	i=1/(1+0.03640)^(h-1)-1/(1+0.03640)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
1955	128,406.23	-50%	64,203	40	15,362	384	4.64	0.0308	1,980	2,364	13,582	0.6080	39,036	52,618
1957	429.81	-50%	215	40	51	1	5.31	0.0301	6	8	45	0.5879	126	171
1958	2,962.10	-50%	1,481	40	354	9	5.64	0.0298	44	53	304	0.5780	856	1,161
1959	7,461.32	-50%	3,731	40	893	22	5.98	0.0294	110	132	759	0.5682	2,120	2,879
1960	11,243.62	-50%	5,622	40	1,345	34	6.32	0.0290	163	197	1,133	0.5585	3,140	4,272
1961	21,349.14	-50%	10,675	40	2,554	64	6.66	0.0287	306	370	2,129	0.5488	5,858	7,987
1962	33,759.34	-50%	16,880	40	4,039	101	7.01	0.0283	478	579	3,332	0.5392	9,101	12,433
1963	18,754.95	-50%	9,377	40	2,244	56	7.35	0.0280	262	319	1,831	0.5296	4,966	6,798
1964	52,543.29	-50%	26,272	40	6,286	157	7.70	0.0276	726	883	5,076	0.5201	13,664	18,740
1965	126,200.66	-50%	63,100	40	15,099	377	8.05	0.0273	1,722	2,100	12,060	0.5106	32,221	44,281
1966	172,308.06	-50%	86,154	40	20,615	515	8.40	0.0270	2,322	2,838	16,284	0.5012	43,181	59,465
1967	169,743.78	-50%	84,872	40	20,308	508	8.76	0.0266	2,259	2,766	15,861	0.4918	41,742	57,603
1968	257,730.29	-50%	128,865	40	30,835	771	9.12	0.0263	3,386	4,156	23,805	0.4825	62,176	85,981
1969	306,291.95	-50%	153,146	40	36,645	916	9.48	0.0259	3,972	4,888	27,958	0.4732	72,466	100,424
1970	2,186.40	-50%	1,093	40	262	7	9.85	0.0256	28	35	197	0.4639	507	704
1972	8,366.97	-50%	4,183	40	1,001	25	10.59	0.0249	104	129	736	0.4455	1,864	2,599
1973	5,828.63	-50%	2,914	40	697	17	10.97	0.0246	72	89	506	0.4363	1,271	1,777
1974	5,637.54	-50%	2,819	40	674	17	11.35	0.0243	68	85	483	0.4271	1,204	1,687
1975	1,165.59	-50%	583	40	139	3	11.74	0.0239	14	17	99	0.4179	244	342
1976	7,006.59	-50%	3,503	40	838	21	12.13	0.0236	83	104	584	0.4088	1,432	2,016
1977	2,914.00	-50%	1,457	40	349	9	12.53	0.0233	34	43	239	0.3997	582	822
1978	2,606.77	-50%	1,303	40	312	8	12.93	0.0229	30	38	211	0.3906	509	720
1979	1,958.59	-50%	979	40	234	6	13.34	0.0226	22	28	156	0.3815	374	530
1980	3,172.89	-50%	1,586	40	380	9	13.75	0.0223	35	45	249	0.3724	591	840
1981	3,865.82	-50%	1,933	40	463	12	14.17	0.0219	42	54	299	0.3634	702	1,001
1982	5,475.17	-50%	2,738	40	655	16	14.59	0.0216	59	76	416	0.3543	970	1,386
1983	472.71	-50%	236	40	57	1	15.02	0.0213	5	6	35	0.3452	82	117
1984	1,690.37	-50%	845	40	202	5	15.46	0.0209	18	23	124	0.3362	284	408
1985	2,165.48	-50%	1,083	40	259	6	15.90	0.0206	22	29	156	0.3271	354	510
1987	2,646.96	-50%	1,323	40	317	8	16.81	0.0200	26	34	184	0.3090	409	593
1989	7,365.97	-50%	3,683	40	881	22	17.75	0.0193	71	93	490	0.2910	1,072	1,562
1992	165.41	-50%	83	40	20	0	19.21	0.0183	2	2	10	0.2638	22	32
1993	129,492.24	-50%	64,746	40	15,492	387	19.72	0.0180	1,164	1,552	7,854	0.2548	16,495	24,348
1994	138,123.66	-50%	69,062	40	16,525	413	20.24	0.0177	1,219	1,632	8,163	0.2457	16,969	25,132
1995	5,329.58	-50%	2,665	40	638	16	20.77	0.0173	46	62	307	0.2366	631	937
1996	98,375.24	-50%	49,188	40	11,770	294	21.30	0.0170	836	1,130	5,501	0.2276	11,194	16,695
1997	2,471.79	-50%	1,236	40	296	7	21.85	0.0167	21	28	134	0.2185	270	404
1998	336,342.35	-50%	168,171	40	40,240	1,006	22.41	0.0163	2,747	3,753	17,692	0.2094	35,223	52,916
1999	582,781.10	-50%	291,391	40	69,724	1,743	22.98	0.0160	4,663	6,406	29,660	0.2004	58,388	88,048
2000	103,394.42	-50%	51,697	40	12,370	309	23.57	0.0157	810	1,120	5,082	0.1913	9,890	14,972
2001	173,076.35	-50%	86,538	40	20,707	518	24.16	0.0153	1,328	1,845	8,198	0.1822	15,770	23,968
2002	27,001.27	-50%	13,501	40	3,230	81	24.77	0.0150	203	283	1,230	0.1732	2,338	3,568
2003	1,277,592.05	-50%	638,796	40	152,850	3,821	25.39	0.0147	9,379	13,200	55,814	0.1641	104,819	160,634
2004	23,501.18	-50%	11,751	40	2,812	70	26.03	0.0144	169	239	982	0.1550	1,822	2,804
2005	415,108.10	-50%	207,554	40	49,663	1,242	26.68	0.0140	2,910	4,152	16,538	0.1460	30,294	46,832
2006	116,564.31	-50%	58,282	40	13,946	349	27.35	0.0137	798	1,147	4,412	0.1369	7,979	12,391
2007	142,935.32	-50%	71,468	40	17,101	428	28.03	0.0134	955	1,383	5,119	0.1279	9,138	14,257
2008	132,996.79	-50%	66,498	40	15,912	398	28.72	0.0130	867	1,265	4,486	0.1188	7,902	12,387
2009	128,207.31	-50%	64,104	40	15,339	383	29.44	0.0127	815	1,198	4,051	0.1098	7,039	11,090
2010	35,502.43	-50%	17,751	40	4,247	106	30.17	0.0124	220	326	1,044	0.1008	1,789	2,834
2011	117,656.26	-50%	58,828	40	14,076	352	30.92	0.0121	709	1,061	3,197	0.0918	5,402	8,599
2012	39,330.62	-50%	19,665	40	4,705	118	31.68	0.0117	231	348	979	0.0829	1,630	2,608
2013	125,748.84	-50%	62,874	40	15,045	376	32.47	0.0114	717	1,093	2,833	0.0740	4,650	7,484
2014	326,225.26	-50%	163,113	40	39,029	976	33.27	0.0111	1,807	2,783	6,565	0.0651	10,615	17,180
2015	1,285,113.63	-50%	642,557	40	153,750	3,844	34.10	0.0108	6,912	10,756	22,693	0.0562	36,134	58,827
2016	1,118,691.51	-50%	559,346	40	133,839	3,346	34.94	0.0104	5,838	9,184	16,926	0.0474	26,534	43,460
2017	1,026,800.99	-50%	513,400	40	122,846	3,071	35.81	0.0101	5,195	8,266	12,874	0.0387	19,863	32,738
2018	298,587.77	-50%	149,294	40	35,723	893	36.70	0.0098	1,463	2,356	2,950	0.0300	4,478	7,429
2019	33,861.39	-50%	16,931	40	4,051	101	37.61	0.0095	161	262	242	0.0214	362	604
2020	16,662.19	-50%	8,331	40	1,993	50	38.54	0.0092	76	126	73	0.0128	107	179
2021	145,915.87	-50%	72,958	40	17,457	436	39.51	0.0089	647	1,083	215	0.0043	311	526
	9,777,266.22		4,888,633		1,169,745	29,244			71,377	100,621	375,148		791,159	1,166,307

Account 390 - Structures and Improvements - Benning Office Buildings
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 3.64%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 3.64%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.03640)^e)	g=f/e	h	i=1/(1+0.03640)^(h-1)-1/(1+0.03640)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
1982	2,177,370.23	-20%	435,474	65	42,627	656	18.02	0.0191	8,323	8,979	30,811	0.4272	186,036	216,846
1984	48,440.59	-20%	9,688	65	948	15	18.21	0.0190	184	198	683	0.4236	4,104	4,786
1986	2,305.10	-20%	461	65	45	1	18.39	0.0189	9	9	32	0.4202	194	226
1987	8,313.50	-20%	1,663	65	163	3	18.48	0.0188	31	34	116	0.4186	696	813
1989	24,141.99	-20%	4,828	65	473	7	18.64	0.0187	90	98	337	0.4157	2,007	2,344
1990	1,103.73	-20%	221	65	22	0	18.71	0.0186	4	4	15	0.4143	91	107
1991	15,406.96	-20%	3,081	65	302	5	18.79	0.0186	57	62	214	0.4130	1,272	1,487
1992	204.40	-20%	41	65	4	0	18.86	0.0185	1	1	3	0.4117	17	20
1993	2,826.71	-20%	565	65	55	1	18.93	0.0185	10	11	39	0.4104	232	271
1994	919.71	-20%	184	65	18	0	18.99	0.0185	3	4	13	0.4093	75	88
1996	39,159.14	-20%	7,832	65	767	12	19.11	0.0184	144	156	541	0.4070	3,188	3,729
1998	93,670.34	-20%	18,734	65	1,834	28	19.23	0.0183	343	371	1,291	0.4050	7,587	8,879
1999	70,418.21	-20%	14,084	65	1,379	21	19.28	0.0183	257	279	970	0.4040	5,690	6,660
2001	4,118.99	-20%	824	65	81	1	19.38	0.0182	15	16	57	0.4022	331	388
2002	43,858.87	-20%	8,772	65	859	13	19.43	0.0182	159	173	602	0.4014	3,521	4,123
2003	63,140.76	-20%	12,628	65	1,236	19	19.47	0.0181	229	248	866	0.4006	5,058	5,924
2005	24,173.19	-20%	4,835	65	473	7	19.56	0.0181	87	95	331	0.3990	1,929	2,260
2006	87,371.20	-20%	17,474	65	1,710	26	19.60	0.0181	316	342	1,195	0.3983	6,960	8,155
2007	99,422.51	-20%	19,885	65	1,946	30	19.64	0.0180	359	389	1,358	0.3976	7,906	9,264
2008	78,768.17	-20%	15,754	65	1,542	24	19.68	0.0180	284	307	1,075	0.3969	6,253	7,328
2009	100,107.72	-20%	20,022	65	1,960	30	19.71	0.0180	360	390	1,365	0.3963	7,934	9,300
2010	243,598.39	-20%	48,720	65	4,769	73	19.75	0.0180	875	949	3,320	0.3957	19,277	22,597
2011	95,243.59	-20%	19,049	65	1,865	29	19.78	0.0179	342	371	1,297	0.3951	7,526	8,823
2012	82,818.68	-20%	16,564	65	1,621	25	19.81	0.0179	297	322	1,127	0.3945	6,535	7,662
2014	408,642.40	-20%	81,728	65	8,000	123	19.88	0.0179	1,462	1,585	5,554	0.3935	32,156	37,710
2015	1,164,379.36	-20%	232,876	65	22,795	351	19.90	0.0179	4,161	4,511	15,815	0.3930	91,510	107,324
2016	1,002,392.32	-20%	200,478	65	19,624	302	19.93	0.0178	3,578	3,880	13,606	0.3925	78,682	92,288
2017	3,763,417.94	-20%	752,684	65	73,677	1,133	19.96	0.0178	13,422	14,555	51,054	0.3920	295,056	346,110
2018	1,919,287.43	-20%	383,857	65	37,574	578	19.98	0.0178	6,839	7,417	26,022	0.3916	150,303	176,325
2019	354,959.81	-20%	70,992	65	6,949	107	20.01	0.0178	1,264	1,371	4,810	0.3911	27,767	32,578
2020	552,512.33	-20%	110,502	65	10,817	166	20.03	0.0178	1,965	2,132	7,483	0.3907	43,176	50,659
2021	4,040,264.69	-20%	808,053	65	79,097	1,217	20.05	0.0178	14,360	15,577	54,693	0.3903	315,408	370,101
	16,612,758.96		3,322,552		325,230	5,004			59,831	64,835	226,697		1,318,479	1,545,176

Account 390 - Structures and Improvements - Benning Warehouses
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 3.64%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 3.64%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.03640)^e)	g=f/e	h	i=1/(1+0.03640)^(h-1)-1/(1+0.03640)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
1940	1,301.47	-20%	260	65	25	0	10.52	0.0250	7	7	21	0.5885	153	175
1949	7,155.66	-20%	1,431	65	140	2	12.54	0.0232	33	35	113	0.5408	774	887
1952	86,792.01	-20%	17,358	65	1,699	26	13.19	0.0227	394	420	1,354	0.5262	9,134	10,488
1954	3,263.95	-20%	653	65	64	1	13.61	0.0224	15	16	51	0.5168	337	388
1959	1,903.32	-20%	381	65	37	1	14.62	0.0216	8	9	29	0.4951	188	217
1960	46,966.54	-20%	9,393	65	919	14	14.81	0.0214	201	216	710	0.4910	4,612	5,322
1962	3,319.96	-20%	664	65	65	1	15.18	0.0212	14	15	50	0.4832	321	371
1963	341.86	-20%	68	65	7	0	15.36	0.0210	1	2	5	0.4795	33	38
1964	1,991.15	-20%	398	65	39	1	15.54	0.0209	8	9	30	0.4758	189	219
1965	257.15	-20%	51	65	5	0	15.72	0.0208	1	1	4	0.4723	24	28
1966	1,134.83	-20%	227	65	22	0	15.88	0.0206	5	5	17	0.4688	106	123
1967	8,070.64	-20%	1,614	65	158	2	16.05	0.0205	33	36	119	0.4655	751	870
1968	1,353.84	-20%	271	65	27	0	16.21	0.0204	6	6	20	0.4622	125	145
1969	156.69	-20%	31	65	3	0	16.37	0.0203	1	1	2	0.4591	14	17
1971	1,971.71	-20%	394	65	39	1	16.67	0.0201	8	9	29	0.4532	179	207
1973	2,985.71	-20%	597	65	58	1	16.95	0.0199	12	13	43	0.4476	267	310
1974	3,102.32	-20%	620	65	61	1	17.09	0.0198	12	13	45	0.4450	276	321
1976	1,426.43	-20%	285	65	28	0	17.34	0.0196	6	6	20	0.4400	126	146
1978	607.10	-20%	121	65	12	0	17.58	0.0194	2	3	9	0.4354	53	62
1981	7,614.34	-20%	1,523	65	149	2	17.92	0.0192	29	32	108	0.4291	654	761
1982	167,799.48	-20%	33,560	65	3,285	51	18.02	0.0191	641	692	2,374	0.4272	14,337	16,711
1983	19,199.15	-20%	3,840	65	376	6	18.12	0.0190	73	79	271	0.4253	1,633	1,904
1986	28,479.26	-20%	5,696	65	558	9	18.39	0.0189	107	116	400	0.4202	2,393	2,793
1987	2,386,493.47	-20%	477,299	65	46,721	719	18.48	0.0188	8,974	9,693	33,439	0.4186	199,817	233,257
1988	0.00	-20%	0	65	0	0	18.56	0.0187	-	0	-	0.4171	-	-
1989	12,843.57	-20%	2,569	65	251	4	18.64	0.0187	48	52	179	0.4157	1,068	1,247
1991	3,752.46	-20%	750	65	73	1	18.79	0.0186	14	15	52	0.4130	310	362
1992	8,550.42	-20%	1,710	65	167	3	18.86	0.0185	32	34	119	0.4117	704	823
1993	11,440.87	-20%	2,288	65	224	3	18.93	0.0185	42	46	159	0.4104	939	1,098
1995	3,396.95	-20%	679	65	67	1	19.05	0.0184	13	14	47	0.4081	277	324
1996	40,692.65	-20%	8,139	65	797	12	19.11	0.0184	150	162	562	0.4070	3,313	3,875
1997	16,399.79	-20%	3,280	65	321	5	19.17	0.0183	60	65	226	0.4060	1,332	1,558
1998	7,720.65	-20%	1,544	65	151	2	19.23	0.0183	28	31	106	0.4050	625	732
1999	11,701.52	-20%	2,340	65	229	4	19.28	0.0183	43	46	161	0.4040	946	1,107
2000	37,363.63	-20%	7,473	65	731	11	19.33	0.0182	136	148	514	0.4031	3,012	3,526
2001	21,457.01	-20%	4,291	65	420	6	19.38	0.0182	78	85	295	0.4022	1,726	2,021
2002	58,573.03	-20%	11,715	65	1,147	18	19.43	0.0182	213	231	804	0.4014	4,702	5,506
2003	12,773.56	-20%	2,555	65	250	4	19.47	0.0181	46	50	175	0.4006	1,023	1,198
2006	74,515.67	-20%	14,903	65	1,459	22	19.60	0.0181	269	292	1,019	0.3983	5,936	6,955
2007	47,047.73	-20%	9,410	65	921	14	19.64	0.0180	170	184	643	0.3976	3,741	4,384
2012	34,805.73	-20%	6,961	65	681	10	19.81	0.0179	125	135	474	0.3945	2,746	3,220
	3,186,723.27		637,345		62,387	960			12,059	13,019	44,799		268,899	313,698

Account 390 - Structures and Improvements - Consolidated Control Center
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 3.64%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 3.64%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.03640)^e)	g=f/e	h	i=1/(1+0.03640)^(h-1)-1/(1+0.03640)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
1975	624,954.30	-20%	124,991	65	12,235	188	19.65	0.0180	2,253	2,441	8,535	0.3974	49,666	58,201
1976	480.64	-20%	96	65	9	0	19.83	0.0179	2	2	7	0.3942	38	44
1977	568.15	-20%	114	65	11	0	20.01	0.0178	2	2	8	0.3911	44	52
1978	16,211.50	-20%	3,242	65	317	5	20.18	0.0177	57	62	219	0.3882	1,259	1,477
1979	6,746.76	-20%	1,349	65	132	2	20.34	0.0176	24	26	91	0.3854	520	611
1981	65,647.61	-20%	13,130	65	1,285	20	20.65	0.0174	228	248	877	0.3800	4,989	5,866
1982	49,444.42	-20%	9,889	65	968	15	20.80	0.0173	171	186	658	0.3775	3,733	4,391
1983	704.04	-20%	141	65	14	0	20.94	0.0172	2	3	9	0.3750	53	62
1986	28,234.33	-20%	5,647	65	553	9	21.35	0.0170	96	104	371	0.3683	2,080	2,451
1991	9,697,949.12	-20%	1,939,590	65	189,858	2,921	21.93	0.0166	32,238	35,159	125,816	0.3587	695,801	821,617
1992	36,551.22	-20%	7,310	65	716	11	22.03	0.0166	121	132	473	0.3570	2,610	3,083
1993	18,823.73	-20%	3,765	65	369	6	22.13	0.0165	62	68	243	0.3554	1,338	1,581
1994	45,732.89	-20%	9,147	65	895	14	22.23	0.0164	150	164	589	0.3539	3,237	3,826
1995	70,146.88	-20%	14,029	65	1,373	21	22.32	0.0164	230	251	902	0.3524	4,944	5,845
1996	326.65	-20%	65	65	6	0	22.41	0.0163	1	1	4	0.3509	23	27
1998	215,243.48	-20%	43,049	65	4,214	65	22.58	0.0162	699	764	2,750	0.3482	14,991	17,742
1999	1,725.16	-20%	345	65	34	1	22.66	0.0162	6	6	22	0.3470	120	142
2002	9,741.31	-20%	1,948	65	191	3	22.88	0.0161	31	34	124	0.3435	669	793
2003	76,853.23	-20%	15,371	65	1,505	23	22.95	0.0160	246	269	973	0.3424	5,263	6,236
2005	2,645.37	-20%	529	65	52	1	23.07	0.0160	8	9	33	0.3404	180	213
2008	446,567.85	-20%	89,314	65	8,743	135	23.25	0.0159	1,416	1,550	5,615	0.3376	30,153	35,769
2009	141,436.66	-20%	28,287	65	2,769	43	23.30	0.0158	448	490	1,776	0.3368	9,526	11,302
2010	3,446.73	-20%	689	65	67	1	23.36	0.0158	11	12	43	0.3360	232	275
2012	404,821.28	-20%	80,964	65	7,925	122	23.46	0.0157	1,274	1,396	5,065	0.3344	27,077	32,142
2013	154,353.96	-20%	30,871	65	3,022	46	23.50	0.0157	485	531	1,929	0.3337	10,302	12,231
2014	52,129.25	-20%	10,426	65	1,021	16	23.55	0.0157	164	179	651	0.3330	3,472	4,123
2015	34,740.45	-20%	6,948	65	680	10	23.59	0.0157	109	119	433	0.3324	2,309	2,743
2016	5,662,960.30	-20%	1,132,592	65	110,864	1,706	23.63	0.0156	17,711	19,417	70,559	0.3317	375,708	446,267
2017	317,668.30	-20%	63,534	65	6,219	96	23.67	0.0156	992	1,088	3,954	0.3311	21,037	24,991
2018	1,839.35	-20%	368	65	36	1	23.71	0.0156	6	6	23	0.3305	122	144
2019	184,421.49	-20%	36,884	65	3,610	56	23.75	0.0156	574	630	2,291	0.3300	12,171	14,462
2020	378,391.75	-20%	75,678	65	7,408	114	23.78	0.0156	1,177	1,291	4,698	0.3294	24,930	29,628
2021	1,159,905.18	-20%	231,981	65	22,708	349	23.82	0.0155	3,604	3,953	14,388	0.3289	76,300	90,688
	19,911,413.33		3,982,283		389,808	5,997			64,599	70,596	254,132		1,384,894	1,639,026

Account 390 - Structures and Improvements - Forestville Service Center
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 3.64%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 3.64%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.03640)^e)	g=f/e	h	i=1/(1+0.03640)^(h-1)-1/(1+0.03640)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
1981	79,359.82	-20%	15,872	65	1,554	24	14.10	0.0220	349	373	1,217	0.5061	8,033	9,250
1982	3,812,336.71	-20%	762,467	65	74,635	1,148	14.16	0.0219	16,730	17,878	58,378	0.5049	384,972	443,351
1983	8,690.52	-20%	1,738	65	170	3	14.21	0.0219	38	41	133	0.5037	876	1,008
1984	19,434.04	-20%	3,887	65	380	6	14.27	0.0219	85	91	297	0.5026	1,953	2,250
1985	4,803.91	-20%	961	65	94	1	14.32	0.0218	21	22	73	0.5015	482	555
1986	75,865.21	-20%	15,173	65	1,485	23	14.37	0.0218	330	353	1,157	0.5004	7,593	8,750
1987	1,303,674.70	-20%	260,735	65	25,522	393	14.41	0.0217	5,669	6,062	19,863	0.4994	130,222	150,085
1988	1,567.73	-20%	314	65	31	0	14.46	0.0217	7	7	24	0.4985	156	180
1989	11,932.20	-20%	2,386	65	234	4	14.50	0.0217	52	55	181	0.4976	1,187	1,369
1990	46,773.80	-20%	9,355	65	916	14	14.54	0.0216	202	217	711	0.4967	4,646	5,357
1991	17,471.40	-20%	3,494	65	342	5	14.58	0.0216	76	81	265	0.4958	1,733	1,998
1992	80,122.60	-20%	16,025	65	1,569	24	14.62	0.0216	346	370	1,216	0.4950	7,932	9,148
1993	61,057.62	-20%	12,212	65	1,195	18	14.66	0.0216	263	282	926	0.4942	6,035	6,961
1994	47,153.92	-20%	9,431	65	923	14	14.69	0.0215	203	217	714	0.4935	4,654	5,368
1995	3,457.50	-20%	692	65	68	1	14.73	0.0215	15	16	52	0.4928	341	393
1996	25,436.02	-20%	5,087	65	498	8	14.76	0.0215	109	117	385	0.4921	2,503	2,888
1997	2,541.20	-20%	508	65	50	1	14.79	0.0215	11	12	38	0.4914	250	288
1999	18,037.32	-20%	3,607	65	353	5	14.85	0.0214	77	83	272	0.4902	1,768	2,041
2000	30,990.04	-20%	6,198	65	607	9	14.88	0.0214	133	142	468	0.4896	3,034	3,502
2001	93,161.25	-20%	18,632	65	1,824	28	14.91	0.0214	398	426	1,406	0.4890	9,111	10,517
2002	1,466,440.38	-20%	293,288	65	28,709	442	14.93	0.0213	6,260	6,701	22,114	0.4885	143,263	165,377
2003	174,120.78	-20%	34,824	65	3,409	52	14.96	0.0213	743	795	2,624	0.4880	16,992	19,617
2005	26,553.62	-20%	5,311	65	520	8	15.00	0.0213	113	121	400	0.4870	2,586	2,986
2006	317,382.49	-20%	63,476	65	6,213	96	15.02	0.0213	1,350	1,446	4,777	0.4865	30,883	35,660
2007	147,535.56	-20%	29,507	65	2,888	44	15.05	0.0213	627	672	2,220	0.4861	14,343	16,563
2008	3,202.66	-20%	641	65	63	1	15.07	0.0212	14	15	48	0.4857	311	359
2009	12,823.57	-20%	2,565	65	251	4	15.09	0.0212	54	58	193	0.4852	1,245	1,437
2012	134,633.39	-20%	26,927	65	2,636	41	15.14	0.0212	570	611	2,022	0.4841	13,036	15,058
2013	803,169.12	-20%	160,634	65	15,724	242	15.16	0.0212	3,401	3,643	12,058	0.4838	77,711	89,768
2014	31,823.83	-20%	6,365	65	623	10	15.17	0.0212	135	144	478	0.4834	3,077	3,555
2015	447,975.28	-20%	89,595	65	8,770	135	15.19	0.0211	1,895	2,030	6,721	0.4831	43,286	50,007
2016	91,165.52	-20%	18,233	65	1,785	27	15.20	0.0211	385	413	1,367	0.4828	8,803	10,171
2017	268,332.11	-20%	53,666	65	5,253	81	15.22	0.0211	1,134	1,215	4,023	0.4825	25,895	29,919
2018	23,550.59	-20%	4,710	65	461	7	15.23	0.0211	99	107	353	0.4822	2,271	2,624
2019	354,228.49	-20%	70,846	65	6,935	107	15.24	0.0211	1,495	1,602	5,309	0.4820	34,146	39,454
2020	270,016.42	-20%	54,003	65	5,286	81	15.26	0.0211	1,139	1,221	4,046	0.4817	26,014	30,060
2021	179,874.40	-20%	35,975	65	3,521	54	15.27	0.0211	759	813	2,694	0.4815	17,321	20,015
	10,496,695.72		2,099,339		205,495	3,161			45,287	48,449	159,224		1,038,665	1,197,888

Account 390 - Structures and Improvements - Kenilworth Service Center
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 3.64%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 3.64%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.03640)^e)	g=f/e	h	i=1/(1+0.03640)^(h-1)-1/(1+0.03640)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
1955	47,696.59	-20%	9,539	65	934	14	12.14	0.0236	225	239	759	0.5500	5,246	6,006
1959	88,281.89	-20%	17,656	65	1,728	27	12.70	0.0231	408	435	1,391	0.5371	9,483	10,873
1960	94.52	-20%	19	65	2	0	12.84	0.0230	0	0	1	0.5340	10	12
1962	321.55	-20%	64	65	6	0	13.09	0.0228	1	2	5	0.5283	34	39
1963	3,690.52	-20%	738	65	72	1	13.22	0.0227	17	18	58	0.5255	388	445
1964	1,513.00	-20%	303	65	30	0	13.34	0.0226	7	7	24	0.5228	158	182
1965	511.30	-20%	102	65	10	0	13.46	0.0225	2	2	8	0.5202	53	61
1966	355.60	-20%	71	65	7	0	13.57	0.0224	2	2	6	0.5177	37	42
1967	12,695.58	-20%	2,539	65	249	4	13.68	0.0223	57	60	196	0.5153	1,308	1,505
1968	2,416.54	-20%	483	65	47	1	13.79	0.0222	11	11	37	0.5129	248	285
1971	192.55	-20%	39	65	4	0	14.09	0.0220	1	1	3	0.5064	20	22
1975	704.17	-20%	141	65	14	0	14.45	0.0217	3	3	11	0.4987	70	81
1977	503,497.38	-20%	100,699	65	9,857	152	14.61	0.0216	2,174	2,326	7,642	0.4953	49,872	57,514
1978	31,465.95	-20%	6,293	65	616	9	14.68	0.0215	136	145	477	0.4937	3,107	3,583
1979	2,951.76	-20%	590	65	58	1	14.76	0.0215	13	14	45	0.4921	291	335
1980	39,075.67	-20%	7,815	65	765	12	14.83	0.0214	167	179	590	0.4906	3,834	4,425
1981	115,035.12	-20%	23,007	65	2,252	35	14.90	0.0214	492	526	1,736	0.4892	11,255	12,991
1982	10,323.76	-20%	2,065	65	202	3	14.96	0.0213	44	47	156	0.4878	1,007	1,163
1987	5,036.81	-20%	1,007	65	99	2	15.25	0.0211	21	23	75	0.4818	485	561
1988	3,172,459.52	-20%	634,492	65	62,108	956	15.30	0.0211	13,363	14,318	47,485	0.4807	305,001	352,486
1989	15,407.44	-20%	3,081	65	302	5	15.35	0.0210	65	69	230	0.4797	1,478	1,709
1990	15,140.34	-20%	3,028	65	296	5	15.40	0.0210	64	68	226	0.4787	1,450	1,676
1992	14,169.98	-20%	2,834	65	277	4	15.49	0.0209	59	64	211	0.4769	1,351	1,563
1993	18,663.51	-20%	3,733	65	365	6	15.53	0.0209	78	84	278	0.4760	1,777	2,055
1996	27,128.70	-20%	5,426	65	531	8	15.65	0.0208	113	121	403	0.4736	2,570	2,973
1997	5,249.25	-20%	1,050	65	103	2	15.69	0.0208	22	23	78	0.4729	496	574
1998	7,372.78	-20%	1,475	65	144	2	15.72	0.0207	31	33	109	0.4722	696	806
1999	28,406.15	-20%	5,681	65	556	9	15.75	0.0207	118	126	421	0.4715	2,679	3,100
2000	24,946.03	-20%	4,989	65	488	8	15.79	0.0207	103	111	370	0.4708	2,349	2,719
2001	55,950.99	-20%	11,190	65	1,095	17	15.82	0.0207	231	248	829	0.4702	5,262	6,090
2002	6,589.82	-20%	1,318	65	129	2	15.85	0.0207	27	29	98	0.4696	619	716
2003	25,465.94	-20%	5,093	65	499	8	15.87	0.0206	105	113	377	0.4690	2,389	2,766
2005	105,688.79	-20%	21,138	65	2,069	32	15.93	0.0206	435	467	1,562	0.4679	9,891	11,453
2007	118,909.68	-20%	23,782	65	2,328	36	15.98	0.0206	489	525	1,756	0.4670	11,105	12,861
2008	5,115.54	-20%	1,023	65	100	2	16.00	0.0205	21	23	75	0.4665	477	553
2012	451,617.16	-20%	90,323	65	8,841	136	16.08	0.0205	1,850	1,986	6,654	0.4648	41,981	48,634
2013	658,983.69	-20%	131,797	65	12,901	198	16.10	0.0205	2,698	2,896	9,705	0.4644	61,206	70,911
	5,623,125.57		1,124,625		110,085	1,694			23,652	25,345	84,086		539,683	623,769

Account 390 - Structures and Improvements - Rockville Service Center
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 3.64%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 3.64%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.03640)^e)	g=f/e	h	i=1/(1+0.03640)^(h-1)-1/(1+0.03640)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
1985	3,973,506.11	-20%	794,701	65	77,790	1,197	19.79	0.0179	14,255	15,452	54,103	0.3949	313,840	367,943
1987	536.58	-20%	107	65	11	0	20.00	0.0178	2	2	7	0.3912	42	49
1989	14,638.10	-20%	2,928	65	287	4	20.20	0.0177	52	56	198	0.3878	1,135	1,333
1990	6,804.80	-20%	1,361	65	133	2	20.29	0.0176	24	26	92	0.3862	526	617
1991	5,840.24	-20%	1,168	65	114	2	20.38	0.0176	21	22	78	0.3846	449	528
1992	5,645.66	-20%	1,129	65	111	2	20.47	0.0175	20	21	76	0.3831	433	508
1993	20,520.52	-20%	4,104	65	402	6	20.55	0.0175	72	78	275	0.3817	1,567	1,841
1994	4,541.72	-20%	908	65	89	1	20.63	0.0174	16	17	61	0.3803	345	406
1995	116,971.12	-20%	23,394	65	2,290	35	20.71	0.0174	406	441	1,560	0.3790	8,867	10,428
1996	63,506.90	-20%	12,701	65	1,243	19	20.78	0.0173	220	239	846	0.3778	4,798	5,644
1997	2,737.27	-20%	547	65	54	1	20.85	0.0173	9	10	36	0.3766	206	243
1998	120,505.79	-20%	24,101	65	2,359	36	20.92	0.0172	415	452	1,600	0.3754	9,048	10,648
1999	30,023.53	-20%	6,005	65	588	9	20.99	0.0172	103	112	398	0.3743	2,248	2,646
2000	36,100.39	-20%	7,220	65	707	11	21.05	0.0171	124	135	478	0.3732	2,695	3,173
2001	86,927.73	-20%	17,386	65	1,702	26	21.11	0.0171	297	324	1,149	0.3722	6,471	7,620
2002	39,749.61	-20%	7,950	65	778	12	21.17	0.0171	136	148	525	0.3712	2,951	3,476
2003	28,796.09	-20%	5,759	65	564	9	21.23	0.0170	98	107	380	0.3703	2,133	2,512
2007	191,588.49	-20%	38,318	65	3,751	58	21.43	0.0169	648	706	2,514	0.3669	14,057	16,571
2008	154,490.93	-20%	30,898	65	3,024	47	21.48	0.0169	522	568	2,025	0.3661	11,312	13,337
2009	335,895.04	-20%	67,179	65	6,576	101	21.52	0.0169	1,133	1,234	4,398	0.3653	24,544	28,942
2010	8,985.07	-20%	1,797	65	176	3	21.57	0.0168	30	33	118	0.3646	655	773
2012	630,797.20	-20%	126,159	65	12,349	190	21.65	0.0168	2,118	2,308	8,236	0.3633	45,834	54,070
2014	1,711,302.98	-20%	342,261	65	33,502	515	21.72	0.0167	5,730	6,246	22,306	0.3621	123,920	146,226
2015	54,000.28	-20%	10,800	65	1,057	16	21.76	0.0167	181	197	703	0.3615	3,904	4,607
2016	296,612.63	-20%	59,323	65	5,807	89	21.79	0.0167	991	1,080	3,860	0.3609	21,411	25,271
2017	70,478.25	-20%	14,096	65	1,380	21	21.82	0.0167	235	256	916	0.3604	5,080	5,996
2018	57,736.74	-20%	11,547	65	1,130	17	21.86	0.0167	192	210	750	0.3599	4,156	4,906
2019	2,867,245.87	-20%	573,449	65	56,132	864	21.89	0.0166	9,545	10,408	37,232	0.3594	206,086	243,318
2020	361,313.25	-20%	72,263	65	7,073	109	21.92	0.0166	1,202	1,310	4,689	0.3589	25,935	30,624
2021	308,489.73	-20%	61,698	65	6,039	93	21.94	0.0166	1,025	1,118	4,001	0.3584	22,116	26,116
	11,606,288.59		2,321,258		227,218	3,496			39,821	43,317	153,610		866,762	1,020,372

Account 390 - Structures and Improvements - TSO Building
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 3.64%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 3.64%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.03640)^e)	g=f/e	h	i=1/(1+0.03640)^(h-1)-1/(1+0.03640)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
2013	2,626,911.60	-20%	525,382	65	51,427	791	29.65	0.0126	6,626	7,417	27,971	0.2486	130,603	158,574
2021	3,129,934.85	-20%	625,987	65	61,275	943	30.21	0.0124	7,736	8,679	32,793	0.2416	151,256	184,049
	5,756,846.45		1,151,369		112,702	1,734			14,362	16,096	60,764		281,859	342,623

Account 390 - Structures and Improvements - Other Small Structures
Calculation of Present Value Based Net Salvage
DC Present Value Method - Handy Whitman Discount Rates

Year	Original Cost 12/31/2021	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 3.64%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2021 at 3.64%	Increment in Removal Cost 2021	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.03640)^e)	g=f/e	h	i=1/(1+0.03640)^(h-1)-1/(1+0.03640)^h	j=d*i	k=g+j	l	m	n=d*m	o=l+n
1970	362.07	-20%	72	50	12	0	9.41	0.0260	2	2	10	0.5470	40	49
1938	94.58	-20%	19	50	3	0	0.50	0.0358	1	1	3	0.8149	15	19
1936	12,097.47	-20%	2,419	50	405	8	0.00	0.0364	88	96	405	0.8326	2,015	2,419
1951	10,883.71	-20%	2,177	50	364	7	3.46	0.0322	70	77	339	0.7162	1,559	1,898
1937	2,037.01	-20%	407	50	68	1	0.00	0.0364	15	16	68	0.8326	339	407
1939	1,149.65	-20%	230	50	38	1	0.60	0.0356	8	9	38	0.8114	187	225
1940	5,203.63	-20%	1,041	50	174	3	0.80	0.0354	37	40	171	0.8045	837	1,009
1949	2,550.03	-20%	510	50	85	2	2.95	0.0328	17	18	80	0.7325	374	454
1950	862.26	-20%	172	50	29	1	3.21	0.0325	6	6	27	0.7243	125	152
1960	6,961.31	-20%	1,392	50	233	5	5.84	0.0295	41	46	206	0.6441	897	1,103
1956	227.90	-20%	46	50	8	0	4.75	0.0307	1	2	7	0.6764	31	38
1952	6,883.33	-20%	1,377	50	230	5	3.72	0.0319	44	48	213	0.7081	975	1,188
2007	51,884.32	-20%	10,377	50	1,737	35	36.11	0.0100	104	139	483	0.1077	1,117	1,600
1955	846.36	-20%	169	50	28	1	4.49	0.0310	5	6	26	0.6843	116	142
1962	3,130.82	-20%	626	50	105	2	6.44	0.0289	18	20	91	0.6270	393	484
1959	2,341.54	-20%	468	50	78	2	5.56	0.0298	14	16	70	0.6524	306	375
1954	479.79	-20%	96	50	16	0	4.23	0.0313	3	3	15	0.6922	66	81
1961	35,094.39	-20%	7,019	50	1,175	23	6.14	0.0292	205	229	1,030	0.6357	4,462	5,492
1967	43,307.99	-20%	8,662	50	1,450	29	8.17	0.0272	235	264	1,213	0.5794	5,018	6,231
1964	11,414.00	-20%	2,283	50	382	8	7.09	0.0283	64	72	328	0.6089	1,390	1,718
1973	630.05	-20%	126	50	21	0	10.82	0.0247	3	4	17	0.5119	65	81
1966	2,329.79	-20%	466	50	78	2	7.79	0.0275	13	14	66	0.5895	275	341
1972	817.90	-20%	164	50	27	1	10.33	0.0252	4	5	22	0.5239	86	107
1968	10,168.85	-20%	2,034	50	340	7	8.56	0.0268	55	61	282	0.5689	1,157	1,439
1965	5,163.76	-20%	1,033	50	173	3	7.43	0.0279	29	32	147	0.5993	619	766
1971	336.68	-20%	67	50	11	0	9.86	0.0256	2	2	9	0.5356	36	45
1980	2,618.74	-20%	524	50	88	2	14.76	0.0215	11	13	62	0.4227	221	283
1977	134,894.91	-20%	26,979	50	4,515	90	12.96	0.0229	618	708	3,345	0.4618	12,459	15,804
1974	68,544.02	-20%	13,709	50	2,294	46	11.32	0.0243	333	379	1,775	0.4997	6,850	8,625
1963	22,110.85	-20%	4,422	50	740	15	6.76	0.0286	126	141	640	0.6181	2,733	3,373
1976	0.23	-20%	0	50	0	0	12.40	0.0234	0	0	0	0.4746	0	0
1982	278,794.57	-20%	55,759	50	9,331	187	16.04	0.0205	1,144	1,331	6,339	0.3963	22,097	28,435
1979	100,528.98	-20%	20,106	50	3,365	67	14.14	0.0220	441	509	2,413	0.4358	8,762	11,176
1975	4,736.02	-20%	947	50	159	3	11.85	0.0238	23	26	121	0.4873	462	582
1981	411,138.25	-20%	82,228	50	13,761	275	15.39	0.0210	1,727	2,002	9,526	0.4095	33,672	43,198
1983	31,888.15	-20%	6,378	50	1,067	21	16.70	0.0200	128	149	711	0.3831	2,443	3,154
1984	3,742.86	-20%	749	50	125	3	17.38	0.0196	15	17	82	0.3699	277	359
1985	124,626.28	-20%	24,925	50	4,171	83	18.07	0.0191	476	559	2,664	0.3568	8,893	11,557
1986	4,143.48	-20%	829	50	139	3	18.77	0.0186	15	18	87	0.3437	285	371
1987	103,637.18	-20%	20,727	50	3,469	69	19.49	0.0181	376	445	2,116	0.3308	6,856	8,972
1988	8,761.38	-20%	1,752	50	293	6	20.22	0.0177	31	37	175	0.3179	557	732
1989	19,513.22	-20%	3,903	50	653	13	20.97	0.0172	67	80	379	0.3052	1,191	1,570
1990	148,451.38	-20%	29,690	50	4,969	99	21.72	0.0167	497	596	2,810	0.2926	8,688	11,498
1991	65,166.38	-20%	13,033	50	2,181	44	22.49	0.0163	212	256	1,200	0.2802	3,652	4,852
1992	133,451.55	-20%	26,690	50	4,467	89	23.27	0.0158	423	512	2,388	0.2679	7,150	9,539
1993	553,879.68	-20%	110,776	50	18,539	371	24.05	0.0154	1,706	2,077	9,620	0.2558	28,337	37,957
1994	329.64	-20%	66	50	11	0	24.85	0.0150	1	1	6	0.2439	16	22
1995	278,633.07	-20%	55,727	50	9,326	187	25.66	0.0145	810	997	4,539	0.2321	12,937	17,476
1996	16,047.91	-20%	3,210	50	537	11	26.48	0.0141	45	56	253	0.2206	708	961
1997	15,770.31	-20%	3,154	50	528	11	27.31	0.0137	43	54	240	0.2093	660	900
1998	99,392.89	-20%	19,879	50	3,327	67	28.15	0.0133	264	331	1,454	0.1981	3,939	5,392
1999	3,953.73	-20%	791	50	132	3	29.00	0.0129	10	13	56	0.1872	148	204
2005	72,882.40	-20%	14,576	50	2,439	49	34.28	0.0107	156	205	767	0.1262	1,840	2,607
2001	10,012.94	-20%	2,003	50	335	7	30.73	0.0121	24	31	129	0.1660	332	462
2012	4,663.82	-20%	933	50	156	3	40.78	0.0085	8	11	29	0.0653	61	90
2003	264,358.87	-20%	52,872	50	8,848	177	32.49	0.0114	602	779	3,099	0.1457	7,701	10,800
2011	128,681.82	-20%	25,736	50	4,307	86	39.84	0.0088	225	312	875	0.0733	1,887	2,763
2006	8,215.04	-20%	1,643	50	275	5	35.19	0.0103	17	22	81	0.1168	192	273
2002	52,826.16	-20%	10,565	50	1,768	35	31.60	0.0118	124	160	651	0.1557	1,645	2,296
2008	5,115.54	-20%	1,023	50	171	3	37.03	0.0097	10	13	44	0.0987	101	145
2019	335,560.20	-20%	67,112	50	11,231	225	47.54	0.0067	446	671	551	0.0154	1,030	1,582
2017	19,508.42	-20%	3,902	50	653	13	45.59	0.0071	28	41	58	0.0286	111	169
2014	845,897.42	-20%	169,179	50	28,312	566	42.69	0.0079	1,338	1,904	4,137	0.0500	8,451	12,587
2000	35,050.92	-20%	7,010	50	1,173	23	29.86	0.0125	88	111	473	0.1765	1,237	1,710
2016	40,830.61	-20%	8,166	50	1,367	27	44.62	0.0074	60	88	147	0.0355	290	437
2021	3,306,255.86	-20%	661,251	50	110,661	2,213	49.51	0.0062	4,100	6,313	1,090	0.0030	1,966	3,056
2018	83,186.71	-20%	16,637	50	2,784	56	46.57	0.0069	115	170	191	0.0219	364	555
2015	264,140.83	-20%	52,828	50	8,841	177	43.66	0.0076	404	581	1,122	0.0426	2,251	3,372
2020	1,004,781.78	-20%	200,956	50	33,630	673	48.53	0.0064	1,290	1,963	992	0.0091	1,821	2,813
	9,333,984.18		1,866,797		312,411	6,248			19,663	25,911	72,799		227,770	300,568

Depreciation Calculations

I have developed an Excel model to calculate depreciation rates using a depreciation system consisting of the Straight Line Method, the Average Life Group Procedure, and the Remaining Life Technique. This is the same depreciation system utilized by Gannett Fleming to calculate the depreciation rates presented in Table 1 of Section VI of Pepco's 2021 Depreciation Study. The detailed depreciation calculations in Section IX of Pepco's 2021 Depreciation Study are also a result of using this traditional method.

The depreciation calculations I present below were calculated using the traditional method and do not represent the depreciation rates that result using the DC Present Value net salvage discount method.

Report Label	ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS Survivor Curve: 65-R3 Net Salvage Rate: -25%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
36100								
Mass Property								
1935	$	53	60	55	11	5.82	2	3.46%
1936	$	376,860	427,016	393,516	77,559	6.08	12,758	3.39%
1937	$	14,315	16,147	14,881	3,013	6.34	475	3.32%
1938	$	5,189	5,826	5,369	1,116	6.61	169	3.26%
1939	$	2,130	2,381	2,194	469	6.88	68	3.20%
1940	$	228,923	254,663	234,685	51,469	7.15	7,195	3.14%
1941	$	22,951	25,407	23,414	5,275	7.43	709	3.09%
1942	$	46,287	50,985	46,986	10,874	7.72	1,408	3.04%
1943	$	195,698	214,448	197,625	46,998	8.02	5,862	3.00%
1944	$	1,707	1,860	1,714	419	8.32	50	2.95%
1945	$	33,142	35,923	33,105	8,322	8.64	964	2.91%
1946	$	26,395	28,445	26,214	6,779	8.96	757	2.87%
1947	$	3,548	3,801	3,503	932	9.29	100	2.83%
1948	$	42,785	45,549	41,976	11,506	9.64	1,193	2.79%
1949	$	12,444	13,162	12,129	3,425	10.00	343	2.75%
1950	$	84,789	89,077	82,089	23,898	10.37	2,304	2.72%
1951	$	3,199	3,337	3,076	923	10.75	86	2.68%
1952	$	35,644	36,911	34,015	10,540	11.15	945	2.65%
1953	$	28,646	29,437	27,127	8,680	11.56	751	2.62%
1954	$	245,045	249,803	230,206	76,100	11.99	6,347	2.59%
1955	$	77,523	78,372	72,224	24,680	12.43	1,985	2.56%
1956	$	917	919	847	299	12.89	23	2.53%
1957	$	948,973	942,495	868,556	317,660	13.35	23,786	2.51%
1958	$	3,656	3,597	3,315	1,255	13.84	91	2.48%
1959	$	510,797	497,653	458,612	179,885	14.34	12,546	2.46%
1960	$	117,312	113,134	104,259	42,381	14.85	2,854	2.43%
1961	$	14,157	13,510	12,450	5,247	15.38	341	2.41%
1962	$	540,927	510,526	470,475	205,684	15.92	12,918	2.39%
1963	$	6,702	6,254	5,763	2,614	16.48	159	2.37%
1964	$	1,020,549	941,072	867,244	408,443	17.05	23,956	2.35%
1965	$	1,098,133	1,000,289	921,815	450,850	17.63	25,568	2.33%
1966	$	422,308	379,822	350,025	177,861	18.23	9,756	2.31%
1967	$	234,651	208,291	191,950	101,364	18.84	5,380	2.29%
1968	$	1,256,056	1,099,885	1,013,598	556,472	19.47	28,588	2.28%
1969	$	125,093	108,010	99,537	56,829	20.10	2,827	2.26%
1970	$	140,675	119,711	110,320	65,523	20.75	3,158	2.24%
1971	$	159,344	133,577	123,098	76,082	21.41	3,554	2.23%
1972	$	332,953	274,818	253,258	162,933	22.08	7,379	2.22%
1973	$	1,412,677	1,147,476	1,057,456	708,390	22.76	31,122	2.20%
1974	$	2,566,632	2,050,632	1,889,758	1,318,532	23.45	56,217	2.19%
1975	$	1,126,369	884,672	815,269	592,693	24.16	24,534	2.18%
1976	$	85,400	65,905	60,734	46,016	24.87	1,850	2.17%
1977	$	13,534	10,256	9,452	7,466	25.59	292	2.16%
1978	$	1,925,491	1,432,004	1,319,661	1,087,202	26.33	41,296	2.14%
1979	$	53,470	39,003	35,943	30,895	27.07	1,141	2.13%
1980	$	52,870	37,801	34,835	31,252	27.82	1,123	2.12%
1981	$	26,810	18,776	17,303	16,209	28.58	567	2.12%
1982	$	11,769	8,068	7,435	7,276	29.35	248	2.11%
1983	$	6,701,184	4,493,868	4,141,320	4,235,161	30.13	140,570	2.10%
1984	$	1,633,519	1,070,753	986,752	1,055,147	30.91	34,131	2.09%
1985	$	108,345	69,364	63,923	71,508	31.71	2,255	2.08%
1986	$	52,209	32,620	30,060	35,201	32.51	1,083	2.07%
1987	$	1,442,226	878,609	809,682	993,101	33.32	29,804	2.07%
1988	$	2,514,919	1,492,509	1,375,421	1,768,228	34.14	51,793	2.06%
1989	$	113,264	65,420	60,288	81,292	34.97	2,325	2.05%
1990	$	822,561	461,905	425,668	602,534	35.80	16,831	2.05%
1991	$	5,301,837	2,891,510	2,664,668	3,962,628	36.64	108,149	2.04%
1992	$	9,567	5,061	4,664	7,294	37.49	195	2.03%
1993	$	85,383	43,769	40,335	66,393	38.34	1,732	2.03%
1994	$	260,315	129,123	118,993	206,401	39.21	5,264	2.02%
1995	$	557,167	267,053	246,102	450,356	40.08	11,238	2.02%
1996	$	129,049	59,680	54,998	106,314	40.95	2,596	2.01%
1997	$	1,687,572	751,775	692,798	1,416,667	41.84	33,863	2.01%
1998	$	90,905	38,942	35,887	77,744	42.72	1,820	2.00%
1999	$	262,893	108,090	99,610	229,006	43.62	5,250	2.00%
2000	$	336,968	132,708	122,297	298,914	44.52	6,714	1.99%
2001	$	679,815	255,864	235,791	613,978	45.43	13,515	1.99%
2002	$	7,141,526	2,562,544	2,361,510	6,565,397	46.34	141,675	1.98%
2003	$	77,312	26,374	24,305	72,335	47.26	1,531	1.98%
2005	$	719,716	219,881	202,632	697,013	49.11	14,192	1.97%

Report Label	ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS Survivor Curve: 65-R3 Net Salvage Rate: -25%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
2006	$	202,889	58,341	53,764	199,847	50.05	3,993	1.97%
2007	$	13,015,715	3,507,656	3,232,477	13,037,167	50.99	255,699	1.96%
2008	$	142,527	35,825	33,014	145,144	51.93	2,795	1.96%
2009	$	212,880	49,629	45,736	220,364	52.88	4,167	1.96%
2010	$	144,828	31,114	28,673	152,362	53.83	2,831	1.95%
2011	$	305,196	59,960	55,256	326,239	54.78	5,955	1.95%
2012	$	536,821	95,563	88,066	582,961	55.74	10,458	1.95%
2013	$	346,151	55,213	50,882	381,807	56.71	6,733	1.95%
2014	$	92,733	13,069	12,044	103,872	57.67	1,801	1.94%
2015	$	935,524	114,407	105,432	1,063,973	58.64	18,144	1.94%
2016	$	2,291,916	237,452	218,824	2,646,072	59.61	44,388	1.94%
2017	$	7,601,638	645,186	594,571	8,907,477	60.59	147,021	1.93%
2018	$	34,387	2,272	2,094	40,889	61.56	664	1.93%
2019	$	4,979,379	235,297	216,837	6,007,386	62.54	96,052	1.93%
2020	$	8,341,960	236,728	218,156	10,209,293	63.52	160,715	1.93%
2021	$	4,566,577	43,251	39,858	5,668,363	64.51	87,871	1.92%
Mass Property Total	$	90,174,871	35,139,157	32,382,456	80,336,133	43.62	1,841,558	2.04%
36100 Total	**$**	**90,174,871**	**35,139,157**	**32,382,456**	**80,336,133**	**43.62**	**1,841,558**	**2.04%**
Grand Total	**$**	**90,174,871**	**35,139,157**	**32,382,456**	**80,336,133**	**43.62**	**1,841,558**	**2.04%**

Report Label	ACCOUNT 362.00 STATION EQUIPMENT Survivor Curve: 53-R2 Net Salvage Rate: -25%

Year	Sum of Original Cost		Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
36200								
Mass Property								
1934	$	10,380	12,257	12,454	520	2.93	177	1.71%
1936	$	38,476	44,922	45,647	2,447	3.50	700	1.82%
1937	$	53,124	61,666	62,662	3,743	3.78	990	1.86%
1938	$	16,240	18,742	19,045	1,256	4.07	309	1.90%
1939	$	9,572	10,982	11,159	807	4.36	185	1.93%
1940	$	203,180	231,702	235,444	18,530	4.65	3,987	1.96%
1941	$	187,011	211,986	215,410	18,353	4.94	3,717	1.99%
1942	$	216,583	244,023	247,964	22,765	5.23	4,354	2.01%
1943	$	166,332	186,270	189,279	18,636	5.52	3,378	2.03%
1944	$	10,219	11,374	11,558	1,216	5.81	209	2.05%
1945	$	63,937	70,721	71,863	8,058	6.10	1,321	2.07%
1946	$	40,719	44,757	45,480	5,419	6.40	847	2.08%
1947	$	4,278	4,672	4,747	600	6.69	90	2.09%
1948	$	47,443	51,481	52,313	6,991	6.99	1,000	2.11%
1949	$	118,112	127,322	129,378	18,261	7.29	2,504	2.12%
1950	$	47,419	50,774	51,594	7,680	7.60	1,010	2.13%
1951	$	6,629	7,049	7,163	1,123	7.91	142	2.14%
1952	$	50,808	53,651	54,518	8,992	8.23	1,093	2.15%
1953	$	168,048	176,175	179,021	31,039	8.55	3,631	2.16%
1954	$	679,825	707,429	718,856	130,926	8.88	14,747	2.17%
1955	$	240,395	248,252	252,262	48,231	9.21	5,235	2.18%
1956	$	4,545	4,657	4,732	949	9.56	99	2.19%
1957	$	1,967,509	1,999,524	2,031,821	427,565	9.91	43,145	2.19%
1958	$	140,722	141,814	144,105	31,797	10.27	3,096	2.20%
1959	$	1,664,149	1,662,546	1,689,400	390,786	10.64	36,725	2.21%
1960	$	625,027	618,837	628,833	152,451	11.02	13,834	2.21%
1961	$	557,673	547,031	555,866	141,225	11.41	12,378	2.22%
1962	$	729,624	708,832	720,281	191,749	11.81	16,239	2.23%
1963	$	291,358	280,240	284,767	79,431	12.22	6,501	2.23%
1964	$	2,005,141	1,908,744	1,939,575	566,851	12.64	44,852	2.24%
1965	$	1,117,299	1,052,231	1,069,227	327,396	13.07	25,051	2.24%
1966	$	316,689	294,944	299,708	96,153	13.51	7,116	2.25%
1967	$	1,010,361	930,191	945,216	317,736	13.96	22,753	2.25%
1968	$	1,308,259	1,190,130	1,209,353	425,971	14.43	29,523	2.26%
1969	$	829,001	744,850	756,881	279,370	14.90	18,745	2.26%
1970	$	1,530,292	1,357,377	1,379,301	533,564	15.39	34,667	2.27%
1971	$	319,189	279,374	283,886	115,101	15.89	7,244	2.27%
1972	$	431,815	372,763	378,784	160,985	16.40	9,817	2.27%
1973	$	3,498,549	2,977,158	3,025,246	1,347,939	16.92	79,671	2.28%
1974	$	2,923,623	2,451,260	2,490,854	1,163,675	17.45	66,685	2.28%
1975	$	1,916,570	1,582,373	1,607,932	787,781	17.99	43,782	2.28%
1976	$	2,271,281	1,845,576	1,875,386	963,716	18.55	51,961	2.29%
1977	$	1,851,177	1,479,562	1,503,460	810,511	19.11	42,409	2.29%
1978	$	2,695,985	2,118,188	2,152,402	1,217,579	19.69	61,847	2.29%
1979	$	2,074,556	1,601,257	1,627,121	966,074	20.27	47,653	2.30%
1980	$	2,623,671	1,988,159	2,020,273	1,259,316	20.87	60,340	2.30%
1981	$	1,274,605	947,616	962,922	630,334	21.48	29,349	2.30%
1982	$	4,288,980	3,126,229	3,176,724	2,184,500	22.09	98,870	2.31%
1983	$	11,674,495	8,336,735	8,471,393	6,121,725	22.72	269,416	2.31%
1984	$	7,136,895	4,989,171	5,069,757	3,851,362	23.36	164,873	2.31%
1985	$	2,020,893	1,381,895	1,404,216	1,121,900	24.01	46,733	2.31%
1986	$	4,329,551	2,893,514	2,940,251	2,471,688	24.66	100,217	2.31%
1987	$	3,223,648	2,103,757	2,137,738	1,891,822	25.33	74,688	2.32%
1988	$	4,876,813	3,104,898	3,155,050	2,940,966	26.01	113,091	2.32%
1989	$	7,956,556	4,937,190	5,016,937	4,928,757	26.69	184,667	2.32%
1990	$	19,903,323	12,024,803	12,219,031	12,660,122	27.38	462,326	2.32%
1991	$	11,142,049	6,546,970	6,652,719	7,274,843	28.09	259,019	2.32%
1992	$	39,121,607	22,331,494	22,692,200	26,209,809	28.80	910,155	2.33%
1993	$	3,050,770	1,689,689	1,716,981	2,096,482	29.52	71,028	2.33%
1994	$	1,775,404	952,839	968,230	1,251,025	30.24	41,364	2.33%
1995	$	1,562,028	811,210	824,313	1,128,222	30.98	36,417	2.33%
1996	$	1,053,327	528,543	537,081	779,579	31.72	24,574	2.33%
1997	$	2,785,681	1,348,386	1,370,165	2,111,936	32.48	65,029	2.33%
1998	$	15,420,741	7,187,977	7,304,079	11,971,847	33.24	360,204	2.34%
1999	$	6,046,528	2,708,980	2,752,736	4,805,424	34.00	141,320	2.34%
2000	$	2,549,882	1,095,810	1,113,510	2,073,843	34.78	59,630	2.34%
2001	$	3,421,509	1,407,281	1,430,012	2,846,875	35.56	80,057	2.34%
2002	$	4,145,228	1,627,781	1,654,074	3,527,461	36.35	97,042	2.34%
2003	$	11,920,154	4,457,092	4,529,085	10,371,108	37.15	279,198	2.34%
2004	$	16,163	5,737	5,830	14,374	37.95	379	2.34%

Report Label	ACCOUNT 362.00 STATION EQUIPMENT Survivor Curve: 53-R2 Net Salvage Rate: -25%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
2005	$	12,477,593	4,190,601	4,258,289	11,338,702	38.76	292,537	2.34%
2006	$	9,708,944	3,073,696	3,123,344	9,012,836	39.58	227,730	2.35%
2007	$	26,389,240	7,841,857	7,968,521	25,018,029	40.40	619,253	2.35%
2008	$	5,915,794	1,642,169	1,668,693	5,726,049	41.23	138,880	2.35%
2009	$	14,486,871	3,735,711	3,796,051	14,312,537	42.07	340,238	2.35%
2010	$	19,250,893	4,581,771	4,655,778	19,407,839	42.91	452,306	2.35%
2011	$	9,927,267	2,164,072	2,199,026	10,210,057	43.76	233,335	2.35%
2012	$	26,210,949	5,185,661	5,269,421	27,494,266	44.61	616,306	2.35%
2013	$	22,094,740	3,923,019	3,986,385	23,632,040	45.47	519,710	2.35%
2014	$	28,742,413	4,516,269	4,589,217	31,338,799	46.34	676,314	2.35%
2015	$	22,258,433	3,039,948	3,089,051	24,733,991	47.21	523,924	2.35%
2016	$	26,028,443	3,016,566	3,065,291	29,470,263	48.09	612,866	2.35%
2017	$	84,677,963	8,051,639	8,181,692	97,665,761	48.97	1,994,469	2.36%
2018	$	10,730,739	795,718	808,571	12,604,854	49.86	252,826	2.36%
2019	$	45,433,311	2,412,902	2,451,876	54,339,763	50.75	1,070,774	2.36%
2020	$	35,510,376	1,134,608	1,152,935	43,235,035	51.65	837,155	2.36%
2021	$	28,135,724	300,241	305,091	34,864,564	52.55	663,487	2.36%
Mass Property Total	$	635,759,317	188,865,869	191,916,493	602,782,653	40.52	14,877,511	2.34%
36200 Total	**$**	**635,759,317**	**188,865,869**	**191,916,493**	**602,782,653**	**40.52**	**14,877,511**	**2.34%**
Grand Total	**$**	**635,759,317**	**188,865,869**	**191,916,493**	**602,782,653**	**40.52**	**14,877,511**	**2.34%**

Report Label	ACCOUNT 364.00 POLES, TOWERS AND FIXTURES Survivor Curve: 60-R2.5 Net Salvage Rate: -90%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
36400								
Mass Property								
1955	$	610,240	934,072	548,047	611,410	11.66	52,422	8.59%
1956	$	112,938	171,535	100,645	113,937	12.04	9,466	8.38%
1957	$	146,883	221,292	129,839	149,238	12.42	12,013	8.18%
1958	$	125,327	187,226	109,851	128,270	12.82	10,002	7.98%
1959	$	159,882	236,745	138,905	164,870	13.24	12,453	7.79%
1960	$	210,265	308,489	181,000	218,504	13.67	15,985	7.60%
1961	$	253,421	368,242	216,058	265,441	14.11	18,808	7.42%
1962	$	186,144	267,780	157,114	196,560	14.57	13,489	7.25%
1963	$	275,198	391,760	229,857	293,020	15.05	19,475	7.08%
1964	$	344,826	485,555	284,890	370,280	15.53	23,838	6.91%
1965	$	300,673	418,600	245,605	325,673	16.04	20,310	6.75%
1966	$	421,116	579,391	339,946	460,175	16.55	27,801	6.60%
1967	$	303,507	412,485	242,017	334,647	17.08	19,590	6.45%
1968	$	159,108	213,495	125,264	177,041	17.63	10,044	6.31%
1969	$	295,941	391,871	229,922	332,366	18.18	18,277	6.18%
1970	$	157,402	205,580	120,620	178,443	18.76	9,514	6.04%
1971	$	197,905	254,823	149,512	226,508	19.34	11,713	5.92%
1972	$	109,234	138,586	81,312	126,231	19.94	6,332	5.80%
1973	$	398,019	497,307	291,785	464,452	20.54	22,608	5.68%
1974	$	645,062	793,303	465,454	760,164	21.16	35,918	5.57%
1975	$	422,278	510,868	299,741	502,586	21.80	23,059	5.46%
1976	$	498,690	593,164	348,026	599,485	22.44	26,717	5.36%
1977	$	355,222	415,161	243,587	431,335	23.09	18,679	5.26%
1978	$	266,530	305,893	179,476	326,931	23.76	13,761	5.16%
1979	$	636,153	716,519	420,402	788,289	24.43	32,265	5.07%
1980	$	382,638	422,679	247,998	479,013	25.12	19,072	4.98%
1981	$	265,368	287,302	168,569	335,631	25.81	13,003	4.90%
1982	$	370,086	392,430	230,250	472,914	26.51	17,836	4.82%
1983	$	299,820	311,152	182,562	387,097	27.23	14,217	4.74%
1984	$	477,195	484,315	284,162	622,508	27.95	22,272	4.67%
1985	$	524,861	520,551	305,423	691,813	28.68	24,122	4.60%
1986	$	828,564	802,359	470,768	1,103,505	29.42	37,509	4.53%
1987	$	814,747	769,674	451,590	1,096,428	30.17	36,344	4.46%
1988	$	1,269,587	1,168,963	685,865	1,726,350	30.92	55,826	4.40%
1989	$	2,284,293	2,047,964	1,201,600	3,138,556	31.69	99,045	4.34%
1990	$	1,138,009	992,431	582,288	1,579,928	32.46	48,672	4.28%
1991	$	363,925	308,384	180,938	510,520	33.24	15,358	4.22%
1992	$	1,692,924	1,392,324	816,917	2,399,639	34.03	70,519	4.17%
1993	$	2,473,217	1,971,767	1,156,893	3,542,219	34.82	101,719	4.11%
1994	$	1,940,105	1,497,442	878,593	2,807,606	35.63	78,807	4.06%
1995	$	3,179,466	2,372,505	1,392,018	4,648,969	36.44	127,593	4.01%
1996	$	1,406,404	1,013,055	594,389	2,077,779	37.25	55,775	3.97%
1997	$	2,141,547	1,486,724	872,305	3,196,634	38.08	83,952	3.92%
1998	$	1,202,828	803,395	471,376	1,813,997	38.91	46,623	3.88%
1999	$	1,688,314	1,082,877	635,356	2,572,442	39.75	64,723	3.83%
2000	$	3,216,108	1,976,894	1,159,902	4,950,703	40.59	121,972	3.79%
2001	$	2,561,831	1,505,723	883,452	3,984,027	41.44	96,141	3.75%
2002	$	2,658,476	1,490,420	874,473	4,176,632	42.30	98,748	3.71%
2003	$	3,568,352	1,903,066	1,116,585	5,663,284	43.16	131,221	3.68%
2004	$	907,278	458,919	269,261	1,454,567	44.03	33,038	3.64%
2005	$	2,161,456	1,033,465	606,364	3,500,402	44.90	77,958	3.61%
2006	$	2,162,584	973,786	571,348	3,537,562	45.78	77,272	3.57%
2007	$	1,590,375	671,554	394,020	2,627,691	46.67	56,309	3.54%
2008	$	3,339,283	1,315,887	772,070	5,572,569	47.56	117,179	3.51%
2009	$	2,652,809	970,172	569,229	4,471,109	48.45	92,281	3.48%
2010	$	2,793,064	941,834	552,601	4,754,219	49.35	96,334	3.45%
2011	$	4,847,098	1,495,565	877,491	8,331,994	50.26	165,790	3.42%
2012	$	12,345,831	3,453,852	2,026,476	21,430,603	51.17	418,849	3.39%
2013	$	17,254,480	4,327,763	2,539,225	30,244,287	52.08	580,735	3.37%
2014	$	14,893,752	3,302,643	1,937,757	26,360,372	53.00	497,390	3.34%
2015	$	9,888,726	1,904,122	1,117,204	17,671,375	53.92	327,738	3.31%
2016	$	6,452,726	1,053,270	617,984	11,642,195	54.85	212,273	3.29%
2017	$	6,290,732	841,635	493,812	11,458,580	55.78	205,443	3.27%
2018	$	3,404,037	354,844	208,198	6,259,473	56.71	110,381	3.24%
2019	$	4,722,098	352,213	206,654	8,765,332	57.64	152,058	3.22%
2020	$	7,821,007	350,532	205,667	14,654,247	58.58	250,138	3.20%
2021	$	11,406,175	170,660	100,131	21,571,601	59.53	362,381	3.18%
Mass Property Total	$	159,274,143	60,996,860	35,788,639	266,832,232	46.01	5,799,154	3.64%
36400 Total	**$**	**159,274,143**	**60,996,860**	**35,788,639**	**266,832,232**	**46.01**	**5,799,154**	**3.64%**
Grand Total	**$**	**159,274,143**	**60,996,860**	**35,788,639**	**266,832,232**	**46.01**	**5,799,154**	**3.64%**

Report Label	ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES Survivor Curve: 54-R2 Net Salvage Rate: -90%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
36500								
Mass Property								
1955	$	684,481	1,064,000	858,751	441,762	9.82	44,984	6.57%
1956	$	21,840	33,677	27,181	14,315	10.17	1,407	6.44%
1957	$	26,376	40,337	32,556	17,560	10.54	1,667	6.32%
1958	$	38,668	58,628	47,319	26,151	10.91	2,397	6.20%
1959	$	55,258	83,041	67,022	37,968	11.29	3,363	6.09%
1960	$	73,814	109,911	88,709	51,537	11.68	4,412	5.98%
1961	$	100,295	147,929	119,393	71,167	12.08	5,891	5.87%
1962	$	96,187	140,480	113,381	69,375	12.49	5,554	5.77%
1963	$	93,802	135,605	109,447	68,777	12.91	5,326	5.68%
1964	$	120,643	172,577	139,286	89,936	13.34	6,740	5.59%
1965	$	121,511	171,926	138,761	92,111	13.79	6,681	5.50%
1966	$	109,832	153,648	124,009	84,672	14.24	5,946	5.41%
1967	$	158,518	219,166	176,888	124,295	14.71	8,453	5.33%
1968	$	119,964	163,855	132,247	95,684	15.18	6,303	5.25%
1969	$	144,073	194,316	156,832	116,906	15.67	7,462	5.18%
1970	$	111,465	148,386	119,762	92,022	16.16	5,693	5.11%
1971	$	85,634	112,466	90,771	71,934	16.67	4,314	5.04%
1972	$	104,784	135,701	109,524	89,567	17.19	5,209	4.97%
1973	$	454,168	579,694	467,869	395,051	17.72	22,289	4.91%
1974	$	830,728	1,044,500	843,013	735,372	18.27	40,261	4.85%
1975	$	460,757	570,367	460,341	415,097	18.82	22,059	4.79%
1976	$	438,007	533,525	430,606	401,607	19.38	20,722	4.73%
1977	$	397,339	475,966	384,151	370,793	19.95	18,582	4.68%
1978	$	256,838	302,384	244,053	243,939	20.54	11,877	4.62%
1979	$	420,758	486,570	392,709	406,731	21.13	19,246	4.57%
1980	$	537,881	610,570	492,789	529,186	21.74	24,344	4.53%
1981	$	321,088	357,535	288,565	321,501	22.35	14,383	4.48%
1982	$	471,453	514,598	415,330	480,432	22.98	20,908	4.43%
1983	$	413,272	441,861	356,625	428,593	23.61	18,151	4.39%
1984	$	447,357	468,160	377,851	472,128	24.26	19,463	4.35%
1985	$	712,396	729,137	588,484	765,068	24.91	30,712	4.31%
1986	$	996,387	996,557	804,318	1,088,818	25.57	42,575	4.27%
1987	$	1,099,191	1,073,386	866,327	1,222,136	26.25	46,564	4.24%
1988	$	1,040,941	991,559	800,284	1,177,504	26.93	43,729	4.20%
1989	$	2,094,500	1,944,258	1,569,205	2,410,344	27.62	87,276	4.17%
1990	$	990,424	895,017	722,365	1,159,440	28.32	40,945	4.13%
1991	$	600,496	527,704	425,909	715,034	29.02	24,636	4.10%
1992	$	2,175,027	1,856,603	1,498,458	2,634,094	29.74	88,571	4.07%
1993	$	3,328,809	2,756,664	2,224,895	4,099,843	30.46	134,581	4.04%
1994	$	3,717,576	2,982,861	2,407,458	4,655,937	31.20	149,249	4.01%
1995	$	3,538,476	2,747,034	2,217,122	4,505,983	31.94	141,095	3.99%
1996	$	1,695,308	1,271,498	1,026,222	2,194,864	32.68	67,154	3.96%
1997	$	2,278,747	1,648,482	1,330,485	2,999,135	33.44	89,688	3.94%
1998	$	1,144,450	797,189	643,408	1,531,046	34.20	44,764	3.91%
1999	$	1,729,109	1,157,563	934,265	2,351,043	34.97	67,224	3.89%
2000	$	3,393,475	2,178,915	1,758,596	4,689,008	35.75	131,157	3.86%
2001	$	1,943,467	1,194,211	963,844	2,728,744	36.54	74,687	3.84%
2002	$	3,113,931	1,826,678	1,474,306	4,442,164	37.33	119,004	3.82%
2003	$	4,723,981	2,638,327	2,129,385	6,846,179	38.13	179,563	3.80%
2004	$	266,661	141,369	114,099	392,557	38.93	10,083	3.78%
2005	$	3,492,202	1,751,561	1,413,679	5,221,505	39.74	131,375	3.76%
2006	$	3,526,484	1,667,176	1,345,573	5,354,747	40.56	132,009	3.74%
2007	$	2,206,103	978,903	790,070	3,401,526	41.39	82,185	3.73%
2008	$	3,744,107	1,551,847	1,252,491	5,861,312	42.22	138,828	3.71%
2009	$	4,065,553	1,565,210	1,263,276	6,461,274	43.06	150,060	3.69%
2010	$	3,220,973	1,144,425	923,662	5,196,187	43.90	118,359	3.67%
2011	$	6,178,851	2,010,613	1,622,759	10,117,058	44.75	226,071	3.66%
2012	$	14,574,279	4,303,817	3,473,597	24,217,532	45.61	531,003	3.64%
2013	$	13,891,260	3,681,255	2,971,130	23,422,264	46.47	504,049	3.63%
2014	$	9,765,209	2,290,047	1,848,290	16,705,608	47.33	352,924	3.61%
2015	$	7,193,323	1,466,186	1,183,354	12,483,960	48.21	258,966	3.60%
2016	$	8,417,416	1,455,812	1,174,981	14,818,109	49.08	301,890	3.59%
2017	$	8,365,251	1,186,932	957,969	14,936,007	49.97	298,916	3.57%
2018	$	3,879,137	429,207	346,412	7,023,948	50.86	138,116	3.56%
2019	$	10,011,833	793,336	640,299	18,382,183	51.75	355,226	3.55%
2020	$	15,392,720	733,756	592,212	28,653,956	52.65	544,285	3.54%
2021	$	15,836,596	252,116	203,482	29,886,049	53.55	558,123	3.52%
Mass Property Total	$	182,061,445	67,288,595	54,308,413	291,608,332	42.76	6,819,726	3.75%
36500 Total	**$**	**182,061,445**	**67,288,595**	**54,308,413**	**291,608,332**	**42.76**	**6,819,726**	**3.75%**
Grand Total	**$**	**182,061,445**	**67,288,595**	**54,308,413**	**291,608,332**	**42.76**	**6,819,726**	**3.75%**

Report Label	ACCOUNT 366.00 UNDERGROUND CONDUIT Survivor Curve: 75-R3.5 Net Salvage Rate: -60%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
36600								
Mass Property								
1955	$	15,550,638	19,049,746	17,318,756	7,562,265	17.58	430,225	2.77%
1956	$	691,217	837,714	761,594	344,353	18.19	18,931	2.74%
1957	$	1,417,377	1,698,892	1,544,519	723,285	18.81	38,442	2.71%
1958	$	1,584,290	1,877,381	1,706,789	828,075	19.45	42,568	2.69%
1959	$	1,767,535	2,070,087	1,881,985	946,071	20.10	47,065	2.66%
1960	$	1,870,009	2,163,875	1,967,251	1,024,763	20.76	49,365	2.64%
1961	$	1,773,083	2,026,411	1,842,277	994,655	21.43	46,419	2.62%
1962	$	1,699,759	1,918,026	1,743,741	975,874	22.11	44,146	2.60%
1963	$	2,276,610	2,535,584	2,305,184	1,337,391	22.79	58,676	2.58%
1964	$	3,720,466	4,088,221	3,716,738	2,236,007	23.49	95,183	2.56%
1965	$	3,444,724	3,733,222	3,393,996	2,117,563	24.20	87,506	2.54%
1966	$	3,998,926	4,272,702	3,884,455	2,513,827	24.92	100,893	2.52%
1967	$	3,603,468	3,794,196	3,449,430	2,316,120	25.64	90,318	2.51%
1968	$	808,760	838,854	762,630	531,386	26.38	20,143	2.49%
1969	$	6,480,199	6,618,283	6,016,901	4,351,417	27.13	160,414	2.48%
1970	$	3,821,883	3,841,628	3,492,552	2,622,461	27.88	94,053	2.46%
1971	$	2,641,580	2,612,123	2,374,768	1,851,759	28.65	64,639	2.45%
1972	$	3,000,167	2,917,218	2,652,140	2,148,127	29.42	73,013	2.43%
1973	$	7,128,152	6,811,877	6,192,904	5,212,140	30.20	172,560	2.42%
1974	$	7,054,287	6,622,125	6,020,393	5,266,466	31.00	169,904	2.41%
1975	$	10,605,235	9,774,605	8,886,418	8,081,959	31.80	254,179	2.40%
1976	$	5,071,774	4,586,953	4,170,152	3,944,687	32.61	120,981	2.39%
1977	$	4,879,149	4,327,694	3,934,450	3,872,189	33.42	115,854	2.37%
1978	$	6,501,831	5,652,639	5,139,002	5,263,928	34.25	153,704	2.36%
1979	$	8,676,661	7,389,117	6,717,692	7,164,966	35.08	204,242	2.35%
1980	$	8,407,888	7,009,467	6,372,540	7,080,081	35.92	197,099	2.34%
1981	$	6,773,730	5,524,657	5,022,649	5,815,319	36.77	158,159	2.33%
1982	$	17,665,358	14,085,381	12,805,487	15,459,085	37.62	410,879	2.33%
1983	$	11,248,708	8,762,221	7,966,026	10,031,908	38.49	260,660	2.32%
1984	$	7,524,841	5,722,103	5,202,154	6,837,591	39.35	173,742	2.31%
1985	$	13,562,534	10,059,792	9,145,691	12,554,363	40.23	312,055	2.30%
1986	$	11,360,955	8,213,053	7,466,759	10,710,769	41.11	260,519	2.29%
1987	$	13,435,558	9,458,403	8,598,949	12,897,945	42.00	307,088	2.29%
1988	$	18,864,826	12,920,591	11,746,538	18,437,184	42.90	429,820	2.28%
1989	$	14,637,738	9,744,514	8,859,062	14,561,319	43.79	332,490	2.27%
1990	$	9,464,456	6,117,885	5,561,973	9,581,157	44.70	214,345	2.26%
1991	$	9,982,103	6,258,474	5,689,787	10,281,578	45.61	225,420	2.26%
1992	$	13,201,725	8,019,216	7,290,535	13,832,225	46.53	297,299	2.25%
1993	$	19,593,828	11,517,338	10,470,794	20,879,330	47.45	440,059	2.25%
1994	$	18,970,556	10,776,422	9,797,203	20,555,686	48.37	424,949	2.24%
1995	$	15,546,206	8,522,819	7,748,378	17,125,552	49.30	347,361	2.23%
1996	$	8,530,303	4,506,600	4,097,100	9,551,385	50.24	190,131	2.23%
1997	$	8,355,779	4,247,135	3,861,212	9,508,035	51.17	185,798	2.22%
1998	$	5,158,284	2,518,205	2,289,384	5,963,871	52.12	114,434	2.22%
1999	$	6,056,313	2,834,454	2,576,896	7,113,205	53.06	134,055	2.21%
2000	$	9,617,182	4,306,157	3,914,870	11,472,621	54.01	212,411	2.21%
2001	$	19,590,337	8,373,516	7,612,641	23,731,898	54.96	431,770	2.20%
2002	$	10,900,115	4,436,811	4,033,652	13,406,531	55.92	239,745	2.20%
2003	$	42,046,512	16,254,387	14,777,403	52,497,016	56.88	922,960	2.20%
2004	$	4,829,446	1,767,867	1,607,226	6,119,887	57.84	105,805	2.19%
2005	$	18,810,378	6,498,670	5,908,157	24,188,449	58.81	411,330	2.19%
2006	$	8,933,009	2,901,838	2,638,157	11,654,657	59.77	194,982	2.18%
2007	$	8,171,619	2,485,485	2,259,637	10,814,953	60.74	178,046	2.18%
2008	$	39,894,535	11,307,317	10,279,858	53,551,398	61.71	867,732	2.18%
2009	$	24,629,423	6,468,845	5,881,042	33,526,036	62.69	534,804	2.17%
2010	$	15,122,421	3,656,944	3,324,650	20,871,224	63.66	327,831	2.17%
2011	$	24,413,156	5,394,226	4,904,070	34,156,979	64.64	528,397	2.16%
2012	$	24,010,961	4,803,432	4,366,959	34,050,579	65.62	518,885	2.16%
2013	$	26,812,645	4,802,642	4,366,242	38,533,990	66.60	578,555	2.16%
2014	$	39,402,499	6,231,157	5,664,952	57,379,046	67.59	848,964	2.15%
2015	$	31,948,161	4,381,288	3,983,174	47,133,884	68.57	687,367	2.15%
2016	$	40,649,041	4,719,713	4,290,848	60,747,618	69.56	873,345	2.15%
2017	$	51,046,724	4,852,229	4,411,322	77,263,436	70.54	1,095,247	2.15%
2018	$	69,193,013	5,117,787	4,652,750	106,056,070	71.53	1,482,619	2.14%
2019	$	33,916,465	1,792,690	1,629,794	52,636,549	72.52	725,798	2.14%
2020	$	54,204,827	1,719,943	1,563,658	85,164,066	73.51	1,158,496	2.14%
2021	$	44,139,776	467,058	424,618	70,199,023	74.50	942,218	2.13%
Mass Property Total	$	990,691,715	381,617,906	346,941,512	1,238,165,233	56.19	22,037,093	2.22%
36600 Total	**$**	**990,691,715**	**381,617,906**	**346,941,512**	**1,238,165,233**	**56.19**	**22,037,093**	**2.22%**
Grand Total	**$**	**990,691,715**	**381,617,906**	**346,941,512**	**1,238,165,233**	**56.19**	**22,037,093**	**2.22%**

Report Label	ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES Survivor Curve: 67-R2.5 Net Salvage Rate: -70%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
36700								
Mass Property								
1955	$	4,428,406	5,703,068	4,337,609	3,190,681	16.24	196,422	4.44%
1956	$	906,739	1,156,873	879,888	661,568	16.72	39,577	4.36%
1957	$	716,738	905,641	688,807	529,648	17.20	30,792	4.30%
1958	$	1,005,497	1,257,808	956,657	752,688	17.70	42,528	4.23%
1959	$	875,927	1,084,373	824,746	664,330	18.21	36,483	4.17%
1960	$	984,218	1,205,371	916,775	756,397	18.73	40,379	4.10%
1961	$	1,070,643	1,296,661	986,208	833,885	19.27	43,278	4.04%
1962	$	679,413	813,398	618,650	536,352	19.82	27,067	3.98%
1963	$	1,508,790	1,784,888	1,357,540	1,207,402	20.38	59,256	3.93%
1964	$	1,645,048	1,922,229	1,461,998	1,334,584	20.95	63,711	3.87%
1965	$	1,803,457	2,080,634	1,582,477	1,483,400	21.53	68,896	3.82%
1966	$	1,637,230	1,864,176	1,417,845	1,365,447	22.13	61,715	3.77%
1967	$	1,620,792	1,820,553	1,384,666	1,370,681	22.73	60,301	3.72%
1968	$	1,476,377	1,635,270	1,243,745	1,266,096	23.35	54,231	3.67%
1969	$	3,536,701	3,861,077	2,936,636	3,075,756	23.97	128,298	3.63%
1970	$	3,179,476	3,419,752	2,600,976	2,804,133	24.61	113,944	3.58%
1971	$	1,768,250	1,872,853	1,424,444	1,581,581	25.26	62,620	3.54%
1972	$	1,508,354	1,572,481	1,195,989	1,368,214	25.91	52,801	3.50%
1973	$	4,197,212	4,304,711	3,274,053	3,861,206	26.58	145,274	3.46%
1974	$	4,998,409	5,040,892	3,833,974	4,663,321	27.25	171,111	3.42%
1975	$	5,767,663	5,716,550	4,347,862	5,457,165	27.94	195,335	3.39%
1976	$	5,979,053	5,821,097	4,427,378	5,737,013	28.63	200,389	3.35%
1977	$	5,096,545	4,871,179	3,704,895	4,959,232	29.33	169,078	3.32%
1978	$	6,757,641	6,337,274	4,819,969	6,668,020	30.04	221,972	3.28%
1979	$	7,103,510	6,532,212	4,968,234	7,107,732	30.76	231,087	3.25%
1980	$	6,849,867	6,172,971	4,695,004	6,949,769	31.48	220,748	3.22%
1981	$	5,649,145	4,985,734	3,792,022	5,811,525	32.22	180,389	3.19%
1982	$	10,376,674	8,963,119	6,817,120	10,823,226	32.96	328,404	3.16%
1983	$	12,884,519	10,884,430	8,278,420	13,625,262	33.71	404,237	3.14%
1984	$	8,116,685	6,701,153	5,096,726	8,701,638	34.46	252,503	3.11%
1985	$	5,524,973	4,454,370	3,387,880	6,004,574	35.23	170,462	3.09%
1986	$	6,788,494	5,340,435	4,061,799	7,478,641	36.00	207,768	3.06%
1987	$	7,188,160	5,512,966	4,193,021	8,026,850	36.77	218,281	3.04%
1988	$	13,690,849	10,227,944	7,779,113	15,495,329	37.56	412,584	3.01%
1989	$	12,776,441	9,288,180	7,064,353	14,655,596	38.35	382,169	2.99%
1990	$	6,616,086	4,675,887	3,556,360	7,690,986	39.15	196,470	2.97%
1991	$	13,880,954	9,526,800	7,245,841	16,351,780	39.95	409,298	2.95%
1992	$	8,538,713	5,684,790	4,323,706	10,192,106	40.76	250,046	2.93%
1993	$	18,712,929	12,070,153	9,180,251	22,631,729	41.58	544,311	2.91%
1994	$	10,143,328	6,330,788	4,815,036	12,428,620	42.40	293,116	2.89%
1995	$	23,197,605	13,989,860	10,640,331	28,795,597	43.23	666,075	2.87%
1996	$	11,055,584	6,433,021	4,892,792	13,901,701	44.07	315,467	2.85%
1997	$	6,726,891	3,770,600	2,867,823	8,567,892	44.91	190,785	2.84%
1998	$	9,253,272	4,987,882	3,793,656	11,936,906	45.76	260,885	2.82%
1999	$	7,040,999	3,642,953	2,770,737	9,198,961	46.61	197,366	2.80%
2000	$	11,108,909	5,505,823	4,187,589	14,697,557	47.47	309,640	2.79%
2001	$	17,685,509	8,377,617	6,371,802	23,693,563	48.33	490,239	2.77%
2002	$	13,713,751	6,193,924	4,710,941	18,602,436	49.20	378,104	2.76%
2003	$	27,164,571	11,666,494	8,873,238	37,306,533	50.07	745,034	2.74%
2004	$	6,757,707	2,751,606	2,092,802	9,395,300	50.95	184,394	2.73%
2005	$	31,231,399	12,016,292	9,139,285	43,954,093	51.84	847,941	2.72%
2006	$	21,828,957	7,906,593	6,013,553	31,095,674	52.72	589,774	2.70%
2007	$	24,968,381	8,477,755	6,447,964	35,998,283	53.62	671,383	2.69%
2008	$	23,409,261	7,415,370	5,639,942	34,155,803	54.52	626,535	2.68%
2009	$	28,333,126	8,326,475	6,332,905	41,833,410	55.42	754,875	2.66%
2010	$	22,758,004	6,164,947	4,688,902	33,999,705	56.32	603,649	2.65%
2011	$	23,446,815	5,810,180	4,419,075	35,440,510	57.23	619,226	2.64%
2012	$	41,929,412	9,417,856	7,162,982	64,117,019	58.15	1,102,661	2.63%
2013	$	31,582,474	6,358,343	4,835,994	48,854,212	59.07	827,121	2.62%
2014	$	36,919,978	6,569,894	4,996,894	57,767,068	59.99	962,999	2.61%
2015	$	33,021,873	5,101,106	3,879,772	52,257,412	60.91	857,920	2.60%
2016	$	50,121,974	6,562,218	4,991,056	80,216,300	61.84	1,297,160	2.59%
2017	$	51,412,294	5,516,064	4,195,378	83,205,522	62.77	1,325,532	2.58%
2018	$	44,256,189	3,698,698	2,813,135	72,422,387	63.71	1,136,821	2.57%
2019	$	73,390,121	4,387,965	3,337,375	121,425,830	64.64	1,878,392	2.56%
2020	$	100,880,646	3,623,907	2,756,251	168,740,847	65.58	2,572,891	2.55%
2021	$	59,640,544	715,003	543,813	100,845,112	66.53	1,515,843	2.54%
Mass Property Total	$	1,050,826,153	360,089,184	273,874,663	1,512,529,798	52.31	28,916,044	2.75%
36700 Total	**$**	**1,050,826,153**	**360,089,184**	**273,874,663**	**1,512,529,798**	**52.31**	**28,916,044**	**2.75%**
Grand Total	**$**	**1,050,826,153**	**360,089,184**	**273,874,663**	**1,512,529,798**	**52.31**	**28,916,044**	**2.75%**

Report Label	ACCOUNT 368.00 LINE TRANSFORMERS Survivor Curve: 37-R2 Net Salvage Rate: -50%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
36800								
Mass Property								
1955	$	299,780	441,418	325,520	124,150	1.00	124,150	41.41%
1956	$	52,536	76,874	56,690	22,114	1.00	22,114	42.09%
1957	$	7,808	11,349	8,369	3,343	1.15	2,912	37.29%
1958	$	9,578	13,821	10,192	4,175	1.41	2,968	30.98%
1959	$	69,100	98,956	72,974	30,676	1.68	18,307	26.49%
1960	$	60,447	85,898	63,344	27,326	1.95	14,030	23.21%
1961	$	31,777	44,798	33,036	14,629	2.23	6,574	20.69%
1962	$	66,912	93,565	68,999	31,370	2.51	12,508	18.69%
1963	$	84,163	116,714	86,070	40,175	2.79	14,383	17.09%
1964	$	110,891	152,493	112,455	53,882	3.08	17,498	15.78%
1965	$	52,695	71,847	52,983	26,059	3.37	7,737	14.68%
1966	$	149,091	201,525	148,613	75,024	3.66	20,508	13.76%
1967	$	178,338	238,970	176,226	91,281	3.95	23,126	12.97%
1968	$	98,637	131,005	96,609	51,346	4.24	12,114	12.28%
1969	$	676,421	890,322	656,560	358,071	4.53	78,990	11.68%
1970	$	353,841	461,474	340,310	190,452	4.83	39,430	11.14%
1971	$	360,850	466,201	343,796	197,479	5.13	38,481	10.66%
1972	$	285,330	365,070	269,218	158,777	5.44	29,188	10.23%
1973	$	399,502	506,048	373,181	226,072	5.75	39,284	9.83%
1974	$	487,171	610,713	450,365	280,392	6.08	46,132	9.47%
1975	$	550,816	683,054	503,712	322,512	6.41	50,303	9.13%
1976	$	497,026	609,407	449,402	296,137	6.76	43,833	8.82%
1977	$	479,584	581,096	428,524	290,851	7.11	40,895	8.53%
1978	$	916,114	1,096,307	808,462	565,710	7.48	75,614	8.25%
1979	$	1,711,688	2,021,786	1,490,949	1,076,583	7.86	136,890	8.00%
1980	$	2,323,489	2,707,002	1,996,255	1,488,978	8.26	180,223	7.76%
1981	$	2,720,234	3,123,753	2,303,584	1,776,766	8.67	204,832	7.53%
1982	$	3,471,605	3,926,416	2,895,501	2,311,907	9.10	254,006	7.32%
1983	$	3,328,573	3,704,822	2,732,089	2,260,771	9.55	236,852	7.12%
1984	$	2,397,572	2,623,936	1,934,999	1,661,360	10.00	166,062	6.93%
1985	$	4,646,041	4,995,156	3,683,635	3,285,427	10.48	313,501	6.75%
1986	$	6,164,725	6,505,182	4,797,190	4,449,897	10.97	405,604	6.58%
1987	$	7,622,650	7,886,698	5,815,978	5,617,997	11.48	489,422	6.42%
1988	$	8,143,680	8,252,871	6,086,008	6,129,511	12.00	510,683	6.27%
1989	$	9,054,992	8,978,297	6,620,967	6,961,521	12.54	555,047	6.13%
1990	$	9,851,506	9,546,299	7,039,835	7,737,424	13.10	590,756	6.00%
1991	$	5,679,097	5,371,619	3,961,254	4,557,391	13.67	333,416	5.87%
1992	$	5,702,893	5,258,591	3,877,903	4,676,437	14.26	328,055	5.75%
1993	$	4,676,370	4,198,068	3,095,829	3,918,726	14.86	263,777	5.64%
1994	$	4,109,705	3,586,658	2,644,950	3,519,608	15.47	227,473	5.54%
1995	$	6,379,515	5,404,474	3,985,483	5,583,789	16.10	346,748	5.44%
1996	$	5,583,638	4,584,320	3,380,667	4,994,789	16.75	298,233	5.34%
1997	$	5,194,453	4,126,091	3,042,750	4,748,930	17.41	272,824	5.25%
1998	$	6,691,591	5,132,990	3,785,279	6,252,108	18.08	345,829	5.17%
1999	$	8,629,429	6,379,861	4,704,773	8,239,370	18.76	439,116	5.09%
2000	$	6,746,469	4,796,896	3,537,429	6,582,275	19.46	338,222	5.01%
2001	$	12,271,406	8,371,832	6,173,735	12,233,373	20.17	606,460	4.94%
2002	$	10,001,207	6,530,133	4,815,590	10,186,219	20.89	487,514	4.87%
2003	$	9,065,409	5,649,336	4,166,054	9,432,060	21.63	436,098	4.81%
2004	$	6,729,026	3,989,885	2,942,306	7,151,232	22.37	319,620	4.75%
2005	$	19,338,291	10,872,857	8,018,094	20,989,342	23.13	907,403	4.69%
2006	$	19,665,158	10,444,518	7,702,220	21,795,517	23.90	911,983	4.64%
2007	$	23,488,715	11,733,889	8,653,055	26,580,018	24.68	1,077,091	4.59%
2008	$	22,310,671	10,431,723	7,692,784	25,773,222	25.47	1,012,039	4.54%
2009	$	21,292,735	9,266,068	6,833,182	25,105,921	26.27	955,847	4.49%
2010	$	15,882,559	6,390,916	4,712,926	19,110,913	27.07	705,866	4.44%
2011	$	17,215,096	6,355,832	4,687,053	21,135,591	27.89	757,739	4.40%
2012	$	25,596,450	8,591,328	6,335,600	32,059,075	28.72	1,116,237	4.36%
2013	$	31,139,375	9,395,483	6,928,618	39,780,444	29.56	1,345,870	4.32%
2014	$	30,315,037	8,107,353	5,978,697	39,493,858	30.40	1,299,005	4.29%
2015	$	27,500,318	6,402,091	4,721,167	36,529,311	31.26	1,168,657	4.25%
2016	$	30,684,192	6,070,556	4,476,679	41,549,609	32.12	1,293,580	4.22%
2017	$	37,387,441	6,077,155	4,481,545	51,599,616	32.99	1,564,077	4.18%
2018	$	48,420,131	6,146,203	4,532,464	68,097,732	33.87	2,010,630	4.15%
2019	$	37,580,399	3,420,528	2,522,439	53,848,160	34.75	1,549,374	4.12%
2020	$	41,956,080	2,300,242	1,696,294	61,237,826	35.65	1,717,869	4.09%
2021	$	42,979,276	787,652	580,847	63,888,067	36.55	1,748,066	4.07%
Mass Property Total	$	657,927,293	268,496,291	198,000,267	788,890,673	25.44	31,009,671	4.71%
36800 Total	**$**	**657,927,293**	**268,496,291**	**198,000,267**	**788,890,673**	**25.44**	**31,009,671**	**4.71%**
Grand Total	**$**	**657,927,293**	**268,496,291**	**198,000,267**	**788,890,673**	**25.44**	**31,009,671**	**4.71%**

Report Label	ACCOUNT 369.10 SERVICES - OVERHEAD Survivor Curve: 50-R0.5 Net Salvage Rate: -70%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
36910								
Mass Property								
1955	$	398,732	484,577	(184,220)	862,065	14.26	60,470	15.17%
1956	$	30,420	36,540	(13,891)	65,606	14.67	4,472	14.70%
1957	$	27,658	32,829	(12,480)	59,500	15.09	3,943	14.26%
1958	$	27,871	32,681	(12,424)	59,805	15.51	3,855	13.83%
1959	$	30,986	35,886	(13,643)	66,319	15.94	4,161	13.43%
1960	$	30,194	34,529	(13,127)	64,456	16.37	3,939	13.04%
1961	$	32,843	37,075	(14,095)	69,927	16.80	4,163	12.67%
1962	$	47,419	52,826	(20,083)	100,696	17.23	5,843	12.32%
1963	$	31,494	34,614	(13,159)	66,699	17.67	3,774	11.98%
1964	$	51,185	55,481	(21,092)	108,106	18.12	5,966	11.66%
1965	$	65,927	70,456	(26,785)	138,861	18.57	7,479	11.34%
1966	$	57,991	61,083	(23,222)	121,807	19.02	6,404	11.04%
1967	$	44,927	46,624	(17,725)	94,101	19.48	4,831	10.75%
1968	$	79,835	81,598	(31,021)	166,741	19.94	8,363	10.47%
1969	$	8,845	8,900	(3,384)	18,421	20.40	903	10.21%
1970	$	85,180	84,349	(32,067)	176,872	20.87	8,473	9.95%
1971	$	38,134	37,146	(14,122)	78,950	21.35	3,698	9.70%
1972	$	5,863	5,616	(2,135)	12,103	21.83	554	9.46%
1973	$	36,626	34,477	(13,107)	75,371	22.31	3,378	9.22%
1974	$	39,967	36,958	(14,050)	81,994	22.80	3,596	9.00%
1975	$	37,921	34,429	(13,089)	77,555	23.30	3,329	8.78%
1976	$	42,110	37,520	(14,264)	85,851	23.79	3,608	8.57%
1977	$	69,518	60,753	(23,096)	141,278	24.30	5,815	8.36%
1978	$	79,520	68,121	(25,897)	161,081	24.80	6,494	8.17%
1979	$	65,698	55,137	(20,961)	132,649	25.32	5,240	7.98%
1980	$	84,258	69,233	(26,320)	169,558	25.83	6,564	7.79%
1981	$	64,589	51,927	(19,741)	129,543	26.35	4,915	7.61%
1982	$	88,979	69,946	(26,591)	177,855	26.88	6,617	7.44%
1983	$	63,037	48,416	(18,406)	125,569	27.41	4,581	7.27%
1984	$	102,032	76,513	(29,088)	202,542	27.94	7,248	7.10%
1985	$	29,279	21,420	(8,143)	57,917	28.48	2,033	6.94%
1986	$	74,526	53,147	(20,205)	146,900	29.03	5,061	6.79%
1987	$	76,530	53,153	(20,207)	150,309	29.57	5,083	6.64%
1988	$	99,407	67,179	(25,539)	194,532	30.12	6,458	6.50%
1989	$	81,254	53,378	(20,293)	158,424	30.68	5,164	6.36%
1991	$	7,383	4,569	(1,737)	14,288	31.80	449	6.09%
1992	$	182,373	109,348	(41,571)	351,604	32.37	10,864	5.96%
1993	$	21,507	12,479	(4,744)	41,305	32.93	1,254	5.83%
1994	$	26,830	15,046	(5,720)	51,331	33.51	1,532	5.71%
1995	$	31,365	16,976	(6,454)	59,775	34.08	1,754	5.59%
1996	$	19,167	9,997	(3,801)	36,384	34.66	1,050	5.48%
1997	$	19,721	9,897	(3,763)	37,289	35.24	1,058	5.37%
1998	$	26,898	12,965	(4,929)	50,656	35.82	1,414	5.26%
1999	$	57,081	26,377	(10,028)	107,066	36.41	2,941	5.15%
2000	$	79,655	35,217	(13,388)	148,802	37.00	4,022	5.05%
2001	$	51,014	21,531	(8,186)	94,909	37.59	2,525	4.95%
2002	$	82,973	33,352	(12,679)	153,734	38.18	4,027	4.85%
2003	$	2	1	(0)	4	38.77	0	4.76%
2004	$	121,437	43,909	(16,693)	223,136	39.37	5,668	4.67%
2005	$	479,645	163,709	(62,237)	877,633	39.96	21,962	4.58%
2006	$	75,296	24,169	(9,188)	137,191	40.56	3,383	4.49%
2007	$	118,128	35,514	(13,501)	214,319	41.16	5,207	4.41%
2008	$	125,669	35,217	(13,388)	227,025	41.76	5,437	4.33%
2009	$	89,590	23,275	(8,848)	161,152	42.36	3,804	4.25%
2010	$	120,110	28,745	(10,928)	215,115	42.96	5,007	4.17%
2011	$	257,266	56,285	(21,398)	458,750	43.57	10,530	4.09%
2012	$	1,280,759	253,860	(96,509)	2,273,799	44.17	51,478	4.02%
2013	$	2,954,667	524,672	(199,463)	5,222,398	44.78	116,631	3.95%
2014	$	1,655,643	259,750	(98,748)	2,913,342	45.39	64,191	3.88%
2015	$	1,170,532	159,368	(60,586)	2,050,491	46.00	44,580	3.81%
2016	$	709,176	81,811	(31,102)	1,236,701	46.61	26,535	3.74%
2017	$	980,626	92,672	(35,231)	1,702,295	47.22	36,050	3.68%
2018	$	1,006,218	74,066	(28,158)	1,738,729	47.83	36,349	3.61%
2019	$	447,879	23,578	(8,964)	770,358	48.45	15,900	3.55%
2020	$	1,262,911	39,938	(15,183)	2,162,133	49.07	44,062	3.49%
2021	$	1,803,832	18,999	(7,223)	3,073,737	49.69	61,858	3.43%
Mass Property Total	$	17,496,112	4,371,814	(1,662,021)	31,405,411	38.39	817,996	4.68%
36910 Total	**$**	**17,496,112**	**4,371,814**	**(1,662,021)**	**31,405,411**	**38.39**	**817,996**	**4.68%**
Grand Total	**$**	**17,496,112**	**4,371,814**	**(1,662,021)**	**31,405,411**	**38.39**	**817,996**	**4.68%**

Report Label	ACCOUNT 369.20 SERVICES - UNDERGROUND Survivor Curve: 60-R4 Net Salvage Rate: -70%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
36920								
Mass Property								
1955	$	1,443,803	2,198,665	2,454,465	0		0	0.00%
1956	$	27,156	41,096	45,967	198	6.59	30	0.11%
1957	$	38,726	58,218	65,119	715	6.94	103	0.27%
1958	$	51,915	77,499	86,686	1,570	7.31	215	0.41%
1959	$	74,090	109,779	122,792	3,161	7.70	410	0.55%
1960	$	91,017	133,790	149,649	5,080	8.12	626	0.69%
1961	$	132,002	192,395	215,201	9,203	8.56	1,075	0.81%
1962	$	227,310	328,315	367,231	19,196	9.02	2,127	0.94%
1963	$	174,186	249,154	278,688	17,428	9.52	1,832	1.05%
1964	$	347,749	492,310	550,666	40,508	10.03	4,037	1.16%
1965	$	490,688	687,069	768,511	65,659	10.58	6,206	1.26%
1966	$	477,515	660,864	739,200	72,575	11.15	6,507	1.36%
1967	$	399,343	545,919	610,630	68,254	11.75	5,808	1.45%
1968	$	826,217	1,114,949	1,247,109	157,461	12.37	12,727	1.54%
1969	$	90,346	120,278	134,535	19,053	13.01	1,464	1.62%
1970	$	911,880	1,197,024	1,338,913	211,282	13.67	15,457	1.70%
1971	$	190,509	246,459	275,673	48,192	14.34	3,361	1.76%
1972	$	425,071	541,678	605,885	116,735	15.02	7,770	1.83%
1973	$	567,921	712,551	797,013	168,453	15.72	10,717	1.89%
1974	$	652,758	805,944	901,477	208,212	16.42	12,678	1.94%
1975	$	643,733	781,708	874,368	219,978	17.14	12,833	1.99%
1976	$	1,039,840	1,241,229	1,388,358	379,369	17.87	21,229	2.04%
1977	$	1,113,923	1,306,242	1,461,077	432,593	18.61	23,242	2.09%
1978	$	1,138,111	1,310,261	1,465,573	469,216	19.37	24,227	2.13%
1979	$	1,266,613	1,430,686	1,600,272	552,970	20.13	27,464	2.17%
1980	$	1,660,871	1,839,316	2,057,339	766,142	20.91	36,633	2.21%
1981	$	1,128,065	1,223,928	1,369,005	548,705	21.71	25,278	2.24%
1982	$	1,323,753	1,406,073	1,572,742	677,638	22.51	30,102	2.27%
1983	$	1,689,053	1,754,990	1,963,017	908,373	23.33	38,939	2.31%
1984	$	1,553,118	1,577,248	1,764,206	876,095	24.16	36,266	2.34%
1985	$	1,969,293	1,952,989	2,184,486	1,163,313	25.00	46,536	2.36%
1986	$	1,660,302	1,606,469	1,796,891	1,025,623	25.85	39,676	2.39%
1987	$	1,655,454	1,561,285	1,746,351	1,067,921	26.71	39,977	2.41%
1988	$	1,938,222	1,780,005	1,990,998	1,303,980	27.59	47,268	2.44%
1989	$	1,482,247	1,324,128	1,481,084	1,038,737	28.47	36,484	2.46%
1990	$	1,365,967	1,185,668	1,326,211	995,934	29.36	33,916	2.48%
1991	$	666,891	561,814	628,408	505,306	30.27	16,695	2.50%
1992	$	1,291,687	1,054,807	1,179,839	1,016,029	31.18	32,588	2.52%
1993	$	2,801,284	2,214,559	2,477,061	2,285,122	32.10	71,192	2.54%
1994	$	3,797,060	2,902,015	3,246,004	3,208,997	33.03	97,167	2.56%
1995	$	323,213	238,468	266,735	282,728	33.96	8,325	2.58%
1996	$	1,311,229	932,458	1,042,986	1,186,103	34.90	33,985	2.59%
1997	$	1,718,642	1,176,049	1,315,452	1,606,240	35.85	44,806	2.61%
1998	$	1,789,548	1,176,247	1,315,674	1,726,558	36.80	46,915	2.62%
1999	$	2,633,018	1,659,137	1,855,802	2,620,329	37.76	69,394	2.64%
2000	$	2,058,106	1,240,701	1,387,767	2,111,012	38.72	54,515	2.65%
2001	$	6,743,314	3,880,265	4,340,211	7,123,423	39.69	179,472	2.66%
2002	$	3,980,055	2,180,650	2,439,133	4,326,961	40.66	106,411	2.67%
2003	$	3,286,143	1,709,652	1,912,305	3,674,138	41.64	88,240	2.69%
2004	$	810,516	399,217	446,538	931,340	42.62	21,854	2.70%
2005	$	3,491,894	1,622,819	1,815,180	4,121,039	43.60	94,525	2.71%
2006	$	4,297,142	1,877,252	2,099,771	5,205,370	44.58	116,761	2.72%
2007	$	3,260,338	1,333,223	1,491,256	4,051,319	45.57	88,908	2.73%
2008	$	2,841,831	1,082,527	1,210,844	3,620,269	46.56	77,762	2.74%
2009	$	2,296,864	810,501	906,573	2,998,096	47.55	63,057	2.75%
2010	$	2,144,775	696,599	779,171	2,866,946	48.54	59,067	2.75%
2011	$	3,180,569	943,546	1,055,389	4,351,578	49.53	87,858	2.76%
2012	$	3,596,658	965,690	1,080,158	5,034,160	50.52	99,640	2.77%
2013	$	4,169,520	1,001,918	1,120,680	5,967,504	51.52	115,831	2.78%
2014	$	3,629,946	769,858	861,113	5,309,795	52.51	101,111	2.79%
2015	$	4,684,568	861,291	963,384	7,000,382	53.51	130,822	2.79%
2016	$	5,883,126	915,416	1,023,925	8,977,389	54.51	164,698	2.80%
2017	$	5,418,294	689,908	771,685	8,439,414	55.51	152,045	2.81%
2018	$	4,331,970	429,100	479,963	6,884,387	56.50	121,839	2.81%
2019	$	1,025,911	72,595	81,200	1,662,848	57.50	28,918	2.82%
2020	$	1,954,996	83,005	92,844	3,230,649	58.50	55,223	2.82%
2021	$	5,164,500	73,091	81,754	8,697,896	59.50	146,182	2.83%
Mass Property Total	$	124,852,376	69,350,560	77,566,190	134,682,849	42.23	3,189,029	2.55%
36920 Total	**$**	**124,852,376**	**69,350,560**	**77,566,190**	**134,682,849**	**42.23**	**3,189,029**	**2.55%**
Grand Total	**$**	**124,852,376**	**69,350,560**	**77,566,190**	**134,682,849**	**42.23**	**3,189,029**	**2.55%**

Report Label	ACCOUNT 369.30 SERVICES - UNDERGROUND CABLE Survivor Curve: 65-R3 Net Salvage Rate: -60%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
36930								
Mass Property								
1955	$	280,709	363,241	320,731	128,403	12.43	10,330	3.68%
1956	$	95,108	122,007	107,728	44,445	12.89	3,449	3.63%
1957	$	117,520	149,399	131,914	56,117	13.35	4,202	3.58%
1958	$	136,891	172,392	152,217	66,809	13.84	4,827	3.53%
1959	$	170,669	212,835	187,927	85,144	14.34	5,938	3.48%
1960	$	185,175	228,583	201,832	94,449	14.85	6,359	3.43%
1961	$	220,478	269,298	237,782	114,983	15.38	7,476	3.39%
1962	$	346,045	418,043	369,119	184,552	15.92	11,591	3.35%
1963	$	244,939	292,550	258,313	133,589	16.48	8,107	3.31%
1964	$	438,806	517,931	457,317	244,773	17.05	14,357	3.27%
1965	$	590,168	688,107	607,578	336,691	17.63	19,094	3.24%
1966	$	551,158	634,508	560,251	321,602	18.23	17,640	3.20%
1967	$	450,528	511,894	451,987	268,859	18.84	14,269	3.17%
1968	$	936,599	1,049,789	926,932	571,627	19.47	29,366	3.14%
1969	$	97,722	108,002	95,363	60,992	20.10	3,034	3.11%
1970	$	992,942	1,081,567	954,991	633,717	20.75	30,542	3.08%
1971	$	509,852	547,079	483,054	332,709	21.41	15,541	3.05%
1972	$	587,847	621,064	548,381	392,174	22.08	17,762	3.02%
1973	$	884,408	919,525	811,912	603,140	22.76	26,498	3.00%
1974	$	989,335	1,011,760	893,353	689,583	23.45	29,401	2.97%
1975	$	1,174,583	1,180,852	1,042,656	836,677	24.16	34,633	2.95%
1976	$	1,198,580	1,183,953	1,045,394	872,334	24.87	35,075	2.93%
1977	$	1,183,831	1,148,283	1,013,899	880,230	25.59	34,391	2.91%
1978	$	1,377,170	1,310,993	1,157,566	1,045,906	26.33	39,727	2.88%
1979	$	1,833,110	1,711,504	1,511,206	1,421,770	27.07	52,522	2.87%
1980	$	2,425,853	2,220,070	1,960,254	1,921,111	27.82	69,052	2.85%
1981	$	1,824,707	1,635,752	1,444,319	1,475,212	28.58	51,614	2.83%
1982	$	2,034,261	1,785,111	1,576,198	1,678,619	29.35	57,192	2.81%
1983	$	2,509,032	2,153,699	1,901,650	2,112,802	30.13	70,127	2.79%
1984	$	1,785,824	1,498,352	1,322,999	1,534,319	30.91	49,631	2.78%
1985	$	2,432,403	1,993,308	1,760,030	2,131,814	31.71	67,231	2.76%
1986	$	2,341,821	1,872,804	1,653,628	2,093,285	32.51	64,386	2.75%
1987	$	2,219,307	1,730,573	1,528,043	2,022,849	33.32	60,707	2.74%
1988	$	1,815,326	1,378,979	1,217,597	1,686,925	34.14	49,412	2.72%
1989	$	3,237,153	2,393,276	2,113,189	3,066,256	34.97	87,694	2.71%
1990	$	2,204,564	1,584,591	1,399,145	2,128,158	35.80	59,446	2.70%
1991	$	1,022,251	713,618	630,103	1,005,499	36.64	27,442	2.68%
1992	$	1,950,526	1,320,888	1,166,304	1,954,538	37.49	52,136	2.67%
1993	$	4,175,336	2,739,647	2,419,024	4,261,513	38.34	111,139	2.66%
1994	$	2,185,562	1,387,643	1,225,247	2,271,653	39.21	57,941	2.65%
1995	$	2,436,492	1,494,813	1,319,874	2,578,513	40.08	64,340	2.64%
1996	$	1,722,293	1,019,499	900,187	1,855,482	40.95	45,308	2.63%
1997	$	3,354,488	1,912,767	1,688,914	3,678,267	41.84	87,923	2.62%
1998	$	3,494,363	1,916,076	1,691,836	3,899,145	42.72	91,264	2.61%
1999	$	2,698,966	1,420,415	1,254,183	3,064,163	43.62	70,247	2.60%
2000	$	4,617,068	2,327,462	2,055,078	5,332,231	44.52	119,769	2.59%
2001	$	8,456,008	4,073,742	3,596,989	9,932,623	45.43	218,642	2.59%
2002	$	4,531,740	2,081,398	1,837,811	5,412,973	46.34	116,807	2.58%
2003	$	5,168,261	2,256,783	1,992,670	6,276,548	47.26	132,807	2.57%
2004	$	1,722,400	712,944	629,508	2,126,332	48.18	44,129	2.56%
2005	$	7,317,422	2,861,512	2,526,627	9,181,249	49.11	186,940	2.55%
2006	$	6,153,125	2,264,758	1,999,712	7,845,288	50.05	156,757	2.55%
2007	$	6,240,209	2,152,574	1,900,657	8,083,678	50.99	158,546	2.54%
2008	$	5,222,132	1,680,146	1,483,517	6,871,895	51.93	132,331	2.53%
2009	$	4,912,322	1,465,882	1,294,329	6,565,386	52.88	124,163	2.53%
2010	$	4,638,728	1,275,586	1,126,303	6,295,662	53.83	116,957	2.52%
2011	$	4,501,285	1,131,955	999,481	6,202,575	54.78	113,219	2.52%
2012	$	5,316,098	1,211,326	1,069,564	7,436,193	55.74	133,401	2.51%
2013	$	5,959,837	1,216,807	1,074,404	8,461,336	56.71	149,215	2.50%
2014	$	5,957,116	1,074,604	948,843	8,582,544	57.67	148,817	2.50%
2015	$	6,317,962	988,977	873,236	9,235,503	58.64	157,493	2.49%
2016	$	5,607,531	743,633	656,605	8,315,444	59.61	139,491	2.49%
2017	$	5,191,552	564,008	498,002	7,808,482	60.59	128,882	2.48%
2018	$	2,783,761	235,463	207,907	4,246,110	61.56	68,971	2.48%
2019	$	1,745,621	105,585	93,228	2,699,765	62.54	43,167	2.47%
2020	$	10,760,153	390,850	345,108	16,871,137	63.52	265,585	2.47%
2021	$	8,044,097	97,519	86,106	12,784,449	64.51	198,185	2.46%
Mass Property Total	$	184,629,130	81,540,554	71,997,811	223,408,797	46.31	4,824,642	2.61%
36930 Total	**$**	**184,629,130**	**81,540,554**	**71,997,811**	**223,408,797**	**46.31**	**4,824,642**	**2.61%**
Grand Total	**$**	**184,629,130**	**81,540,554**	**71,997,811**	**223,408,797**	**46.31**	**4,824,642**	**2.61%**

Report Label	ACCOUNT 370.00 METERS Survivor Curve: 30-O1 Net Salvage Rate: 0%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
37000								
Mass Property								
1955	$	75,456	75,456	75,456	0		0	0.00%
1956	$	16,858	16,858	16,858	0		0	0.00%
1957	$	15,991	15,991	15,991	0		0	0.00%
1958	$	15,904	15,904	15,904	0		0	0.00%
1959	$	25,124	25,124	25,124	0		0	0.00%
1960	$	28,408	28,408	28,408	0		0	0.00%
1961	$	33,584	33,584	33,584	0		0	0.00%
1962	$	36,128	35,526	32,375	3,754	1.00	3,754	10.39%
1963	$	44,068	42,844	39,043	5,025	1.00	5,025	11.40%
1964	$	40,963	39,188	35,711	5,251	1.30	4,039	9.86%
1965	$	45,935	43,201	39,369	6,566	1.79	3,677	8.01%
1966	$	43,926	40,591	36,990	6,936	2.28	3,045	6.93%
1967	$	36,149	32,808	29,898	6,251	2.77	2,255	6.24%
1968	$	31,944	28,463	25,938	6,006	3.27	1,837	5.75%
1969	$	28,962	25,326	23,079	5,883	3.77	1,562	5.39%
1970	$	32,245	27,661	25,208	7,038	4.26	1,650	5.12%
1971	$	23,807	20,027	18,251	5,556	4.76	1,167	4.90%
1972	$	41,677	34,367	31,318	10,359	5.26	1,969	4.72%
1973	$	65,648	53,042	48,337	17,312	5.76	3,005	4.58%
1974	$	77,653	61,449	55,998	21,655	6.26	3,459	4.45%
1975	$	89,777	69,549	63,380	26,397	6.76	3,905	4.35%
1976	$	75,199	57,005	51,948	23,252	7.26	3,203	4.26%
1977	$	53,708	39,819	36,287	17,421	7.76	2,246	4.18%
1978	$	60,706	43,997	40,094	20,612	8.26	2,496	4.11%
1979	$	56,449	39,972	36,426	20,024	8.76	2,287	4.05%
1980	$	67,655	46,779	42,630	25,025	9.26	2,703	4.00%
1981	$	67,649	45,649	41,599	26,050	9.76	2,670	3.95%
1982	$	84,580	55,665	50,727	33,853	10.26	3,301	3.90%
1983	$	60,215	38,626	35,200	25,015	10.76	2,326	3.86%
1984	$	57,347	35,831	32,653	24,694	11.26	2,194	3.83%
1985	$	81,407	49,508	45,117	36,291	11.76	3,087	3.79%
1986	$	118,704	70,213	63,984	54,719	12.26	4,465	3.76%
1987	$	102,055	58,665	53,461	48,594	12.75	3,810	3.73%
1988	$	79,569	44,414	40,474	39,095	13.25	2,950	3.71%
1989	$	83,662	45,304	41,285	42,377	13.75	3,081	3.68%
1990	$	78,124	41,004	37,366	40,758	14.25	2,859	3.66%
1991	$	95,629	48,598	44,287	51,342	14.75	3,480	3.64%
1992	$	81,276	39,949	36,406	44,870	15.25	2,942	3.62%
1993	$	87,360	41,484	37,804	49,555	15.75	3,146	3.60%
1994	$	91,028	41,709	38,009	53,018	16.25	3,262	3.58%
1995	$	137,593	60,753	55,364	82,229	16.75	4,908	3.57%
1996	$	165,606	70,362	64,121	101,485	17.25	5,882	3.55%
1997	$	156,852	64,029	58,350	98,502	17.75	5,548	3.54%
1998	$	201,206	78,783	71,794	129,412	18.25	7,090	3.52%
1999	$	246,618	92,454	84,253	162,365	18.75	8,658	3.51%
2000	$	320,257	114,724	104,547	215,710	19.25	11,204	3.50%
2001	$	294,803	100,693	91,761	203,042	19.75	10,279	3.49%
2002	$	551,436	179,160	163,267	388,169	20.25	19,166	3.48%
2003	$	130,860	40,335	36,757	94,103	20.75	4,534	3.47%
2004	$	92,390	26,938	24,548	67,842	21.25	3,192	3.46%
2005	$	222,747	61,234	55,802	166,945	21.75	7,675	3.45%
2006	$	168,007	43,386	39,537	128,469	22.25	5,773	3.44%
2007	$	208,637	50,401	45,930	162,706	22.75	7,151	3.43%
2008	$	200,070	44,998	41,006	159,064	23.25	6,841	3.42%
2009	$	220,295	45,875	41,806	178,489	23.75	7,514	3.41%
2010	$	207,254	39,706	36,184	171,070	24.25	7,054	3.40%
2011	$	144,007	25,189	22,955	121,052	24.75	4,891	3.40%
2013	$	39,832	5,640	5,139	34,693	25.75	1,347	3.38%
2014	$	32,021	4,000	3,645	28,376	26.25	1,081	3.38%
2015	$	94,717	10,254	9,344	85,373	26.75	3,191	3.37%
2016	$	85,492	7,830	7,136	78,357	27.25	2,875	3.36%
2017	$	37,516	2,811	2,562	34,954	27.75	1,260	3.36%
2019	$	26,400	1,098	1,001	25,399	28.75	883	3.35%
2020	$	36,109	900	820	35,289	29.25	1,206	3.34%
2021	$	99,824	825	752	99,072	29.75	3,330	3.34%
Mass Property Total	$	6,453,080	2,821,940	2,590,358	3,862,722	16.14	239,388	3.71%
37000 Total	**$**	**6,453,080**	**2,821,940**	**2,590,358**	**3,862,722**	**16.14**	**239,388**	**3.71%**
Grand Total	**$**	**6,453,080**	**2,821,940**	**2,590,358**	**3,862,722**	**16.14**	**239,388**	**3.71%**

Report Label	ACCOUNT 370.10 METERS - AMI Survivor Curve: 15-R4 Net Salvage Rate: -5%

Year	Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
37010							
Mass Property							
2010	$ 1,165,613	866,446	745,314	478,579	4.38	109,243	9.37%
2011	$ 31,704,416	21,896,148	18,835,005	14,454,632	5.13	2,815,579	8.88%
2012	$ 4,891,874	3,103,247	2,669,404	2,467,063	5.94	415,498	8.49%
2013	$ 7,195,276	4,135,773	3,557,580	3,997,460	6.79	588,839	8.18%
2014	$ 1,111,034	569,200	489,624	676,961	7.68	88,132	7.93%
2015	$ 2,877,885	1,287,688	1,107,666	1,914,113	8.61	222,365	7.73%
2016	$ 3,373,189	1,284,367	1,104,809	2,437,040	9.56	254,904	7.56%
2017	$ 1,929,722	603,564	519,184	1,507,025	10.53	143,092	7.42%
2019	$ 6,918,917	1,207,582	1,038,759	6,226,104	12.51	497,822	7.20%
2020	$ 3,316,926	347,717	299,105	3,183,667	13.50	235,785	7.11%
2021	$ 1,248,219	43,644	37,542	1,273,088	14.50	87,796	7.03%
Mass Property Total	$ 65,733,071	35,345,374	30,403,992	38,615,732	7.07	5,459,056	8.30%
37010 Total	**$ 65,733,071**	**35,345,374**	**30,403,992**	**38,615,732**	**7.07**	**5,459,056**	**8.30%**
Grand Total	**$ 65,733,071**	**35,345,374**	**30,403,992**	**38,615,732**	**7.07**	**5,459,056**	**8.30%**

Report Label	ACCOUNT 371.10 INSTALLATIONS ON CUSTOMERS' PREMISES Survivor Curve: 40-S1.5 Net Salvage Rate: 0%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
37110								
Mass Property								
1962	$	1,120	972	1,120	0		0	0.00%
1966	$	1,723	1,448	1,723	0		0	0.00%
1969	$	275,603	225,754	275,603	0		0	0.00%
1970	$	118,404	96,106	117,634	770	7.53	102	0.09%
1971	$	126,375	101,614	124,377	1,999	7.84	255	0.20%
1972	$	97,247	77,438	94,784	2,463	8.15	302	0.31%
1973	$	37,573	29,621	36,256	1,316	8.47	156	0.41%
1974	$	85,887	67,013	82,025	3,862	8.79	439	0.51%
1975	$	90,580	69,922	85,585	4,994	9.12	547	0.60%
1976	$	135,707	103,604	126,812	8,895	9.46	940	0.69%
1977	$	11,239	8,482	10,382	857	9.81	87	0.78%
1979	$	1,977	1,456	1,782	194	10.53	18	0.93%
1980	$	189,523	137,826	168,700	20,823	10.91	1,908	1.01%
1983	$	1,883	1,313	1,608	276	12.10	23	1.21%
1985	$	43,720	29,563	36,185	7,535	12.95	582	1.33%
1987	$	8,864	5,794	7,092	1,772	13.85	128	1.44%
1988	$	5,238	3,362	4,116	1,123	14.32	78	1.50%
1996	$	24,217	12,930	15,827	8,390	18.64	450	1.86%
1998	$	72,071	36,227	44,342	27,730	19.89	1,394	1.93%
2008	$	38,251	12,129	14,846	23,405	27.32	857	2.24%
Mass Property Total	$	1,367,203	1,022,574	1,250,798	116,405	14.08	8,268	0.60%
37110 Total	**$**	**1,367,203**	**1,022,574**	**1,250,798**	**116,405**	**14.08**	**8,268**	**0.60%**
Grand Total	**$**	**1,367,203**	**1,022,574**	**1,250,798**	**116,405**	**14.08**	**8,268**	**0.60%**

Report Label	ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS Survivor Curve: 40-S0.5 Net Salvage Rate: -50%

Year	Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
37300							
Mass Property							
1955	$ 128,406	170,289	192,609	0		0	0.00%
1957	$ 430	559	645	0		0	0.00%
1958	$ 2,962	3,816	4,443	0		0	0.00%
1959	$ 7,461	9,519	11,192	0		0	0.00%
1960	$ 11,244	14,201	16,865	0		0	0.00%
1961	$ 21,349	26,691	32,024	0		0	0.00%
1962	$ 33,759	41,771	50,639	0		0	0.00%
1963	$ 18,755	22,962	28,132	0		0	0.00%
1964	$ 52,543	63,645	78,815	0		0	0.00%
1965	$ 126,201	151,205	189,301	0		0	0.00%
1966	$ 172,308	204,163	258,462	0		0	0.00%
1967	$ 169,744	198,855	254,616	0		0	0.00%
1968	$ 257,730	298,456	386,595	0		0	0.00%
1969	$ 306,292	350,522	459,438	0		0	0.00%
1970	$ 2,186	2,472	3,280	0		0	0.00%
1972	$ 8,367	9,227	12,550	0		0	0.00%
1973	$ 5,829	6,345	8,743	0		0	0.00%
1974	$ 5,638	6,056	8,456	0		0	0.00%
1975	$ 1,166	1,235	1,748	0		0	0.00%
1976	$ 7,007	7,322	10,510	0		0	0.00%
1977	$ 2,914	3,002	4,371	0		0	0.00%
1978	$ 2,607	2,646	3,910	0		0	0.00%
1979	$ 1,959	1,958	2,938	0		0	0.00%
1980	$ 3,173	3,124	4,759	0		0	0.00%
1981	$ 3,866	3,745	5,799	0		0	0.00%
1982	$ 5,475	5,217	8,213	0		0	0.00%
1983	$ 473	443	709	0		0	0.00%
1984	$ 1,690	1,556	2,532	4	15.46	0	0.01%
1985	$ 2,165	1,957	3,185	63	15.90	4	0.18%
1987	$ 2,647	2,302	3,746	224	16.81	13	0.50%
1989	$ 7,366	6,147	10,003	1,046	17.75	59	0.80%
1992	$ 165	129	210	38	19.21	2	1.21%
1993	$ 129,492	98,467	160,229	34,009	19.72	1,724	1.33%
1994	$ 138,124	102,350	166,549	40,636	20.24	2,008	1.45%
1995	$ 5,330	3,844	6,255	1,739	20.77	84	1.57%
1996	$ 98,375	68,967	112,227	35,336	21.30	1,659	1.69%
1997	$ 2,472	1,682	2,737	971	21.85	44	1.80%
1998	$ 336,342	221,821	360,957	143,557	22.41	6,405	1.90%
1999	$ 582,781	371,867	605,119	269,053	22.98	11,706	2.01%
2000	$ 103,394	63,714	103,678	51,414	23.57	2,182	2.11%
2001	$ 173,076	102,787	167,260	92,355	24.16	3,822	2.21%
2002	$ 27,001	15,419	25,091	15,411	24.77	622	2.30%
2003	$ 1,277,592	699,782	1,138,716	777,672	25.39	30,625	2.40%
2004	$ 23,501	12,312	20,035	15,217	26.03	585	2.49%
2005	$ 415,108	207,345	337,401	285,261	26.68	10,692	2.58%
2006	$ 116,564	55,315	90,011	84,835	27.35	3,102	2.66%
2007	$ 142,935	64,181	104,438	109,965	28.03	3,924	2.75%
2008	$ 132,997	56,243	91,521	107,974	28.72	3,759	2.83%
2009	$ 128,207	50,787	82,643	109,668	29.44	3,726	2.91%
2010	$ 35,502	13,091	21,303	31,951	30.17	1,059	2.98%
2011	$ 117,656	40,084	65,226	111,259	30.92	3,599	3.06%
2012	$ 39,331	12,269	19,965	39,031	31.68	1,232	3.13%
2013	$ 125,749	35,524	57,806	130,818	32.47	4,029	3.20%
2014	$ 326,225	82,313	133,944	355,394	33.27	10,682	3.27%
2015	$ 1,285,114	284,521	462,986	1,464,685	34.10	42,958	3.34%
2016	$ 1,118,692	212,214	345,324	1,332,714	34.94	38,141	3.41%
2017	$ 1,026,801	161,415	262,662	1,277,540	35.81	35,678	3.47%
2018	$ 298,588	36,988	60,189	387,693	36.70	10,565	3.54%
2019	$ 33,861	3,037	4,942	45,850	37.61	1,219	3.60%
2020	$ 16,662	910	1,480	23,513	38.54	610	3.66%
2021	$ 145,916	2,699	4,391	214,482	39.51	5,429	3.72%
Mass Property Total	$ 9,777,266	4,703,486	7,074,521	7,591,378	31.38	241,947	2.47%
37300 Total	**$ 9,777,266**	**4,703,486**	**7,074,521**	**7,591,378**	**31.38**	**241,947**	**2.47%**
Grand Total	**$ 9,777,266**	**4,703,486**	**7,074,521**	**7,591,378**	**31.38**	**241,947**	**2.47%**

Report Label	ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS BENNING OFFICE BUILDINGS Interim Survivor Curve: 65-R2 Probable Retirement Date: 6-2042 Average Net Salvage Rate: -20%

Year	Sum of Original Cost		Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
39000								
BENNING OFFICE BUILDINGS								
1982	$	2,177,370	1,714,307	1,618,546	994,298	18.02	55,185	2.53%
1984	$	48,441	37,425	35,335	22,794	18.21	1,252	2.58%
1986	$	2,305	1,745	1,647	1,119	18.39	61	2.64%
1987	$	8,314	6,225	5,877	4,099	18.48	222	2.67%
1989	$	24,142	17,662	16,675	12,295	18.64	660	2.73%
1990	$	1,104	797	753	572	18.71	31	2.77%
1991	$	15,407	10,987	10,374	8,115	18.79	432	2.80%
1992	$	204	144	136	110	18.86	6	2.84%
1993	$	2,827	1,960	1,850	1,542	18.93	81	2.88%
1994	$	920	628	593	511	18.99	27	2.92%
1996	$	39,159	25,864	24,419	22,572	19.11	1,181	3.02%
1998	$	93,670	59,592	56,263	56,141	19.23	2,920	3.12%
1999	$	70,418	43,886	41,434	43,067	19.28	2,234	3.17%
2001	$	4,119	2,453	2,316	2,627	19.38	136	3.29%
2002	$	43,859	25,460	24,038	28,593	19.43	1,472	3.36%
2003	$	63,141	35,663	33,671	42,098	19.47	2,162	3.42%
2005	$	24,173	12,835	12,118	16,890	19.56	863	3.57%
2006	$	87,371	44,787	42,285	62,561	19.60	3,192	3.65%
2007	$	99,423	49,037	46,298	73,009	19.64	3,717	3.74%
2008	$	78,768	37,234	35,154	59,368	19.68	3,017	3.83%
2009	$	100,108	45,143	42,621	77,508	19.71	3,932	3.93%
2010	$	243,598	104,218	98,396	193,922	19.75	9,819	4.03%
2011	$	95,244	38,405	36,259	78,033	19.78	3,945	4.14%
2012	$	82,819	31,221	29,477	69,905	19.81	3,528	4.26%
2014	$	408,642	130,308	123,029	367,342	19.88	18,482	4.52%
2015	$	1,164,379	333,721	315,079	1,082,176	19.90	54,369	4.67%
2016	$	1,002,392	252,441	238,339	964,531	19.93	48,391	4.83%
2017	$	3,763,418	806,474	761,425	3,754,677	19.96	188,126	5.00%
2018	$	1,919,287	333,219	314,606	1,988,539	19.98	99,508	5.18%
2019	$	354,960	45,935	43,369	382,582	20.01	19,121	5.39%
2020	$	552,512	44,847	42,342	620,673	20.03	30,985	5.61%
2021	$	4,040,265	114,481	108,086	4,740,231	20.05	236,373	5.85%
BENNING OFFICE BUILDINGS Total	$	16,612,759	4,409,101	4,162,811	15,772,500	19.83	795,427	4.79%
39000 Total	**$**	**16,612,759**	**4,409,101**	**4,162,811**	**15,772,500**	**19.83**	**795,427**	**4.79%**
Grand Total	**$**	**16,612,759**	**4,409,101**	**4,162,811**	**15,772,500**	**19.83**	**795,427**	**4.79%**

Report Label	ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS BENNING WAREHOUSES Interim Survivor Curve: 65-R2 Probable Retirement Date: 6-2042 Average Net Salvage Rate: -20%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
39000								
BENNING WAREHOUSES								
1940	$	1,301	1,308	1,235	327	10.52	31	2.39%
1949	$	7,156	6,907	6,519	2,068	12.54	165	2.30%
1952	$	86,792	82,594	77,948	26,202	13.19	1,987	2.29%
1954	$	3,264	3,076	2,903	1,014	13.61	74	2.28%
1959	$	1,903	1,749	1,650	634	14.62	43	2.28%
1960	$	46,967	42,918	40,504	15,856	14.81	1,071	2.28%
1962	$	3,320	3,001	2,832	1,152	15.18	76	2.28%
1963	$	342	307	290	120	15.36	8	2.29%
1964	$	1,991	1,780	1,680	710	15.54	46	2.29%
1965	$	257	229	216	93	15.72	6	2.30%
1966	$	1,135	1,003	946	416	15.88	26	2.30%
1967	$	8,071	7,089	6,690	2,995	16.05	187	2.31%
1968	$	1,354	1,182	1,115	509	16.21	31	2.32%
1969	$	157	136	128	60	16.37	4	2.33%
1971	$	1,972	1,689	1,594	772	16.67	46	2.35%
1973	$	2,986	2,523	2,381	1,201	16.95	71	2.37%
1974	$	3,102	2,604	2,457	1,266	17.09	74	2.39%
1976	$	1,426	1,180	1,114	598	17.34	34	2.42%
1978	$	607	494	467	262	17.58	15	2.45%
1981	$	7,614	6,049	5,709	3,429	17.92	191	2.51%
1982	$	167,799	132,113	124,682	76,677	18.02	4,256	2.54%
1983	$	19,199	14,977	14,134	8,905	18.12	492	2.56%
1986	$	28,479	21,558	20,345	13,830	18.39	752	2.64%
1987	$	2,386,493	1,786,988	1,686,471	1,177,321	18.48	63,717	2.67%
1989	$	12,844	9,396	8,868	6,545	18.64	351	2.73%
1991	$	3,752	2,676	2,526	1,977	18.79	105	2.80%
1992	$	8,550	6,014	5,676	4,584	18.86	243	2.84%
1993	$	11,441	7,932	7,486	6,243	18.93	330	2.88%
1995	$	3,397	2,282	2,154	1,922	19.05	101	2.97%
1996	$	40,693	26,876	25,365	23,467	19.11	1,228	3.02%
1997	$	16,400	10,637	10,038	9,641	19.17	503	3.07%
1998	$	7,721	4,912	4,636	4,629	19.23	241	3.12%
1999	$	11,702	7,293	6,882	7,159	19.28	371	3.17%
2000	$	37,364	22,779	21,497	23,339	19.33	1,207	3.23%
2001	$	21,457	12,776	12,057	13,691	19.38	706	3.29%
2002	$	58,573	34,002	32,089	38,199	19.43	1,966	3.36%
2003	$	12,774	7,215	6,809	8,519	19.47	437	3.42%
2006	$	74,516	38,197	36,048	53,370	19.60	2,723	3.65%
2007	$	47,048	23,205	21,900	34,558	19.64	1,760	3.74%
2012	$	34,806	13,121	12,383	29,384	19.81	1,483	4.26%
BENNING WAREHOUSES Total	$	3,186,723	2,352,764	2,220,423	1,603,645	18.40	87,158	2.74%
39000 Total	**$**	**3,186,723**	**2,352,764**	**2,220,423**	**1,603,645**	**18.40**	**87,158**	**2.74%**
Grand Total	**$**	**3,186,723**	**2,352,764**	**2,220,423**	**1,603,645**	**18.40**	**87,158**	**2.74%**

Report Label	ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS CONSOLIDATED CONTROL CENTER Interim Survivor Curve: 65-R2 Probable Retirement Date: 6-2046 Average Net Salvage Rate: -20%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
39000								
CONSOLIDATED CONTROL CENTER								
1975	$	624,954	496,845	469,020	280,925	19.65	14,293	2.29%
1976	$	481	379	358	219	19.83	11	2.30%
1977	$	568	444	419	263	20.01	13	2.31%
1978	$	16,211	12,548	11,845	7,609	20.18	377	2.33%
1979	$	6,747	5,173	4,883	3,213	20.34	158	2.34%
1981	$	65,648	49,350	46,586	32,191	20.65	1,559	2.37%
1982	$	49,444	36,787	34,726	24,607	20.80	1,183	2.39%
1983	$	704	518	489	356	20.94	17	2.41%
1986	$	28,234	20,078	18,953	14,928	21.35	699	2.48%
1991	$	9,697,949	6,445,219	6,084,270	5,553,269	21.93	253,281	2.61%
1992	$	36,551	23,919	22,579	21,282	22.03	966	2.64%
1993	$	18,824	12,120	11,441	11,147	22.13	504	2.68%
1994	$	45,733	28,947	27,326	27,554	22.23	1,240	2.71%
1995	$	70,147	43,607	41,165	43,011	22.32	1,927	2.75%
1996	$	327	199	188	204	22.41	9	2.79%
1998	$	215,243	125,950	118,897	139,395	22.58	6,175	2.87%
1999	$	1,725	987	932	1,139	22.66	50	2.91%
2002	$	9,741	5,155	4,866	6,824	22.88	298	3.06%
2003	$	76,853	39,470	37,259	54,965	22.95	2,395	3.12%
2005	$	2,645	1,270	1,199	1,975	23.07	86	3.24%
2008	$	446,568	189,221	178,625	357,257	23.25	15,366	3.44%
2009	$	141,437	56,983	53,792	115,932	23.30	4,975	3.52%
2010	$	3,447	1,313	1,239	2,897	23.36	124	3.60%
2012	$	404,821	134,846	127,294	358,491	23.46	15,284	3.78%
2013	$	154,354	47,393	44,739	140,485	23.50	5,978	3.87%
2014	$	52,129	14,563	13,747	48,808	23.55	2,073	3.98%
2015	$	34,740	8,682	8,196	33,493	23.59	1,420	4.09%
2016	$	5,662,960	1,237,283	1,167,992	5,627,560	23.63	238,144	4.21%
2017	$	317,668	58,741	55,451	325,751	23.67	13,762	4.33%
2018	$	1,839	274	259	1,949	23.71	82	4.47%
2019	$	184,421	20,347	19,207	202,098	23.75	8,511	4.61%
2020	$	378,392	26,008	24,551	429,519	23.78	18,061	4.77%
2021	$	1,159,905	27,625	26,078	1,365,808	23.82	57,351	4.94%
CONSOLIDATED CONTROL CENTER Total	$	19,911,413	9,172,241	8,658,572	15,235,124	22.86	666,372	3.35%
39000 Total	**$**	**19,911,413**	**9,172,241**	**8,658,572**	**15,235,124**	**22.86**	**666,372**	**3.35%**
Grand Total	**$**	**19,911,413**	**9,172,241**	**8,658,572**	**15,235,124**	**22.86**	**666,372**	**3.35%**

	ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS FORESTVILLE SERVICE CENTER Interim Survivor Curve: 65-R2 Probable Retirement Date: 6-2037
Report Label	Average Net Salvage Rate: -20%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
39000								
FORESTVILLE SERVICE CENTER								
1981	$	79,360	68,277	64,439	30,792	14.10	2,184	2.75%
1982	$	3,812,337	3,256,779	3,073,702	1,501,102	14.16	106,026	2.78%
1983	$	8,691	7,369	6,955	3,473	14.21	244	2.81%
1984	$	19,434	16,353	15,434	7,887	14.27	553	2.84%
1985	$	4,804	4,010	3,785	1,980	14.32	138	2.88%
1986	$	75,865	62,796	59,266	31,772	14.37	2,212	2.92%
1987	$	1,303,675	1,069,629	1,009,501	554,909	14.41	38,502	2.95%
1988	$	1,568	1,274	1,203	678	14.46	47	2.99%
1989	$	11,932	9,606	9,066	5,252	14.50	362	3.04%
1990	$	46,774	37,273	35,178	20,950	14.54	1,441	3.08%
1991	$	17,471	13,774	13,000	7,966	14.58	546	3.13%
1992	$	80,123	62,452	58,941	37,206	14.62	2,545	3.18%
1993	$	61,058	47,024	44,381	28,888	14.66	1,971	3.23%
1994	$	47,154	35,857	33,842	22,743	14.69	1,548	3.28%
1995	$	3,458	2,594	2,448	1,701	14.73	115	3.34%
1996	$	25,436	18,812	17,754	12,769	14.76	865	3.40%
1997	$	2,541	1,851	1,747	1,303	14.79	88	3.47%
1999	$	18,037	12,701	11,987	9,658	14.85	650	3.61%
2000	$	30,990	21,417	20,213	16,975	14.88	1,141	3.68%
2001	$	93,161	63,097	59,550	52,244	14.91	3,505	3.76%
2002	$	1,466,440	971,804	917,175	842,553	14.93	56,430	3.85%
2003	$	174,121	112,698	106,363	102,582	14.96	6,859	3.94%
2005	$	26,554	16,289	15,373	16,491	15.00	1,099	4.14%
2006	$	317,382	188,805	178,191	202,668	15.02	13,489	4.25%
2007	$	147,536	84,846	80,077	96,966	15.05	6,445	4.37%
2008	$	3,203	1,774	1,674	2,169	15.07	144	4.50%
2009	$	12,824	6,813	6,430	8,959	15.09	594	4.63%
2012	$	134,633	60,895	57,472	104,088	15.14	6,875	5.11%
2013	$	803,169	338,607	319,572	644,231	15.16	42,507	5.29%
2014	$	31,824	12,354	11,659	26,529	15.17	1,749	5.49%
2015	$	447,975	157,577	148,719	388,851	15.19	25,604	5.72%
2016	$	91,166	28,428	26,830	82,569	15.20	5,431	5.96%
2017	$	268,332	71,887	67,846	254,152	15.22	16,703	6.22%
2018	$	23,551	5,166	4,875	23,385	15.23	1,536	6.52%
2019	$	354,228	58,588	55,295	369,779	15.24	24,260	6.85%
2020	$	270,016	28,372	26,777	297,243	15.26	19,485	7.22%
2021	$	179,874	6,692	6,316	209,533	15.27	13,724	7.63%
FORESTVILLE SERVICE CENTER Total	$	10,496,696	6,964,542	6,573,036	6,022,999	14.78	407,618	3.88%
39000 Total	**$**	**10,496,696**	**6,964,542**	**6,573,036**	**6,022,999**	**14.78**	**407,618**	**3.88%**
Grand Total	**$**	**10,496,696**	**6,964,542**	**6,573,036**	**6,022,999**	**14.78**	**407,618**	**3.88%**

Report Label	ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS KENILWORTH SERVICE CENTER Interim Survivor Curve: 65-R2 Probable Retirement Date: 6-2038 Average Net Salvage Rate: -20%

Year	Sum of Original Cost		Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
39000								
KENILWORTH SERVICE CENTER								
1955	$	47,697	46,090	43,506	13,729	12.14	1,131	2.37%
1959	$	88,282	83,961	79,256	26,683	12.70	2,100	2.38%
1960	$	95	90	85	29	12.84	2	2.38%
1962	$	322	302	285	101	13.09	8	2.39%
1963	$	3,691	3,451	3,257	1,171	13.22	89	2.40%
1964	$	1,513	1,408	1,330	486	13.34	36	2.41%
1965	$	511	474	447	166	13.46	12	2.42%
1966	$	356	328	310	117	13.57	9	2.43%
1967	$	12,696	11,656	11,003	4,232	13.68	309	2.44%
1968	$	2,417	2,208	2,084	816	13.79	59	2.45%
1971	$	193	173	164	68	14.09	5	2.49%
1975	$	704	620	585	260	14.45	18	2.56%
1977	$	503,497	437,661	413,132	191,065	14.61	13,079	2.60%
1978	$	31,466	27,176	25,653	12,106	14.68	824	2.62%
1979	$	2,952	2,532	2,390	1,152	14.76	78	2.64%
1980	$	39,076	33,293	31,427	15,464	14.83	1,043	2.67%
1981	$	115,035	97,309	91,855	46,187	14.90	3,101	2.70%
1982	$	10,324	8,668	8,182	4,206	14.96	281	2.72%
1987	$	5,037	4,053	3,826	2,218	15.25	145	2.89%
1988	$	3,172,460	2,528,438	2,386,728	1,420,223	15.30	92,801	2.93%
1989	$	15,407	12,156	11,474	7,015	15.35	457	2.97%
1990	$	15,140	11,818	11,156	7,013	15.40	455	3.01%
1992	$	14,170	10,808	10,202	6,802	15.49	439	3.10%
1993	$	18,664	14,058	13,270	9,126	15.53	588	3.15%
1996	$	27,129	19,589	18,491	14,063	15.65	899	3.31%
1997	$	5,249	3,731	3,521	2,778	15.69	177	3.37%
1998	$	7,373	5,152	4,863	3,984	15.72	253	3.44%
1999	$	28,406	19,492	18,399	15,688	15.75	996	3.51%
2000	$	24,946	16,788	15,847	14,089	15.79	893	3.58%
2001	$	55,951	36,873	34,806	32,335	15.82	2,044	3.65%
2002	$	6,590	4,246	4,008	3,900	15.85	246	3.73%
2003	$	25,466	16,012	15,115	15,445	15.87	973	3.82%
2005	$	105,689	62,867	59,344	67,483	15.93	4,237	4.01%
2007	$	118,910	66,175	62,466	80,225	15.98	5,021	4.22%
2008	$	5,116	2,739	2,586	3,553	16.00	222	4.34%
2012	$	451,617	196,392	185,385	356,556	16.08	22,168	4.91%
2013	$	658,984	266,679	251,733	539,048	16.10	33,474	5.08%
KENILWORTH SERVICE CENTER Total	$	5,623,126	4,055,464	3,828,169	2,919,582	15.47	188,673	3.36%
39000 Total	**$**	**5,623,126**	**4,055,464**	**3,828,169**	**2,919,582**	**15.47**	**188,673**	**3.36%**
Grand Total	**$**	**5,623,126**	**4,055,464**	**3,828,169**	**2,919,582**	**15.47**	**188,673**	**3.36%**

Report Label	ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS ROCKVILLE SERVICE CENTER Interim Survivor Curve: 65-R2 Probable Retirement Date: 6-2044 Average Net Salvage Rate: -20%

Year	Sum of Original Cost		Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
39000								
ROCKVILLE SERVICE CENTER								
1985	$	3,973,506	2,945,250	2,779,913	1,988,294	19.79	100,456	2.53%
1987	$	537	389	367	277	20.00	14	2.58%
1989	$	14,638	10,345	9,764	7,802	20.20	386	2.64%
1990	$	6,805	4,746	4,479	3,687	20.29	182	2.67%
1991	$	5,840	4,017	3,791	3,217	20.38	158	2.70%
1992	$	5,646	3,826	3,612	3,163	20.47	155	2.74%
1993	$	20,521	13,696	12,927	11,698	20.55	569	2.77%
1994	$	4,542	2,983	2,815	2,635	20.63	128	2.81%
1995	$	116,971	75,512	71,273	69,093	20.71	3,336	2.85%
1996	$	63,507	40,263	38,002	38,206	20.78	1,838	2.89%
1997	$	2,737	1,702	1,607	1,678	20.85	80	2.94%
1998	$	120,506	73,437	69,315	75,292	20.92	3,599	2.99%
1999	$	30,024	17,904	16,899	19,129	20.99	911	3.04%
2000	$	36,100	21,035	19,854	23,466	21.05	1,115	3.09%
2001	$	86,928	49,410	46,636	57,677	21.11	2,732	3.14%
2002	$	39,750	22,001	20,766	26,934	21.17	1,272	3.20%
2003	$	28,796	15,487	14,618	19,937	21.23	939	3.26%
2007	$	191,588	89,459	84,437	145,469	21.43	6,787	3.54%
2008	$	154,491	69,022	65,148	120,241	21.48	5,598	3.62%
2009	$	335,895	142,912	134,890	268,184	21.52	12,460	3.71%
2010	$	8,985	3,620	3,417	7,365	21.57	342	3.80%
2012	$	630,797	223,060	210,538	546,419	21.65	25,242	4.00%
2014	$	1,711,303	509,557	480,952	1,572,612	21.72	72,396	4.23%
2015	$	54,000	14,416	13,606	51,194	21.76	2,353	4.36%
2016	$	296,613	69,390	65,494	290,441	21.79	13,328	4.49%
2017	$	70,478	13,989	13,204	71,370	21.82	3,270	4.64%
2018	$	57,737	9,256	8,736	60,548	21.86	2,770	4.80%
2019	$	2,867,246	341,464	322,295	3,118,400	21.89	142,484	4.97%
2020	$	361,313	26,890	25,381	408,195	21.92	18,626	5.16%
2021	$	308,490	7,983	7,535	362,653	21.94	16,527	5.36%
ROCKVILLE SERVICE CENTER Total	$	11,606,289	4,823,020	4,552,270	9,375,276	21.30	440,055	3.79%
39000 Total	**$**	**11,606,289**	**4,823,020**	**4,552,270**	**9,375,276**	**21.30**	**440,055**	**3.79%**
Grand Total	**$**	**11,606,289**	**4,823,020**	**4,552,270**	**9,375,276**	**21.30**	**440,055**	**3.79%**

Report Label	ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS TSO BUILDING Interim Survivor Curve: 65-R2 Probable Retirement Date: 6-2053 Average Net Salvage Rate: -20%

Year	Sum of Original Cost		Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
39000								
TSO BUILDING								
2013	$	2,626,912	669,039	631,222	2,521,072	29.65	85,038	3.24%
2021	$	3,129,935	58,442	55,138	3,700,783	30.21	122,486	3.91%
TSO BUILDING Total	$	5,756,846	727,481	686,360	6,221,856	29.98	207,524	3.60%
39000 Total	**$**	**5,756,846**	**727,481**	**686,360**	**6,221,856**	**29.98**	**207,524**	**3.60%**
Grand Total	**$**	**5,756,846**	**727,481**	**686,360**	**6,221,856**	**29.98**	**207,524**	**3.60%**

	ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS
	OTHER
	Interim Survivor Curve: 65-R2
	Probable Retirement Date: -
Report Label	Average Net Salvage Rate: -20%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
39000								
OTHER								
1936	$	12,097	14,517	14,517	0		0	0.00%
1937	$	2,037	2,444	2,444	0		0	0.00%
1938	$	95	112	106	7	1.00	7	7.91%
1939	$	1,150	1,363	1,286	94	1.00	94	8.14%
1940	$	5,204	6,145	5,798	447	1.00	447	8.58%
1949	$	2,550	2,879	2,717	343	2.95	116	4.56%
1950	$	862	968	914	121	3.21	38	4.38%
1951	$	10,884	12,156	11,469	1,591	3.46	459	4.22%
1952	$	6,883	7,646	7,214	1,046	3.72	281	4.09%
1954	$	480	527	497	79	4.23	19	3.87%
1955	$	846	924	872	143	4.49	32	3.77%
1956	$	228	247	234	40	4.75	8	3.69%
1959	$	2,342	2,497	2,356	453	5.56	82	3.48%
1960	$	6,961	7,377	6,961	1,393	5.84	238	3.42%
1961	$	35,094	36,946	34,859	7,254	6.14	1,182	3.37%
1962	$	3,131	3,273	3,088	669	6.44	104	3.32%
1963	$	22,111	22,948	21,652	4,881	6.76	723	3.27%
1964	$	11,414	11,756	11,092	2,605	7.09	368	3.22%
1965	$	5,164	5,276	4,978	1,219	7.43	164	3.18%
1966	$	2,330	2,360	2,227	569	7.79	73	3.13%
1967	$	43,308	43,479	41,023	10,946	8.17	1,340	3.09%
1968	$	10,169	10,113	9,541	2,661	8.56	311	3.06%
1970	$	362	353	333	102	9.41	11	2.98%
1971	$	337	324	306	98	9.86	10	2.95%
1972	$	818	779	735	247	10.33	24	2.92%
1973	$	630	592	559	197	10.82	18	2.89%
1974	$	68,544	63,623	60,030	22,223	11.32	1,962	2.86%
1975	$	4,736	4,336	4,091	1,592	11.85	134	2.84%
1976	$	0	0	0	0	12.40	0	2.81%
1977	$	134,895	119,916	113,143	48,730	12.96	3,760	2.79%
1979	$	100,529	86,518	81,632	39,003	14.14	2,758	2.74%
1980	$	2,619	2,215	2,090	1,053	14.76	71	2.72%
1981	$	411,138	341,525	322,236	171,130	15.39	11,121	2.70%
1982	$	278,795	227,254	214,419	120,134	16.04	7,491	2.69%
1983	$	31,888	25,486	24,046	14,220	16.70	852	2.67%
1984	$	3,743	2,930	2,765	1,726	17.38	99	2.65%
1985	$	124,626	95,508	90,114	59,438	18.07	3,290	2.64%
1986	$	4,143	3,105	2,930	2,042	18.77	109	2.63%
1987	$	103,637	75,881	71,595	52,769	19.49	2,707	2.61%
1988	$	8,761	6,261	5,908	4,606	20.22	228	2.60%
1989	$	19,513	13,597	12,829	10,587	20.97	505	2.59%
1990	$	148,451	100,751	95,061	83,081	21.72	3,825	2.58%
1991	$	65,166	43,029	40,598	37,601	22.49	1,672	2.57%
1992	$	133,452	85,625	80,789	79,353	23.27	3,411	2.56%
1993	$	553,880	344,899	325,419	339,236	24.05	14,103	2.55%
1994	$	330	199	188	208	24.85	8	2.54%
1995	$	278,633	162,745	153,553	180,806	25.66	7,045	2.53%
1996	$	16,048	9,058	8,546	10,711	26.48	404	2.52%
1997	$	15,770	8,587	8,102	10,823	27.31	396	2.51%
1998	$	99,393	52,116	49,173	70,099	28.15	2,490	2.51%
1999	$	3,954	1,993	1,880	2,864	29.00	99	2.50%
2000	$	35,051	16,943	15,986	26,075	29.86	873	2.49%
2001	$	10,013	4,632	4,370	7,646	30.73	249	2.49%
2002	$	52,826	23,324	22,007	41,385	31.60	1,310	2.48%
2003	$	264,359	111,108	104,833	212,398	32.49	6,538	2.47%
2005	$	72,882	27,494	25,941	61,518	34.28	1,794	2.46%
2006	$	8,215	2,920	2,755	7,103	35.19	202	2.46%
2007	$	51,884	17,301	16,324	45,938	36.11	1,272	2.45%
2008	$	5,116	1,592	1,503	4,636	37.03	125	2.45%
2011	$	128,682	31,388	29,615	124,803	39.84	3,133	2.43%
2012	$	4,664	1,032	973	4,623	40.78	113	2.43%
2014	$	845,897	148,312	139,936	875,141	42.69	20,498	2.42%
2015	$	264,141	40,212	37,941	279,028	43.66	6,391	2.42%
2016	$	40,831	5,269	4,971	44,025	44.62	987	2.42%
2017	$	19,508	2,063	1,946	21,464	45.59	471	2.41%
2018	$	83,187	6,853	6,466	93,358	46.57	2,005	2.41%
2019	$	335,560	19,772	18,656	384,017	47.54	8,077	2.41%

	ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS
	OTHER
	Interim Survivor Curve: 65-R2
	Probable Retirement Date: -
Report Label	Average Net Salvage Rate: -20%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
2020	$	1,004,782	35,566	33,557	1,172,181	48.53	24,156	2.40%
2021	$	3,306,256	39,080	36,873	3,930,634	49.51	79,395	2.40%
OTHER Total	$	9,333,984	2,610,023	2,463,567	8,737,214	37.62	232,279	2.49%
39000 Total	**$**	**9,333,984**	**2,610,023**	**2,463,567**	**8,737,214**	**37.62**	**232,279**	**2.49%**
Grand Total	**$**	**9,333,984**	**2,610,023**	**2,463,567**	**8,737,214**	**37.62**	**232,279**	**2.49%**

	ACCOUNT 391.10 FURNITURE
	Survivor Curve: 15-SQ
Report Label	Net Salvage Rate: 0%

Year	Sum of Original Cost		Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
39110								
Mass Property								
2007	$	163,418	157,971	163,418	0		0	0.00%
2008	$	84,240	75,816	83,782	458	1.50	305	0.36%
2009	$	542,921	452,434	499,972	42,949	2.50	17,180	3.16%
2010	$	207,729	159,259	175,992	31,737	3.50	9,068	4.37%
2012	$	506,247	320,623	354,311	151,936	5.50	27,625	5.46%
2013	$	168,855	95,685	105,738	63,117	6.50	9,710	5.75%
2014	$	1,217,688	608,844	672,816	544,873	7.50	72,650	5.97%
2015	$	362,757	157,195	173,711	189,046	8.50	22,241	6.13%
2016	$	173,562	63,639	70,326	103,236	9.50	10,867	6.26%
2017	$	110,303	33,091	36,568	73,735	10.50	7,022	6.37%
2018	$	51,127	11,930	13,183	37,944	11.50	3,299	6.45%
2019	$	75,225	12,538	13,855	61,371	12.50	4,910	6.53%
2020	$	72,003	7,200	7,957	64,046	13.50	4,744	6.59%
2021	$	472,539	15,751	17,406	455,132	14.50	31,388	6.64%
Mass Property Total	$	4,208,614	2,171,976	2,389,035	1,819,579	8.23	221,009	5.25%
39110 Total	**$**	**4,208,614**	**2,171,976**	**2,389,035**	**1,819,579**	**8.23**	**221,009**	**5.25%**
Grand Total	**$**	**4,208,614**	**2,171,976**	**2,389,035**	**1,819,579**	**8.23**	**221,009**	**5.25%**

Report Label	ACCOUNT 391.30 INFORMATION SYSTEMS Survivor Curve: 10-SQ Net Salvage Rate: 0%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
39130								
Mass Property								
2012	$	211,073	200,519	140,137	70,936	1.00	70,936	33.61%
2013	$	505,783	429,916	300,455	205,329	1.50	136,886	27.06%
2014	$	333,992	250,494	175,063	158,930	2.50	63,572	19.03%
2015	$	13,060	8,489	5,933	7,127	3.50	2,036	15.59%
2016	$	1,361,187	748,653	523,210	837,977	4.50	186,217	13.68%
2017	$	766,380	344,871	241,020	525,361	5.50	95,520	12.46%
2018	$	1,279,245	447,736	312,908	966,337	6.50	148,667	11.62%
2019	$	1,652,883	413,221	288,787	1,364,096	7.50	181,879	11.00%
2020	$	4,805,061	720,759	503,716	4,301,345	8.50	506,041	10.53%
2021	$	3,216,547	160,827	112,397	3,104,150	9.50	326,753	10.16%
Mass Property Total	$	14,145,213	3,725,486	2,603,625	11,541,588	6.72	1,718,508	12.15%
39130 Total	**$**	**14,145,213**	**3,725,486**	**2,603,625**	**11,541,588**	**6.72**	**1,718,508**	**12.15%**
Grand Total	**$**	**14,145,213**	**3,725,486**	**2,603,625**	**11,541,588**	**6.72**	**1,718,508**	**12.15%**

Report Label	ACCOUNT 391.50 DATA HANDLING EQUIPMENT Survivor Curve: 10-SQ Net Salvage Rate: 0%

Year	Sum of Original Cost		Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
39150								
Mass Property								
2021	$	205,089	10,254	8,068	197,021	9.50	20,739	10.11%
Mass Property Total	$	205,089	10,254	8,068	197,021	9.50	20,739	10.11%
39150 Total	**$**	**205,089**	**10,254**	**8,068**	**197,021**	**9.50**	**20,739**	**10.11%**
Grand Total	**$**	**205,089**	**10,254**	**8,068**	**197,021**	**9.50**	**20,739**	**10.11%**

Report Label	ACCOUNT 393.00 STORES EQUIPMENT Survivor Curve: 25-SQ Net Salvage Rate: 0%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
39300								
Mass Property								
1997	$	8,759	8,584	6,505	2,255	1.00	2,255	25.74%
2000	$	35,915	30,887	23,404	12,511	3.50	3,575	9.95%
2003	$	14,755	10,919	8,274	6,482	6.50	997	6.76%
2007	$	9,207	5,340	4,046	5,161	10.50	492	5.34%
Mass Property Total	$	68,637	55,730	42,228	26,409	3.61	7,318	10.66%
39300 Total	**$**	**68,637**	**55,730**	**42,228**	**26,409**	**3.61**	**7,318**	**10.66%**
Grand Total	**$**	**68,637**	**55,730**	**42,228**	**26,409**	**3.61**	**7,318**	**10.66%**

Report Label	ACCOUNT 394.00 TOOLS, SHOP AND GARAGE EQUIPMENT Survivor Curve: 25-SQ Net Salvage Rate: 0%

Year	Sum of Original Cost		Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
39400								
Mass Property								
1997	$	55,241	54,136	48,460	6,781	1.00	6,781	12.28%
1998	$	67,771	63,705	57,025	10,746	1.50	7,164	10.57%
1999	$	26,587	23,929	21,419	5,168	2.50	2,067	7.77%
2000	$	136,588	117,466	105,149	31,439	3.50	8,983	6.58%
2001	$	280,845	230,293	206,145	74,700	4.50	16,600	5.91%
2002	$	135	105	94	41	5.50	7	5.49%
2003	$	46,471	34,389	30,783	15,688	6.50	2,414	5.19%
2005	$	59,896	39,531	35,386	24,510	8.50	2,883	4.81%
2006	$	26,367	16,347	14,633	11,733	9.50	1,235	4.68%
2008	$	205,107	110,758	99,144	105,963	11.50	9,214	4.49%
2009	$	82,554	41,277	36,949	45,605	12.50	3,648	4.42%
2010	$	50,261	23,120	20,696	29,565	13.50	2,190	4.36%
2012	$	905,735	344,179	308,089	597,645	15.50	38,558	4.26%
2013	$	40,640	13,818	12,369	28,271	16.50	1,713	4.22%
2014	$	230,189	69,057	61,816	168,373	17.50	9,621	4.18%
2015	$	412,063	107,136	95,902	316,161	18.50	17,090	4.15%
2016	$	749,336	164,854	147,568	601,768	19.50	30,860	4.12%
2017	$	1,078,260	194,087	173,735	904,525	20.50	44,123	4.09%
2018	$	510,262	71,437	63,946	446,316	21.50	20,759	4.07%
2019	$	573,803	57,380	51,364	522,439	22.50	23,220	4.05%
2020	$	2,331,963	139,918	125,246	2,206,717	23.50	93,903	4.03%
2021	$	2,429,967	48,599	43,503	2,386,464	24.50	97,407	4.01%
Mass Property Total	$	10,300,042	1,965,521	1,759,422	8,540,620	19.39	440,441	4.28%
39400 Total	**$**	**10,300,042**	**1,965,521**	**1,759,422**	**8,540,620**	**19.39**	**440,441**	**4.28%**
Grand Total	**$**	**10,300,042**	**1,965,521**	**1,759,422**	**8,540,620**	**19.39**	**440,441**	**4.28%**

Report Label	ACCOUNT 395.00 LABORATORY EQUIPMENT Survivor Curve: 15-SQ Net Salvage Rate: 0%

Year	Sum of Original Cost		Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
39500								
Mass Property								
2008	$	224,276	201,848	218,064	6,212	1.50	4,141	1.85%
Mass Property Total	$	224,276	201,848	218,064	6,212	1.50	4,141	1.85%
39500 Total	**$**	**224,276**	**201,848**	**218,064**	**6,212**	**1.50**	**4,141**	**1.85%**
Grand Total	**$**	**224,276**	**201,848**	**218,064**	**6,212**	**1.50**	**4,141**	**1.85%**

Report Label	ACCOUNT 396.00 POWER OPERATED EQUIPMENT Survivor Curve: 27-R3.5 Net Salvage Rate: 0%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
39600								
Mass Property								
1989	$	7,063	6,311	7,063	0		0	0.00%
1990	$	3,873	3,423	3,873	0		0	0.00%
1991	$	19,985	17,456	19,985	0		0	0.00%
1993	$	5,420	4,600	5,420	0		0	0.00%
1994	$	2,440	2,035	2,440	0		0	0.00%
1995	$	18,154	14,834	18,154	0		0	0.00%
1997	$	3,277	2,549	3,277	0		0	0.00%
1998	$	4,656	3,517	4,656	0		0	0.00%
2000	$	229,234	162,106	222,612	6,622	7.91	837	0.37%
2002	$	1,261	826	1,134	127	9.32	14	1.08%
2008	$	107,983	51,318	70,473	37,510	14.17	2,647	2.45%
2012	$	32,984	11,256	15,457	17,527	17.79	985	2.99%
Mass Property Total	$	436,330	280,232	374,543	61,786	13.78	4,484	1.03%
39600 Total	**$**	**436,330**	**280,232**	**374,543**	**61,786**	**13.78**	**4,484**	**1.03%**
Grand Total	**$**	**436,330**	**280,232**	**374,543**	**61,786**	**13.78**	**4,484**	**1.03%**

Report Label	ACCOUNT 397.00 COMMUNICATION EQUIPMENT Survivor Curve: 24-L2 Net Salvage Rate: 0%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
39700								
Mass Property								
1959	$	12,934	12,337	12,934	0		0	0.00%
1964	$	59,555	54,692	59,555	0		0	0.00%
1965	$	14,724	13,411	14,724	0		0	0.00%
1967	$	21,299	19,079	21,299	0		0	0.00%
1968	$	929	825	929	0		0	0.00%
1969	$	26,380	23,228	26,380	0		0	0.00%
1970	$	106,978	93,356	106,978	0		0	0.00%
1971	$	23,810	20,589	23,810	0		0	0.00%
1972	$	310	266	310	0		0	0.00%
1973	$	1,474	1,251	1,474	0		0	0.00%
1974	$	408	343	408	0		0	0.00%
1975	$	129,406	107,625	129,406	0		0	0.00%
1976	$	22,951	18,892	22,951	0		0	0.00%
1981	$	1,039	809	1,039	0		0	0.00%
1982	$	69,350	53,299	69,350	0		0	0.00%
1983	$	232,895	176,737	232,895	0		0	0.00%
1984	$	481,491	360,639	481,491	0		0	0.00%
1989	$	1,444,572	1,007,807	1,444,572	0		0	0.00%
1990	$	1,954,636	1,343,132	1,954,636	0		0	0.00%
1991	$	1,095,212	741,086	1,095,212	0		0	0.00%
1992	$	329,321	219,402	329,321	0		0	0.00%
1993	$	361,648	237,201	361,648	0		0	0.00%
1994	$	758,972	490,041	758,972	0		0	0.00%
1995	$	387,686	246,392	387,686	0		0	0.00%
1996	$	1,568,010	980,824	1,566,345	1,665	8.99	185	0.01%
1997	$	15,475	9,526	15,212	263	9.23	28	0.18%
1998	$	171,214	103,680	165,573	5,641	9.47	596	0.35%
1999	$	50,615	30,138	48,129	2,486	9.71	256	0.51%
2000	$	55,887	32,697	52,215	3,672	9.96	369	0.66%
2001	$	15,191	8,723	13,930	1,261	10.22	123	0.81%
2002	$	4,024,507	2,264,657	3,616,584	407,923	10.49	38,869	0.97%
2003	$	12,954	7,129	11,385	1,569	10.79	145	1.12%
2006	$	10,357	5,235	8,360	1,998	11.87	168	1.62%
2007	$	81,344	39,606	63,250	18,094	12.31	1,469	1.81%
2008	$	443,691	206,845	330,325	113,366	12.81	8,849	1.99%
2009	$	134,991	59,809	95,513	39,478	13.37	2,953	2.19%
2010	$	673,277	280,999	448,747	224,530	13.98	16,057	2.38%
2011	$	766,681	298,295	476,368	290,313	14.66	19,800	2.58%
2012	$	275,257	98,648	157,537	117,720	15.40	7,645	2.78%
2013	$	349,942	113,961	181,992	167,950	16.18	10,377	2.97%
2014	$	701,598	204,454	326,506	375,092	17.01	22,056	3.14%
2015	$	680,215	174,147	278,107	402,109	17.86	22,520	3.31%
2016	$	208,408	45,739	73,044	135,364	18.73	7,226	3.47%
2017	$	746,842	135,748	216,785	530,058	19.64	26,992	3.61%
2018	$	1,237,042	176,785	282,319	954,722	20.57	46,413	3.75%
2019	$	1,619,367	166,812	266,394	1,352,973	21.53	62,848	3.88%
2020	$	3,382,515	210,481	336,132	3,046,383	22.51	135,355	4.00%
2021	$	797,180	16,599	26,507	770,673	23.50	32,794	4.11%
Mass Property Total	$	25,560,541	10,913,972	16,595,241	8,965,300	19.32	464,096	1.82%
39700 Total	**$**	**25,560,541**	**10,913,972**	**16,595,241**	**8,965,300**	**19.32**	**464,096**	**1.82%**
Grand Total	**$**	**25,560,541**	**10,913,972**	**16,595,241**	**8,965,300**	**19.32**	**464,096**	**1.82%**

Report Label	ACCOUNT 397.10 COMMUNICATION EQUIPMENT - DISTRIBUTION AUTOMATION Survivor Curve: 15-R1.5 Net Salvage Rate: 0%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
39710								
Mass Property								
2010	$	6,054	3,357	3,560	2,495	6.68	373	6.17%
2011	$	435	224	237	198	7.28	27	6.24%
2012	$	68,889	32,528	34,489	34,400	7.92	4,345	6.31%
2013	$	2,946,255	1,261,489	1,337,567	1,608,687	8.58	187,553	6.37%
2014	$	1,977,803	756,486	802,108	1,175,695	9.26	126,932	6.42%
2015	$	3,263,849	1,094,312	1,160,308	2,103,541	9.97	210,978	6.46%
2016	$	4,495,279	1,288,938	1,366,672	3,128,607	10.70	292,429	6.51%
2017	$	6,261,567	1,483,883	1,573,374	4,688,193	11.44	409,632	6.54%
2018	$	1,714,391	319,100	338,344	1,376,047	12.21	112,720	6.57%
2019	$	9,232,134	1,239,144	1,313,875	7,918,259	12.99	609,740	6.60%
2020	$	3,983,020	323,718	343,241	3,639,779	13.78	264,126	6.63%
2021	$	5,934,121	161,880	171,643	5,762,478	14.59	394,951	6.66%
Mass Property Total	$	39,883,798	7,965,058	8,445,419	31,438,379	12.03	2,613,806	6.55%
39710 Total	**$**	**39,883,798**	**7,965,058**	**8,445,419**	**31,438,379**	**12.03**	**2,613,806**	**6.55%**
Grand Total	**$**	**39,883,798**	**7,965,058**	**8,445,419**	**31,438,379**	**12.03**	**2,613,806**	**6.55%**

Report Label	ACCOUNT 397.30 COMMUNICATION EQUIPMENT - AMORTIZED Survivor Curve: 15-SQ Net Salvage Rate: 0%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
39730								
Mass Property								
2007	$	879,235	849,927	779,767	99,468	1.00	99,468	11.31%
2008	$	766,814	690,132	633,163	133,651	1.50	89,100	11.62%
2009	$	735,040	612,533	561,969	173,070	2.50	69,228	9.42%
2010	$	721,879	553,441	507,755	214,124	3.50	61,178	8.47%
2011	$	610,736	427,515	392,224	218,511	4.50	48,558	7.95%
2012	$	2,611,102	1,653,698	1,517,188	1,093,914	5.50	198,894	7.62%
2013	$	7,247,023	4,106,646	3,767,649	3,479,373	6.50	535,288	7.39%
2014	$	4,347,501	2,173,751	1,994,311	2,353,190	7.50	313,759	7.22%
2015	$	3,400,124	1,473,387	1,351,761	2,048,363	8.50	240,984	7.09%
2016	$	880,303	322,778	296,133	584,170	9.50	61,492	6.99%
2017	$	1,628,096	488,429	448,110	1,179,986	10.50	112,380	6.90%
2018	$	774,100	180,623	165,713	608,387	11.50	52,903	6.83%
2019	$	5,117,447	852,908	782,502	4,334,946	12.50	346,796	6.78%
2020	$	1,935,039	193,504	177,530	1,757,508	13.50	130,186	6.73%
2021	$	2,195,576	73,186	67,144	2,128,431	14.50	146,788	6.69%
Mass Property Total	$	33,850,015	14,652,458	13,442,922	20,407,093	8.14	2,507,001	7.41%
39730 Total	**$**	**33,850,015**	**14,652,458**	**13,442,922**	**20,407,093**	**8.14**	**2,507,001**	**7.41%**
Grand Total	**$**	**33,850,015**	**14,652,458**	**13,442,922**	**20,407,093**	**8.14**	**2,507,001**	**7.41%**

Report Label	ACCOUNT 398.00 MISCELLANEOUS EQUIPMENT Survivor Curve: 20-SQ Net Salvage Rate: 0%

Year		Sum of Original Cost	Calculated Accrued	Allocated Book Reserve	Future Accrual	Composite Remaining Life	Annual Accrual	Sum of Depreciation Rate
39800								
Mass Property								
2002	$	20,403	19,893	19,043	1,360	1.00	1,360	6.67%
2003	$	9,694	8,967	8,584	1,110	1.50	740	7.64%
2007	$	67,786	49,145	47,045	20,742	5.50	3,771	5.56%
2008	$	191,862	129,507	123,972	67,890	6.50	10,445	5.44%
2009	$	142,575	89,109	85,301	57,274	7.50	7,636	5.36%
2010	$	1,147,455	659,786	631,589	515,865	8.50	60,690	5.29%
2011	$	8,472	4,448	4,258	4,214	9.50	444	5.24%
2012	$	617,074	293,110	280,583	336,490	10.50	32,047	5.19%
2013	$	321,034	136,439	130,608	190,425	11.50	16,559	5.16%
2014	$	1,049,635	393,613	376,792	672,844	12.50	53,828	5.13%
2015	$	434,261	141,135	135,103	299,158	13.50	22,160	5.10%
2016	$	157,904	43,424	41,568	116,336	14.50	8,023	5.08%
2017	$	399,835	89,963	86,118	313,717	15.50	20,240	5.06%
2018	$	1,022,783	178,987	171,338	851,445	16.50	51,603	5.05%
2019	$	20,436	2,554	2,445	17,990	17.50	1,028	5.03%
2020	$	1,531,025	114,827	109,920	1,421,105	18.50	76,816	5.02%
2021	$	216,394	5,410	5,179	211,215	19.50	10,832	5.01%
Mass Property Total	$	7,358,626	2,360,317	2,259,445	5,099,181	13.48	378,221	5.14%
39800 Total	**$**	**7,358,626**	**2,360,317**	**2,259,445**	**5,099,181**	**13.48**	**378,221**	**5.14%**
Grand Total	**$**	**7,358,626**	**2,360,317**	**2,259,445**	**5,099,181**	**13.48**	**378,221**	**5.14%**

Comparison of BCA and Pepco Recommendations

There are three main areas of difference between this depreciation study and Pepco's 2021 depreciation study: (1) the average service lives and curve types for the certain plant accounts; (2) the net salvage rate for Account 362; and (3) the present value discount rates applied to each account.

My recommendations are based on using the Handy Whitman values to discount the net salvage, with each account having a distinct discount factor. Pepco's recommendations are based on using a uniform discount rate of 2.5% for each account. Additionally, as already discussed, I have proposed changes to the average service lives and/or curve types for 9 accounts, relative to Pepco's proposed Iowa curves. I also recommend an adjustment to the net salvage rate used for Account 362.

The adjustments proposed in this study result in a $22.59 million reduction to Pepco's 2021 study year depreciation expense. Of this $22.59 million, $22.53 million is attributed to the Distribution plant and the remaining $0.058 million is associated with the General plant. The differences between Pepco's proposal and my proposal are summarized in Table 2.

BCA DEPRECIATION STUDY

**TABLE 2. COMPARISON OF PEPCO AND BCA DEPRECIATION MODELS
RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2021
DISTRIBUTION, & GENERAL PLANT ACCOUNTS**

			PEPCO MODEL[1]				BCA MODEL[2]				DELTA			
	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2021	SURVIVOR CURVE	NET SALVAGE PERCENT	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	SURVIVOR CURVE	NET SALVAGE PERCENT	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	SURVIVOR CURVE (ASL)	NET SALVAGE PERCENT	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE
	(1)	(2)	(3)	(4)	(5)	(6) = (5)/(2)	(7)	(8)	(9)	(10) = (9)/(2)	(11) = (7) - (3)	(12) = (8) - (4)	(13) = (9) - (5)	(14) = (10) - (6)
	DISTRIBUTION PLANT													
361.00	STRUCTURES AND IMPROVEMENTS	90,174,871.41	65-R3	(25)	1,710,615	1.90	65-R3	(25)	1,643,445	1.82	0	0	(67,170)	(0.08)
362.00	STATION EQUIPMENT	635,759,316.59	50-R2.5	(30)	16,606,206	2.61	53-R2	(25)	12,936,390	2.03	3	5	(3,669,816)	(0.58)
364.00	POLES, TOWERS AND FIXTURES	159,274,142.83	55-R2	(90)	5,390,312	3.38	60-R2.5	(90)	4,584,326	2.88	5	0	(805,986)	(0.50)
365.00	OVERHEAD CONDUCTORS AND DEVICES	182,061,444.94	50-R2	(90)	6,516,697	3.58	54-R2	(90)	5,034,965	2.77	4	0	(1,481,731)	(0.81)
366.00	UNDERGROUND CONDUIT	990,691,715.33	70-R3	(60)	20,217,841	2.04	75-R3.5	(60)	16,565,556	1.67	5	0	(3,652,285)	(0.37)
367.00	UNDERGROUND CONDUCTORS AND DEVICES	1,050,826,153.31	60-R2.5	(70)	28,731,294	2.73	67-R2.5	(70)	21,957,137	2.09	7	0	(6,774,157)	(0.64)
368.00	LINE TRANSFORMERS	657,927,293.40	35-R1.5	(50)	30,103,214	4.58	37-R2	(50)	25,894,230	3.94	2	0	(4,208,984)	(0.64)
369.10	SERVICES - OVERHEAD	17,496,111.72	50-R0.5	(70)	715,093	4.09	50-R0.5	(70)	686,272	3.92	0	0	(28,821)	(0.17)
369.20	SERVICES - UNDERGROUND	124,852,375.85	55-S4	(70)	3,398,149	2.72	60-R4	(70)	2,485,201	1.99	5	0	(912,947)	(0.73)
369.30	SERVICES - UNDERGROUND CABLE	184,629,130.08	60-R2.5	(60)	4,602,576	2.49	65-R3	(60)	3,691,726	2.00	5	0	(910,850)	(0.49)
370.00	METERS	6,453,080.18	30-O1	0	239,401	3.71	30-O1	0	239,388	3.71	0	0	(13)	-
370.10	METERS - AMI	65,733,070.88	15-R4	(5)	5,448,292	8.29	15-R4	(5)	5,445,915	8.28	0	0	(2,377)	(0.01)
371.10	INSTALLATIONS ON CUSTOMERS' PREMISES	1,367,203.12	40-S1.5	0	8,269	0.60	40-S1.5	0	8,268	0.60	0	0	(1)	-
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	9,777,266.22	40-S0.5	(50)	238,253	2.44	40-S0.5	(50)	223,932	2.29	0	0	(14,321)	(0.15)
	TOTAL DISTRIBUTION PLANT	**4,177,023,175.86**			**123,926,212**	**2.97**			**101,396,751**	**2.43**			**(22,529,462)**	**(0.54)**
	GENERAL PLANT													
390.00	STRUCTURES AND IMPROVEMENTS													
	BENNING OFFICE BUILDINGS	16,612,758.94	65-R2 *	(20)	782,135	4.71	65-R2 *	(20)	770,626	4.71	0	0	(11,509)	-
	BENNING WAREHOUSES	3,186,723.28	65-R2 *	(20)	84,697	2.66	65-R2 *	(20)	82,586	2.66	0	0	(2,111)	-
	CONSOLIDATED CONTROL CENTER	19,911,413.34	65-R2 *	(20)	649,036	3.26	65-R2 *	(20)	634,476	3.26	0	0	(14,560)	-
	FORESTVILLE SERVICE CENTER	10,496,695.72	65-R2 *	(20)	401,148	3.82	65-R2 *	(20)	395,060	3.82	0	0	(6,088)	-
	KENILWORTH SERVICE CENTER	5,623,125.57	65-R2 *	(20)	185,063	3.29	65-R2 *	(20)	181,651	3.29	0	0	(3,412)	-
	ROCKVILLE SERVICE CENTER	11,606,288.62	65-R2 *	(20)	430,495	3.71	65-R2 *	(20)	422,311	3.71	0	0	(8,184)	-
	TSO BUILDING	5,756,846.44	65-R2 *	(20)	201,197	3.49	65-R2 *	(20)	196,645	3.49	0	0	(4,552)	-
	OTHER	9,333,984.17	50-R3	(20)	222,143	2.38	50-R3	(20)	216,551	2.38	0	0	(5,592)	-
	TOTAL STRUCTURES AND IMPROVEMENTS	82,527,836.08			2,955,913	3.58			2,899,907	3.51			(56,007)	(0.07)
	OFFICE FURNITURE AND EQUIPMENT													
391.10	FURNITURE	4,208,613.92	15-SQ	0	221,009	5.25	15-SQ	0	221,009	5.25	0	0	0	-
391.30	INFORMATION SYSTEMS	14,145,213.20	10-SQ	0	1,718,507	12.15	10-SQ	0	1,718,508	12.15	0	0	0	-
391.50	DATA HANDLING EQUIPMENT	205,088.65	10-SQ	0	20,739	10.11	10-SQ	0	20,739	10.11	0	0	0	-
	TOTAL OFFICE FURNITURE AND EQUIPMENT	18,558,915.77			1,960,255	10.56			1,960,256	10.56				
393.00	STORES EQUIPMENT	68,637.06	25-SQ	0	7,319	10.66	25-SQ	0	7,318	10.66	0	0	(1)	-
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	10,300,042.36	25-SQ	0	440,442	4.28	25-SQ	0	440,441	4.28	0	0	(1)	-
395.00	LABORATORY EQUIPMENT	224,275.98	15-SQ	0	4,141	1.85	15-SQ	0	4,141	1.85	0	0	0	-
396.00	POWER OPERATED EQUIPMENT	436,329.69	25-S3	0	5,566	1.28	27-R3.5	0	4,484	1.03	2	0	(1,082)	(0.25)
397.00	COMMUNICATION EQUIPMENT	25,560,541.00	24-L2	0	464,006	1.82	24-L2	0	464,096	1.82	0	0	89	-
397.10	COMMUNICATION EQUIPMENT - DISTRIBUTION AUTOMATION	39,883,797.83	15-R1.5	0	2,614,500	6.56	15-R1.5	0	2,613,806	6.55	0	0	(694)	(0.01)
397.30	COMMUNICATION EQUIPMENT - AMORTIZED	33,850,015.37	15-SQ	0	2,507,000	7.41	15-SQ	0	2,507,001	7.41	0	0	1	-
398.00	MISCELLANEOUS EQUIPMENT	7,358,625.85	20-SQ	0	378,223	5.14	20-SQ	0	378,221	5.14	0	0	(2)	-
	TOTAL GENERAL PLANT	**218,769,016.99**			**11,337,366**	5.18			**11,279,671**	5.16			**(57,695)**	(0.02)
	TOTAL DEPRECIABLE PLANT	**4,395,792,192.85**			**135,263,578**	3.08			**112,676,421**	2.56			**(22,587,157)**	(0.52)
	NONDEPRECIABLE PLANT													
360.10	LAND	38,974,109.52												
360.20	LAND RIGHTS	572,892.46												
389.10	LAND	2,268,980.45												
389.20	LAND RIGHTS	3.52												
	TOTAL NONDEPRECIABLE PLANT	**41,815,985.95**												
	TOTAL ELECTRIC PLANT	**4,437,608,178.80**			**135,263,578**	3.05			**112,676,421**	2.54			**(22,587,157)**	(0.51)

* LIFE SPAN MEHTOD IS USED. CURVE SHOWN IS INTERIM SURVIVOR CURVE.

Source:
[1] Direct Testimony of Witness Ned Allis, Table 3
[2] Exhibit OPC (D)-3, Table 1

Benchmark

This section contains the results of a benchmarking exercise that was performed to ensure that the resulting depreciation rates for each account calculated with the depreciation model used for this study match the depreciation rates calculated by the Gannett Fleming software used by Mr. Ned Allis on behalf of Pepco. As is shown below in Table 3, the two models only differ by only $7,834 out of a total $135.26 million of depreciation expense, or approximately 0.006%. This benchmarking exercise proves that my depreciation model is an accurate and acceptable tool for calculating depreciation expense and depreciation rates.

BCA DEPRECIATION STUDY

TABLE 3. BENCHMARK EXERCISE
COMPARISON OF PEPCO AND BCA DEPRECIATION MODELS
WITH PEPCO PROPOSED SURVIVOR CURVES & NET SALVAGE RATES
RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2021
DISTRIBUTION, & GENERAL PLANT ACCOUNTS

	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2021	SURVIVOR CURVE	NET SALVAGE PERCENT	PEPCO MODEL TOTAL ANNUAL ACCRUAL[1] AMOUNT	PEPCO MODEL RATE	BCA MODEL TOTAL ANNUAL ACCRUAL AMOUNT	BCA MODEL RATE	DELTA TOTAL ANNUAL ACCRUAL AMOUNT	DELTA RATE
	(1)	(2)	(3)	(4)	(5)	(6) = (5)/(2)	(7)	(8) = (7)/(2)	(9) = (7) - (5)	(10) = (8) - (6)
	DISTRIBUTION PLANT									
361.00	STRUCTURES AND IMPROVEMENTS	90,174,871.41	65-R3	(25)	1,710,615	1.90	1,710,569	1.90	(46)	-
362.00	STATION EQUIPMENT	635,759,316.59	50-R2.5	(30)	16,606,206	2.61	16,605,940	2.61	(266)	-
364.00	POLES, TOWERS AND FIXTURES	159,274,142.83	55-R2	(90)	5,390,312	3.38	5,390,022	3.38	(290)	-
365.00	OVERHEAD CONDUCTORS AND DEVICES	182,061,444.94	50-R2	(90)	6,516,697	3.58	6,516,810	3.58	113	-
366.00	UNDERGROUND CONDUIT	990,691,715.33	70-R3	(60)	20,217,841	2.04	20,217,542	2.04	(299)	-
367.00	UNDERGROUND CONDUCTORS AND DEVICES	1,050,826,153.31	60-R2.5	(70)	28,731,294	2.73	28,730,929	2.73	(365)	-
368.00	LINE TRANSFORMERS	657,927,293.40	35-R1.5	(50)	30,103,214	4.58	30,099,115	4.57	(4,098)	(0.01)
369.10	SERVICES - OVERHEAD	17,496,111.72	50-R0.5	(70)	715,093	4.09	715,055	4.09	(38)	-
369.20	SERVICES - UNDERGROUND	124,852,375.85	55-S4	(70)	3,398,149	2.72	3,397,893	2.72	(256)	-
369.30	SERVICES - UNDERGROUND CABLE	184,629,130.08	60-R2.5	(60)	4,602,576	2.49	4,602,579	2.49	3	-
370.00	METERS	6,453,080.18	30-O1	0	239,401	3.71	239,388	3.71	(13)	-
370.10	METERS - AMI	65,733,070.88	15-R4	(5)	5,448,292	8.29	5,446,810	8.29	(1,482)	-
371.10	INSTALLATIONS ON CUSTOMERS' PREMISES	1,367,203.12	40-S1.5	0	8,269	0.60	8,268	0.60	(1)	-
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	9,777,266.22	40-S0.5	(50)	238,253	2.44	238,246	2.44	(7)	-
	TOTAL DISTRIBUTION PLANT	**4,177,023,175.86**			**123,926,212**	**2.97**	**123,919,167**	**2.97**	**(7,046)**	**-**
	GENERAL PLANT									
390.00	STRUCTURES AND IMPROVEMENTS									
	BENNING OFFICE BUILDINGS	16,612,758.94	65-R2 *	(20)	782,135	4.71	782,072	4.71	(62)	-
	BENNING WAREHOUSES	3,186,723.28	65-R2 *	(20)	84,697	2.66	84,706	2.66	9	-
	CONSOLIDATED CONTROL CENTER	19,911,413.34	65-R2 *	(20)	649,036	3.26	648,942	3.26	(94)	-
	FORESTVILLE SERVICE CENTER	10,496,695.72	65-R2 *	(20)	401,148	3.82	401,161	3.82	13	-
	KENILWORTH SERVICE CENTER	5,623,125.57	65-R2 *	(20)	185,063	3.29	185,025	3.29	(38)	-
	ROCKVILLE SERVICE CENTER	11,606,288.62	65-R2 *	(20)	430,495	3.71	430,492	3.71	(3)	-
	TSO BUILDING	5,756,846.44	65-R2 *	(20)	201,197	3.49	201,192	3.49	(5)	-
	OTHER	9,333,984.17	50-R3	(20)	222,143	2.38	222,142	2.38	(1)	-
	TOTAL STRUCTURES AND IMPROVEMENTS	82,527,836.08			2,955,913	3.58	2,955,732	3.58	(181)	-
	OFFICE FURNITURE AND EQUIPMENT									
391.10	FURNITURE	4,208,613.92	15-SQ	0	221,009	5.25	221,009	5.25	0	-
391.30	INFORMATION SYSTEMS	14,145,213.20	10-SQ	0	1,718,507	12.15	1,718,508	12.15	0	-
391.50	DATA HANDLING EQUIPMENT	205,088.65	10-SQ	0	20,739	10.11	20,739	10.11	0	-
	TOTAL OFFICE FURNITURE AND EQUIPMENT	18,558,915.77			1,960,255	10.56	1,960,256	10.56		
393.00	STORES EQUIPMENT	68,637.06	25-SQ	0	7,319	10.66	7,318	10.66	(1)	-
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	10,300,042.36	25-SQ	0	440,442	4.28	440,441	4.28	(1)	-
395.00	LABORATORY EQUIPMENT	224,275.98	15-SQ	0	4,141	1.85	4,141	1.85	0	-
396.00	POWER OPERATED EQUIPMENT	436,329.69	25-S3	0	5,566	1.28	5,565	1.28	(1)	-
397.00	COMMUNICATION EQUIPMENT	25,560,541.00	24-L2	0	464,006	1.82	464,096	1.82	89	-
397.10	COMMUNICATION EQUIPMENT - DISTRIBUTION AUTOMATION	39,883,797.83	15-R1.5	0	2,614,500	6.56	2,613,806	6.55	(694)	(0.01)
397.30	COMMUNICATION EQUIPMENT - AMORTIZED	33,850,015.37	15-SQ	0	2,507,000	7.41	2,507,001	7.41	1	-
398.00	MISCELLANEOUS EQUIPMENT	7,358,625.85	20-SQ	0	378,223	5.14	378,221	5.14	(2)	-
	TOTAL GENERAL PLANT	**218,769,016.99**			**11,337,366**	5.18	**11,336,578**	5.18	**(788)**	-
	TOTAL DEPRECIABLE PLANT	**4,395,792,192.85**			**135,263,578**	3.08	**135,255,744**	3.08	**(7,834)**	-
	NONDEPRECIABLE PLANT									
360.10	LAND	38,974,109.52								
360.20	LAND RIGHTS	572,892.46								
389.10	LAND	2,268,980.45								
389.20	LAND RIGHTS	3.52								
	TOTAL NONDEPRECIABLE PLANT	**41,815,985.95**								
	TOTAL ELECTRIC PLANT	**4,437,608,178.80**			**135,263,578**	3.05	**135,255,744**	3.05	**(7,834)**	-

* LIFE SPAN MEHTOD IS USED. CURVE SHOWN IS INTERIM SURVIVOR CURVE.

Source:
[1] Direct Testimony of Witness Ned Allis, Table 3

Potomac Electric Power Company
District of Columbia

Impact of OPC's Proposed Depreciation Rates
on Traditional Test Year Annual Depreciation Expense

Account No.	Description	DC 13 MA Original Cost 12/31/23[1]	Present Rates[1] Rate %	Present Rates[1] Annual Accrual	Pepco Proposed Rates[1] Rate %	Pepco Proposed Rates[1] Annual Accrual	Pepco Annual Net Change Depreciation Exp.	OPC Proposed Rates[2] Rate %	OPC Proposed Rates[2] Annual Accrual	OPC Annual Net Change Depreciation Exp.	Difference in Annual Net Change OPC vs. Pepco
(1)	(2)	(3)	(4)	(5) = (3)*(4)	(6)	(7) = (3)*(6)	(8) = (7) - (5)	(9)	(10) = (3)*(9)	(11) = (10) - (5)	(12) = (11) - (8)
	Distribution Plant										
361.00	Structures and Improvements	$ 133,235,070	1.76%	$ 2,344,937	1.90%	$ 2,531,466	$ 186,529	1.82%	$ 2,424,878	$ 79,941	$ (106,588)
362.00	Station Equipment	667,662,312	2.54%	16,958,623	2.61%	17,425,986	467,364	2.03%	13,553,545	(3,405,078)	(3,872,441)
364.00	Poles, Towers And Fixtures	181,162,467	3.69%	6,684,895	3.38%	6,123,291	(561,604)	2.88%	5,217,479	(1,467,416)	(905,812)
365.00	Overhead Conductors And Devices	225,734,338	3.96%	8,939,080	3.58%	8,081,289	(857,790)	2.77%	6,252,841	(2,686,239)	(1,828,448)
366.00	Underground Conduit	1,024,656,077	2.07%	21,210,381	2.04%	20,902,984	(307,397)	1.67%	17,111,756	(4,098,624)	(3,791,227)
367.00	Underground Conductors And Devices	1,159,095,798	2.19%	25,384,198	2.73%	31,643,315	6,259,117	2.09%	24,225,102	(1,159,096)	(7,418,213)
368.00	Line Transformers	709,893,973	3.95%	28,040,812	4.58%	32,513,144	4,472,332	3.94%	27,969,823	(70,989)	(4,543,321)
369.10	Services - Overhead	18,447,206	3.92%	723,130	4.09%	754,491	31,360	3.92%	723,130	-	(31,360)
369.20	Services - Underground	135,482,252	2.88%	3,901,889	2.72%	3,685,117	(216,772)	1.99%	2,696,097	(1,205,792)	(989,020)
369.30	Services - Underground Cable	194,537,386	2.56%	4,980,157	2.49%	4,843,981	(136,176)	2.00%	3,890,748	(1,089,409)	(953,233)
370.00	Meters	6,465,856	3.54%	228,891	3.71%	239,883	10,992	3.71%	239,883	10,992	-
370.10	Meters - AMI	70,015,587	7.10%	4,971,107	8.29%	5,804,292	833,185	8.28%	5,797,291	826,184	(7,002)
371.10	Installations on Customers' Premises	1,367,203	0.70%	9,570	0.60%	8,203	(1,367)	0.60%	8,203	(1,367)	-
373.00	Street Lighting and Signal Systems	9,683,671	3.31%	320,530	2.44%	236,282	(84,248)	2.29%	221,756	(98,773)	(14,526)
371.40	EV Charging Station	-		-		-	-		-	-	-
	Total Distribution Depreciable Plant	4,537,439,197	2.76%	124,698,200	2.97%	134,793,726	10,095,526	2.43%	110,332,533	(14,365,667)	(24,461,193)
	Non-Depreciable Plant										
360.10	Land	$ 44,267,587									
360.20	Land Rights	-									
	Total Non-Depreciable Distribution Plant	44,267,587									
	Total Distribution Plant	$ 4,581,706,784		$ 124,698,200		$ 134,793,726	$ 10,095,526		$ 110,332,533	$ (14,365,667)	$ (24,461,193)
	DC Allocated General Plant										
390.00	Structures and Improvements:	$ 76,810,373	2.61%	$ 2,004,751	3.58%	$ 2,749,811	$ 745,061	3.51%	$ 2,696,044	$ 691,293	$ (53,767)
391.10	Office Furniture & Equipment[2]	3,718,025	6.67%	247,992	5.25%	195,196	(52,796)	5.25%	195,196	(52,796)	-
391.30	Information Systems	20,551,580	10.00%	2,055,158	12.15%	2,497,017	441,859	12.15%	2,497,017	441,859	-
393.00	Stores Equipment	565,098	4.00%	22,604	10.66%	60,239	37,636	10.66%	60,239	37,636	-
394.00	Tools, Shop & Garage Equipment	12,917,048	4.00%	516,682	4.28%	552,850	36,168	4.28%	552,850	36,168	(0)
395.00	Laboratory Equipment	203,690	6.67%	13,586	1.85%	3,768	(9,818)	1.85%	3,768	(9,818)	-
396.00	Power Operated Equipment	384,602	2.00%	7,692	1.28%	4,923	(2,769)	1.03%	3,961	(3,731)	(962)
397.00	Communication Equipment	25,870,196	2.02%	522,578	1.82%	470,838	(51,740)	1.82%	470,838	(51,740)	-
397.10	Communication Equipment-Distribution Automation	22,687,930	6.63%	1,504,210	6.56%	1,488,328	(15,882)	6.55%	1,486,059	(18,150)	(2,269)
397.30	Communication Equipment-Amortized	33,762,051	6.67%	2,251,929	7.41%	2,501,768	249,839	7.41%	2,501,768	249,839	-
398.00	Miscellaneous Equipment	8,976,564	5.00%	448,828	5.14%	461,395	12,567	5.14%	461,395	12,567	0
	Total General Depreciable Plant	206,447,158	4.14%	9,596,010	5.18%	10,986,134	1,390,124	5.16%	10,929,137	1,333,127	(56,998)
	Non-Depreciable Plant										
389.10	Land	2,072,628									
389.20	Land Rights	-									
390.30	Structures and Improvements - Leaseholds	-									
	Total Non-Depreciable General Plant	2,072,628									
	Total General Plant	$ 208,519,786		$ 9,596,010		$ 10,986,134	$ 1,390,124		$ 10,929,137	$ 1,333,127	$ (56,998)
	Total Distribution and General	**$ 4,790,226,570**	**2.80%**	**$ 134,294,210**	**3.04%**	**$ 145,779,860**	**$ 11,485,650**	**2.53%**	**$ 121,261,669**	**$ (13,032,540)**	**$ (24,518,190)**

Sources:
[1] FC 1176 Voluntary DR 1-01 Attachment B35
[2] Exhibit OPC (D) - 3, Table 1

POTOMAC ELECTRIC POWER COMPANY

Multi-Year Period Impact of OPC's Proposed Depreciation Rates on District of Columbia Depreciation Expense

Description	Current[1]	Pepco Proposed Total[1]	Pepco Increase Amount	Pepco Increase Percent	OPC Proposed Total	OPC Increase Amount	OPC Increase Percent	Difference Between Pepco and OPC
(1)	(2)	(3)	(4) = (3) - (2)	(5) = (4)/(2)	(6)	(7) = (6) - (2)	(8) = (7)/(2)	(9) = (7) - (4)
2024								
Distribution	$ 134,664,986	$ 144,866,255	$ 10,201,269	7.58%	$ 118,526,936	$ (16,138,050)	-11.98%	$ (26,339,319)
General[2]	$ 6,847,158	$ 8,567,217	$ 1,720,059	25.12%	$ 8,534,139	$ 1,686,981	24.64%	$ (33,078)
Total	**$ 141,512,145**	**$ 153,433,472**	**$ 11,921,328**	**8.42%**	**$ 127,061,075**	**$ (14,451,069)**	**-10.21%**	**$ (26,372,397)**
2025								
Distribution	$ 144,253,721	$ 155,184,568	$ 10,930,846	7.58%	$ 126,969,192	$ (17,284,530)	-11.98%	$ (28,215,376)
General[2]	$ 7,635,509	$ 9,553,608	$ 1,918,099	25.12%	$ 9,516,721	$ 1,881,212	24.64%	$ (36,887)
Total	**$ 151,889,230**	**$ 164,738,176**	**$ 12,848,945**	**8.46%**	**$ 136,485,913**	**$ (15,403,317)**	**-10.14%**	**$ (28,252,262)**
2026								
Distribution	$ 152,527,219	$ 164,087,571	$ 11,560,352	7.58%	$ 134,253,467	$ (18,273,752)	-11.98%	$ (29,834,104)
General[2]	$ 8,355,719	$ 10,454,740	$ 2,099,021	25.12%	$ 10,414,375	$ 2,058,655	24.64%	$ (40,366)
Total	**$ 160,882,939**	**$ 174,542,311**	**$ 13,659,373**	**8.49%**	**$ 144,667,842**	**$ (16,215,097)**	**-10.08%**	**$ (29,874,470)**

Sources and Notes:
[1] Attachment to OPC Data Request No. 7-3
[2] Represents 85.75% of the general expense that is being allocated to the distribution depreciation expense.

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In the Matter of	§	
	§	
The Application of Potomac Electric Power Company for Authority to Implement a Multiyear Plan for Electric Distribution Service in the District of Columbia	§ § § §	**Formal Case No. 1176**

PUBLIC VERSION

DIRECT TESTIMONY
AND SUPPORTING EXHIBITS OF
KEVIN J. MARA P.E.

Exhibit OPC (E)

On Behalf of the
Office of the People's Counsel
for the District of Columbia

January 12, 2024

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I. <u>INTRODUCTION</u>

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is Kevin J. Mara. My business address is 1850 Parkway Place, Suite 800, Marietta, Georgia 30067. I am the Executive Vice President of the firm of GDS Associates, Inc. ("GDS") and Principal Engineer for a GDS company doing business as Hi-Line Engineering.

Q. PLEASE DESCRIBE GDS ASSOCIATES, INC.

A. GDS is an engineering and consulting firm with offices in Marietta, Georgia; Austin, Texas; Auburn, Alabama; Bedford, New Hampshire; Augusta, Maine; Orlando, Florida; Folsom, California, Redmond, Washington; and Madison, Wisconsin. GDS has over 180 employees with backgrounds in engineering, accounting, management, economics, finance, and statistics. GDS provides rate and regulatory consulting services in the electric, natural gas, water, and telephone utility industries. GDS also provides a variety of other services in the electric utility industry including power supply planning, generation support services, financial analysis, load forecasting, and statistical services. Our clients are primarily publicly-owned utilities, municipalities, customers of privately-owned utilities, groups or associations of customers, and government agencies.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL EXPERIENCE.

A. I received a degree of Bachelor of Science in Electrical Engineering from Georgia Institute of Technology in 1982.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. Between 1983 and 1988, I worked at Savannah Electric and Power as a distribution engineer designing new services for residential, commercial, and industrial customers. From 1989-1998, I was employed by Southern Engineering Company as a planning engineer providing planning, design, and consulting services to publicly-owned electric utilities. In 1998, I, along with a partner, formed a new firm, Hi-Line Associates, which specialized in the design and planning of electric distribution systems. In 2000, Hi-Line Associates became a wholly owned subsidiary of GDS Associates, Inc. and the name of the firm was changed to Hi-Line Engineering, LLC. In 2001, we merged our operations with GDS Associates, Inc., and Hi-Line Engineering became a department within GDS. I serve as the Principal Engineer for Hi-Line Engineering and am Executive Vice President of GDS Associates. I have field experience in the operation, maintenance, and design of transmission and distribution systems. I have performed numerous planning studies for electric cooperatives and municipal systems. I have prepared short circuit models and overcurrent protection schemes for numerous electric utilities. My experience includes assisting utilities with improving system reliability. I have also provided general consulting services, underground distribution design, and territorial assistance. I am a registered engineer in Virginia as well as in 22 other states.

Q. HAVE YOU PREPARED AN ATTACHMENT SUMMARIZING YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. Exhibit OPC (E)-1 provides these details.

Q. FOR WHOM ARE YOU APPEARING?

A. I am testifying on behalf of the Office of the People's Counsel for the District of Columbia ("OPC" or "Office").

Q. HAVE YOU TESTIFIED BEFORE IN THE DISTRICT OF COLUMBIA?

A. Yes. I have filed testimony in *Formal Case Nos.* 1076, 1087, 1103, 1119, 1139, and 1156. I have also filed affidavits in *Formal Case Nos.* 1116, 1144, and 1145.

Q. WAS YOUR TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes.

II. SCOPE AND SUMMARY OF TESTIMONY

Q. WHAT IS THE SCOPE AND PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked by OPC to review both the Multi-Year Rate Plan ("MYP") proposal and the traditional rate case filing submitted by Potomac Electric Power Company ("Pepco" or the "Company") in this proceeding. The primary focus of my testimony is the construction and capital investment plans submitted by the Company. I also provide testimony concerning Pepco's new load forecasting methodology and the impacts of those forecasts on the reasonableness of the Company's proposed capital spending. I also discuss Pepco's proposed use of battery energy storage systems ("BESS") to delay capacity upgrades.

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH RESPECT TO THE CAPITAL SPENDING THAT PEPCO HAS INCLUDED IN ITS MULTIYEAR RATE PLAN.

A. The Office opposes the Company's proposed MYP for the reasons detailed in Dr. Dismukes' testimony. Nevertheless, I reviewed the construction and capital investment costs included for recovery under the proposed MYP in the event that the Commission accepts the MYP as proposed or some variant of the Company's proposal to base costs on forecasted construction budgets. Based on my review, I am concerned that many of the projects included in the Company's budget are not consistent with the purported goals of the MYP and, in several cases, could be deferred or eliminated in their entirety.

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH THE COMPANY'S CLIMATE READY GRID INVESTMENTS.

A. Pepco claims that its MYP investments are designed to foster what Pepco calls a "Climate Ready Grid," however, over 90% of the capital improvements are business as usual for Pepco – *i.e.* replacement of poles, cables, transformers, and substations with similar poles, cables, transformers, and substations. These replacements are not "modernizing" the grid or making it ready for the District's climate initiatives but are simply projects that any prudent utility would undertake to maintain system reliability. There are a few advanced projects already included in the Company's capital budgets, such as the Advanced Distribution Management System ("ADMS"), that can help with monitoring and potentially controlling behind the meter resources.

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH THE COMPANY'S CONSTRUCTION AND CAPITAL INVESTMENT PLANS.

A. Load forecasting is one of the most critical steps in developing a capital plan. Pepco has made a significant change in its load forecasting methodology. This change, coupled with a slowdown in construction and energy use in the District, has resulted in a reduction of 528 MVA for projected load for 2025 when compared to the Company's forecast made as recently as 2021. This reduction should have impacts on the Company's planned capital projects, however, these revised load forecasts are not reflected in the MYP budget and therefore I recommend a number of projects be canceled or delayed due to these significant reductions. These delays include the addition of a 5th transformer at the Waterfront Substation, and a 4th transformer at Alabama Substation as well battery energy storage systems that are no longer required to delay capacity expansion at the Alabama Substation and Mt. Vernon Substation.

Q. PLEASE SUMMARIZE YOUR CONCERN WITH THE ALLOCATION OF SUBTRANSMISSION COSTS TO THE DISTRICT.

A. At the direction of the Commission, Pepco allocates the cost of subtransmission between the District and Maryland using the Average and Excess Non-Coincident Peak Demand ("AED-NCP") allocation method. Pepco's data responses in this proceeding demonstrate that at least two projects in Maryland were inadvertently flagged by Pepco as subtransmission when in fact these projects should not have allocated to the District. I document those projects in my testimony along with the adjustments to be made to the allocated capital costs.

Q. PLEASE SUMMARIZE YOUR CONCERN WITH THE DOWNTOWN RESUPPLY PROJECT.

A. In 2018, the Downtown Resupply Project was originally proposed as a means to use the new 230kV Champlain Substation as a source to re-feed the Georgetown, and F Street Substations with 69kV cables and L Street Substation with 35kV cables. The result will be the retirement of older 69kV pipe-type 69kV cables from the Potomac River Substation to Georgetown Substation and from Georgetown Substation to the F Street Substation. Pepco has now significantly changed this project in the MYP proposal, and the budget has grown from $667 million to a nearly $1.4 billion dollar project. As I explain in my testimony, this change is not justified and therefore all projects related to these subtransmission modifications should be eliminated from the MYP budget.

Q: **PLEASE SUMMARIZE YOUR CONCERNS WITH THE COMPANY'S TRADITIONAL TEST YEAR FILING.**

A. In addition to my concerns about the MYP projects that are also included in Pepco's traditional test year budget, the filing also includes several projects that may not be completed and provide benefits to ratepayers during the rate-effective period. These projects include Project 70096: 13kV Distribution Cutovers "F" St to "L" St and Project 80906: Pepco DDOT Bridge 78 Relocation - 69kV pipe type.

III. <u>CONCERNS REGARDING PEPCO'S MYP CONSTRUCTION AND CAPITAL INVESTMENT PLANS</u>

Q. WHAT IS YOUR UNDERSTANDING OF PEPCO'S CLIMATE READY GRID INVESTMENTS?

A. My understanding is that Pepco claims their proposed Climate Ready Grid expenditures constitute a series of investments into the reliability and resiliency of Pepco's distribution system that are needed to prepare the distribution system for the coming energy transformation and to meet the District's climate goals.[1] However, Pepco has not been able to identify which capital projects advance Pepco's objectives for a Climate Ready Grid[2] or explain how the Company proposes to measure the success of its proposed investments.[3]

Q. BASED ON YOUR REVIEW OF THE COMPANY'S CONSTRUCTION BUDGET ARE THE PROJECTS INCLUDED IN THE MYP FUNDAMENTALLY DIFFERENT FROM THE COMPANY'S PRIOR CAPITAL EXPENDITURES?

A. No. In my opinion, the vast majority of the MYP projects are similar to the projects I have seen in at least the last four Pepco rate cases. These types of projects include replacement of aging infrastructure, reliability improvement projects, voltage conversion projects, capacity upgrades to meet projected load forecasts, and upgrades to maintain N-1 contingencies and maintain voltage levels to customers. These types of projects have consistently been included in Pepco construction budgets since at least *Formal Case No. 1103* in 2013.

Q. WILL THE PROJECTS INCLUDED IN THE MYP MODERNIZE THE GRID?

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1 Exhibit Pepco (H) (Cantler) at 6:14-16.

2 Exhibit OPC (E)-2 at page 1-2 (*Formal Case No. 1176*, Pepco Response to OPC Data Request 4-1(b)).

3 Exhibit OPC (E)-2 at page 1 (Pepco Response to OPC Data Request 4-1(a)).

A. Again, in my opinion, no. Modernizing the grid is often thought of improving with new technology. But in this case, Pepco is not modernizing the grid; the Company is simply replacing components like for like such as power transformer replacements at substations. For example, Paper-Insulated Lead Covered ("PILC") Cable Replacement Program does not modernize the grid as stated by Witness Cantler.[4] Rather this program that has been in place in one form or another since 2013,[5] replaces old PILC cable with new ethylene propylene rubber (EPR) cable. Another example is the 4kV conversion projects which also have been an on-going initiative since at least 2013.[6] These 4kV conversion projects replace equipment that has reached the end of its useful life and that, without replacement, would result in a decreased reliability performance for that equipment.[7] Simply replacing old equipment with new equipment, however, is not modernizing the grid in any meaningful way.

The core function of an electric utility is providing reliable service. These projects in the MYP budget will replace aging infrastructure, increase capacity to meet projected loads, and increase reliability with capital improvements; however, I do not see how these projects can be classified as Climate Ready Grid investments when in actuality it is

4 Exhibit Pepco (H) (Cantler) at 37:15-21.

5 *See Formal Case No. 766-ACR-12, In the Matter of the Commission's Fuel Adjustment Clause Audit and Review Program – Annual Consolidated Report*, Order No. 16975 at ¶ 76, rel. November 29, 2012 ("Order No. 16975").

6 *See* Order No. 16975 at ¶ 21.

7 *See e.g.* Exhibit OPC (E)-3, *PEPACR 2015-01*, 2015 Annual Consolidated Report ("2015 ACR"), at page 97.

business as usual for an electric utility. These core utility function costs have been recovered through traditional cost of service rate cases for many years in the District.

Q. TO YOUR KNOWLEDGE HAS PEPCO CHANGED THEIR DESIGN CRITERIA FOR RESILIENCY FOR THE DISTRIBUTION GRID WITHIN THE DISTRICT?

A. No, Pepco has not established any new criteria for planning for resiliency.[8]

Q. IN YOUR ESTIMATION HOW MUCH OF THE BUDGETED COST FOR CAPITAL PROJECTS WITHIN THE MYP ARE CORE UTILITY FUNCTIONS?

A. Based on my review of the proposed capital projects, I estimate that over 95% of the budgeted amount for the executive categories listed in the following table are core utility functions. These functions include replacement of aging infrastructure, reliability improvement projects, voltage conversion projects, capacity upgrades to meet projected load forecasts, upgrades to maintain N-1 contingencies, and maintain voltage levels to customers. I have broken out my analysis by Executive Category in the following table.

	% of Budget that are Core Utility Functions		
Executive Category	**2023**	**2024**	**2025**
Capacity Expansion - Distribution	93%	93%	84%
Corrective Maintenance - Distribution	100%	100%	100%
Corrective Maintenance - Substation	100%	100%	100%
Facilities Relocation - PEPCO	100%	100%	100%
System Performance - Distribution	95%	96%	96%
System Performance - Substation	100%	98%	99%

8 Exhibit OPC (E)-4 at page 1 (Pepco Response to OPC Data Request 4-6(a)).

Q. DO ANY OF THE PROPOSED CAPITAL EXPENDITURES IN THE MYP HELP MODERNIZE THE PEPCO DISTRIBUTION SYSTEM?

A. Yes, the Pepco construction program includes certain projects related to the modernization of the Pepco distribution system which collectively create what Pepco refers to as the ADMS. Those projects and their budgeted costs include:

Project[9]	2023B	2024B	2025B	2026B
61976: ADMS Implementation	$4,554,810	$3,844,510	$3,460,070	$1,640,020
62068: GIS Core	$2,515,180	$1,523,980	$ 158,550	$ 156,860
78116:EU Outage Reporting and Analytics ADMS Integrations	$ 7,240	$1,048,320	$ 837,340	$ 147,820
78124:EU Outage Reporting and Analytics Implementation	$1,625,670	$ 256,710	$ 0	$ 0
84541:EU ADMS Convergence-Stage 2	$ 0	$ 0	$ 0	$3,485,350
78306:EU-Enterprise Asset Management 2.0	$ 541,080	$5,969,240	$7,252,480	$7,207,720
74122: Fiber Optic Builds	$ 927,100	$ 973,500	$2,026,810	$2,020,950

These projects will provide greater control of the grid; however, as I have previously discussed, these projects are a small percentage of the overall MYP construction budget.

Q. CAN YOU EXPLAIN THE PURPOSE OF THESE ADMS PROJECTS?

[9] Exhibit Pepco (H)-2 at pages 174, 175, 179, 184, 185, and 190.

A. Yes. According to Pepco, the ADMS projects will replace Pepco's outage management system and other specific distribution control systems, placing them on a common platform. The functionality will eventually enable the distribution operators to monitor, manage, and control the electrical grid by means of remote switching and reconfiguration of the system due to system conditions.[10] For example, the Enterprise Asset Management, for which Pepco has budgeted significant spending in years 2024-2026, is intended to allow for the management of new types of assets and ownership models needed for Distributed Energy Resources.[11] The proposed fiber optic projects provide additional communication needed to support grid automation, security, and monitoring.[12] These projects are intended to allow for greater communication with distributed generation and potentially more load management of customer devices.

Q. IN YOUR OPINION WILL THE ADMS SYSTEMS BENEFIT RATE PAYERS?

A. The ADMS system is replacing older information technology platforms used for GIS, outage management, remote monitoring, remote switching, etc, So, these new systems are necessary to upgrade older technology. These new systems should have more functionality and improve grid operations and come with an increased cost compared to simple replacement of existing platforms.

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[10] Exhibit OPC (E)-27, Pepco Response to Data Request 6-24

[11] Exhibit Pepco (H)-2 at page 185.

[12] Exhibit Pepco (H)-2 at page 179.

Q. ARE THERE INVESTMENTS IN THE MYP BUDGET THAT GO BEYOND THE ADMS INFORMATION TECHNOLOGY UPGRADES PREVIOUSLY DISCUSSED?

A. Yes. Pepco has also included expenses related to sophisticated control schemes such as ADMS Convergence – Stage 2.0. This platform along with others create the foundation for the future Distributed Energy Resource Management System ("DERMS") that go beyond the necessary information technology upgrades.

Q. CAN YOU EXPLAIN HOW THE ADMS SYSTEM IS DIFFERENT FROM THE DISTRIBUTED ENERGY RESOURCE MANAGEMENT SYSTEM?

A. ADMS system is an Exelon Utilities platform to be deployed by Pepco. It replaces GIS, outage management and remote monitoring, remote switching, etc. The ADMS system provide consolidated control over the grid through remote operation. DERMS allows for common control of distributed energy resources to allow for more Distributed Energy Resources ("DER") to be connected to the grid and work collectively for the coordinated use of DER generated energy and utility generated energy. The DERMS is a future phase of the ADMS implementation with deployment not projected until 2029. The details and functionality and capabilities of the DERMS have yet to be fully scoped or defined.[13]

Q. IN YOUR OPINION, IS IT CLEAR THAT THE ADMS STAGE 2.0 AND THE FUTURE DERMS SYSTEMS BENEFIT RATE PAYERS?

---

[13] Exhibit OPC (E)-29, Pepco Response of OPC Data Request 6-20.

A. I cannot answer that question from an engineering perspective because Pepco has stated in response to OPC Data Request 6-21 that the final functionality of the ADMS Stage 2.0 and the DERMS systems is not clear at this time.[14] Moreover, the decision of whether to invest in DERMS technology is really a question for policy makers who must assess whether such investments are a reasonable means of achieving the District's climate goals. I believe that is a difficult assessment to make at this time because while the systems will purportedly allow more DERs to be deployed within the District, there is no way to know at this time whether the increase in DER deployment would amount to 10 new rooftop solar installations or 100 MW of new distributed generation. Therefore, it is not clear what benefits these proposed expenditures will provide from an engineering perspective or a climate perspective. I believe it is ultimately a policy question whether ratepayers should fund the sophisticated control schemes that Pepco has envisioned for ADMS 2.0 and the DERMS.

Q. CAN YOU PROVIDE A BREAKDOWN OF THE ADMS 2.0 AND DERMS SPENDING INCLUDED IN THE MYP?

A. Yes; based on my review, Project 84541:EU ADMS Convergence-Stage 2 with a budget of $3,485,350 in 2026 is the project not yet defined. From my review Pepco has not included any specific costs for the DERMS in Pepco's budgets through 2026 but Pepco has suggested that the DERMS program would be operational by 2029.

[14] Exhibit OPC (E)-30, Pepco Response of OPC Data Request 6-21.

Q. DO YOU HAVE ANY OBSERVATIONS REGARDING PEPCO'S LOAD FORECASTING METHODOLOGY?

A. Yes. Pepco has changed their method for load forecasting when compared to the prior rate case in *Formal Case No. 1156*. Load Forecasting is, in my opinion, a cornerstone of short- and long-range planning for transmission and distribution systems. Changes in electrical demand need to be met with the necessary capacity to reliably serve the future load. A reasonable load forecast is critical to ensure that a utility is making prudent expenditures that will be used and useful to meet anticipated future demand.

Q. CAN YOU PLEASE EXPLAIN PEPCO'S LOAD FORECASTING METHOD UTILIZED IN THE PRIOR RATE CASE?

A. In *Formal Case No. 1156*, which was filed in 2019, Pepco used an unadjusted 90/10 forecast utilizing the peak demand from the prior ten years as a baseline for load growth projections. The basic concept is that when the load occurs in the future, it will be less than the projection 90% of the time and 10% of the time the load will exceed the projection. This historical peak in the last 10 years was adjusted for known load increases (potential new business) and adjusted for load transfer, load management, and impacts of DER. This methodology based on the unadjusted historical 10-year peak resulted, in my opinion, in very aggressive, *i.e.*, high load projections as evidenced by a persistent overstatement between Pepco's projected 90/10 load and actual load on the distribution system.

Q. CAN YOU PLEASE EXPLAIN PEPCO'S CURRENT LOAD FORECASTING METHOD?

A. Yes. Starting in 2021, Pepco began using a new load forecasting tool known as the Distribution System Planning Load Forecasting ("DSP-LF") program.[15] This program compares the historical weather patterns for the previous year against a thirty-year record of weather patterns. The historical loads are then adjusted to match values expected during temperature extremes projected to occur once in a ten-year period. As with the prior methodology, these historical loads are adjusted further for new business, load transfer, and impacts of load management and DERs.[16] In addition, the growth trends including the anticipated electric vehicle charging loads which are known can be included in the potential new business and fossil fuel heating system conversions.[17]

Q. HAVE YOU COMPARED THESE TWO LOAD FORECASTING METHODS AND IF SO, WHAT IS YOUR CONCLUSION?

A. Yes, I have compared the two different load forecasts. The figure below shows the forecasted substation peak load of the District of Columbia as a whole over the next-10 years with current 2023 projections and the 2021 and 2022 projections.

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15 Exhibit Pepco (H)-1 at page 20 of 82.

16 Exhibit Pepco (H)-1 at pages 20-21 of 82.

17 Exhibit OPC (E)-5 at page 1 (*Formal Case No. 1176*, Pepco Response to OPC Data Request 4-7(c)).

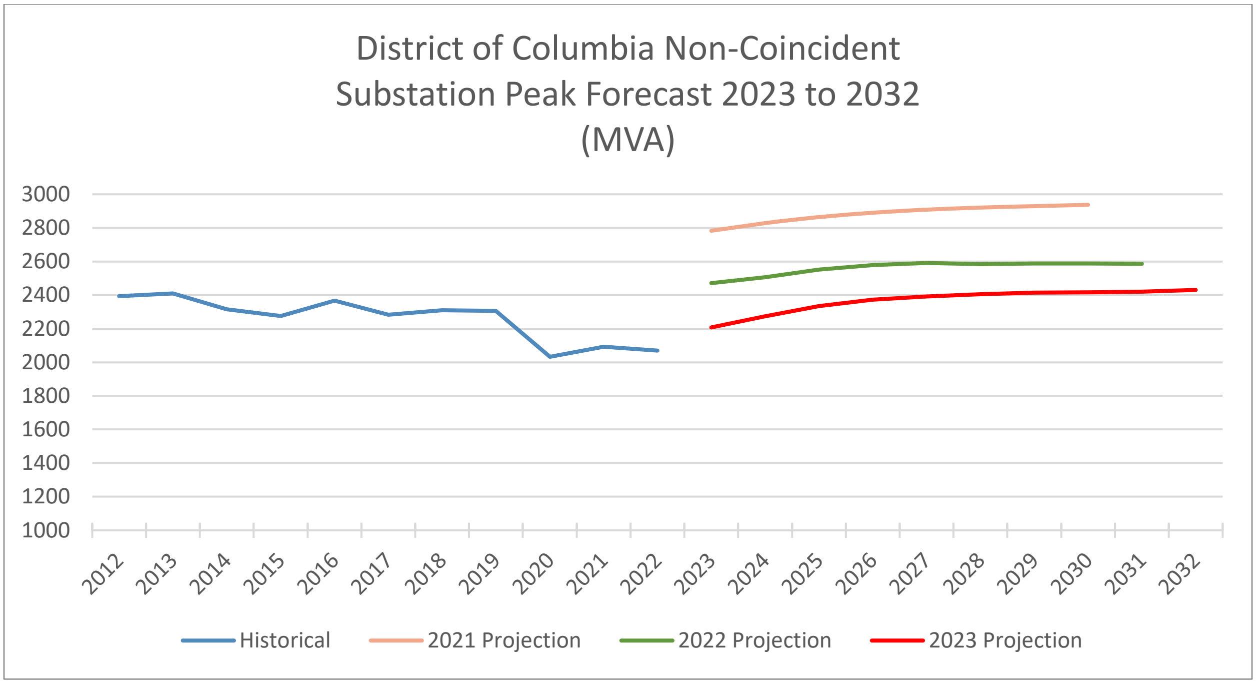

Exhibit OPC (E)-6, is attached to my testimony and shows a non-coincident peak demand forecast by Ward.

I have observed that the forecasts by Pepco in recent years are significantly lower than when the Company used the unadjusted 90/10 forecast method (*i.e*. the process used in the Company's last base rate case in *Formal Case No. 1156*). I have been critical of the overstated load forecasts produced by the prior method and believe the current method is yielding more accurate results that should produce more reasonable capital spending. The reduction in the forecast for the year 2025 from the 2021 forecast to the current 2023 forecast is 528 MVA. To put this in perspective, the new Mt. Vernon Substation will initially be built for 140 MVA with ultimate capacity of 210 MVA at a cost of $138 million. Some of this reduction in demand can be attributed to effects of energy conservation, load control programs and increase in solar interconnections. However, it is my opinion that the current forecast methods yield projections more reasonable than the prior method.

Q. WHAT SHOULD BE THE RESULT TO THE MULTI-YEAR PLAN WITH THE LOWER FORECASTED LOADS?

A. I would expect to see fewer projects justified based on increased capacity since the projected electrical demand at substations and feeders will be lower. As discussed below, however, there are several projects included in the MYP budget that can no longer be justified based on projected demand.

Q. **DOES THE MYP BUDGET SUBMITTED IN THIS PROCEEDING REFLECT THE MORE REASONABLE LOAD FORECAST PRODUCED BY THE COMPANY'S NEW FORECASTING APPROACH?**

A. No. The proposed MYP budget is based on the higher load forecasts produced by Pepco's prior load forecasting methodology.

Q. CAN YOU PROVIDE EXAMPLES OF PROPOSED CAPITAL EXPENSES THAT ARE NO LONGER REQUIRED DUE TO THE UPDATE IN THE LOAD FORECAST?

A. Yes. In my opinion, there are proposed capital projects at the Alabama Substation No. 136 and the Waterfront Substation No. 223 that cannot be justified based on Pepco's current load forecast.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE WATERFRONT SUBSTATION NO. 223?

A. I recommend that ITN 74085 and its associated cost of $635,610 be removed from the MYP budget if the Commission approves the MYP. The Waterfront Substation No. 223 is located near Audi Field which is the home of D.C. United. Pepco has a project budgeted (ITN 74085) to install a 5th transformer at this substation in 2024.[18] The justification for the project states that the existing load on this station is 180.3 MVA and by the year 2027, the load will increase by 21.0 MVA for a total load of 193.4 MVA and will nearly exceed the 216 MVA firm capacity of the substation.[19] However, the actual peak load in 2022 was only 129.6 MVA.[20] Therefore Pepco's statement that the Waterfront Substation has an existing demand of 180.3 MVA is incorrect. The justification appears to be relying on load projections from the 2021 and 2022 Load Forecast[21] and not Pepco's current load forecast for this substation.

In the 2023 load forecast, Pepco is projecting 164.9 MVA in 2023 and 181 MVA by 2027 as shown in the following graph and the peak load is projected to continue to be at 180.4 MVA through 2032.[22] With a peak load of only 180.4 MVA and firm capacity at the substation of 216 MVA, a fifth transformer is not warranted for the Waterfront Substation.

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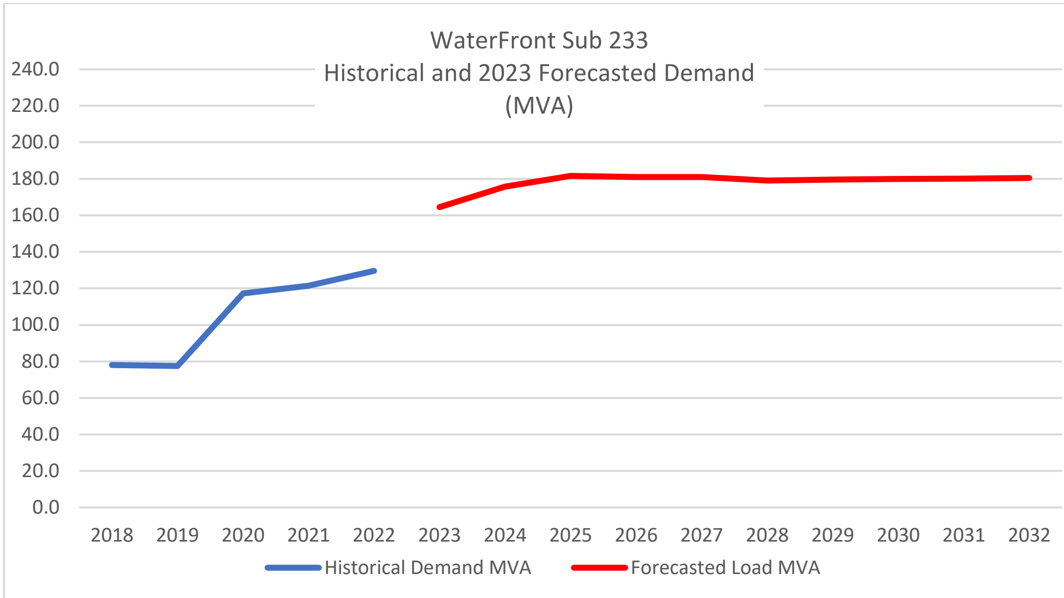
[18] Exhibit Pepco (H)-2 at page 22 of 216.

[19] Exhibit Pepco (H)-2 at page 22 of 216.

[20] Exhibit OPC (E)-7 at page 3 (*Formal Case No. 1176*, Pepco Response to DCG Data Request 5-1).

[21] Exhibit OPC (E)-8 at page 28 (*PEPACR 2021-01*, 2021 Annual Consolidated Report ("2021 ACR")); and Exhibit OPC (E)-9 at page 25 (*PEPACR 2022-01*, 2022 Annual Consolidated Report ("2022 ACR")).

[22] Exhibit OPC (E)-10 at page 3 (*Formal Case No. 1176*, Pepco Response to DCG Data Request 5-2).



Q. DO YOU HAVE ANY CONCERNS WITH PREVIOUS CAPACITY EXPANSIONS AT THE WATERFRONT SUBSTATION?

A. Yes. In 2019, Pepco justified a 4th transformer at the Waterfront Substation stating the firm capacity of the station was 114 MVA and the projected load by the summer of 2019 was anticipated to be 147 MVA.[23] The actual peak load at the Waterfront substation in 2019 was 103.1 MVA and the peak load in 2022 was only 129.6 MVA.[24] In fact, the load at the Waterfront Substation has never exceeded 147 MVA.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE ALABAMA SUBSTATION NO. 136?

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[23] Exhibit OPC (E)-11 at page 3 (Excerpt from *Formal Case No. 1156*, DC Construction Report, Pepco Exhibit (I)-2).

[24] Exhibit OPC (E)-7 at page 3 (Pepco Response to DCG Data Request 5-1).

A. I recommend that ITN 77270 and ITN 77272, which are projects designed to allow for the capacity expansion at the Alabama Substation, be excluded from the MYP which would reduce the capital budget by $6,131,179. Pepco's justification for these projects is that the Alabama Substation No. 136 will be overloaded in 2028.[25] The firm capacity of the existing Alabama Substation is 165 MVA. There are two projects that Pepco believes are necessary to solve this overloaded condition: (i) ITN 77270: Pepco-High Side Bus Land; and (ii) ITN 77272 Pepco 230kV High side-Bus at a cost of $3,647,190 and $2,484,600 respectively.[26] The 2021 and 2022 Load Forecasts projected loads approaching or exceeding 165 MVA;[27] however, Pepco's 2023 Load Forecast for this substation through 2032 does not exceed 143 MVA[28] as shown in the following graph. The current forecasted load of 143 MVA through 2032 therefore does not justify a capacity expansion in 2028.

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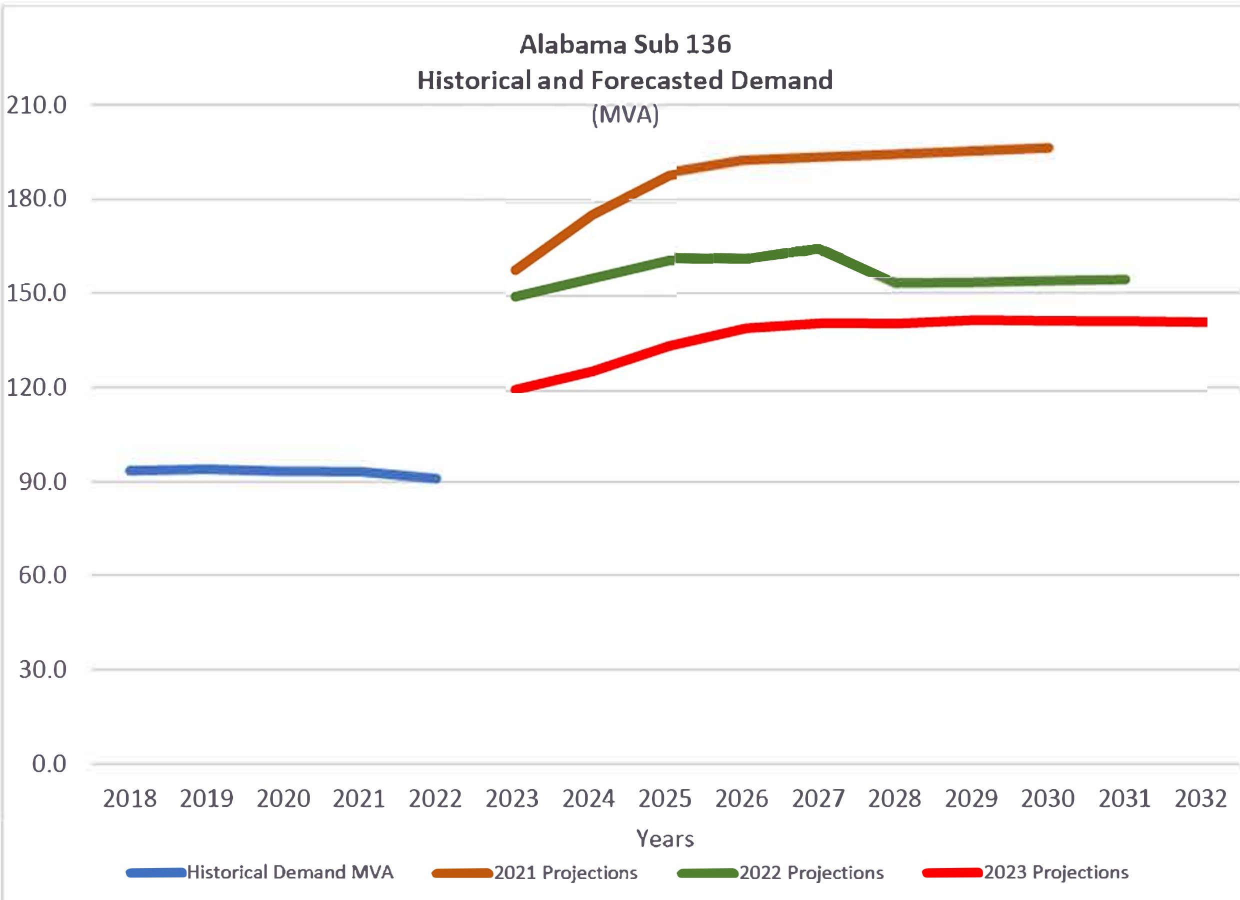
[25] Exhibit Pepco (H)-2 at page 23 of 216.

[26] Exhibit Pepco (H)-2 at pages 23 and 24 of 216.

[27] Exhibit OPC (E)-8, 2021 ACR, at page 28; Exhibit OPC (E)-9, 2022 ACR, at page 25.

[28] Exhibit OPC (E)-10 at page 3 (Pepco Response to DCG Data Request 5-2).



I recommend that the total cost of these projects and the associated $6,031,790 in budgeted capital expense be removed from the MYP budget in the event that the Commission approves a multi-year rate in this proceeding.

Q. ARE YOU AWARE OF ANY CAPITAL COSTS INCLUDED IN THE COMPANY'S CAPITAL BUDGET THAT WERE INCURRED IN MARYLAND AND SHOULD NOT BE CHARGED TO THE DISTRICT?

A. Yes. Through discovery in this proceeding, I learned that the proposed White Flint Substation (ITN 74120) is located in Maryland and portions not chargeable to the District ratepayers were inappropriately included in the Company's proposed rates in this proceeding.[29] Also, the proposed National Harbor Sub (ITN 72730) is also located in Maryland and is not chargeable to District ratepayers and should be removed from any MYP budget approved in this proceeding.[30]

Q. DO YOU HAVE A RECOMMENDATION REGARDING THE DISTRIBUTION COSTS OF THE WHITE FLINT SUBSTATION?

A. Yes. I recommend that ITN 74120 White Flint New Substation 69/13kV be modified such that the distribution costs are directly assigned to Pepco's Maryland jurisdiction and the subtransmission costs are allocated to between the District and Maryland using the AED-NCP allocator. ITN 74120 calls for a new substation to be located in Maryland.[31] The 69kV components which are chargeable to FERC plant accounts 350 through 359 would be allocated between the District and Maryland. The substation costs and the distribution costs which are chargeable to FERC accounts 362 through 373 would be solely assignable to Maryland. My recommendation is consistent with Pepco's response to OPC Data Request 4-73 which states that "[t]he cost of the sub transmission components is recoverable in this rate case using the Average and Excess Non-coincident Peak Demand

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[29] Exhibit OPC (E)-12 at page 1 (*Formal Case No. 1176*, Pepco Response to OPC Date Request 4-73).

[30] Exhibit OPC (E)-13 (*Formal Case No. 1176*, Pepco Response to OPC Data Request 4-72).

[31] Exhibit Pepco (H)-2 at page 172 of 216.

(AED-NCP) allocation method, as referenced at 4-74(a). The cost of the distribution components is not recoverable in this rate case."[32] The breakdown in costs is as follows.

		74120: White Flint New Substation 69/13kV		
	2022A	**2023B**	**2024B**	**2025B**
Capital Expenditures (PEPCO) (H)-2, page 172	--	$2,634,643.00	$520,422.00	$63,135.95
Remove Maryland Direct Distribution Costs	--	($395,196.45)	($78,063.30)	($9,470.46)
PEPCO Sub Transmission Costs		$2,239,446.55	$442,358.70	$53,665.55
Apply AED-NCP Allocator	--	0.4031	0.4031	0.4031
Distribution Cost Allocated to the District	--	$902,720.90	$178,314.79	$21,632.66

Based on my calculation, the required budget reduction to remove the allocated cost to the District is $159,303 in 2023, $31,467 in 2024 and $3,817 in 2025.

Q. DO YOU HAVE A RECOMMENDATION REGARDING THE NATIONAL HARBOR SUBSTATION?

A. Yes. I recommend that ITN 72730 National Harbor Sub – New 69/13 Dist Sub[33] which is located outside of the District be excluded from any MYP budget approved in this proceeding. Pepco agreed that this project was inadvertently tagged as a subtransmission project and should not be included in this rate case.[34] The breakdown in costs is as follows.

[32] Exhibit OPC (E)-12 at page 1.

[33] Exhibit Pepco (H)-2 at page 171 of 216.

[34] Exhibit OPC (E)-13 at page 1.

		72730: National Harbor Sub – New 69/13 Dist Sub			
	2022A	**2023B**	**2024B**	**2025B**	**2026B**
Capital Expenditures (PEPCO) (H)-2, page 172	--	$576,520	$1,796,040	$2,990,010	$4,816,990
Remove Maryland Direct Distribution Costs	--	($576,520)	($1,796,040)	($2,990,010)	($4,816,990)
PEPCO Sub Transmission Costs		$0	$0	$0	$0
Apply AED-NCP Allocator	--	0.4031	0.4031	0.4031	0.4031
Distribution Cost Allocated to the District	--	$0	$0	$0	$0

Based on my calculation, the required budget reduction to remove the allocated cost to the District is $232,395 in 2023, $723,984 in 2024, $1,205,273 in 2025, and $1,941,729 in 2026.

Q. ARE YOU AWARE OF ANY BATTERY ENERGY STORAGE SYSTEMS PROPOSED IN THIS MULTI-YEAR PLAN?

A. Yes. Pepco Witness Cantler states in her direct testimony that Pepco has two proposed battery storage projects.[35] She states that battery energy storage technology is a safe and sustainable energy solution and a promising alternative for providing temporary capacity relief with a zero-carbon footprint.[36] The two battery energy storage systems ("BESS") include a 1MW/3MWh unit at the Alabama Substation and a unit at the Mt. Vernon Substation. Battery storage used as described in Pepco's justification are often referred to

[35] Exhibit Pepco (H) (Cantler) at 10:6-7.

[36] Exhibit Pepco (H) (Cantler) at 10:7-9.

as non-wire alternatives ("NWAs"). NWAs are investments that can deter or replace the need for specific substation and/or distribution projects, at lower total resource cost.

Q. IN YOUR OPINION, IS THE BESS UNIT AT ALABAMA SUBSTATION NECESSARY?

A. No. Pepco notes load growth from major development projects in the Ward 8 area will result in the Alabama Ave. Substation experiencing a capacity overload. The proposed battery storage was initially justified as a means to delay the need for capacity increases at the Alabama Ave. Substation.[37] However, the current load forecasts for the Alabama Ave. Substation do not require the capacity of these proposed batteries to defer upgrades at the substation. The load forecasts in 2021 and 2022, projected future loads that could result in loads beyond the current firm capacity of the substation of 165 MVA. Pepco's new load forecasting method now shows a significant reduction in the projected load for this area in Ward 8.[38] The following graph compares the historical loads and forecasted loads from the 2021, 2022 and 2023 forecasts.

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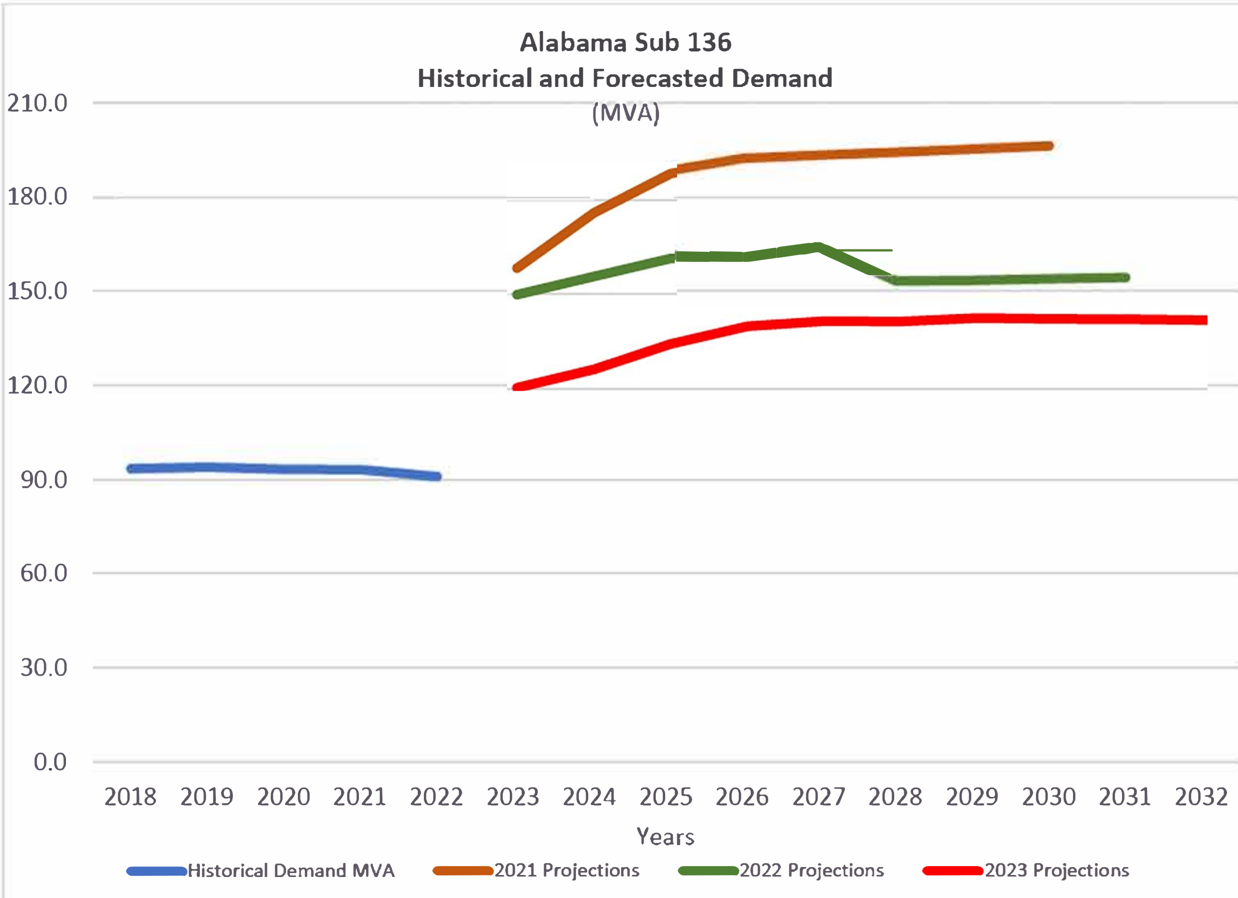
[37] Exhibit Pepco (H)-2 at page 2 of 216.

[38] Exhibit OPC (E)-10 at page 3.



Further, Pepco's "Construction Recommendations-Distribution Systems: Construction Recommendations Distribution Systems 2024-2025," dated April 1, 2023, contains **[BEGIN CONFIDENTIAL]** [redacted]

39 Exhibit OPC (E)-14 at page 6, Pepco Response to OPC Data Request 4-32, Confidential Attachment E.

[redacted] **[END CONFIDENTIAL]**.[40]

As I have stated, based on current load projections, there is no need for a BESS at the Alabama Substation. Therefore, in my opinion, a NWA alternative is not required for this substation or for Feeder 15166.

Q. WHAT IS YOUR OPINION REGARDING THE PROPOSED BATTERY AT THE ALABAMA SUBSTATION?

A. In Order No. 20274, the Commission suggested that Pepco develop a NWA project in order to defer a new substation in Ward 8, which was projected to be needed in the 2026-2028 timeframe.[41] In response to Order No. 20274, Pepco noted that BESS would both help defer the Ward 8 substation and defer a feeder upgrade in the area.[42] Obviously, Pepco's load forecast has changed and a BESS installed in Ward 8 will not defer any required capacity upgrades. Pepco stated in response to an OPC discovery request that the project will "mitigate voltage drop violations during peak load conditions and using the

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[40] Exhibit OPC (E)-14 at page 3.

[41] *Formal Case No. 1144, In the Matter of the Potomac Electric Power Company's Notice to Construct Two 230kV Underground Circuits From the Takoma Substation to the Rebuilt Harvard Substation, And From the Rebuilt Harvard Substation to the Rebuilt Champlain Substation (Capital Grid Project)* ("*Formal Case No. 1144*), Order 20274 ¶ 95, rel. December 20, 2019 ("Order No. 20274").

[42] Exhibit OPC (E)-15 at page 3 (*Formal Case No. 1144*, Pepco's Response to Order 20274, dated June 17, 2020).

capabilities of the battery to augment emergency transfers in response to storms."[43] While Pepco has identified a modest benefit to continuing with the BESS at the Alabama Substation, in the absence of any capacity deferral value, I believe that Pepco should pivot and delay indefinitely the BESS planned for the Alabama Substation.

Q. WHAT IS YOUR RECOMMENDATION FOR THE BESS COSTS INCLUDED IN THE CAPITAL BUDGET FOR THE ALABAMA SUBSTATION?

A. I recommend that costs budgeted for the years 2024 to 2026 be removed from the multi-year plan. The costs total $6,269,000.

	($'s in '000s)		
ITN Name	**2024B**	**2025B**	**2026B**
62900: Pepco Alabam Av. Sub 136 Feeder 15166 Battery Substation	$ 2,038.1	$ 2,258.6	$ 62.1
62935: Pepco Alabama Ave Sub 136 Feeder 15166 Battery Distribution	$ 300.7	$ 1,118.4	$ 35.9
63208: Pepco Alabama Ave Sub 136 Feeder 15166 Fiber/Telecom	$ 316.0	$ 77.7	$ 62.1
Total	$ 2,655	$ 3,455	$ 160
Total 2024 to 2026	$ 6,269		

Q. CAN YOU EXPLAIN PEPCO'S JUSTIFICATION FOR THE BESS UNIT AT THE MOUNT VERNON SUBSTATION?

A. Yes. Pepco's justification for the BESS unit at Mr. Vernon (ITN 67364) has three parts:

1. More non-wire solutions to align with DC's CleanEnergy Act,
2. Defer the capital expenditure for the 4th Mt. Vernon transformer in accordance with DC PSC Order 20274, and
3. Demonstrate learnings from this project.[44]

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[43] Exhibit OPC (E)-16 (*Formal Case No. 1176*, Pepco Response to OPC Data Request at 8-5).

[44] Exhibit Pepco (H)-2 at page 9 of 216.

In Order No. 20274, the Commission stated the "[g]iven that the new transformer will not be needed until 2028, we direct Pepco to use best efforts to expand the 1 MW pilot battery project at the Mt. Vernon Substation during this time to defer or eliminate the need for the transformer."[45] However, as I will demonstrate, the facts are now such that a fourth transformer will not be required through 2032 and the BESS will have limited value.

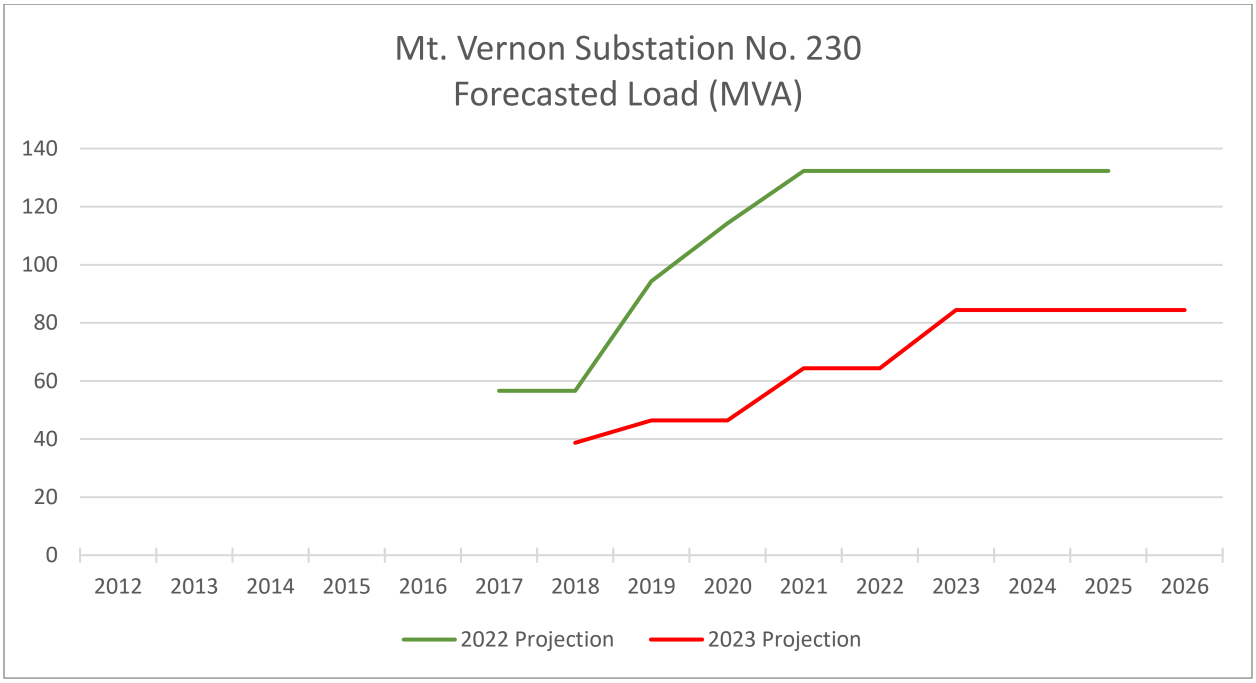
Q. IS THE BESS NEEDED TO DEFER A CAPITAL UPGRADE AT MT. VERNON SUBSTATION?

A. No. The Mt. Vernon Substation No. 230 will have an initial rating of 140 MVA[46] and the ten year forecasted peak demand[47] for this substation does not exceed 84.4 MVA as shown in the following graph.

[45] Order No. 20274 at ¶ 94.

[46] Pepco Exhibit (H)-2 at page 15 of 216.

[47] Pepco Exhibit (H)-1 at page 13 of 75.



In 2018 Pepco believed that the Mt. Vernon Triangle, NoMa, Capitol Crossing, and Northwest One areas (currently served by Florida Avenue Substation, New Jersey Avenue Substation, Northeast Substation and Tenth Street Substation) would see new growth of approximately 126 MW over the next ten years.[48] The updated version of the potential new businesses for the area is down to approximately 54 MW through 2026[49] with some projects complete, some in construction, and some delayed or terminated. With all these revised loads accounted for in the projections, the peak load at the Mt. Vernon Substation

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[48] Exhibit OPC (E)–26 at pages 17-18 (*Formal Case No. 1130 and 1144*, Reply Comments of Potomac Electric Power Company, filed June 29 2018) ("The Mt. Vernon Triangle, NoMa, Capitol Crossing, and Northwest One areas (currently served by Florida Avenue Substation, New Jersey Avenue Substation, Northeast Substation and Tenth Street Substation) are and will be experiencing significant new growth, with approximately 126 MW of load from 132 new developments scheduled to be added over the next ten years.").

[49] Exhibit OPC (E)-17, *Formal Case No. 1176*, Pepco Response to OPC Data Request 4-9. The Total Station PNB Load totals reported on page 13 of Exhibit OPC (E)-17 total to 54.202 MW.

will not exceed 84.4 MW by 2032. A fourth transformer is not required until the load approaches the firm capacity of the substation, and this will not occur prior to 2032.

Q. ARE THERE ANY OTHER RATIONALES FOR THE BESS AT THE MOUNT VERNON SUBSTATION?

A. The Commission asked Pepco to file plans and implementation details for a BESS at the Mt. Vernon Substation in Order No. 20274[50] and Pepco responded that the Company was committed to fulfilling the Commission's directive regarding battery storage to defer a fourth transformer at the Mt. Vernon Substation.[51]

Q. **IN YOUR OPINION, IS THAT RATIONALE STILL VALID?**

No. Order No. 20274 was issued at a time when the assumption was that the battery would defer a fourth transformer, but now there is no need to defer a capacity increase at the substation. I believe that these prior commitments should be adjusted to current load projections and the BESS be deferred or eliminated. Further, Pepco stated that by installing the BESS later than 2024, it would be possible to take advantage of technology advancements and reduce the degradation of its capacity that will occur from repeated use of the battery prior to the need to use the battery for deferral purposes.[52] Given that an additional transformer at the Mt. Vernon Substation will not be needed through 2032, I

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[50] Order No. 20274 at ¶ 94.

[51] *See* Exhibit OPC (E)-18 at page 2 (*Formal Case No. 1144*, Pepco's 90-day Compliance filing pursuant to Order No. 20274, dated March 19, 2020. The Office notes that Pepco's cover letter indicates that the Company was filing in response to Order 20203, but this appears to be in error).

[52] Exhibit OPC (E)-18 at page 2.

recommend not installing the battery system until it is needed at the Mt. Vernon Substation or a more suitable location is identified.

Q. IN YOUR OPINION, WILL A BESS LOCATED AT THE MT. VERNON SUBSTATION PROVIDE EXPERIENCE FOR PEPCO TO OPERATE A BESS ON THE UTILITY SIDE OF THE METER?

A. Yes, it could provide additional experience, but it is not necessary. Pepco does not need the experience in the District because Pepco is part of the larger Exelon organization which already operates battery systems on other distribution systems. Pepco is operating some utility scale battery systems in Maryland including one at National Harbor and another at a Montgomery County Electric Transit Bus depot in Silver Spring.[53] Therefore it is not necessary to spend over six million dollars to learn about battery systems in the District when Pepco already has this operating experience.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE PROPOSED BESS AT THE MT. VERNON SUBSTATION?

A. I recommend that ITN 67364: Pepco Mt. Vernon Battery Energy Storage System be delayed indefinitely and the budgeted cost in 2024 of $4,466,410 removed from the MYP budget.

Q. REGARDING THE DOWNTOWN RESUPPLY PROJECT, DO YOU HAVE ANY RECOMMENDATIONS?

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[53] Exhibit OPC (E)-19, Presentation by Exelon at the PJM Emerging Technology Forum January 11, 2020.

A. Yes. I recommend the following projects be excluded from the MYP capital budget.

ITN Name
68678: L. St Rebuild Distribution Work
72137: L St Sub Capacity Expansion Work
80130: Pepco DC Buzzard to F Street
80425: Pepco DC F Street to Georgetown
80427: Pepco Champlain to L Street 69kV
80740: Pepco DC Champlain to F Street
68612: Pepco DC L St T1 Replacement
68613: Pepco DC L St T2 Replacement
68614: Pepco DC L St T3 Replacement
68615: Pepco DC L St T4 Replacement
71630: F St Sub Rebuild (69kV) (UDSPLM718A)
71631: F St Sub Rebuild (UDSPLM717A)
73368: Champlain Bypass
71012: Champlain - New 69kV Sub (DSPRD8AD17)

These projects represent a fundamental change from the Downtown Resupply that Pepco first proposed as part of the Capital Grid Plan[54] and have not been sufficiently justified for the total cost of the projects. The Office's proposed cost reductions are detailed in my Exhibit OPC (E)-20. Further, these changes are only the start of substantial changes for the feeds from the Potomac C Substation and potentially from a new Livingston Substation.

Q. CAN YOU DESCRIBE PEPCO'S DOWNTOWN RESUPPLY PROJECT?

A. Yes. The Downtown Resupply Project ("DRP") was first included in *Formal Case No. 1144* as an ancillary project to the Company's Capital Grid Project. As conceived in 2018, the DRP project used the Champlain Substation as a source to re-feed Georgetown, and F Street with 69kV cables and L Street with 35kV cables. In turn, the Company planned to

[54] Exhibit OPC (E)-21, *Formal Case No. 1144*, Pepco's 180-Compliance filing Pursuant to Order 20203, dated February 4, 2020.

retire older 69kV pipe-type cables from the Potomac River Substation to Georgetown Substation and from Georgetown Substation to the F Street Substation. In addition the older 35kV cables from Buzzard Point Substation to the L Street Substation would be retired with the addition of the new 35kV cables from the Champlain Substation. The F Street Substation would be re-built, and capacity increased at L Street Substation. In addition, this work would allow for the retirement of the I Street Substation which resides on leased property. Finally, the 22nd Street Substation would be re-fed from the 69kV cables currently serving the I Street Substation. These cables originate at the Potomac C Substation and extend via two different routes to the 9th Street Substation and extend further to the I Street Substation. This work will allow for the Takoma to Champlain 69kV cables to be retired. The following diagram[55] shows the current configuration of sub-transmission feeds to these stations. **[BEGIN CONFIDENTIAL]**

[55] Exhibit OPC (E)-22 at page 22, *Formal Case No. 1176*, Pepco Response to OPC Data Request 4-20, Confidential Attachment Z.

[redacted]

[redacted]

2 **[END CONFIDENTIAL]**

Attachment Z, page 23 of 35.

In 2022 Pepco changed the permanent feed to the L Street Substation from 35kV to 69kV.[57] The total projected cost for the DRP was $494 million as detailed in the 2022 Annual Consolidated Report.

WSB	Downtown Resupply Project	Life Cycle Cost
UDLPLM7W27	13kV cutover F to L	$ 39,849,304
UDLPLM7W28	13kV cutovers I to F & L	$ 32,434,952
UDLPRM4WA8	Champlain to L street 34kV	$ 102,319,736
UDSPLM718A	F St Sub Rebuild (69kV)	$ 50,372,188
UDSPLM717A	F St Sub Rebuild	$ 33,581,458
UDSPLM722A	L St Sub Capacity Expansion	$ 4,011,558
UDLPRM5SG	Repl 69kV UG Supl-Georgetown, F St, 22nd St Subs	$ 177,223,136
UDSPR27RD	Retire I St Sub	$ 2,081,496
UDLPRM4RDR	Retirements Downtown resupply 34kV and 69kV for DC	$ 35,522,470
UDLPRM4RDM	Retirements Downtown resupply 34kV and 69kV for MD	$ 1,309,199
UDLPRM4RDV	Retirements Downtown resupply 34kV and 69kV for VA	$ 13,322,712
UDFPO22SS	Telecom 22nd St	$ 500,000
UDFPOCL01	Telecom Fiber for 34-69kV resupply Champlain, L and F	$ 500,000
UDFPOGS01	Telecom - Georgetown Sub	$ 500,000
UDFPOLS01	Telecom - L Street Sub	$ 500,000
		$ 494,028,209

Q. WHAT IS YOUR UNDERSTANDING OF THE NEED FOR THE DOWNTOWN RESUPPLY PROJECT?

A. In my opinion, the primary reason for the DRP is for reliability due to aging 69kV cables and the fact that many of these cables cross under the Potomac River. These older cables are pipe-encased-type cables that use oil around the cable for cooling and maintaining capacity levels of the cables. As these cables age there is a concern of leaking oil. Newer 69kV cables are solid di-electric cables that do not require oil for cooling.

57 Exhibit OPC (E)-9 at page 315 (2022 ACR, Attachment F at page 2 of 3).

Q. DOES THE DRP PROJECT INCREASE RELIABILITY RESILIENCY?

A. The answer is very subjective but simply put, I would say no. Most utilities, including Pepco, design the 35kV and 69kV systems with contingency capacity often referred to as N-1 meaning with the loss of one system component, the system can continue to serve the load. The existing system meets this criterion, however as components age, they must be renewed. In this case, rather than renewing existing infrastructure, Pepco is building a system to serve the same load with the same N-1 contingency. The new system reduces the number of river crossings and will help Pepco fix cables more quickly, which is the main advantage of the DRP system.

Q. IN YOUR OPINION HAS PEPCO BEEN TRANSPARENT WITH RESPECT TO THE CHANGES PROPOSED TO THE DOWNTOWN RESUPPLY PROJECT?

A. In my opinion, Pepco has not been transparent. In fact, the 2023 ACR filed on April 18, 2023, makes no mention of the changes to the Downtown Resupply Project that are now included in the MYP that was also filed in April 2023.

Q. CAN YOU DESCRIBE PEPCO'S NEW LONG RANGE PLAN FOR RE-SUPPLYING THE SUBSTATIONS INCLUDING GEORGETOWN, F STREET, L STREET, 22ND STREET, AND 9TH STREET SUBSTATIONS?

A. Yes, I can describe the plan as presented in Pepco's confidential response to OPC Data Request 4-21.[58] **[BEGIN CONFIDENTIAL]** [redacted]

[58] Exhibit OPC (E)-23, Pepco Response to OPC Data Request 4-21(a), Confidential Attachment.

[redacted]

59 Exhibit Pepco (H)-2 at page 197 of 216.

[redacted]

[redacted]

[END CONFIDENTIAL]

Q. IN YOUR OPINION HAS PEPCO JUSTIFIED STAGE 1 OF THE REVISED DOWNTOWN RESUPPLY PLAN?

A. No. Witness Cantler did not mention the changes to the DRP in her direct testimony. Also, the justification in the individual projects (*i.e.*, Project ITN 80130: Buzzard to F Street

69kV cables; Project ITN 80245: Pepco DC F Street to Georgetown; ITN 80740: Pepco DC Champlain to F Street; ITN 80247: Pepco Champlain to L Street 69kV; ITN 71631: F St Sub Rebuild; and ITN 72137: L St Sub Capacity Expansion Work), do not clearly explain the master plan and total cost envisioned by Pepco for the Stage 1 and Stage 2 modifications. For instance, ITN 71631: F St Sub Rebuild still calls for 4 cables from the Champlain Substation.[60] Further these projects require that the Buzzard Point 230/69kV Substation be relocated starting in roughly 2027, however, the current budgets do not indicate or justify this relocated substation project. In fact, all of the following ITN projects reference a relocated Buzzard Point 69kV Substation: ITN 68678, ITN 70096, ITN 72137, ITN 80130, ITN 71630, and ITN 71631.[61] This scant justification is not sufficient to start down the road of the revised downtown resupply that will result in an additional $712 million for sub-transmission and substation expenditures that will be borne by District ratepayers.

In addition, it is my understanding that Pepco will need to file a Notice of Construction (NOC) for the 230 kV cables required for a relocated Buzzard Point Substation. However, once the 69kV cables are installed from F Street Substation to Buzzard Point Substation, the review of the NOC will be arguably a fait accompli because a considerable portion of

[60] Exhibit Pepco (H)-2 at page 152 of 216.

[61] Exhibit Pepco (H)-2 at pages 10, 11, 14, 92, 151, and 152 of 216. Specifically, the Solution Statement for these projects provides: "Resupply 22nd Street, F St and Georgetown via Champlain 69kV new 230/69kV sub and Buzzard Point 69kV relocated sub to inside the generation building."

the project will already be in place and considerable spending will have already occurred through the MYP budget.

Q. DOES THE STAGE 1 LONG-TERM DOWNTOWN DC PLAN OR THE DOWNTOWN RESUPPLY PROJECT INCREASE SYSTEM CAPACITY?

A. No. The retirement of the I Street Substation and the Champlain Substation reduces firm capacity by 246 MVA. The L Street and F Street Substation will have capacity increases of 78 MVA and 55 MVA resulting in a net increase for these two stations of 133 MVA. Some of the capacity from Champlain Substation is being absorbed by other adjacent substations, but the substation capacity of these Downtown substations will not be increased.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE DOWNTOWN RESUPPLY PLAN?

A. As I previously stated, I recommend that all projects that modify the 69kV cables and substation equipment associated with modified Downtown Resupply Plan be eliminated from the MYP because Pepco has not justified the modified plan. The list of those projects to exclude are contained in my Exhibit OPC E–(20).

IV. CONCERNS REGARDING PEPCO'S TRADITIONAL TEST YEAR CONSTRUCTION EXPENSE AND CAPITAL INVESTMENTS

Q. WHAT IS YOUR UNDERSTANDING OF THE TRADITIONAL TEST YEAR PERIOD?

A. My understanding is the test year would be the 12 months ending December 2023, with six months of known expenditures and six months of projected expenditures.

Q. IN YOUR OPINION, ARE THERE ANY PROJECTS IN THE TEST YEAR THAT SHOULD BE EXCLUDED?

A. Yes. Project ITN 70096: 13kV Distribution Cutovers "F' St to "L" St. has a budget of $9,527,130 in 2023. Pepco, however, has stated that "[n]o portion of this project will be completed within the test year."[62] Therefore the costs associated with this project should be excluded from the traditional test year revenue requirement as this project will be not be providing benefits to ratepayers. Also, Project 80906: Pepco DDOT Bridge 78 Relocation - 69kV pipe type has a budget of $7,972,280. Again, Pepco has stated that "[n]o portion of this project will be completed within the test year."[63] Therefore these costs should also be excluded from the traditional test year revenue requirement.

Q. YOU PREVIOUSLY DESCRIBED YOUR CONCERNS ABOUT THE LACK OF JUSTIFICATION FOR THE DOWNTOWN RESUPPLY PROJECT. HOW DO THESE CONCERNS RELATE TO THE TRADITIONAL TEST YEAR?

A. I recommend that all projects that modify the 69kV cables and substation equipment associated with the modified Downtown Resupply Plan be eliminated from the MYP because Pepco has not justified the modified plan. For the same reasons and the lack of justification, I recommend these projects that modify the 69kV cables and substation equipment be eliminated from the traditional test year revenue requirement. These costs are detailed in the following table.

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[62] Exhibit OPC (E)-24 (*Formal Case No. 1176*, Pepco Response to OPC Data Request at 11-3).

[63] Exhibit OPC (E)-25 (*Formal Case No. 1176*, Pepco Response to OPC Data Request at 11-4).

Downtown Resupply Projects to be Eliminated from the Test Year

ITN Name	$s in '000s 2023B	
64195: Pepco Champlain Rebuild - 13 kV Champlain Load Transfers	$	3,388
68678: L St Rebuild Distribution Work	$	269
72137: L St Sub Capacity Expansion Work	$	4,449
80130: Pepco DC Buzzard to F Street	$	270
80425: Pepco DC F Street to Georgetown	$	852
80427: Pepco Champlain to L Street 69kV	$	1,179
80740: Pepco DC Champlain to F Street	$	1,482
68612: Pepco DC L St T1 Replacement	$	746
68613: Pepco DC L St T2 Replacement	$	714
68614: Pepco DC L St T3 Replacement	$	192
68615: Pepco DC L St T4 Replacement	$	197
71630: F St Sub Rebuild (69kV) (UDSPLM718A)	$	709
71631: F St Sub Rebuild (UDSPLM717A)	$	540
73368: Champlain Bypass	$	1,790
71012: Champlain - New 69kV Sub (DSPRD8AD17)	$	831
Total	**$**	**17,609**

Q. YOU PREVIOUSLY DESCRIBED YOUR CONCERNS ABOUT DISTRIBUTION AND SUBTRANSMISSION COST ALLOCATIONS BETWEEN MARYLAND AND THE DISTRICT. HOW DO THESE CONCERNS RELATE TO THE TRADITIONAL TEST YEAR?

A. The costs that were not allocated properly should be excluded from the traditional test year revenue requirement. As I previously explained, the proposed White Flint Substation (ITN 74120) is located in Maryland and portions not chargeable to the District ratepayers were inappropriately included in the Company's proposed rates in this proceeding.[64] The

[64] Exhibit OPC (E)-12.

proposed National Harbor Sub (ITN 72730) is also located in Maryland and is not chargeable to District ratepayers and should be removed from any test year costs.[65] The total negative adjustment to the test year is $395,196 for the White Flint Substation and $576,520 for the National Harbor Substation.

Q. YOU PREVIOUSLY DESCRIBED THE IMPACT OF THE CLIMATE PLAN UPGRADES AND SPECIFICALLY THE ADMS SYSTEMS. IN YOUR OPINION, SHOULD THE ADMS SYSTEMS BE INCLUDED IN A TRADITIONAL TEST YEAR FOR RATE MAKING?

A. Yes. The core purpose of the ADMS is replacement of older information control technologies including Pepco's outage management system, remote control of downline devices, and GIS mapping capabilities. The cost of replacing and upgrading older technologies have historically been recovered through traditional rate cases. As I have noted above, it is the ADMS Convergence Stage 2.0 project and advanced DERMS implementation projects included in the MYP that have not been justified from an engineering perspective.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

[65] Exhibit OPC (E)-13.

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In the Matter of the	)	
	)	
Application of Potomac Electric Power Company	)	**Formal Case No. 1176**
for Authority to Implement a Multiyear Rate	)	
Plan for Electric Distribution Service	)	
in the District of Columbia	)	

AFFIDAVIT

I declare under penalty of perjury that the foregoing testimony was prepared by me or under my direction and is true and correct to the best of my knowledge, information, and belief.

Date: 1/7/24

Signature

Subscribed and sworn to before me

This 9th day of January 2024.

State of Georgia

County of Cobb

Notary Public

My Commission expires: January 8, 2027

LISA D PARKER
Notary Public, Georgia
Bartow County
My Commission Expires
January 08, 2027

KEVIN MARA

EXECUTIVE VICE PRESIDENT & PRINCIPAL ENGINEER, P.E.

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

CONTACT

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EDUCATION

Bachelor of Science, Electrical Engineering, Georgia Institute of Technology, 1982

PROFESSIONAL AFFILIATIONS/ CERTIFICATIONS

Registered *Professional Engineer* in Alabama, Arkansas, Georgia, Florida, Idaho, Indiana, Kansas, Kentucky, Louisiana, Michigan, Mississippi, Missouri, North Carolina, Ohio, Oregon, Pennsylvania, South Carolina, South Dakota, Tennessee, Texas, Virginia, Washington, and Wisconsin.

Institute of Electrical and Electronic Engineers Power Engineering Society: Senior Member

National Electric Safety Code Subcommittee 5: Alternate Member

Past Member: Insulated Conductor Committee

EXPERTISE

Overhead & Underground Distribution Design

Distribution System Planning

Power System Modeling & Analysis

Training

PROFILE

Mr. Mara has over 30 years of experience as a distribution engineer. He worked six years at Savannah Electric as a Distribution Engineer and ten years with Southern Engineering Company as a Project Manager. At Savannah Electric, Mr. Mara gained invaluable field experience in the operation, maintenance, and design of transmission and distribution systems. While at Southern Engineering, Mr. Mara performed planning studies, general consulting, underground distribution design, territorial assistance, and training services. Presently, Mr. Mara is a Vice President at GDS Associates, Inc. and serves as the Principal Engineer for GDS Associates' engineering services company known as its trade name Hi-Line Engineering.

Overhead Distribution System Design. Mr. Mara has developed underground specifications for utilities and was an active participant on the Insulated Conductor Committee for IEEE. He has designed underground service to subdivisions, malls, commercial, and industrial areas in various terrains. These designs include concrete-encased ductlines, direct-burial, bridge attachments, long-bores, submarine, and tunneling projects. He has developed overcurrent and overvoltage protection schemes for underground systems for a variety of clients with different operating parameters.

Underground Distribution System Design. Mr. Mara has developed underground specifications for utilities and was an active participant on the Insulated Conductor Committee for IEEE. He has designed underground service to subdivisions, malls, commercial, and industrial areas in various terrains. These designs include concrete-encased ductlines, direct-burial, bridge attachments, long-bores, submarine, and tunneling projects. He has developed overcurrent and overvoltage protection schemes for underground systems for a variety of clients with different operating parameters.

TRAINING SEMINARS

Mr. Mara has developed engineering training courses on the general subject of distribution power line design. These seminars have become extremely popular with more than 25 seminars being presented annually and with more than 4,000 people having attended seminars presented by Mr. Mara. A 3-week certification program is offered by Hi-Line Engineering in eleven states. The following is a list of the training material developed and/or presented:

- Application and Use of the National Electric Safety Code
- How to Design Service to Large Underground Subdivisions
- Cost-Effective Methods for Reducing Losses/Engineering Economics
- Underground System Design
- Joint-Use Contracts – Anatomy of Joint-Use Contract
- Overhead Structure Design
- Easement Acquisition
- Transformer Sizing and Voltage Drop

Construction Specifications for Electric Utilities. Mr. Mara has developed overhead construction specifications including overhead and underground systems for several different utilities. The design included overcurrent protection for padmounted and pole mounted transformers. The following is a representative list of past and present clients:

- Cullman EMC, Alabama
- Blue Ridge EMC, South Carolina
- Buckeye Rural Electric Cooperative, Ohio
- Three Notch EMC, Georgia
- Little River ECI, South Carolina
- Lackland Air Force Base
- Maxwell Air Force Base

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SYSTEM PRIVATIZATION/EVALUATION

Central Electric Power Cooperative, Columbia, SC

- 2017 Independent Certification of Transmission Asset Valuation, Silver Bluff to N. Augusts 115kV
- 2015 Independent Certification of Transmission Asset Valuation, Wadmalaw 115kV

Choctawhatchee Electric Cooperative, DeFuniak Springs, FL

- Inventory and valuation of electrical system assets at Eglin AFB prior to 40-year lease to private-sector entity.

PUBLICATIONS

- Co-author of the NRECA "Simplified Overhead Distribution Staking Manual" including editions 2, 3 and 4.
- Author of "Field Staking Information for Overhead Distribution Lines"
- Author of four chapters of "TVPPA Transmission and Distribution Standards and Specifications"

TESTIMONIES & DEPOSITIONS

Mr. Mara has testified as an expert at trial or by deposition in the following actions.

- *Deposition related to condemnation of property,* Newberry ECI v. Fretwell, 2005, State of South Carolina
- *Testimony in Arbitration regarding territory dispute,* Newberry ECI v. City of Newberry, 2003, State of South Carolina, Civil Action No. 2003-CP-36-0277
- *Expert Report and Deposition, 2005,* United States of America v. Southern California Edison Company, Case No CIV F-o1-5167 OWW DLB
- *Expert Report and Deposition, 2005,* Contesting a transmission condemnation, Moore v. South Carolina Electric and Gas Company, United States District Court of South Carolina, Case No. 1:05-1509-MBS
- *Affidavit October 2007,* FERC Docket No. ER04-1421 and ER04-1422, Intervene in Open Access Transmission Tariff filed by Dominion Virginia Power
- *Affidavit February 26, 2008,* FERC Docket No. ER08-573-000 and ER08-574-000, Service Agreement between Dominion Virginia Power and WM Renewable Energy, LLC
- *Direct Filed Testimony* date December 15, 2006, before the Public Utility Commission of Texas, SOAH Docket No 473-06-2536, PUC Docket No. 32766
- *Expert Report and Direct Testimony* April 2008, United States Tax Court, Docket 25132-06, Entergy Corporation v. Commissioner Internal Revenue
- *Direct Testimony* September 17, 2009, Public Service Commission of the District of Columbia, Formal Case 1076, Reliability Issues
- *Filed Testimony regarding the prudency of hurricane restoration costs on behalf of the City of Houston*, TX, 2009, Cozen O'Connor P.C., TX PUC Docket No. 32093 – Hurricane Restoration Costs
- *Technical Assistance and Filed Comments regarding line losses and distributive generation, interconnection issues*, 2011, Office of the Ohio Consumer's Counsel, OCC Contract 1107, OBM PO# 938 for Energy Efficiency T & D

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TESTIMONIES & DEPOSITIONS [continued]

- *Technical Assistance, Filed Comments, and Recommendations evaluating Pepco's response to Commission Order 15941* concerning worst reliable feeders in the District of Columbia, 2011, 2012 Office of the People's Counsel of the District of Columbia, Formal Case No. 766
- *Technical Assistance, Filed Comments, and Recommendations on proposed rulemaking by the District of Columbia PSC amending the Electric Quality of Service Standards (EQSS),* 2011, Office of the People's Counsel of the District of Columbia, Formal Case No. 766
- *Yearly Technical Review, Filed Comments, and Recommendations evaluating Pepco's Annual Consolidated Report* for 2011 through 2021, Office of the People's Counsel of the District of Columbia, Formal Case Nos. 766; 766-ACR; PEPACR(YEAR)
- *Technical Evaluation, Filed Comments, and Recommendations evaluating Pepco's response to a major service outage occurring May 31, 2011.* (2011), Office of the People's Counsel of the District of Columbia, Formal Case Nos. 766 and 1062
- *Technical Assistance, Filed Comments, and Recommendations evaluating Pepco's response to Commission Order 164261 concerning worst reliable neighborhoods in the District of Columbia*, 2011, Office of the People's Counsel of the District of Columbia, Formal Case No. 766
- *Technical Review, Filed Comments, and Recommendations on Pepco's Incident Response Plan (IRP) and Crisis Management Plan (CMP)*, 2011, Office of the People's Counsel of the District of Columbia
- Formal Case No. 766
- *Technical Assistance, Filed Comments, and Recommendations assessing Pepco's Vegetation, Management Program and trim cycle* in response to Oder 16830, 2012, Office of the People's Counsel of the District of Columbia, Formal Case No. 766
- *Technical Review, Filed Comments, and Recommendations on Pepco's Secondary Splice Pilot Program* in response to Order 16426, 2012, Office of the People's Counsel of the District of Columbia, Formal Case No. 766 and 991
- *Technical Review, Filed Comments, and Recommendations on Pepco's Major Storm Outage Plan (MSO),* 2012 – active, Office of the People's Counsel of the District of Columbia, Formal Case No. 766
- *Technical Assistance and Direct Filed Testimony for fully litigated rate case,* 2011-2012, Office of the People's Counsel of the District of Columbia, Formal Case No. 1087 – Pepco 2011 Rate Case, Hearing transcript date: February 12, 2012.
- *Evaluation of and Filed Comments on Pepco's Storm Response*, 2012, Office of the People's Counsel of the District of Columbia, Storm Dockets SO-02, 03, and 04-E-2012
- *Technical Assistance and Direct Filed Testimony for fully litigated rate cas*e, 2013 – 2014, Office of the People's Counsel of the District of Columbia, Formal Case No. 1103 – Pepco 2013 Rate Case. Hearing transcript date: November 6, 2013.
- *Evaluation of and Filed Comments on Prudency of 2011 and 2012 Storm Costs,* 2013 – 2014, State of New Jersey Division of Rate Counsel, BPU Docket No. AX13030196 and EO13070611

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TESTIMONIES & DEPOSITIONS [continued]

- *Technical Assistance and Direct Filed Testimony for DTE Acquisition of Detroit Public Lighting Department,* 2013 – 2014, Office of the State of Michigan Attorney General, Docket U-17437, Evaluation of and Filed Comments on the Siemens Management Audit of Pepco System Reliability and the Liberty Management Audit, 2014, Office of the People's Counsel of the District of Columbia, Formal Case No. 1076
- *Expert witness for personal injury case,* District of Columbia, Koontz, McKenney, Johnson, DePaolis & Lightfoot LLP, Ghafoorian v Pepco 2013 – 2016, Plaintive expert assistance regarding electric utility design. operation of distribution systems and overcurrent protection systems.
- *Technical Assistance and Direct Filed Testimony in the Matter of the Application for approval of the Triennial Underground Infrastructure Improvement Projects Plan,* 2014 – 2017, Office of the People's Counsel of the District of Columbia, Formal Case No. 1116
- *Technical Assistance and Direct Filed Testimony in the Matter of the Merger of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC and New Special Purpose Entity,* LLC, 2014 – 2016, Office of the People's Counsel of the District of Columbia, Formal Case No. 1119. Hearing transcript date: April 21, 2015.
- *Technical Assistance to Inform and advise the OPC in the matter of the investigation into modernizing the energy delivery system for increased sustainability.* 2015 – active, Office of the People's Counsel of the District of Columbia, Formal Case No 1130.
- *Technical Assistance and Direct Filed Testimony in the Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc.,* 2014 – 2016, State of Maryland and the Maryland Energy Administration, Case No. 9361.
- *Technical Assistance and Direct Filed Testimony for fully litigated rate case,* 2015 – 2016, State of Oklahoma Office of the Attorney General, Cause No. PUD 201500273 - OG&E 2016 Rate Case, Hearing transcript date: May 17, 2016.
- *Technical Assistance and Filed Comments on Notice of Inquiry, The Commission's Investigation into Electricity Quality of Service Standards and Reliability Performance,* 2016 – 2018, Office of the People's Counsel of the District of Columbia, Formal Case No. 1076; RM36-2016-01-E.
- *Technical Assistance and Direct Filed Testimony for fully litigated rate case,* 2016 – 2017, Office of the People's Counsel of the District of Columbia, Formal Case No. 1139 – Pepco 2016 Rate Case. Hearing transcript date: March 21, 2017.
- *Technical Assistance in the Matter of the Application for approval of the Biennial Underground Infrastructure Improvement Projects Plan,* 2017- active, Office of the People's Counsel of the District of Columbia, Formal Case No. 1145
- *Technical Assistance to Inform and advise the OPC Regarding Pepco's Capital Grid Project,* 2017 – active, Office of the People's Counsel of the District of Columbia, Formal Case No. 1144. Confidential Comments and Confidential Affidavit filed November 29, 2017.
- *Expert witness for personal injury case Mecklenburg County, NC, Tin, Fulton, Walker & Owen, PLLC, Norton v Duke, Witness testimony* December 1, 2017, Technical assistance and pre-filed Direct Testimony on behalf of the Joint Municipal Intervenors in a rate case before the Indiana Utility Regulatory Commission, Cause No. 44967. Testimony filed November 7, 2017.
- *Prefiled Direct Testimony and Prefiled Surrebuttal Testimony on behalf of the Vermont Department of Public Service in a case before the State of Vermont Public Utility Commission, Tariff Filing of Green Mountain Power Corp*., Case No. 18-0974-TF. Direct Testimony Filed August 10, 2018. Surrebuttal Testimony Filed October 8, 2018.

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TESTIMONIES & DEPOSITIONS [continued]

- *Technical assistance and pre-filed Direct Testimony on behalf of McCord Development, Inc. and Generation Park Management District against CenterPoint Energy Houston Electric, LLC in a case before the State Office of Administrative Hearings of Texas*, TX PUC Docket No. 48583. Direct Testimony filed April 5, 2019.
- *Technical Assistance, Direct Filed Testimony, Rebuttal Testimony, Surrebuttal Testimony, and Supplemental Testimony for fully litigated rate case,* 2019 – active, Office of the People's Counsel of the District of Columbia, Formal Case No. 1156 – Pepco 2019 Rate Case. Direct Testimony Filed March 6, 2020. Rebuttal Testimony Filed April 8, 2020. Surrebuttal Testimony Filed June 1, 2020. Supplemental Testimony filed July 27, 2020.
- *Technical assistance and pre-filed Direct Testimony on behalf of The State of Florida Public Counsel for Review of 2020-2029 Storm Protection Plan* pursuant to Rule 25-6.030, F.A.C., Docket No. 20200071-EI, Gulf Power SPP. Direct Testimony filed May 26, 2020, Florida Power& Light Company SPP. Direct Testimony filed May 28, 2020.
- *Prefiled Direct Testimony on behalf of the Vermont Department of Public Service in a case before the State of Vermont Public Utility Commission, Petition of Green Mountain Power for approval of its climate Plan pursuant to the Multi-Year Regulation Plan,* Case No. 20-0276-PET. Direct Testimony Filed May 29, 2020.
- *Technical assistance and Filed Comments on behalf of East Texas Electric Cooperative on a Proposal for Publication by the Public Utility Commission of Texas on Project 51841* Review of 16 TAC § 25.53 Relating to Electric Service Emergency Operations Plans, Project 51841. Comments filed January 4, 2022.
- *Technical assistance, filed affidavit and direct testimony on behalf of Bloomfield, NM in an action concerning Bloomfield's exercise of its right to acquire from Farmington the electric utility system serving Bloomfield, Bloomfield v Farmington, NM*. State of New Mexico, County of San Juan, Eleventh Judicial District Court Action No. D-1116-CV-1959-07581.
- *Technical assistance and pre-filed Direct Testimony on behalf of Sawnee EMC in a territorial dispute with Electrify America, Public Service Commission State of Georgia, Sawnee Electric Membership Corporation v Georgia Power Corporation,* Docket No. 43899. Direct Testimony Filed September 9, 2021
- *Prefiled Direct Testimony on behalf of the Vermont Department of Public Service in a case before the State of Vermont Public Utility Commission, Petition of Green Mountain Power for approval of a Multi-Year Rate Plan* pursuant to 30 V.S.A. Sections 209, 218, and 218d, Case No. 21-3707-PET. Direct Testimony Filed April 20, 2022.
- *Technical assistance and pre-filed Direct Testimony on behalf of The State of Florida Public Counsel for Review of Storm Protection Plans* pursuant to Rule 25-6.030, F.A.C., all testimony filed May 31, 2022
  - Docket No. 20220048-EI Tampa Electric Company
  - Docket No. 20220049-EI Florida Public Utilities Company
  - Docket No. 20220050-EI Duke Energy Florida
  - Docket No. 20220051-EI Florida Power & Light
- *Technical assistance and pre-filed Direct Testimony on behalf of The State of Florida Public Counsel for Review of Storm Protection Plan Cost Recovery Clause,* Docket No. 20220010-EI. Testimony filed September 2, 2022

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 4

QUESTION NO. 1
Referencing the testimony presented by Witness Cantler at page 5, lines 20-23 and the statement that "[t]he Company's investments during this MYP period are implemented to advance and support various Company objectives such as driving solutions to address climate change, enhancing grid performance, improving social equity and affordability, and looking for new opportunities to enhance customer experience."

a. For each of the identified objectives, explain how the Company intends to measure the Company's performance relative to the stated objective. Provide any objective criteria that the Company proposes to use to measure the success of the MYP period projects in achieving the stated objectives.

b. Provide a breakdown to the MYP projects sorted by the Company objectives that they are intended to advance and support.

c. Provide any cost-benefit analyses performed with respect to the cost of the MYP period projects and the benefits to ratepayers.

RESPONSE:

a. The Company does not have internal metrics in place for measuring the status of the identified objective. The Company's objectives, as noted on pg. 5, lines 17-23 of Company Witness Cantler's Direct Testimony are features of its capital investment strategy throughout this MYP and support a pathway to a Climate Ready Grid. As such, please see the Company's response provided for AOBA DR 1-2. The Company is committed to supporting solutions to address climate change, enhancing our grid's performance, improving social equity and affordability and looking to enhance our customers' experience.

b. The requested breakdown has not been performed. There are too many direct, indirect and tertiary benefits to certain projects to accurately ascertain and/or categorize which singular Company objective a project supports or does not support.

   However, projects, like the implementation of Advanced Distribution Management System, as referenced Pepco (H)-2 on pg. 174, are indicative of enhancing grid performance, and if granted IIJA funding would also, in turn, support affordability for our customer base through subsidization offered by a federal grant. Additionally, there are components of the Company's IT investments referenced in Pepco (H)-2 that will contribute to making energy more affordable by increasing customer participation in energy assistance and energy efficiency programs. For a full list of every project and the justification for that project work please refer to Pepco (H)-2 in its entirety.

c. The Company does not generally conduct cost-benefit analysis (CBA), though as mentioned previously, does conduct robust alternative analyses. The Company has conducted cost-benefit analysis in a few areas including: evaluating technologies or initiatives that have not previously been proposed, an initiative that has a societal benefit, or when required by the Commission or regulatory body.

   That being stated, and in an effort to be responsive to this request, the Company is currently in the process of compiling relevant information pertinent to CBAs that exist for project work specific to this MYP for a similar request related to AOBA DR 7-25. Once that information has been compiled it will be shared and made available in response.

SPONSOR: Jaclyn Cantler

pepco

A PHI Company

Peter E. Meier
Vice President, Legal Services

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April 1, 2015

Ms. Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission of the District of Columbia
1333 H Street, N.W.
2nd Floor, West Tower
Washington, DC 20005

Re: Docket PEPACR

Dear Ms. Westbrook-Sedgwick:

Enclosed please find an original and twenty-five (25) copies of Potomac Electric Power Company's Consolidated Report pursuant to Order Nos. 12735; 7668; 13812; 16975 and 17074 in the above-referenced proceedings.

Section 2.4.7 of the Electricity Quality of Service Standards ("EQSS"), provides the errata to the EQSS reports that were filed in 2014.

Please feel free to contact me if you have any questions regarding this matter.

Sincerely,

Peter E. Meier

Peter E. Meier

PEM/mda

Enclosures

cc: All Parties of Record

2015 CONSOLIDATED REPORT

- **Comprehensive Plan**
- **Productivity Improvement Plan**
- **Manhole Event Report**

Filed By

POTOMAC ELECTRIC POWER COMPANY

In accordance with

D.C. Formal Case No. 991, Order No. 12735 (Comprehensive Plan)

D.C. Formal Case No. 766, Order No. 7668 (Productivity Improvement Plan)

D.C. Formal Case No. 991, Order No. 13812 (Manhole Event Report)

D.C. Formal Case No. 766, Order No. 16975 (Consolidated Report)

D.C. Formal Case No. 991, Order No. 17074 (Consolidated Report)

D.C. Formal Case No. RM5-2014-01-E, Order No. 17684 (Consolidated Report)

and

D.C. Formal Case No. PEPACR-2014-01, Order No. 17816 (Consolidated Report)

pepco

A PHI Company

April 2015

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INTRODUCTION

Potomac Electric Power Company (Pepco) herein presents its 2015 Consolidated Report combining three reporting requirements directed by the District of Columbia Public Service Commission (Commission) in Formal Case Nos. 766 and 991. The three reports comprising the Consolidated Report are identified respectively as the Comprehensive Plan for the Planning, Design, and Operation of the Distribution System within the District of Columbia (Comprehensive Plan), the Productivity Improvement Plan (PIP), and the annual Manhole Event Report. Additionally, a section of References has been included at the end of the report.

The 2015 Consolidated Report maintains the format of the 2014 Consolidated Report. References to previous Commission directives are included in footnotes or the body of the report, as noted throughout. However, the 2015 Consolidated Report has been filed on April 1, 2015, reflecting the Commission's acceptance of Pepco's proposal, as stated in Order No. 17684.[1]

Summary

The following is a brief description of the four parts of this Report:

Part 1: Comprehensive Plan

During Commission hearings on November 5-7, 2001, addressing Formal Case No. 991, the Commission issued directives, followed by Order No. 12293, requiring the Company to produce and submit its first Comprehensive Plan on February 8, 2002. Pepco's filed report presented a compilation of major elements of its underground distribution construction and plans as well as supporting technologies and conversion programs to improve system reliability. Over the years, the Comprehensive Plan has evolved with Commission orders to

[1] *In The Matter of the Annual Consolidated Report of the Potomac Electric Power Company*, Formal Case No. RM5-2014-01-E, Order No. 17684 ("Order No. 17684") at P 3 (Oct. 27, 2014).

address current issues. In 2015, the Comprehensive Plan covers similar material to the 2014 Comprehensive Plan.

Part 2: PIP

On November 1, 1982, in Order No. 7668, the Commission adopted final rules regarding the submission of an annual PIP in Formal Case No. 766. These rules are codified in Title 15 of the District of Columbia Municipal Regulations, Chapter 5, Rules 502.1 and 502.2. Because of the divestiture or transfer to an affiliate of all of Pepco's generating stations, most of these rules are no longer applicable to Pepco's operations. Instead, this PIP was compiled pursuant to the latest requirements for Pepco to report on its transmission and distribution system operating performance and measures to improve service reliability.

Part 3: Manhole Event Report

Part 3 of the Consolidated Report is the 2014 Manhole Event Report. On June 6, 2000, the Commission issued Order No. 11716 in Case No. 991 requiring Pepco file an annual Manhole Event Report on the previous year's manhole incidents. Part 3 of the Consolidated Report includes descriptive statistics regarding reportable events, a trend analysis for slotted manhole covers, and a listing of splice data. Appendix 3A contains a listing of 2014 Manhole Events. Appendix 3B includes a discussion of the 2014 Manhole Inspection Program including annual program results. Appendix 3C contains Pepco's update on implementation of its Network Accuracy Procedure.

Part 4: References

Part 4 of the filing contains a compilation of abbreviations, acronyms, and technical terms and diagrams; and a section providing Commission Order references delineating the history of the Consolidated Report requirements.

Attachment A

Finally, Attachment A reflects the REP and Non-REP project budgets and work plans for 2015.

PART 1: 2015 COMPREHENSIVE PLAN

Since Pepco's first Comprehensive Plan was filed in 2002, the document has evolved with Commission orders addressing additional issues. In 2015, the Comprehensive Plan covers similar material to the 2014 Comprehensive Plan.

SECTION 1.1 – ELECTRIC SYSTEM OVERVIEW

Pepco has an extensive transmission and distribution electric system used to deliver energy to its customers. Pepco's transmission lines typically transmit power at 230,000 or 500,000 volts. Subtransmission lines carry the energy at 138,000, 115,000, 69,000 or 34,500 volts. The overhead or underground transmission lines deliver the energy to the load areas. Substations that are supplied by voltage levels ranging between 34,500 and 230,000 volts are generally equipped with circuit breakers, relay schemes and other equipment to isolate faulted or damaged equipment and protect the rest of the electric system.

Distribution circuits radiate from the distribution substations to supply customers. These distribution lines may exit the substation underground and then rise on utility poles to connect to the overhead distribution system. These underground 'getaway' duct banks minimize the overhead circuits in the vicinity of the substation, which may be the origin of a number of distribution feeders. Distribution lines may also deliver energy to customers using circuits completely underground. Distribution feeders are typically 13,200 or 4,160 volts.

Distribution transformers are connected to the feeders to further reduce the voltage in order to supply residential or commercial customers. Pole-type transformers are used on the overhead system, and pad-mounted or submersible transformers are used on the underground system.

Pepco serves both the District of Columbia and Maryland with an integrated system, and components residing in Maryland are important to serving District load and vice-versa. Therefore, the planning process for meeting load growth is the same across both the District and Maryland and any description of the planning process is applicable to both jurisdictions unless otherwise noted.

Pepco's distribution system delivers electricity at regulated rates to about 816,000 customers system-wide in a total service territory of approximately 640 square miles. Pepco owns and maintains approximately 4,200 circuit miles of overhead and underground primary and secondary distribution and transmission lines in the District of Columbia.

Pepco's transmission and distribution (T&D) electric system consists primarily of substations that are remotely monitored and operated from its centralized Control Center. Control Center system operations enable the safe, reliable and efficient operation of the system by performing the following:

- Monitoring and controlling the electric system to provide for the reliable operation of the transmission and distribution and bulk power system;
- Coordinating the safe operation and rapid restoration of facilities during emergency conditions;
- Evaluating transmission system outage requests to provide reliable and safe transmission operations;
- Minimizing power outages and safely resolving trouble reports and emergency calls by the effective dispatch of crews; and
- Maintaining the Outage Management System and coordinating scheduled power outages.

Pepco owns nearly 1,000 miles of transmission lines, including major portions of a 100-mile 500 kV loop that encircles the Washington, D.C. metropolitan area. Pepco is a member of the PJM Interconnection, the Regional Transmission Organization (RTO) responsible for coordinating the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. In addition PJM is responsible for the operation of the transmission system and directs the operation of Pepco's transmission system. Pepco can exchange power with its neighbors through three transmission interconnections with Potomac Edison to the west, two interconnections with Dominion Resources to the south, and seven interconnections with other PJM companies to the north and east.

Pepco's substations are capable of supplying the maximum load during peak periods and are designed to withstand the loss of one supply circuit or station transformer without loss of load.

If capacity problems arise, Pepco's system is designed to allow switching, or transfer of load, to other circuits or substations to relieve a localized problem.

The distribution system across the Pepco service area is managed based on a longstanding planning, engineering and maintenance program that closely monitors system load growth and performance. As growth occurs, work plans are issued in advance of meeting peak load conditions to add new facilities and capacity that will provide service to the existing and new load growth. The Company will continue to expand its existing approach to increase system reliability and ensure compliance with the Electricity Quality of Service Standards (EQSS) requirements.

SECTION 1.2 – SYSTEM PLANNING[2]

The mission of System Planning is to develop a rational and orderly plan for Pepco's existing and future electric system needs that will provide reliable electric service to customers and support load growth in a cost effective manner. In order to accomplish this mission, the North American Electric Reliability Corporation (NERC) / Reliability First Corporation (RFC) Standards and Pepco's Planning Criteria for the Transmission, Subtransmission, and Distribution Systems govern the design of the electric system.

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[2] The initial requirements for the Comprehensive Plan section of the Consolidated Report were delineated in hearings taking place from November 5-7, 2001. The Commission requested that the Company provide a Comprehensive Plan detailing proposed changes to the electric system for the purposes of meeting load growth or maintaining system reliability. On pages 143-144 of the hearing transcript, Pepco's Witness Gausman explained the nature of the Company's existing plans for the distribution and transmission systems:

> *We have plans for each of our substations in D.C., and in each of those plans we address the needs for that location, what the growth forecast is, what type of construction is going to be needed for expansion in the distribution system in each of those locations… Now when you go up to the transmission level or the substation supply level, there you have a plan that is addressing a larger area of the town because you're looking at the whole capacity of the system.*

The Company expanded its responses to the Commission's requests in the first filed Comprehensive Plan. Since that date, the Company's Comprehensive Plans have been expanded based on several Commission directives. The report that follows either expands upon the discussion in the initial hearings requesting the Consolidated Report or responds to subsequent Commission directives as cited below.

The following section of the report addresses system plans based on forecasted load growth.
In Order No. 12804 paragraph 53 B, the Commission stated the following:

> *53. The 2003 PIP is hereby APPROVED, provided that PEPCO:*
> *(b) Submit quarterly reports to the PIWG as well as a report in the 2004 and subsequent PIPs on its plans for implementing the recommendations for alleviating the anticipated transmission constraints identified in the RTEP report.*

Pepco continuously analyzes the adequacy of its electric system to meet demand for energy on its system and to plan for future growth. The Company maintains engineering and operating criteria to be used in the design of new and modified portions of the system. To provide for rational and orderly changes to the electric system, Pepco has developed engineering and operating criteria which it applies to the design of new and modified systems. The three major components of system planning criteria are (1) voltage and reactive support, (2) ratings of facilities, and (3) reliability. For example, voltage on a nominal 120 volt system must be maintained between 114 and 126 volts under normal conditions and between 105 and 126 volts under contingency conditions. Ratings of facilities include normal, emergency, and short-term emergency ratings on all facilities including feeders, power transformers, circuit breakers, for both summer and winter periods. In terms of reliability, the data that are reviewed and tracked include historical and forecasted load vs. capacity of the feeders, feeder groups, and substations.

1.2.1 LOAD FORECASTING[3]

Planning for future load growth starts with the development of load growth projections. Short-term, summer-peak forecasts are developed for three years to allow adequate time to complete routine 4 kV and 13 kV construction work. Long range forecasting (four to ten years) is used to develop advance plans for large 4 kV and 13 kV construction projects that require more than two or three years to complete, to develop routine and advance plans for 34.5 kV to 230 kV construction work, and to identify future capital projects in the Construction Budget Forecast process.

Forecasting begins with the examination of the summer historical loads for each feeder and substation on a two year cycle. Further, actual new customer loads from submitted class of service forms and other available development reports, planned changes in feeder configuration and emergency transfers are also analyzed. The individual feeder and feeder

[3] In the initial November 5-7, 2001 hearings requiring the production of the Comprehensive Plan, the following topics were discussed, as cited on pages 141-144 of the hearing transcript:

- *Comprehensive long-term planning on the underground system*
- *Pepco's 10-year construction plans*
- *Distribution load growth forecasts by substation*
- *Transmission/substation supply load growth forecasts*

group loads for each year are calculated and adjusted to produce the substation load predictions for each year of the plan.

Customer Growth Projections and Historical Comparisons[4]

Pepco's System Planning group forecasts electric load growth in order to plan for future additions to the electric system. Changes in the number of customers do not necessarily correspond to a similar change in load since neighborhoods containing specific types of customers may be redeveloped into ones containing different types of customers with different load usages. In addition, existing customers may increase their load, which has no effect on the customer count. Both new customer additions and increases in existing customer load are factors used in forecasting load growth. Since forecasting customer growth has little impact on the electric system planning, Pepco focuses on forecasting system load growth.

District of Columbia customer counts for six years (2009-2014) are provided on a substation basis in Table 1.2-A. Substations have been assigned to District of Columbia wards based on their location rather than the area that they serve.

Load Growth Projections and Historical Comparisons

Table 1.2-B provides six years of historical loads, Table 1.2-B-2 provides six years of previously forecasted loads for comparison to the actual historical loads recorded in Table 1.2-B-1, and Table 1.2-C provides Pepco's projections for electric load growth in the District of Columbia for 2015 to 2024. The 32 substations listed in Table 1.2-B represent all the 13 kV distribution substations and the 4 kV substations not supplied by a listed 13 kV substation within the District of Columbia. Pepco tracks and projects load by substation. Substations have been assigned to one of the eight District wards based on the substations' locations rather

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[4] In Order No. 12735 issued on May 16, 2003, the Commission directed (paragraph 139) the following:
139. PEPCO shall file the additional information not included in its expurgated comprehensive plan as outlined below, within three months of the issuance date of this Report and Order:
(a) Customer growth projections by District of Columbia wards (including historical comparisons);
(b) Load growth projections encompassing commercial and residential development by District of Columbia wards (including historical comparisons);
The summary should cover a 10-year planning horizon while historical comparisons should provide at least five years of history.

In Order No. 12804 (paragraph 53) the Commission directed the following:
53. The 2003 PIP is hereby APPROVED, provided that PEPCO:
(a) Provide the projected zonal and projected default (i.e., SOS) load data for the District of Columbia to the PIWG on a quarterly basis as well as in the 2004 and subsequent PIPs;…

than the area that they serve. Because feeders may cross ward boundaries, all feeders emanating from a substation will be assumed to supply load in the ward to which that substation is assigned.

The District has experienced uneven overall load growth from 2009 to 2014, as there are certain neighborhoods that have been growing relatively rapidly. Pepco's planning process examines historical load data on its substations and feeders, then examines prospective new business (PNB) report data to develop a short-term forecast for each feeder and substation. Pepco uses trends developed in the short-term forecasting process combined with information about long-term neighborhood development projects to determine the long-term forecast for each feeder and substation. The trend analysis also takes into consideration energy efficiency activities that customers have supported during the past year and further uses AMI data from recently constructed buildings to refine expected loadings for new buildings. Since energy efficiency activities generally result in small reductions per customer across large portions of the city, no other method can accurately predict where these reductions would occur. Developing energy usage trends will reflect these reductions in aggregate and are included in the decision-making process to determine when and where increased capacity is needed.

Accuracy of Load Forecasts[5]

The comparison of actual measured peak loads in Table 1.2-B-1 versus forecasted loads in Tables 1.2-B-2 and 1.2-B-3 reflect variances that range from 8% in 2011 to 15% in 2014. Pepco bases its historical load analysis and load forecasting on the 90/10 concept – meaning that the peak loading is predicted in such a way there is a 90% chance that a peak could fall short of the prediction and a 10% chance it could exceed the prediction. Accordingly, much of the variance in load can be explained through the fact that the summers of 2010, 2012, 2013, and 2014 were less than 90/10 load years. Year 2011 was considered a 90/10 load year based upon the number of days of extremely hot and humid weather in the District of Columbia and the large number of Pepco feeders and substations experiencing all-time peak loading. The

5 This section is included in response to the Commission directive to Pepco "to provide in its 2015 Annual Consolidated Report the five-year historical data and a discussion of variance and trends in the accuracy of these forecasts," *In The Matter of the Annual Consolidated Report of the Potomac Electric Power Company*, Formal Case No. PEPACR-2014-01, Order No. 17816 at P 169 (February 27, 2015).

reason for the 8% variance in that year was due to accumulation of error in assumed load going in service over the years between the previous 90/10 peak 2007 and the new 90/10 peak of 2011. In the past, planners used interval billing data for commercial loads to determine the amount of new customer load going into service and an assumed kilo-watts peak demand per unit of residential load. In the future, new load coming in service will be taken from AMI readings which should improve historical analysis accuracy.

A 90/10 peak is established by comparing the system peak load of the year being examined versus the peak loadings of the past ten years along with reviewing the weather occurring during the peak loading. Generally, sustained high temperatures with high humidity over three or more days are needed to generate peaking conditions. Peak loading of a 90/10 peak will be near or above the previously established peak. Once a 90/10 peak load is established, as it was in 2011, the historical loads at each substation are set to the actual measured peak load for that summer and subsequent forecasts are based off of this new baseline load, as can be seen in the reduced forecasts for years 2012 through 2014. The adjusted baseline is the actual measured peak seen by the system.

Pepco's short range forecast is generally determined by the amount of PNB load that is predicted to come on line in the next three years. Most of the load and timing information about PNBs comes from the developers who either apply for service through Pepco's class-of-service process or provide information on their projects through public announcements or disclosures. Often times developers provide aggressive timelines for when their projects will be in service and carrying load. Pepco is cautious about depending on these timelines. Thus planners continuously look at the status of each PNB during the planning process compared with the developer's proposed in-service date to make an estimate of when load will come into service, often spreading load over two or three years to account for a building not being fully-occupied upon completion. This process helps minimize the variance as well as ensure that customers in-service dates are met.

Using peak load for new PNB load coming in service does not account for the diversity in loads that is likely to occur for multiple customers. Further, reductions in load due to conservation measures, both passive and active, are not accounted for in non-90/10 years when load is calculated based on previous peak rather than on measured load. It is not possible to determine the effects of passive conservation in advance of a measured 90/10 peak, therefore effects of conservation are only accounted for once a 90/10 peak is established.

Though Pepco planners spread PNB growth over several years rather than assuming all PNB load is realized during the in service year, the forecasts prepared are appropriately conservative. Some projects will be delayed beyond the timeline of the short term forecast which affects PNB growth in an area for future years as other projects become delayed. This happened in the area around the Washington Nationals baseball stadium where much of the growth stopped from 2009-2012 following the economic downturn. Load did not grow as quickly as predicted during those years in that area leading to forecasts for the Buzzard Point substation being adjusted. However, from the number of developments currently under construction in the area around the baseball stadium, along with ongoing construction activity and measured load increases, Pepco planners are more persuaded that the area has recovered and will be undergoing significant load growth in the near future. Thus, planners will take a more aggressive approach to including PNB growth in the load forecast, again so that adequate infrastructure is in place to meet the customer in-service dates.

While the area around the baseball stadium did see reduced load growth during the years 2009-2012 as a result of the economic downturn, conversely, the NoMa area showed little slowdown in completed projects during that time. Because Pepco had a conservative forecast for that area, a new transformer was added to Northeast Sub. 212 and a new LVAC feeder group was extended in time to meet the load growth. (The variance between predicted and actual peak loading for the Benning NW Spot Network Group in 2012, a non-90/10 year, was 2.5%.)

Pepco's approach is appropriately conservative because the consequences of not building facilities to meet potential area load growth can be high as severe damage due to overloads causes extended outages to customers. Such outages would be difficult for customers, would negatively impact Pepco reliability indices, and are contrary to improving reliability. Therefore, it is critical from a reliability perspective that Pepco prepare its load forecasts assuming a 90/10 season, making baseline adjustments when necessary, and considering what is the largest amount of load growth that could reasonably occur during the forecasting period given the available data.

Discussion of Load Growth Trend Variances Affecting The L Street Substation and Mt. Vernon Square Substation Projects[6]

L Street Substation

In the 2014 Consolidated Report, the L Street Sub project called for double-legging the four 34 kV supply feeders from Buzzard Point to the L Street substation. This project was first reported in the 2012 Consolidated Report with a June 2016 in service date. Pepco's plans were based on the predicted need to relieve a predicted overload on Georgetown Sub. 12. In the 2013 ACR, the projected in-service date of this project changed to June 2019 based on revised load predictions at the Georgetown substation. In the 2014 ACR, the in-service date remained the same while the project was being reevaluated. No change was made to the project in service date until that evaluation was completed.

As discussed in Section 1.2.3 of this report, the current projection for the in service date is revised to June 2024, based on the need to replace aging infrastructure by that time. In addition, the scope of the work required was changed, and Pepco now expects to extend three new 34 kV feeders from Takoma substation rather than double-legging the feeders from Buzzard Point substation. The revised configuration will allow the aging 34 kV and 13 kV substations at Buzzard Point to be retired.

Changes in load forecasts as well as assessments of field equipment led to changes to both the in service date and scope of this project. The adjustment of in service dates and reevaluation of the overall project is an example of how Pepco's forecasting and budgeting process revisits projects annually to ensure that the projected timeframes match the load requirements.

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[6] This section includes clarifications in response to the Commission directive to Pepco to:

> [C]larify whether project descriptions, cost estimates, projected in-service dates and related data for the L Street and Mt. Vernon Square substation projects are final or subject to change. In its clarification, Pepco is to provide a showing that these projects are needed to ensure reliable electric distribution service, including a description of any aging infrastructure to be replaced and the load projections upon which additional capacity requirements are predicated. In describing these load projections, Pepco is to indicate how AMI data and/or Smart Meter data have been incorporated into the projections.

In The Matter of the Annual Consolidated Report of the Potomac Electric Power Company, Formal Case No. PEPACR-2014-01, Order No. 17816 at P 167 (February 27, 2015).

Mt. Vernon Square Substation

The load predictions for the Mt. Vernon Square substation project have been relatively consistent since the project was introduced in the 2013 CR.

Facility: Northeast Sub. 212 Southwest LVAC Group

Summer Rating = 50.0 MVA

	2015 Anticipated	2016 Anticipated	2017 Anticipated	2018 Anticipated	2019 Anticipated	2020 Anticipated	2021 Anticipated	2022 Anticipated
2015 ACR	38.7	40.3	43.5	46.6	49.2	52.0	54.5	56.6
2014 ACR	41.0	42.1	43.6	46.8	48.6	51.2	53.2	55.1
2013 ACR	41.6	44.3	46.5	48.8	50.9	53.1	55.2	57.5

<u>Forecasted Loads for Northeast Sub. 212 SW LVAC Group from Past Three ACRs</u>

The amount of development currently occurring in the Mt. Vernon Triangle area, including Capitol Crossing, is evidence that the existing load forecast is in line with actual and developing load. As previously stated, the ten year forecast is conducted each year and a reduction in the forecast could lead to a deferral of the Mt. Vernon substation if warranted.

Incorporation of Field Information into the Planning Process[7]

Pepco's planning process incorporates equipment condition assessments (ECA) and other field information into its short-term and long-range plans, when applicable. The planning group creates long-range plans to upgrade or replace utility infrastructure evaluated to be approaching end-of-life.

The planning group is an active participant in ECA meetings and is the sponsor of substation transformer and switchgear replacement projects. The planning group participates in decision making regarding actions to take when equipment is evaluated to be near end-of-life, including whether to replace the equipment in kind or through a new capital project. The decision

[7] Order No. 16975 states the following at paragraphs 89 and 116:

89. Decision: The Commission believes that OPC's recommendation has merit. However, we understand that equipment condition assessments may be included within the distribution system planning process, as shown in the description of the Pepco Planning Process provided by OPC at "Existing System Analysis." We direct Pepco to explain in the 2013 Consolidated Report the extent to which field information is considered within "Existing System Analysis."

116. Pepco is DIRECTED to provide field information consistent with paragraph 89 herein;

depends upon how close to failure a piece of equipment is evaluated to be, what other load-driven or reliability-driven capital projects are in the area, and the age and condition of other equipment in the substation.

An example of a condition assessment being incorporated into the planning process is the proposed 34 kV feeder extension project to L Street Substation 21 in order to increase capacity at the station. Originally, the project scope was to double-leg existing 34 kV feeders from Buzzard Point Sta. B. However, assessments of Buzzard Point facility determined that it is in deteriorating condition, and it would not be economically feasible to rebuild the 34 kV substation there for the sole purpose of supplying L Street Substation 21. Therefore, the decision was made to extend 34 kV feeders from Takoma Substation 27.

D.C. Historical Customer Counts per Substation

			2009			2010			2011			2012			2013			2014			2009 - 2014 Avg. Trend		
Ward 1	Substation Number	KVLEV	Res.	Comm.	Total	Res.	Comm.	Total	Res.	Comm.	Total	Res.	Comm.	Total	Res.	Comm.	Total	Res.	Comm.	Total	Res.	Comm.	Total
	10	13.8	15488	1335	16823	15627	1339	16966	16777	1372	18149	18261	1604	19865	17111	1295	18406	19764	1555	21319			
	13 (4kV)	4.33	4584	444	5028	4651	444	5095	4550	410	4960	3985	355	4340	5117	523	5640	2958	290	3248			
	13 (13kV)	13.8	7390	639	8029	7473	638	8111	7575	645	8220	7763	632	8395	7705	675	8380	7616	664	8280			
	25	13.8	9345	1205	10550	9021	1192	10213	9518	1213	10731	9473	1185	10658	9578	1172	10750	9924	1154	11078			
	Subtotal - Ward 1		**36807**	**3623**	**40430**	**36772**	**3613**	**40385**	**38420**	**3640**	**42060**	**39482**	**3776**	**43258**	**39511**	**3665**	**43176**	**40262**	**3663**	**43925**	**1.81%**	**0.22%**	**1.67%**
Ward 2	Substation Number	KVLEV																					
	2	13.8	8775	1858	10633	8817	1829	10646	8820	1832	10652	8902	1814	10716	8770	1815	10585	9155	1804	10959			
	12	13.8	6480	1594	8074	6416	1595	8011	6482	1587	8069	6437	1551	7988	6366	1529	7895	6208	1429	7637			
	18	13.8	5918	1140	7058	5911	1135	7046	5919	1163	7082	3538	625	4163	3437	605	4042	3394	565	3959			
	21	13.8	44	225	269	44	174	218	44	229	273	44	228	272	42	218	260	42	223	265			
	52	13.8	6637	1279	7916	6890	1288	8178	7024	1332	8356	7118	1341	8459	7017	1330	8347	7109	1326	8435			
	74	13.8	4	19	23	4	20	24	4	19	23	4	18	22	4	20	24	4	19	23			
	124	13.8	2689	1094	3783	2701	1100	3801	2720	1102	3822	2718	1087	3805	2729	1077	3806	2775	1075	3850			
	197	13.8	173	651	824	174	575	749	429	619	1048	481	621	1102	459	619	1078	469	609	1078			
	Subtotal - Ward 2		**30720**	**7860**	**38580**	**30957**	**7716**	**38673**	**31442**	**7883**	**39325**	**29242**	**7285**	**36527**	**28824**	**7213**	**36037**	**29156**	**7050**	**36206**	**-1.04%**	**-2.15%**	**-1.26%**
Ward 3	Substation Number	KVLEV																					
	38 (13kV)	13.8	5801	373	6174	5302	360	5662	5399	359	5758	5361	361	5722	5323	371	5694	5538	383	5921			
	38-5 (4kV)	4.33	409	12	421	432	19	451	377	11	388	343	10	353	299	12	311	148	3	151			
	77	13.8	5301	521	5822	5279	518	5797	5912	549	6461	6112	562	6674	6525	620	7145	6175	587	6762			
	93	4.33	880	23	903	882	26	908	865	20	885	868	20	888	821	18	839	728	15	743			
	129	13.8	16958	1368	18326	16896	1358	18254	16975	1362	18337	16841	1324	18165	16716	1378	18094	17109	1357	18466			
	145	4.33	374	34	408	373	32	405	375	34	409	366	33	399	360	36	396	358	37	395			
	146	4.33	638	18	656	644	18	662	639	17	656	639	16	655	636	18	654	618	14	632			
	Subtotal - Ward 3		**30361**	**2349**	**32710**	**29808**	**2331**	**32139**	**30542**	**2352**	**32894**	**30530**	**2326**	**32856**	**30680**	**2453**	**33133**	**30674**	**2396**	**33070**	**0.21%**	**0.40%**	**0.22%**
Ward 4	Substation Number	KVLEV																					
	27	13.8	9732	698	10430	9720	697	10417	9731	713	10444	9144	675	9819	9021	708	9729	8781	683	9464			
	190	13.8	18500	1452	19952	18950	1467	20417	19329	1469	20798	19967	1469	21436	19836	1541	21377	20030	1542	21572			
	Subtotal - Ward 4		**28232**	**2150**	**30382**	**28670**	**2164**	**30834**	**29060**	**2182**	**31242**	**29111**	**2144**	**31255**	**28857**	**2249**	**31106**	**28811**	**2225**	**31036**	**0.41%**	**0.69%**	**0.43%**
Ward 5	Substation Number	KVLEV																					
	133	13.8	15677	1864	17541	14721	1775	16496	14806	1740	16546	15750	1850	17600	15137	1767	16904	16534	1819	18353			
	212	13.8	3365	125	3490	4823	270	5093	4851	312	5163	6383	409	6792	8325	447	8772	8680	407	9087			
	Subtotal - Ward 5		**19042**	**1989**	**21031**	**19544**	**2045**	**21589**	**19657**	**2052**	**21709**	**22133**	**2259**	**24392**	**23462**	**2214**	**25676**	**25214**	**2226**	**27440**	**5.78%**	**2.28%**	**5.46%**
Ward 6	Substation Number	KVLEV																					
	Sta. 'B'	13.8	8012	821	8833	8112	830	8942	9080	801	9881	11751	1313	13064	12147	1352	13499	12462	1344	13806			
	33	13.8	0	2	2	0	2	2	0	2	2	0	2	2	0	2	2	0	2	2			
	117	13.8	1331	391	1722	1320	376	1696	1325	369	1694	1228	364	1592	1178	374	1552	1233	357	1590			
	161	13.8	3097	637	3734	3050	650	3700	3214	653	3867	3334	664	3998	3346	677	4023	3371	670	4041			
	Subtotal - Ward 6		**12440**	**1851**	**14291**	**12482**	**1858**	**14340**	**13619**	**1825**	**15444**	**16313**	**2343**	**18656**	**16671**	**2405**	**19076**	**17066**	**2373**	**19439**	**6.53%**	**5.09%**	**6.35%**
Ward 7	Substation Number	KVLEV																					
	98	4.33	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0			
	7	13.8	39895	3569	43464	39264	3491	42755	39410	3496	42906	38684	3450	42134	39124	3555	42679	39640	3493	43133			
	Subtotal - Ward 7		**39895**	**3569**	**43464**	**39264**	**3491**	**42755**	**39410**	**3496**	**42906**	**38684**	**3450**	**42134**	**39124**	**3555**	**42679**	**39640**	**3493**	**43133**	**-0.13%**	**-0.43%**	**-0.15%**
Ward 8	Substation Number	KVLEV																					
	8 (4kV)	4.33	1152	199	1351	419	134	553	539	147	686	382	93	475	341	94	435	329	94	423			
	8 (13kV)	13.8	6963	859	7822	8136	941	9077	8216	935	9151	8528	964	9492	8601	984	9585	7098	846	7944			
	136	13.8	13373	1107	14480	13386	1097	14483	13402	1115	14517	13418	1139	14557	13079	1169	14248	14641	1302	15943			
	168	13.8	5280	622	5902	5195	599	5794	5288	627	5915	5348	628	5976	5165	635	5800	5226	622	5848			
	Subtotal - Ward 8		**26768**	**2787**	**29555**	**27136**	**2771**	**29907**	**27445**	**2824**	**30269**	**27676**	**2824**	**30500**	**27186**	**2882**	**30068**	**27294**	**2864**	**30158**	**0.39%**	**0.55%**	**0.40%**
	DC TOTAL		**224265**	**26178**	**250443**	**224633**	**25989**	**250622**	**229595**	**26254**	**255849**	**233171**	**26407**	**259578**	**234315**	**26636**	**260951**	**238117**	**26290**	**264407**	**1.21%**	**0.09%**	**1.09%**

Table 1.2-A

Historical District of Columbia Loads

Loads in Mega-Volt-Amperes (MVA)

Ward 1	**Sub. Number**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**		
	10	91.9	97.0	101.8	97.4	103.0	135.4		
	13 (4.33kV)	13.3	15.1	15.6	14.0	11.0	10.0		
	13	33.4	32.8	36.0	34.0	33.0	32.5		
	25	39.7	46.2	46.2	44.3	43.5	40.1		
	Subtotal - Ward 1	**178.3**	**191.1**	**199.6**	**189.7**	**190.5**	**218.0**	Avg. Trend =	4.10%
Ward 2	**Sub. Number**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**		
	2	165.1	168.4	174.4	165.7	166.5	159.1		
	12	119.1	115.6	119.6	111.6	111.6	104.8		
	18	138.1	143.0	148.5	138.3	142.1	129.7		
	21	37.7	38.6	38.7	37.0	38.5	36.5		
	52	176.8	182.0	183.2	178.9	178.9	177.4		
	74	49.2	50.7	51.0	46.9	48.6	48.1		
	124	107.4	107.0	111.4	104.0	105.5	103.2		
	197	121.2	125.4	127.4	124.9	123.6	120.5		
	Subtotal - Ward 2	**914.6**	**930.7**	**954.2**	**907.3**	**915.3**	**879.3**	Avg. Trend =	-0.78%
Ward 3	**Sub. Number**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**		
	38	48.8	54.2	50.6	52.1	52.6	46.1		
	38 (4.33kV)	2.4	2.8	3.4	3.3	3.5	3.9		
	77	61.5	71.0	71.4	68.1	73.3	67.0		
	93 (4.33kV)	4.5	4.2	4.5	3.5	4.6	4.0		
	129	153.4	162.7	169.7	164.3	163.8	150.2		
	145 (4.33kV)	3.9	3.9	3.9	3.1	2.7	2.8		
	146 (4.33kV)	3.1	3.8	4.4	3.5	4.2	4.0		
	Subtotal - Ward 3	**277.6**	**302.6**	**307.9**	**297.9**	**304.7**	**278.0**	Avg. Trend =	0.03%
Ward 4	**Sub. Number**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**		
	27	38.8	43.4	39.7	39.4	38.3	36.6		
	190	85.3	96.6	99.7	89.3	87.5	80.7		
	Subtotal - Ward 4	**124.1**	**140.0**	**139.4**	**128.7**	**125.8**	**117.3**	Avg. Trend =	-1.12%
Ward 5	**Sub. Number**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**		
	133	127.1	129.5	136.5	126.4	129.6	99.1		
	212	31.7	40.1	42.6	75.1	79.7	79.9		
	Subtotal - Ward 5	**158.8**	**169.6**	**179.1**	**201.5**	**209.3**	**179.0**	Avg. Trend =	2.42%
Ward 6	**Sub. Number**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**		
	Sta. 'B'	108.8	112.9	112.3	123.3	124.9	118.7		
	33	18.8	18.0	18.9	18.2	17.0	16.3		
	117	128.8	116.8	119.6	112.0	111.2	108.5		
	161	113.4	116.5	116.3	113.2	113.2	109.5		
	Subtotal - Ward 6	**369.8**	**364.2**	**367.1**	**366.7**	**366.3**	**353.0**	Avg. Trend =	-0.93%
Ward 7	**Sub. Number**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**		
	7	176.7	189.0	201.3	166.8	165.9	160.7		
	Subtotal - Ward 7	**176.7**	**189.0**	**201.3**	**166.8**	**165.9**	**160.7**	Avg. Trend =	-1.88%
Ward 8	**Sub. Number**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**		
	8 (4.33kV)	4.6	3.4	3.6	2.7	1.6	1.5		
	8	29.0	31.0	32.5	32.2	32.2	25.8		
	136	72.7	78.2	83.1	78.9	77.4	80.6		
	168	22.1	23.1	23.8	22.1	20.9	21.6		
	Subtotal - Ward 8	**128.4**	**135.7**	**143.0**	**135.9**	**132.1**	**129.5**	Avg. Trend =	0.17%
	DC TOTAL	**2328.3**	**2422.9**	**2491.6**	**2394.5**	**2409.9**	**2314.8**	Avg. Trend =	-0.12%

Notes: All substations supply 13.8kV of primary power unless otherwise noted.
Loads shown are actual readings taken during peak summer conditions.
Totals shown are the sum of undiversified peak loads and are not meant to be used as official Pepco system peak loads.
Trends shown are based on the straight line regression of the loads and include transfers amongst the substations.

Table 1.2-B

Previously Forecasted District of Columbia Loads

Loads in Mega-Volt-Amperes (MVA)

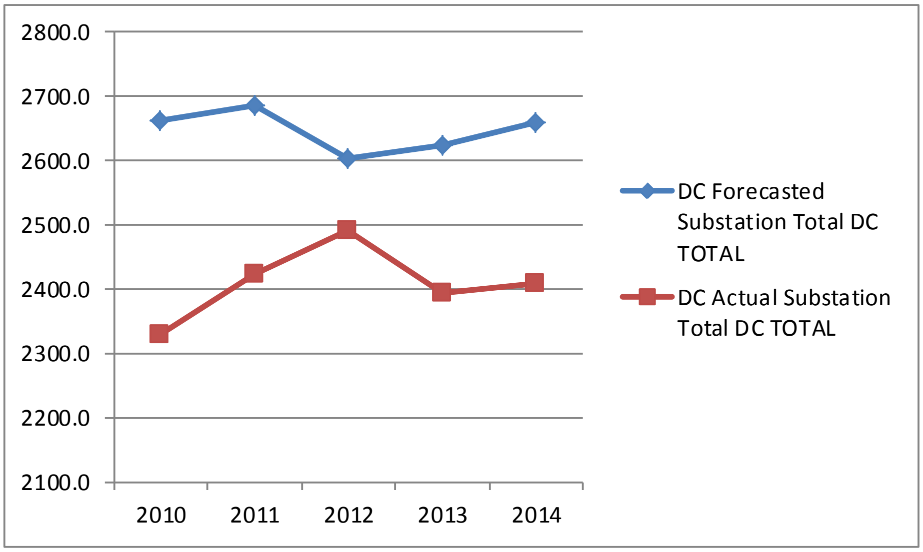
Ward 1	**Sub. Number**	**2010 (1)**	**2011 (2)**	**2012 (3)**	**2013 (4)**	**2014 (5)**		
	10	124.9	114.8	113.1	112.2	147.9		
	13 (4.33kV)	6.8	15.2	14.1	10.7	4.5		
	13	37.4	37.0	36.0	35.8	37.0		
	25	50.5	49.8	46.5	47.1	55.7		
	Subtotal - Ward 1	**219.6**	**216.8**	**209.7**	**205.8**	**245.1**	Avg. Trend =	2.78%
Ward 2	**Sub. Number**	**2010 (1)**	**2011 (2)**	**2012 (3)**	**2013 (4)**	**2014 (5)**		
	2	190.6	189.3	183.8	177.7	180.9		
	12	129.4	127.8	124.6	122.7	122.9		
	18	148.1	152.0	140.0	150.4	146.9		
	21	49.4	50.6	43.1	43.7	40.6		
	52	193.9	195.4	196.0	192.0	199.8		
	74	51.8	55.7	53.4	55.6	54.2		
	124	117.1	117.9	114.2	117.6	115.0		
	197	134.7	137.9	131.1	137.1	134.5		
	Subtotal - Ward 2	**1015.0**	**1026.6**	**986.2**	**996.8**	**994.8**	Avg. Trend =	-0.50%
Ward 3	**Sub. Number**	**2010 (1)**	**2011 (2)**	**2012 (3)**	**2013 (4)**	**2014 (5)**		
	38	51.5	51.7	54.1	54.4	52.1		
	38 (4.33kV)	2.8	2.8	2.7	2.6	2.7		
	77	79.8	81.7	77.0	77.5	79.4		
	93 (4.33kV)	3.9	3.9	3.8	4.0	4.0		
	129	160.2	163.7	170.6	173.5	174.9		
	145 (4.33kV)	3.9	3.9	3.1	3.1	3.1		
	146 (4.33kV)	3.6	3.6	3.3	3.5	3.5		
	Subtotal - Ward 3	**305.7**	**311.3**	**314.6**	**318.6**	**319.7**	Avg. Trend =	1.13%
Ward 4	**Sub. Number**	**2010 (1)**	**2011 (2)**	**2012 (3)**	**2013 (4)**	**2014 (5)**		
	27	35.8	41.8	40.8	38.6	34.8		
	190	108.7	103.4	101.9	97.6	101.6		
	Subtotal - Ward 4	**144.5**	**145.2**	**142.7**	**136.2**	**136.4**	Avg. Trend =	-1.43%
Ward 5	**Sub. Number**	**2010 (1)**	**2011 (2)**	**2012 (3)**	**2013 (4)**	**2014 (5)**		
	133	135.5	135.2	135.5	130.5	113.9		
	212	56.0	51.8	87.3	97.5	99.6		
	Subtotal - Ward 5	**191.5**	**187.0**	**222.8**	**228.0**	**213.5**	Avg. Trend =	2.76%
Ward 6	**Sub. Number**	**2010 (1)**	**2011 (2)**	**2012 (3)**	**2013 (4)**	**2014 (5)**		
	Sta. 'B'	144.5	155.6	142.4	142.0	149.5		
	33	18.9	17.8	18.3	19.0	18.5		
	117	136.1	130.9	126.0	122.3	119.8		
	161	127.9	127.5	125.5	124.9	119.1		
	Subtotal - Ward 6	**427.4**	**431.8**	**412.2**	**408.2**	**406.9**	Avg. Trend =	-1.22%
Ward 7	**Sub. Number**	**2010 (1)**	**2011 (2)**	**2012 (3)**	**2013 (4)**	**2014 (5)**		
	7	208.4	213.0	174.5	186.1	188.3		
	Subtotal - Ward 7	**208.4**	**213.0**	**174.5**	**186.1**	**188.3**	Avg. Trend =	-2.50%
Ward 8	**Sub. Number**	**2010 (1)**	**2011 (2)**	**2012 (3)**	**2013 (4)**	**2014 (5)**		
	8 (4.33kV)	3.4	2.2	1.6	1.6	1.6		
	8	38.0	21.4	18.3	18.9	16.6		
	136	82.0	105.7	96.9	96.5	113.7		
	168	25.7	23.6	23.8	27.2	24.0		
	Subtotal - Ward 8	**149.1**	**152.9**	**140.6**	**144.2**	**155.9**	Avg. Trend =	1.12%
	DC TOTAL	**2661.2**	**2684.6**	**2603.3**	**2623.9**	**2660.6**	Avg. Trend =	-0.01%
Variance from Forecasted to Actual		**10%**	**8%**	**9%**	**9%**	**15%**		

Notes: All substations supply 13.8kV of primary power unless otherwise noted.
Trends shown are based on the straight line regression of the loads and include transfers amongst the substations.
(1) Forecasted loads from the 2010 Consolidated Report - Table 2.2-C
(2) Forecasted loads from the 2011 Consolidated Report - Table 2.2-C
(3) Forecasted loads from the 2012 Consolidated Report - Table 2.2-C
(4) Forecasted loads from the 2013 Consolidated Report - Table 2.2-C
(5) Forecasted loads from the 2014 Consolidated Report - Table 2.2-C

Table 1.2-B-2

Comparison of Forecasted Loads versus Actual Loads

Loads in Mega-Volt-Amperes (MVA)



	2010	2011	2012	2013	2014	
DC Forecasted Substation Total	**2661.2**	**2684.6**	**2603.3**	**2623.9**	**2660.6**	Avg. Trend = -0.01%
DC Actual Substation Total	**2328.3**	**2422.9**	**2491.6**	**2394.5**	**2409.9**	Avg. Trend = -0.12%
Variance from Forecasted to Actual	**10%**	**8%**	**9%**	**9%**	**15%**	

Notes: All substations supply 13.8kV of primary power unless otherwise noted.
Trends shown are based on the straight line regression of the loads
2010 Forecasted loads from the 2010 Consolidated Report - Table 2.2-C
2011 Forecasted loads from the 2011 Consolidated Report - Table 2.2-C
2012 Forecasted loads from the 2012 Consolidated Report - Table 2.2-C
2013 Forecasted loads from the 2013 Consolidated Report - Table 2.2-C
2014 Forecasted loads from the 2014 Consolidated Report - Table 2.2-C

Table 1.2-B-3

Forecasted District of Columbia Loads

Loads in Mega-Volt-Amperes (MVA)

Ward	Sub. Number	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	
Ward 1	**Sub. Number**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	
	10	153.0	148.3	151.5	154.6	157.4	160.1	162.6	165.2	168.3	171.4	
	13 (4.33kV)	2.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	13	35.1	38.1	38.9	39.6	40.2	40.7	41.1	41.7	42.3	42.9	
	25	56.1	57.2	57.9	58.5	59.0	59.4	59.6	60.0	60.5	61.0	
	Subtotal - Ward 1	**246.6**	**243.6**	**248.3**	**252.7**	**256.6**	**260.2**	**263.3**	**266.9**	**271.1**	**275.3**	
											Avg. Trend =	1.23%
Ward 2	**Sub. Number**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	
	2	178.7	179.6	182.3	185.0	187.3	189.4	191.2	193.1	195.7	198.3	
	12	124.0	125.1	125.7	126.8	127.7	128.6	129.7	130.6	131.7	132.8	
	18	156.0	159.9	161.7	163.4	164.8	166.0	167.0	168.1	170.0	171.9	
	21	40.6	41.8	42.4	43.1	43.7	44.2	44.7	45.2	45.8	46.5	
	52	200.1	186.2	187.4	190.9	194.0	196.9	199.5	202.2	205.0	208.6	
	74	44.5	45.6	46.3	47.0	47.6	48.2	48.7	49.2	49.9	50.6	
	124	115.0	116.9	118.4	119.9	121.1	122.2	123.1	124.1	125.5	127.0	
	197	129.6	132.8	134.6	136.3	137.8	139.2	140.5	141.9	143.7	145.8	
	Subtotal - Ward 2	**988.5**	**987.9**	**998.8**	**1012.4**	**1024.0**	**1034.7**	**1044.4**	**1054.4**	**1067.3**	**1081.5**	
											Avg. Trend =	1.00%
Ward 3	**Sub. Number**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	
	38	48.4	49.2	50.1	51.0	51.7	52.3	52.9	53.5	54.3	55.1	
	38 (4.33kV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	77	78.0	79.8	80.8	81.8	82.6	83.3	83.9	84.5	85.3	86.2	
	93 (4.33kV)	3.5	3.5	3.6	3.7	3.7	3.8	3.8	3.8	3.9	3.9	
	129	177.3	181.9	182.8	185.0	186.8	188.4	189.8	191.3	193.3	195.4	
	145 (4.33kV)	3.1	3.1	3.1	3.2	3.3	3.3	3.4	3.4	3.5	3.6	
	146 (4.33kV)	6.0	6.0	6.1	6.1	6.2	6.3	6.3	6.4	6.4	6.5	
	Subtotal - Ward 3	**316.3**	**323.5**	**326.5**	**330.8**	**334.3**	**337.4**	**340.1**	**342.9**	**346.7**	**350.7**	
											Avg. Trend =	1.15%
Ward 4	**Sub. Number**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	
	27	36.2	32.7	33.3	33.8	34.3	34.7	35.1	35.5	36.0	36.5	
	190	103.2	110.8	112.3	113.6	114.7	115.7	116.6	117.4	118.6	119.9	
	Subtotal - Ward 4	**139.4**	**143.5**	**145.6**	**147.4**	**149.0**	**150.4**	**151.7**	**152.9**	**154.6**	**156.4**	
											Avg. Trend =	1.29%
Ward 5	**Sub. Number**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	
	133	117.3	121.4	123.4	125.4	127.2	128.9	130.4	131.9	133.8	135.8	
	212	109.6	155.2	159.7	164.2	168.4	172.5	176.2	180.0	184.4	188.7	
	Subtotal - Ward 5	**226.9**	**276.6**	**283.1**	**289.6**	**295.6**	**301.4**	**306.6**	**311.9**	**318.2**	**324.5**	
											Avg. Trend =	4.06%
Ward 6	**Sub. Number**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	
	Sta. 'B'	153.1	161.3	171.3	176.2	180.6	184.7	188.1	191.9	197.0	201.0	
	33	18.5	18.7	18.8	18.9	19.0	19.1	19.2	19.3	19.4	19.5	
	117	120.9	121.7	123.6	125.5	127.2	128.8	130.2	131.6	133.5	135.5	
	161	119.6	122.1	124.1	126.0	127.7	129.3	130.7	132.2	134.1	136.1	
	Subtotal - Ward 6	**412.1**	**423.8**	**437.8**	**446.6**	**454.5**	**461.9**	**468.2**	**475.0**	**484.0**	**492.1**	
											Avg. Trend =	1.99%
Ward 7	**Sub. Number**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	
	7	193.3	197.9	199.9	201.9	203.9	205.7	207.3	209.0	212.2	215.0	
	Subtotal - Ward 7	**193.3**	**197.9**	**199.9**	**201.9**	**203.9**	**205.7**	**207.3**	**209.0**	**212.2**	**215.0**	
											Avg. Trend =	1.19%
Ward 8	**Sub. Number**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	
	8 (4.33 kV)	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	8 (13.8 kV)	16.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	136	120.0	150.2	152.1	154.1	155.6	157.0	158.2	159.4	160.8	162.9	
	168	24.1	24.2	24.6	25.0	25.3	25.6	25.9	26.2	26.6	27.0	
	Subtotal - Ward 8	**162.3**	**174.4**	**176.7**	**179.1**	**180.9**	**182.6**	**184.1**	**185.6**	**187.4**	**189.9**	
											Avg. Trend =	1.76%
	DC TOTAL	**2685.4**	**2771.2**	**2816.7**	**2860.5**	**2898.8**	**2934.3**	**2965.7**	**2998.6**	**3041.5**	**3085.4**	
											Avg. Trend =	1.55%

Notes: All substations supply 13.8kV of primary power unless otherwise noted.
Totals shown are the sum of undiversified peak loads and are not meant to be used as official Pepco system peak loads.
Totals shown for first two years include planned transfers, the last eight years do not show planned transfers.

Table 1.2-C

On a system basis, Pepco's control area loads over the ten-year period between 2005 and 2014 are provided below in Figure 1.2-A.

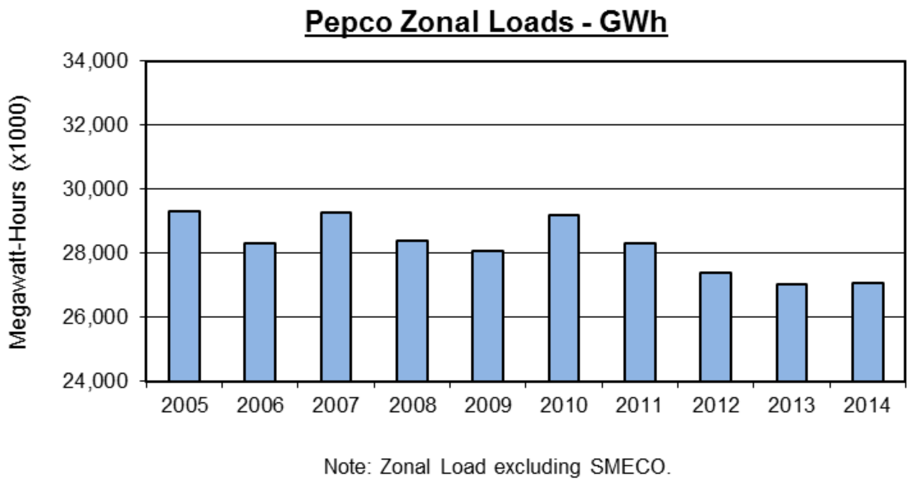


Figure 1.2-A

Pepco's projected monthly and annual zonal loads for 2015 are provided in Table 1.2-D. Pepco's zonal loads are for the Pepco distribution system (Maryland and District of Columbia), excluding the Southern Maryland Electric Cooperative (SMECO) and include demands for Pepco distribution customers.

2015 Forecast -- Pepco Zonal Load* (x 1,000)												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
MWh	2,219	2,110	1,965	1,812	1,916	2,244	2,420	2,400	2,170	1,898	1,964	2,207	25,323
*Excludes SMECO load													

Table 1.2-D Pepco Zonal Load

1.2.2 POWER FACTORS AND ENERGY LOSSES[8]

Power Factors

The power factor provides one measure of how efficiently Pepco's electric system is being used. Substation load has two components: real power (kilowatts) and reactive power (kilovars). Real power is the power which serves the customers' end-use electrical devices. Reactive power does not serve customer requirements but decreases the substation's ability to deliver real power and increases system losses. This reduced ability to deliver real power is based on a substation's power delivery limitations. The power delivered is a combination of reactive and real power, so the greater the reactive power, the lower the real power that can be delivered. As the system power factor approaches unity, real power delivered is greater and system losses due to reactive power are reduced. By making appropriate use of capacitors, the reactive power flow on the electric system can be reduced such that it approaches zero. (When the reactive power flow is zero, the power factor is unity (*i.e.*, 1.0).) A unity power factor would be ideal and would result in the maximum usable power being delivered to the customers. However, a unity power factor is not technically or economically practical to maintain because of changing loads and system conditions.

[8] In Order No. 10133, the Commission directed Pepco to include performance factors relating to the transmission and distribution (T&D) system in future PIPs.

> *"PEPCO…was directed to…provide in future PIP reports forecasts of plant performance factors which are based on analyses of both the projected performance and the prior year's actual performance"(page 10, Section B).*
>
> *"…the Commission finds it entirely appropriate to include performance measures for PEPCO's transmission and distribution in the mix of issues examined by the PIWG and reported in the PIP"(page 12, third paragraph).*

By way of compliance with the above requirements, in the September 1993 PIWG Meeting, Pepco proposed reporting performance data on its 13 kV distribution substation power factors.

Pepco plans for a 98% (.98) power factor or higher on its 4 kV and 13 kV distribution substations at the summer peak. Table 1.2-E below provides the percent of all Pepco's 4 kV and 13 kV distribution substations that had power factors ≥ 98% at the summer peak hour for the years 2007 - 2014. In 2014, 97% of the 4 kV and 13 kV substations in the District of Columbia had a power factor of ≥ 0.98 at the summer peak hour.

% of Pepco Substations with Power Factors
Greater than 98% on Peak Summer Days
(System-wide)

	2007	2008	2009	2010	2011	2012	2013	2014
% of 4 kV and 13 kV Substations with Power Factor ≥ 0.98	92%	93%	94%	96%	95%	96%	97%	97%
Total Number of 4 kV and 13 kV Distribution Substations (Pepco system-wide)	116	117	116	116	116	116	115	115

Table 1.2-E: Power Factor

Annual System Energy Losses[9]

Table 1.2-F shows a ten-year comparison of annual system energy losses for PJM and adjacent utilities. Data for 2004 through 2013 were obtained from the Federal Energy Regulatory Commission (FERC) web site. All data are from FERC Form 1. A comparison of annual system energy losses over the past ten years is provided for PJM utilities and utilities adjacent to the Pepco service territory. Pepco's system energy losses for 2013 are 2.71% or approximately52% better than the group average of 5.62%.

% Annual System Energy Losses:

$$\%\ \text{Annual System Energy Losses} = \left(\frac{\text{Total Energy Losses (FERC Form 1, Line 27, page 401a)}}{\text{Total Energy (FERC Form 1, Line 28, page 401a)}} \right) \text{X } 100$$

Industry Comparison

Annual System Energy Losses (% of Total Energy)
2004 - 2013

UTILITY	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Atlantic City Electric Company	8.20%	10.32%	5.63%	5.07%	4.44%	4.94%	4.63%	5.61%	5.52%	5.15%
Baltimore Gas & Electric Co. #	6.09%	5.42%	5.33%	5.69%	6.61%	6.27%	5.77%	6.41%	6.17%	6.51%
Delmarva Power & Light Co.	6.42%	7.84%	6.99%	6.81%	5.03%	5.16%	5.25%	5.54%	4.52%	7.26%
Jersey Central Power & Light Co.	7.11%	5.94%	5.88%	7.87%	5.22%	5.07%	5.59%	6.35%	5.71%	8.39%
Metropolitan Edison Company	7.88%	6.64%	5.82%	4.69%	5.49%	5.37%	4.87%	4.71%	6.21%	5.30%
Pennsylvania Electric Company	9.55%	8.98%	9.55%	5.83%	4.94%	4.54%	5.45%	5.90%	6.08%	7.12%
PPL Electric Utilities Corp.	6.66%	6.82%	6.94%	6.69%	6.58%	6.04%	6.93%	6.55%	6.58%	6.66%
PECO Energy Company	6.72%	6.27%	5.36%	5.38%	4.68%	4.98%	5.25%	4.23%	5.67%	5.81%
Potomac Edison Company #	4.98%	4.59%	5.63%	5.38%	4.82%	3.81%	4.28%	2.07%	4.79%	5.12%
Potomac Electric Power Co.	5.54%	4.99%	5.52%	5.30%	4.55%	4.51%	4.38%	4.14%	4.12%	2.71%
Public Service Electric & Gas	5.65%	6.26%	6.26%	4.89%	4.56%	4.60%	4.13%	4.86%	3.99%	5.32%
Virginia Electric & Power Co. #	4.64%	4.24%	4.25%	3.38%	1.92%	2.63%	3.97%	3.12%	1.65%	2.07%
ANNUAL AVG.	**6.62%**	**6.53%**	**6.10%**	**5.58%**	**4.90%**	**4.83%**	**5.04%**	**4.96%**	**5.09%**	**5.62%**

Table 1.2-F Annual System Energy Losses

[9] Industry comparison of annual system energy losses is presented in Table 1.2-F.

1.2.3 SUBSTATION ADDITIONS AND ENHANCEMENTS[10] [11]

The discussion below updates the information provided in the 2014 Consolidated Report. All planning data is based on current information, and may be revised as the Company receives new information affecting the costs, timing, or necessity of projects.

[10] In the initial November 5-7, 2001 hearings requiring the production of the Comprehensive Plan, Commissioner Meyers stated the following (page 266 of the hearing transcript):

> *But what we were talking about here yesterday was that the comprehensive plan would include… any rebuilt substations you might have; any new substations you might have…*

[11] Order No. 16975 states the following at paragraphs 50 and 101:

> *50. Decision: …Consequently, we require Pepco to include a report on substation additions and enhancements in future Consolidated Reports. In addition to the information provided in the 2012 Consolidated Report, the Commission requires that Pepco provide details concerning the justification for these projects, including, as applicable, load growth projections and equipment age and condition in future Consolidated Reports.*
>
> *101. Pepco is DIRECTED to provide a report on substation additions and enhancements consistent with paragraph 50 herein;*

Table 1.2-G shows Pepco's planned substation additions and enhancements for the District of Columbia with their anticipated in service dates.

#	Project Cost	Project Description	Projected Date Required	Areas Served
1	**$21.6 million**	**Florida Ave Sub. –** Install 4th transformer to relieve predicted substation overload.	Completed	Shaw, Mt. Vernon Square/Convention Center
2	**$21.1 million**	**Northeast Sub. –** Install 4th transformer to relieve predicted substation overload.	June 2016	NoMa, Mt. Vernon Square/Convention Center
3	**$16.3 million**	**Alabama Ave Sub**. – Install 2-100 MVAR reactors to relieve predicted substation overload.	December 2015	St. Elizabeth's, Barry Farm, Buena Vista, Douglass
4	**$150.0 million**	**Waterfront Sub. –** Build new substation to relieve predicted substation overload.	June 2017	Southwest, Navy Yard
5	**$106.7 million**	**Harrison Sub. (Formerly Northwest Sub.) –** Upgrade substation to replace aging infrastructure.	December 2017	Friendship Heights, Chevy Chase
6	**$67.5 million**	**L Street Sub. –**Extend new 34 kV supplies to increase capacity.	June 2024	Downtown, Dupont Circle
7	**$298.4 million**	**Mt. Vernon Square Sub. –** Build new substation to relieve predicted network overloads.	June 2020	NoMa, Mt. Vernon Triangle, Shaw
8	**$109.3 million**	**Harvard Sub. –** Upgrade Harvard as a new 230/13 kV substation to retire existing Harvard and Champlain substations.	December 2021	Columbia Heights, Adams Morgan

Table 1.2-G: Substation Additions and Enhancements

Justification of Substation Additions and Enhancements

The capacity improvements to the Florida Avenue and Northeast substations are to serve new load in the Mt. Vernon Triangle/Convention Center and NoMa areas. The capacity improvement to the Alabama Avenue Sub. is needed to serve new load in the St. Elizabeth's area. The new Waterfront Sub. is being proposed to serve load in the Navy Yard, M Street and

Buzzard Point areas and is needed to replace aging infrastructure at the Buzzard Point Substation and retire aging substations at G Street and Navy Yard. The new Harrison Sub. upgrade is being proposed to replace aging infrastructure and in order to meet area load growth. The capacity improvements to L Street Sub. are recommended to retire aging infrastructure and to serve new load in the West End and Georgetown areas. The new substation at Mt. Vernon Square is needed to provide capacity to the redeveloping Mt. Vernon Triangle and Shaw areas. The capacity improvements at Harvard Sub. are needed to replace aging infrastructure at Harvard Sub. and Champlain Sub., and to create capacity to serve the growing Columbia Heights area.

1. Florida Avenue Sub. – Install 4th Transformer to relieve predicted substation overload (2014 Load Relief Project)

Overview: This project consists of installing a new 69kV/13kV substation transformer at Florida Avenue Sub. 10 and extending a 69 kV supply feeder from New Jersey Avenue Sub. 161. This also requires substation terminal work at New Jersey Avenue Sub. 161. When this work is completed, the total firm capacity at Florida Avenue Sub. 10 will increase from 144 MVA to approximately 210 MVA. This capacity will immediately facilitate a transfer of approximately 33 MVA of load from 12th and Irving Sub. 133 by extending a new high voltage customer feeder group.

Load Growth Projections:

Facility: 12th & Irving Sub. 133

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
History	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated
126.6	133.3	137.5	139.4	140.5	142.5	143.9	145.7	147.2	148.5	149.8

Current Status: This project was completed in June 2014.

Total Planned Capital Investment (Includes Administrative & General (A & G)): $21,639,000

2. Northeast Sub. – Install 4th Transformer to relieve predicted substation overload (2016 Load Relief Project)

Overview: Install a new 69/13 kV transformer at Northeast Sub. 212. Extend a new 69 kV feeder from Benning Sub. 7 in order to supply the new transformer. This new transformer will increase the firm capacity at Northeast Sub. 212 enabling the extension of a new Low Voltage Alternating Current (LVAC) network group to the Penn Quarter area in order to relieve a predicted overload on Tenth Street Sub. 52.

Load Growth Projections:

Facility: Tenth Street Sub. 52

Summer — Summer Rating = 205.0 MVA

2014 History	2015 Anticipated	2016 Anticipated	2017 Anticipated	2018 Anticipated	2019 Anticipated	2020 Anticipated	2021 Anticipated	2022 Anticipated	2023 Anticipated	2024 Anticipated
195.6	200.1	209.6	210.8	214.3	217.4	220.3	222.9	225.6	228.4	232.0

Facility: Florida Avenue Sub. 10 South LVAC Network Group

Summer — Summer Rating = 50.0 MVA

2014 History	2015 Anticipated	2016 Anticipated	2017 Anticipated	2018 Anticipated	2019 Anticipated	2020 Anticipated	2021 Anticipated	2022 Anticipated	2023 Anticipated	2024 Anticipated
35.7	41.8	50.2	50.9	51.9	53.0	53.8	54.9	55.4	56.6	57.4

Magnitude of Load: This project will increase the firm capacity at Northeast Sub. 212 from 144 MVA to approximately 210 MVA. Approximately 40 MVA will be transferred from Tenth Street Sub. 52 to Northeast Sub. 212. Also, approximately 15 MVA of load will be transferred from Florida Avenue Sub. 10 to Tenth Street Sub. 52.

Identified Need: Project is needed to relieve a predicted firm capacity overload at Tenth Street Sub. 52 and a predicted overload on the Florida Avenue Sub. 10 South LVAC Network Group. Without this additional supply and transformer, the new Mt. Vernon Sub. would have to be advanced to supply the added capacity required. This addition will complete the expansion of Northeast Sub. and bring the station to its full capacity.

Justification: The load at Tenth Street Sub. 52 is predicted to exceed its summer firm capacity by 3% in 2016. If the Tenth Street load were transferred to Northeast Sub. 212 without the transformer addition, an 8% firm capacity overload is predicted. The Florida Avenue Sub. 10

South Network Group is predicted to be at 100% firm capacity but will be overloaded under certain contingencies in 2016.

Current Status: In construction.

Total Planned Capital Investment (Includes A & G): $21,107,000

3. Alabama Ave Sub. – Install 2-100 MVAR Reactors to relieve predicted substation overload
(Dec. 2015 Load Relief Project)

Overview: This project consists of installing two new 100 MVA shunt reactors on 230 kV Feeders 23088 and 23089 at Alabama Avenue Sub. 136. These reactors will relieve the operating restriction that exists if either Feeder 23088 or 23089 are out of service and a second 230 kV feeder needs to also be removed from service, thereby limiting the firm capacity at Sub. 136. The reactors will allow any one 230 kV feeder to be out of service without the need for taking a second one out. This project also includes the addition of 18.0 MVAR of bus capacitors which will maintain substation power factor as the load increases.

Load Growth Projections:

Facility: Alabama Avenue Sub. 136										
Summer	Summer Rating = 124.0 MVA									
2014 History	2015 Anticipated	2016 Anticipated	2017 Anticipated	2018 Anticipated	2019 Anticipated	2020 Anticipated	2021 Anticipated	2022 Anticipated	2023 Anticipated	2024 Anticipated
94.5	120.0	150.2	152.1	154.1	155.6	157.0	158.2	159.4	160.8	162.9

Magnitude of Load: This project will increase the firm capacity at Alabama Avenue Sub. 136 from 124 MVA to 165 MVA, facilitating the transfer of load from Anacostia Sub. 8 4 kV and 13 kV substations and enable the ultimate retirement of Sub. 8.

Identified Need: Project is needed to relieve a predicted firm capacity overload at Alabama Avenue Sub. 136.

Justification: The load at Alabama Avenue Sub. 136 is predicted to exceed its summer firm capacity by 21% in 2016 after the planned transfers of load from Anacostia Sub. 8 are completed.

Total Planned Capital Investment (Includes A & G): $16,295,000

Current Status: In design.

In-service Date: December 2015

4. Construct New Waterfront Sub. 223

(2017 Load Relief Project)

Overview: This project consists of constructing a new 230/138/13 kV substation with an ultimate capacity of 350 MVA. It will initially have three 230/138/13 kV transformers for 144 MVA of capacity. This work will bring distribution capacity to the rapidly growing Southeast and Southwest District of Columbia areas. The new Waterfront Sub. 223 will allow for the transfer of load from and ultimate retirement of Buzzard Point Sta. B 13 kV bus, Navy Yard Sub. 33 and G Street 4 kV Sub. 28.

Load Growth Projections:

Facility: Buzzard Point Sta. B East LVAC Network Group

Summer Rating = 39.0 MVA

2014 History	2015 Anticipated	2016 Anticipated	2017 Anticipated	2018 Anticipated	2019 Anticipated	2020 Anticipated	2021 Anticipated	2022 Anticipated	2023 Anticipated	2024 Anticipated
34.8	38.7	39.7	42.2	43.4	44.5	45.5	46.3	47.2	48.5	49.5

Facility: G Street Sub. 28 Forecasted Loadings

Summer Rating = 18.0 MVA

2014 Historical	2015 Anticipated	2016 Anticipated	2017 Anticipated	2018 Anticipated	2019 Anticipated	2020 Anticipated	2021 Anticipated	2022 Anticipated	2023 Anticipated	2024 Anticipated
14.3	14.5	14.8	14.9	15.0	15.1	15.2	15.3	15.4	15.5	15.6

Facility: Navy Yard Sub. 33 Forecasted Loadings

Summer Rating = 21.0 MVA

2014 Historical	2015 Anticipated	2016 Anticipated	2017 Anticipated	2018 Anticipated	2019 Anticipated	2020 Anticipated	2021 Anticipated	2022 Anticipated	2023 Anticipated	2024 Anticipated
18.1	18.5	18.7	18.8	18.9	19.0	19.1	19.2	19.3	19.4	19.5

Magnitude of Load: Initially, approximately 83 MVA of load will be transferred from Buzzard Point Sta. B by June 2017. The 4 kV conversion (approximately 14 MVA) from G Street Sub. 28 to Waterfront Sub. 228 are scheduled to begin in 2017 and to continue through 2021. All load (approximately 20 MVA) from the Navy Yard Sub. 33 is scheduled to be transferred to Waterfront Sub. 228 by 2019.

Identified Need: This project is needed to relieve a predicted LVAC network feeder group overload and improve reliability by replacing aging infrastructure.

Justification: The Buzzard Point Area is expected to continue to experience intensive development. The Buzzard Point Sta. B East LVAC Network Group is predicted exceed its firm capacity in 2017 by 8%. There are no nearby substations with available feeder positions for extending a new LVAC network feeder group to relieve the Buzzard Point Sta. B East LVAC Network Group.

Buzzard Point Sta. B was originally constructed in the 1930's as a generating station and was modified over time to include transmission and distribution substations. The station has been renovated over the years, most recently with a life-extension project performed in the early 1990's, which replaced circuit breakers and relays but did little to improve the physical substation building. The substation bus configuration is considered non-standard, with a double-bus configuration that reduces feeder group redundancy. High fault current availability required installation of in-line reactors between Buzzard Point's 13 kV busses, creating operational issues on the Southeast LVAC Network Group. This requires extra maintenance and could reduce network reliability and is the only group supplied by all six of Buzzard Point Sta. B's busses. Three of Buzzard Point Sta. B's 138/13 kV transformers were installed in 1964 while the other three were installed in 1979, 1980, and 2008, respectively.

Navy Yard Sub. 33 was put in service in 1957 as a temporary substation to supply the Navy Yard. It has been maintained as a permanent substation, but the equipment is aging. The load on the substation is approaching the firm capacity of 21 MVA due to load additions within the Navy Yard. In order to support this growth, new 13 kV supplies to the Navy Yard and O St. Pumping Station will be extended from the future Waterfront Sub. 223.

G Street Sub. 28 and its 4 kV system were constructed in the 1950's. The area supplied by G Street Sub. 28 is predicted to experience only moderate new development and renovations; however, this system was identified for 4 kV conversion in Pepco's 4 kV Long Range Plan. The G Street Sub. 28 – 4 kV system is planned to be converted to 13 kV distribution in coordination with the construction of the new Waterfront Sub. New 13 kV feeders are to be extended from the proposed Waterfront Sub. 223.

<u>Total Planned Capital Investment (Includes A & G):</u> $150,000,000

<u>Current Status:</u> In design.

<u>In-service Date:</u> June 2017

<u>Alternative</u>: When the substation was initially proposed, a study was conducted comparing the overall cost of the substation if it were located near the existing Buzzard Point Station on Pepco-owned land or at a site purchased somewhere near the Navy Yard closer to where much of the new development was occurring at that time. The analysis showed that locating the substation near Buzzard Point on Pepco-owned land required the same amount of revenue as locating the substation near the Navy Yard, however, Pepco assessed the risk of locating the substation near Buzzard Point on Pepco owned property to be less than obtaining a two acre property near the Navy Yard and building a substation there. This is due to the limited land available and the difficulty of building a new substation in the area of the Navy Yard.

5. Upgrade Harrison Sub. 38 (formerly Construct New Northwest Sub. 228)
(2017 Aging Infrastructure Project)

The upgraded Harrison Sub. 38 will be a 138 kV / 13 kV substation with an ultimate capacity of 150 MVA. All 13 kV load currently supplied from Harrison Sub. 38 will be temporarily supplied from temporary equipment to be assembled on the site next to Harrison Sub. 38. This will allow the existing substation to be de-energized so that the station can be upgraded on the site of the existing station. Once construction is finished, all circuits will be transferred from the temporary equipment and the temporary equipment will be removed from the property.

Load Growth Projections:

Facility: Harrison Sub. 38										
Summer	Summer Rating = 56.0 MVA									
2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
History	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated
51.4	48.4	49.2	50.1	51.0	51.7	52.3	52.9	53.5	54.3	55.1

Note: Loads shown include the net effects of converting and transferring the 4 kV load off of Harrison Sub. 38 to other area substations.

Magnitude of Load: Approximately 50 MVA of load will initially be served from the upgraded Harrison Sub. 38 in 2017. Approximately 70% of the load is in the District of Columbia. Additional load will be transferred from neighboring substations in the following years in order to provide capacity for future growth in those areas.

Identified Need: Project is needed to improve reliability by meeting load growth and replacing aging infrastructure.

Justification: The main building at Harrison Sub. 38 was constructed in 1940 and has had various additions over time. Harrison Sub. 38 – 13 kV substation is anticipated to exceed its firm capacity in the summer of 2015, prior to planned conversions and transfers from the Harrison Sub. 38 – 4 kV Substation currently in progress. The transformers are 47 to 60 years old. Transformer 1 has been assessed as impaired and will need eventual replacement. The switchgear is a double bus configuration and in need of replacement based on its assessed condition. Some of the switches are 52 years old with only a 500 MVA rating. Reactors are in place to help with duty. This substation is already "landlocked", meaning that there is only access from the front or from a 12 foot driveway. Given that there is no additional space for new equipment, there is no realistic way that the existing equipment inside Harrison Sub. 38 can be upgraded without first removing it.

The existing 4 kV substations at Harrison Sub. 38 are also in need of replacement. Transformer 6 has been assessed as impaired and needs eventual replacement. Pepco plans to convert and re-route existing 4 kV feeders in order to retire the 34/4 kV and 13/4 kV substations at Harrison Sub. 38 and not build a 4 kV substation on the Harrison substation property.

Total Planned Capital Investment (Includes A & G): $106,691,000

In-service Date: December 2017

Current Status: In planning stages with preliminary engineering started to support development of conceptual design and permitting. Pepco acquired a parcel of land on Wisconsin Avenue next to the existing Harrison Sub. that will be used for staging temporary equipment to allow the upgrade of Harrison Sub. Construction is planned to start in the third quarter 2015.

Alternative: An alternative to upgrading the Harrison Sub. 38 would be to extend 17 feeders from Little Falls Sub. 77 and transfer all load from Harrison Sub. 38 to that substation.

The total cost of completing this alternative is also estimated to be approximately $107 million and would leave Little Falls Sub. 77 without any spare substation bus feeder positions for future use. Also, it is predicted that Little Falls Sub. 77 will exceed its firm capacity in 2021 if this alternative work is completed, requiring the construction of a new substation at that time.

Economic analysis shows that upgrading Harrison Sub. 38 saves approximately $83 million in cumulative present worth of annual revenue requirements in comparison to the alternative plan to extend 17 new 13.8 kV distribution feeders from Little Falls Sub. 77.

6. **L Street Sub. –** Extend New Feeders from Takoma Sub. 27
(2024 Aging Infrastructure Project)

Overview: Extend three new 34 kV feeders from Takoma Sub. 27 to L Street Sub. 21. These feeders would replace the existing four 34 kV feeders which were installed in 1940 from Buzzard Point Sta. B.

Completion of this project (along with other projects to retire 34 kV supplies to Anacostia Sub. 8, Navy Yard Sub. 33 and upgrading Harvard Sub. 13 as a 230/13 kV substation) will enable the retirement of the 34 kV substation at Buzzard Point. This plan would eliminate the need to rebuild that facility due to its age and condition.

This project would upgrade capacity at L Street Sub. 21 from 55.5 MVA to ultimately 90 MVA.

Pepco is currently investigating further alternatives for re-supplying L Street Sub. 21.

Load Growth Projections:

Facility: L Street Sub. 21										
Summer	Summer Rating = 55.5 MVA									
2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
History	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated
38.5	40.6	41.8	42.4	43.1	43.7	44.2	44.7	45.2	45.8	46.5

Facility: Georgetown Sub. 12										
Summer	Summer Rating = 134.0 MVA									
2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
History	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated
122.1	124.0	125.1	125.7	126.8	127.7	128.6	129.7	130.6	131.7	132.8

Magnitude of Load: No overloads are currently anticipated in the area of L Street Sub. 21 for the next ten years. However, Georgetown Sub. 12 is predicted to be at 99% of its firm capacity in 2024 and the increased capacity at L Street Sub. 21 would facilitate future load transfers from Georgetown Sub. 12.

Identified Need: This project is needed to enable the retirement of the existing 34 kV feeders that were installed around 1940. The project will also increase capacity at L Street Sub. 21, which will enable load to be transferred from substations and network feeder groups, approaching capacity limits in the future.

Justification: Completion of the L Street substation resupply project, along with upgrading Harvard Sub. 13 and retiring Anacostia Sub. 8 and Navy Yard Sub. 33, will allow the retirement of the 34 kV Buzzard Point Sub.

Total Planned Capital Investment (Includes A & G): $67,510,000

In-service Date: June 2024

Current Status: In the early planning stages.

7. Construct New Mt. Vernon Square Area Substation
(2020 Load Relief Project)

Overview: This project consists of constructing a new 13 kV substation with an ultimate capacity of 210 MVA. This substation will provide capacity to the rapidly redeveloping area in and around the Mt. Vernon Triangle. This project will also extend the 230 kV feeders using solid dielectric underground cable from Takoma Sub. 27.

Load Growth Projections:

Facility: Northeast Sub. 212 Southwest LVAC Group

Summer — Summer Rating = 50.0 MVA

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
History	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated
34.8	38.7	40.3	43.5	46.6	49.2	52.0	54.5	56.6	60.0	62.8

Facility: Northeast Sub. 212

Summer — Summer Rating = 210.0 MVA

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
History	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated
92.6	109.6	155.2	159.7	164.2	168.4	172.5	176.2	180.0	184.4	188.7

Facility: Harvard Sub. 13

Summer — Summer Rating = 46.5 MVA

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
History	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated
48.3	39.9	38.1	38.9	39.6	40.2	40.7	41.1	41.7	42.3	42.9

Facility: Tenth Street Sub. 52 (after recommended transfer to Northeast Sub. 212 in 2016)

Summer — Summer Rating = 205.0 MVA

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
History	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated
195.6	200.1	186.2	187.4	190.9	194.0	196.9	199.5	202.2	205.0	208.6

Magnitude of Load: Initially, approximately 30 MVA of load would be transferred from the Northeast Sub. 212 Southwest LVAC Network Group in 2020.

Justification: Approximately 140 MVA of long-term growth is identified to come into service in the Mt. Vernon Triangle and NoMa neighborhoods over the next 10 years, eventually surpassing the capacity of Northeast Sub. 212, which was built in 2007. The new Mt. Vernon Square Area Sub. will also provide relief to 10th Street Sub. 52 (built in 1974), which has had a peak loading of 90% of capacity or greater every year since 2005. In addition, the Northeast Sub. 212 Southwest LVAC Network Group is expected to exceed its firm capacity in 2020 by approximately 4%, necessitating construction by that year. Due to space limitations in the streets around the Northeast substation, no new feeder groups can be extended to relieve this overload.

Total Planned Capital Investment (Includes A & G): $298,398,000

Current Status: In planning stages.

In-service Date: June 2020.

Alternative: Multiple sites were evaluated for locating the proposed Mt. Vernon Square Sub. A final selection will be made in 2015.

8. Upgrade Harvard Sub. 13

(2021 Aging Infrastructure Project)

Overview: This project consists of removing the current 34 kV/13 kV substation at Harvard Sub. 13 and upgrading to a new 230 kV / 13 kV substation with an ultimate capacity of 210 MVA. It will initially have three 230 kV/13 kV transformers for 144 MVA of capacity. The upgraded Harvard Sub. 13 will serve all 13 kV load served by the existing Harvard Sub. 13 and will provide capacity to enable the transfer of all load from Champlain Sub. 25, which allows the retirement of that facility. The upgraded Harvard Sub. 13 will also provide capacity for future load growth in the Columbia Heights and Adams Morgan areas.

Load Growth Projections:

Facility: Harvard Sub. 13										
Summer	Summer Rating = 46.5 MVA									
2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
History	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated	Anticipated
48.3	39.9	38.1	38.9	39.6	40.2	40.7	41.1	41.7	42.3	42.9

Magnitude of Load: Approximately 41 MVA of load will be served from upgraded Harvard Sub. 13. While the existing Harvard Sub. 13 is being upgraded, all load currently served by Harvard Sub. 13 will be transferred to temporary equipment that will be staged on the adjacent property. Soon after the upgraded Harvard Sub. 13 is put into service, all load (approximately 60 MVA) will be transferred from Champlain Sub. 25, enabling its retirement.

Identified Need: This project is needed to retire aging infrastructure including Harvard Sub. 13 13 kV substation constructed in 1907, the 34 kV supplies to Harvard Sub. 13 from Buzzard Point, constructed around 1960, and Champlain Sub. 25 13 kV substation, constructed around 1954. This upgraded substation will also supply capacity to the growing Columbia Heights area as well as Adams Morgan.

Justification: Both the Harvard and Champlain substations were constructed with concrete cubicles making them difficult to maintain as they age and potentially lead to an extended outage if there is a significant failure at either substation. In addition, completion of this project along with the project to resupply L Street Sub. 21 and the retirements of Anacostia Sub. 8 and Navy Yard Sub. 33 will enable the retirement of Buzzard Point Sta. B 13/34 kV substation. The upgraded Harvard substation will provide capacity to accommodate projected load growth in the Columbia Heights area.

Total Planned Capital Investment (Includes A & G): Budget has not been fully developed – Early estimate based upon similar substation projects is $109,300,000.

Current Status: In the early planning stages.

In-service Date: June 2021

Alternative: An alternative would be to maintain the Harvard and Champlain substations, replacing the switchgear in each substation. This was not considered a viable option as the switchgear would have to be demolished rather than removed because it is concrete encased. In addition, if this station is maintained, the 34 kV transformers at Harvard and Buzzard Point as well as the 34 kV supply feeders would have to be replaced. Even with these replacements, there would not be any increased capacity for future load growth.

1.2.4 DISTRIBUTION PROJECTS[12] [13]

Overhead and Underground Distribution Projects[14]

Pepco's overhead and underground distribution project budgets over the past six years are provided in Table 1.2-H.

Pepco DC 2009 - 2014 Capital Budgets (Dollars in Millions)						
Distribution Construction	2009	2010	2011	2012	2013	2014
Customer Driven	$41.5	$46.1	$44.9	$34.4	$47.0	$53.0
Reliability	$48.5	$58.5	$84.2	$110.3	$138.0	$133.7
Load	$19.2	$6.2	$37.0	$26.9	$36.4	$84.8
TOTAL	$109.2	$110.8	$166.1	$171.6	$221.4	$271.6

Table 1.2-H: Historical Routine Overhead and Underground Distribution Projects

[12] In the initial November 5-7, 2001 hearings requiring the production of the Comprehensive Plan, Commissioner Meyers stated the following (pages 266-267 of the hearing transcript):

But what we were talking about here yesterday was that the comprehensive plan would include… anything that you might envision to account for distribution load growth…

[13] Order No. 16975 states the following at paragraphs 51, 52 and 102:

51. *Staff Recommendation #7: Continue to provide annual updates of on-going and planned OH and UG distribution projects driven by customer, reliability, and load considerations in future Consolidated Reports. Include budget as well as actual spending for each of the three categories and explanation of significant differences in actual versus budgeted amounts…*
85. *Decision: The Commission adopts recommendation #7, noting that Section 1.2.4 of the Consolidated Report does not contain a comparison of actual vs. budgeted spending, nor does it include an explanation of any variances. Pepco is therefore directed to include this information in future Consolidated Reports.*
102. *Pepco is DIRECTED to continue providing updates of on-going and planned overhead and underground distribution projects consistent with paragraph 52 herein;*

[14] In Order No. 12735 issued on May 16, 2003, the Commission stated the following at paragraphs 74 and 135:

74. *During the November 2001 hearings the Commission requested that PEPCO submit a comprehensive plan to include a current assessment of, and future plans for, its underground distribution and network facilities.179 The Commission requested the plan as a tool to evaluate PEPCO's planning methodology and to assess PEPCO's ability to anticipate and respond to changing conditions in its underground distribution system…*
135. *PEPCO shall file the additional information not included in its expurgated comprehensive plan as outlined below, within three months of the issuance date of this Report and Order:*
    (c) *Listing of underground distribution projects, such as the Adams-Morgan neighborhood project (including budgets, time schedules, and expected benefits) by secondary vs. primary system by District of Columbia wards affected, but not specific locations;*

    The summary should cover a 10-year planning horizon while historical comparisons should provide at least five years of history.

Pepco's overhead and underground distribution project variances for 2014 are provided in Table 1.2-I.

Pepco DC 2014 Capital Budget Variances (Dollars in Millions)			
Distribution Construction	**2014 Budget**	**2014 Actual**	**Variance**
Customer Driven	$53.0	$57.3	$4.3
Reliability	$133.7	$111.7	($22.0)
Load	$84.8	$27.8	($57.0)
TOTAL	$271.5	$196.8	($74.7)

<u>Table 1.2-I: 2014 Routine Overhead and Underground Distribution Project Variances</u>

Pepco significantly increased its construction budget from 2011 through 2013 to fund the Reliability Enhancement Plan (REP). Pepco's actual spending has also significantly increased in response to the extensive REP effort and to fund feeder and substation load relief work required to accommodate the load growth being experienced in some sections of the city. Pepco's 2014 actual spending on Load was lower than budgeted primarily due to the budget item to purchase land for the proposed Mt. Vernon substation not being completed in 2014. Pepco's 2014 spending on Reliability was lower than budgeted due to the amount of work on seven feeders being carried over into 2015, and the average cost of work per feeder decreasing.

Pepco's overhead and underground distribution project budgets for the next five years are provided in Table 1.2-J. In developing forecasts, system planners review each component of the existing electric system, along with requirements for new service hook-ups, to develop the costs and schedules for changes to the electric system. Results are then proposed as candidates for inclusion in the construction budget process, which takes place during the second half of each year. The construction budget process culminates with the approval of the following year's budget and the selection of projects to be included in the Five-Year Forecast of electric system additions. Projects may be added or deleted from the Five-Year Forecast from year to year as required. The summary Five-Year Forecast for overhead and underground distribution projects, which identifies types of projects and their respective cash flows for the years 2015 through 2019, is provided as Table 1.2-J.

Pepco DC 2015 - 2019 Capital Budget & Forecast (Dollars in Millions)					
Distribution Construction	**Budget**	**Forecast**			
	2015	**2016**	**2017**	**2018**	**2019**
Customer Driven	$55.4	$64.0	$64.8	$65.8	$58.1
Reliability	$127.5	$108.2	$110.9	$144.2	$172.9
Load	$51.8	$51.9	$24.0	$16.4	$37.0
TOTAL	$234.7	$224.2	$199.6	$226.4	$268.0

Note: Pepco only prepares a 5-year forecast; Prospective work for the DC PLUG initiative has not been included in this five-year plan.

<u>Table 1.2-J: Planned Routine Overhead and Underground Distribution Projects</u>

Spending for load driven distribution system improvements is planned to be higher in the 2015 – 2016 period than 2017-2018 in order to build two new substations (Waterfront Sub. 223 in 2016 and Mt. Vernon Area Sub. in 2020), rebuild one substation (Harrison Sub. 38 in 2017), add two new transformers to existing substations (Florida Ave. Sub. 10 and Northeast Sub. 212), install two 100 MVAR reactors at Alabama Ave. Sub. 136 and to add feeder capacity to accommodate predicted increased load growth at various stations. Projected spending for load driven projects will decrease in 2017 and 2018 because of the completion of Waterfront Sub. 223, the fourth transformers at Florida Ave. Sub. 10 and Northeast Sub. 212, and the reactors at Alabama Ave. Sub. 136, which will be completed prior to 2017. This will leave the last portion of the rebuild of Harrison Sub. 38 and the building of Mt. Vernon Square Area Sub. to be completed in those years.

SECTION 1.3 – MAINTAINING SYSTEM RELIABILITY

Pepco is committed to maintaining a safe and reliable electric distribution system and has programs in place that advance the operation of the electric distribution system by increasing the capabilities to monitor and analyze the performance of its system and enhance the ability to determine where to make modifications and additions to replace poorly performing equipment. Pepco monitors the performance of its distribution feeders system-wide. This process is performed annually and enables Pepco to analyze and determine the relative ranking of each feeder's performance from the least to the most reliable.

This section of the Consolidated Report addresses:

- Technology: Monitoring, Automation, and Information Systems;
- Equipment Standards and Inspections;
- Vegetation Management (VM) Program Detail;
- Industry Comparisons;
- Best Practices;
- Reliability Enhancement Work Plan;
- Storm Readiness.

1.3.1 TECHNOLOGY: MONITORING, AUTOMATION, AND INFORMATION SYSTEMS

Systems and Technology[15]

The discussion below addresses the Company's technology initiatives that contribute to improved reliability performance.

[15] In Order No. 12804 paragraph 53 E, the Commission ordered the following:
53. The 2003 PIP is hereby APPROVED, provided that PEPCO:
(e) Provide to the PIWG, quarterly status reports on the new Technology Initiatives being undertaken by Pepco. An annual status report should be included in the 2004 and future PIPs. The status reports should include current accomplishments, plans for the future, and anticipated completion dates.

SCADA[16]

The System Control and Data Acquisition (SCADA) System is the primary tool used by the System Operators to monitor and operate the electric system. This system provides the System Operator at the Control Center the ability to remotely monitor and operate all major equipment at all substations and selected equipment outside of the substations. It is through this system that the System Operator learns what is happening across the electric system and has the ability to take appropriate actions to maintain a safe and reliable system and restore service during outages.

The Remote Terminal Unit (RTU) at each substation gathers data from all substation monitored equipment, and provides an interface to pass the data to the central computer system, Energy Management System (EMS), and to the System Operator, who can then remotely control devices at each substation. Major equipment status (open or closed) and equipment metering (watt, var, voltage and ampere) is monitored by the Operator. Additionally, there are specific equipment alarms that indicate abnormal conditions like high temperature, low oil pressure or overloads on a particular device or feeder.

Pepco maintains its own extensive communication system that allows for direct communication between the RTUs at the substations and the computer system at the Control Center.

The computer system at the Control Center gathers the data from all the RTUs, analyzes the data, displays results to the System Operators, and provides the interface for the System Operator to remotely operate the system to protect equipment. Any change of electric system status at the substation is displayed to the System Operator within approximately 4 seconds. The system also provides various analyses. For example, it provides an indication if any substation equipment exceeds its capability limits. It does this by comparing the design limit

[16] The initial requirements for the Comprehensive Plan section of the Consolidated Report were delineated in hearings taking place from November 5-7, 2001. On page 313 of the hearing transcript, Commissioner Meyers stated the following:

> *We're going to ask Pepco to please include a section on reporting and monitoring in the comprehensive plan… And just as a quick for instance of this real-time systems control and data acquisition system, SCADA, what could it do? Give me a for instance there.*

of the equipment with the present loading. Through the SCADA system automatic switching activities can be performed or the System Operator can take action manually to protect remote system equipment and relieve the condition that caused the equipment to be operating outside of its limits.

All raw data from the SCADA system (meter values and status changes) are retained and made available to those areas (System Planning, Distribution and Engineering, etc.) that need the data for analysis. The available data consists of meter values (watts, vars, volts and amps) and status (open and closed) of various facilities, equipment and feeders.

Substation Automation[17]

Although all 13 kV substations have full SCADA control, some 4 kV substations have only limited monitoring capability and do not have the full RTU capability that provides remote control and operation. At these substations all equipment status indications are grouped together on a substation basis and when there is a change of status, a single alarm point provides a single substation alarm indication. Personnel are dispatched to the substation to determine the specific problem. A project is underway to install full RTU capability in the Company's 4 kV substations that are not scheduled for conversion and retirement by installing smart relays on all critical equipment. This will provide for improved restoration capability and hourly data for analyses. The 4 kV substation RTUs completed by the end of 2014 were at G St Substation Sub. 28.

The following nine substations will be automated over the next ten years:

- Macarthur Boulevard Sub. 152
- Texas Avenue Sub. 111
- Fort Davis Sub. 100
- Fort Dupont Sub. 58
- 53rd Street SE Sub. 48
- Seat Pleasant Sub. 30
- Twining City Sub. 150 (under construction)
- Chesapeake Street Sub. 181

[17] Substation Automation and the following section, Distribution Automation, are also addressed in Sections 2.3.2.1 and 2.3.2.4, respectively, as PIP Projects.

- Congress Heights Sub. 64

In addition, conventional electro-mechanical relays are being replaced with new generation Smart Relays. Additional information provided by these relays is allowing for more effective and efficient operation. In certain applications, the smart relays can provide information with respect to the distance from the substation to the fault on the feeder. This will allow for faster troubleshooting of system problems, improved restoration capability and increased data for system analyses.

Distribution Automation (DA)

Additionally, as part of the DA projects, ten 13 kV substations have been equipped with upgraded Smart Relays and enhanced RTU's for improved visibility and control at these locations. Additional information provided by these relays will allow for more effective and efficient operation and will support the operation of the Automatic Sectionalizing and Restoration (ASR) system being installed at each location. The following ten 13kV substations, which supply load within the District of Columbia, have been equipped with enhanced RTU's and upgraded Smart Relays:

- 12th & Irving Substation
- Benning Substation
- Fort Slocum Substation
- Harrison Substation
- Little Falls Substation
- Van Ness Substation
- Green Meadows Substation (located in MD but serves some D.C. customers)
- Takoma Substation (located in MD but serves some D.C. customers)
- Tuxedo Substation (located in MD but serves some D.C. customers)
- Walker Mill Substation (located in MD but serves some D.C. customers)

In 2014, the Company expanded the ASR technology to include three additional feeders out of Van Ness Substation, one additional feeder from Benning Substation, and three additional feeders from 12th and Irving and Fort Slocum Substations. These seven feeders serve approximately 9,500 customers in the District of Columbia. ASR functionality for these seven feeders is expected to be activated in first quarter of 2016. The Anacostia area ASR plan has been deferred until technology planning for DC PLUG initiative is completed.

Pepco is also initiating a plan to install overhead fault detectors that would communicate back to the Control Center. This will improve outage response through quicker identification of fault locations. This work will commence once a smart fault indicator technology is selected, currently targeted for fourth quarter 2015.

Projects are underway to install additional 13 kV and 69 kV remotely operated switches on feeders in addition to the feeders associated with the ASR systems. The additional switches will allow more capability to isolate the faulted portion of the feeder and return more customers to service sooner. The remote control capability of these switches allows the System Operator to perform switching without the need for field crews, thus reducing customer outage time.

In regards to 69 kV remotely operated switches, all planned additions are in Maryland, but some do improve the reliability of power supply to customers in the District of Columbia. The Company completed its phase 1 and 2 plans to install 50 switches by end of year 2013 (four affecting substations that supply District load). Phase 3 of the project is currently underway which encompasses the installation of 18 switches (ten affecting substations that supply District of Columbia load). Fifteen switches were installed in 2014, with the remaining to be installed by mid-2015. In all, approximately 6,800 District of Columbia customers are impacted by the following planned 69 kV switch additions:

Subtransmission Substations	Distribution Supply Substations	2014/2015
Ritchie	Walker Mill Rd & Suitland	2
Bells Mill Road	Linden	2
Palmers Corner	Beech Rd & St. Barnabas Rd	6
Total		10

In addition, Pepco completed the installation, testing and integration of the network transformer remote monitoring system (RMS) on 41 network transformers in the Buzzard Point Network (in Southeast District of Columbia) in the fourth quarter of 2013. There have since been an additional 9 transformers installed on the Buzzard Point Network, which have all been equipped with RMS, as well as 49 transformers in the Sub 212 Southeast group. The installation of RMS on 60 network transformers in the Sub 212 Northeast Network (formerly referred to as the Benning Network, located in the Northeast District of Columbia), and on 75 transformer protectors in Sub 18 Central Network (located in Southwest District of Columbia) is currently in progress. Integration of the RMS data into the EMS for these two networks is expected to be completed by third quarter of 2015. These monitors will provide increased visibility and control capability for system operators to remotely open or close the network transformer protectors through two-way communications. Load, voltage, protector status, and equipment condition data are recorded for study and operating purposes, and for increased ability to schedule maintenance of this equipment. RMS will provide operational data to evaluate the performance of the transformer and protector, perform maintenance when needed and not just on a time-based interval, and allow opening the protector to disconnect network load from the transformer without the need to wait for a crew to manually operate the protector. This will provide great benefits during emergencies when there is a need to very quickly isolate a transformer from the network. The development of the RMS system and the initial installation at Buzzard Point are part of the Department of Energy Smart Grid Investment Grant (SGIG) that the Company received. The installations in the Northeast Network and the Sub 18 Central Network are part of the Company's long term plan to install RMS in all of its 49 networks which contain approximately 4,000 transformers.

Outage Management System (OMS)[18]

The OMS is the primary tool used to receive customer trouble reports, analyze reports and provide summary reports for crew dispatching. Typically the process starts with the customer reporting an outage by calling the Pepco Call Center or from an Advanced Metering

[18] In Order No. 13422 on the 2004 Consolidated Report, paragraph 66, the Commission ordered the following:

66. The 2004 Consolidated Report: Productivity Improvement Plan and Comprehensive Plan is hereby APPROVED, provided that PEPCO:

(a) Report in the 2005 Consolidated Report, due February 15, 2005, on the corrective actions taken to fix the OMS;

Infrastructure (AMI) meter reporting the loss of power. Information from that call or meter report is entered into the OMS system. The OMS database has the customer information, including customer phone number, address, and connected transformer. Additionally, the database contains the electrical network configuration of each feeder connecting each transformer to a feeder and the location of switches, fuses and taps. The system then analyzes all reported trouble by sorting the reports, prioritizing and grouping multiple problems to a common source. The analyzed data are then displayed to the System Operator for dispatch of crews to investigate and resolve the problem.

The SCADA system also provides input to the OMS. When a feeder breaker at a substation opens and the entire feeder is out, all customers connected to that feeder are known to be out of service. Information obtained from customers (pole struck, line down, tree limb on wire, etc.) in the OMS is then used to determine the source of the problem and to dispatch crews. For trouble involving these pieces of equipment, the customer trouble calls provide the data necessary to determine the problem. The OMS analyzes all the customer calls as well as AMI meter statuses and then determines the common source of the problem. Information is also passed back through the OMS to the Call Center to provide that information to the customer when they call in. This information includes knowledge of current trouble and estimated restoration time under non-major storm outage conditions.

Information Systems

<u>Customer Relationship Management and Billing System (CRMB)</u>

A new Customer Relationship Management and Billing system (CRMB) was implemented on January 5, 2015 to replace the legacy CIS system. Included in this development effort was a new bill format that presents data. The new bill format also includes enhanced presentment of budget billing and payment arrangement information, as well as a daily usage graph for AMI-activated accounts.

<u>Work Management Information System (WMIS)</u>

WMIS continues to be the primary tool used for construction and engineering work management at Pepco and is closely integrated with the Graphical Work Design (GWD) system.

SAP PM (Plant Maintenance)

SAP PM continues to be the primary tool used for maintenance work management at Pepco. Planned, periodic maintenance is scheduled through SAP PM, as is corrective work. In 2014, minor enhancements were made to the system to improve the work order process and work began on maintenance analytics and enabling mobile technology for substation inspections.

GIS/GWD System

Pepco started a project to upgrade the existing GIS/GWD system to the latest version in August 2013 and the system was deployed September 9, 2014. Pepco continues to deploy new functions offered by the GIS vendor for greater use of GIS data throughout the company. The GIS/GWD system continues to be Pepco's official database of field assets. The Pepco GIS/GWD system is also being used for the DC PLUG initiative, coordinating the work between the District of Columbia and Pepco.

Power Delivery Information System Projects[19]

Pepco's Power Delivery Information System Projects are provided in Table 1.3-A. Included in Table 1.3-A are historical information system projects for the years 2010 - 2014. All costs are for those allocated to the District of Columbia.

[19] In Order No. 12735, paragraph 139, the Commission ordered the following:
PEPCO shall file the additional information not included in its expurgated comprehensive plan as outlined below, within three months of the issuance date of this Report and Order:…
(d) Listing of power delivery information system projects with implementation schedules, annual costs, and milestones;
(e) Listing of new technology investigations with decisions, annual costs, and implementation schedules;
…The summary should cover a 10-year planning horizon while historical comparisons should provide at least five years of history.

Rollup-1	Estimated DC Portion 2010	Estimated DC Portion 2011	Estimated DC Portion 2012	Estimated DC Portion 2013	Estimated DC Portion 2014
ROLLUP ($000s)					
Customer Systems	739	951	999	251	216
CIS Replacement	0	0	1,764	8,751	9,459
Smart Grid Systems	4,507	5,901	1,932	1,815	777
Meter Systems	142	0	0	0	0
Network Operating Center (NOC)	759	2,300	987	168	387
Energy Supply Systems	55	5	690	332	52
Operations Systems	138	100	36	110	115
Energy Management System (EMS)	(6)	0	0	0	0
Engineering Systems	113	217	156	331	636
Field technologies	54	690	500	130	257
Work Management (WMIS)	187	(0)	7	93	214
Planning and Performance	76	55	183	308	116
Subtotal IT Capital (DC Portion)	**6,764**	**10,219**	**7,255**	**12,289**	**12,228**

Table 1.3-A: Historical Information System Projects

1.3.2 EQUIPMENT STANDARDS & INSPECTIONS

Equipment Standards

Pepco establishes and maintains material specifications, engineering and construction standards and practices, and operating guidelines to support the efficient, safe, and reliable operation of the Pepco distribution system. Further, Pepco established and maintains guidelines for the design and operation of its four-wire 13 kV distribution system and guidelines for the design and operation of its low voltage AC network system located in the downtown business district. These guidelines ensure that the electric distribution system is constructed and expanded in a consistent fashion according to the Company's established standards, practices, and requirements, to support the safe and reliable operation of Pepco's distribution system and downtown network system.

In addition, Pepco evaluates new products and equipment upgrades to improve system reliability and evaluates the technical capabilities of potential equipment suppliers to validate that their products or services meet or exceed established Company specifications and requirements. Manufacturer inspections and equipment reviews are performed to verify that these established requirements are met.

Pepco has been actively involved in the standardization of major equipment across the PHI utilities, for such items as capacitors, regulators, switches, reclosers and transformers. The consistent construction standards are intended to support the consistent proper installation of equipment throughout the PHI regions for safe, reliable, and cost-effective operation.

Equipment Inspections[20]

A proactive inspection and monitoring program reduces the possibility of unexpected failures and secondary damage to surrounding units, and increases the opportunities that Pepco can plan for the replacement of impending problem equipment. The frequency of inspections and monitoring is based on Pepco's experience, manufacturers' recommendations, and/or industry practices. Inspections may lead to repair or replacement of transmission and distribution system components to maintain safety and reliability of the system.

Inspection and modeling activities identify equipment to be replaced due to loading or condition. Distribution line equipment such as transformers, cable, and other components are not subject to detailed electrical testing and are replaced only when physical inspection indicates a need for replacement. Other than those inspections, equipment is replaced when it is upgraded, relocated or fails.

As new technologies are installed, actual operational data will be available to better analyze the loading and performance of equipment. For example, load data from the AMI system can potentially identify overloaded transformers prior to failure.

[20] In Order No. 16091, paragraphs 63 and 46, the Commission ordered the following:

63. Pepco IS DIRECTED to provide a description of its maintenance policies and methodologies, consistent with paragraph 46 of this Order;

46. Decision. … we shall require that Pepco provide a list of the types of equipment for which a "run to failure" method applies and those for which a preventive method applies. (Footnote: If other maintenance methods are used, Pepco shall describe them as well.) The Commission requires that Pepco provide an explanation of why different maintenance methods apply to different types of equipment. We also require a description of the "test procedures" that Pepco uses to assess the performance and remaining life of the equipment. (Footnote: See Pepco comments at 7.) Further, Pepco shall provide an estimate of the current book value of equipment maintained under each method used by Pepco. The 2011 Consolidated Report shall include this description of maintenance policies and methods.

Table 1.3-B below provides a range of inspection or maintenance cycles for different classes of equipment. These were developed by weighing factors such as criticality, duty cycle, varying manufacturer's recommendations, and technological differences.

The equipment types and asset groups listed on Table 1.3-B have been designated as either a "preventive" or a "predictive" maintenance. It should be noted that Pepco views its overall maintenance methodology to be defined by "reliability-centered" practices, with predictive and preventive methodologies to be subsets of this reliability-centered focus.[21]

Table 1.3-B: Equipment Inspections

Equipment	Inspection	Periodicity	Maintenance Methodology
Substation	General Inspection	Monthly	Preventive
Substation Power Transformers	Predictive Maintenance Routine	Annually	Predictive
	Oil Collection and Analysis Of Transformer Main Tank And Load Tap Changer (LTC)	Twice yearly to once every two years based on Transformer MVA rating or triggered by Transformer Oil Analyst (TOA) Program Rating	Predictive
	Routine Inspection and Test	2 to 10 Years or more frequent, as recommended based on ECA Process	Preventive
	External Inspection and Test	N/A	Preventive
	LTC Filter Change	Where applicable and condition-based maintenance on high filter differential pressure	Preventive
	Routine Cooler Inspection	As recommended based on ECA	Preventive
Substation Capacitor Banks - Metal Enclosed	Routine Inspection	4 to 8 years or more frequent, as recommended based on an ECA	Preventive

[21] Table 1.3-B has been modified in response to the Commission's directive to "describe Pepco's maintenance methodology (reactive, preventive, predictive, and/or reliability-centered) for each equipment type or asset group listed," *In The Matter of the Annual Consolidated Report of the Potomac Electric Power Company*, Formal Case No. PEPACR-2014-01, Order No. 17816 at P 354 (February 27, 2015).

Substation Capacitor Banks - Open Rack	Routine Inspection	3 to 5 years or more frequent, as recommended based on an ECA.	Preventive
Substation Capacitor Banks - Open Rack With Circuit Switcher	Routine Inspection	3 to 5 years or more frequent, as recommended based on an ECA.	Preventive
Substation Circuit Breakers – Air Magnetic	Predictive Maintenance (PDM) Tasks	Annually	Predictive
	Routine Test	4 to 8 years or more frequent, as recommended based on an ECA.	Preventive

Equipment	Inspection	Periodicity	Type
Substation Circuit Breakers – Oil	Oil Collection And Analysis Of OCB	1 to 5 years depending upon breaker application or triggered by Transformer Oil Analyst (TOA) Program Rating	Predictive
	Predictive Maintenance (PDM) Inspections	Annually	Predictive
	Internal Inspection and Test	As recommended based on the ECA Process.	Preventive
	Diagnostic Testing	Every 72 Months	Preventive
	Compressor Inspection/Pre-Charge Inspection (as applicable)	Every 24 Months - 36 Months	Preventive
Substation Circuit Breakers – SF6	Predictive Maintenance (PDM) Inspections – Non-intrusive	Annually	Predictive
	Routine Inspection – Intrusive	Performed as recommended based on ECA.	Preventive
	Diagnostic Testing	8 Years or more frequent, as recommended based on an ECA.	Preventive
Substation Circuit Breakers – Vacuum	Predictive Maintenance (PDM)	Annually	Predictive
	Routine Inspection	48 to 96 Months or more frequent, as recommended based on an ECA.	Preventive
Substation – 69 to 230kV High-Pressure Pipe-Type Potheads	Periodic Inspections where sample ports are available.	Every 4 to 6 years (230kV),	Preventive
		Every 6 to 8 years (115kV),	Preventive
		Every 8 to 10 years (69kV)	Preventive
Substation – Battery & Charger Systems	Visual & On-line Test/Inspection	Annually or more frequent as recommended based on an ECA.	Preventive
Substation – Building Heating, Ventilation and Air Conditioning (HVAC) System	Annual Inspection	Annually	Preventive
Substation – Emergency Generators	Start and Run Test	Annual Standby Generator and Inspection and Black Start	Preventive
Substation – Fire Protection Pump	Routine Inspection	Annually	Preventive
Right-of-Way Integrated VM (Transmission)	Routine Inspection	Interval based on Right-of-Way inspections and height of vegetation.	Preventive
Scheduled Tree Trimming - Overhead Distribution Feeders Not In Transmission Rights-of-Way	Routine and Condition-based Tree Inspection	Every 2 years	Preventive
Protective Relays and Automatic Reclosing Relays	Preventive Maintenance	4 to 6 years based on system voltage class	Preventive

Equipment	Inspection	Periodicity	Type
Under-Frequency Relays	Preventive Maintenance	6 years	Preventive
RTUs - SCADA	Predictive Maintenance	Failure to operate properly based on condition monitoring – self diagnostics, EMS trouble logs, real time data analysis, and remote communications.	Predictive
SCADA (Supervisory Control and Data Acquisition) Metering	Preventive Maintenance	Condition based maintenance	Preventive
Digital Fault Recorder	Preventive Maintenance	Every 48 Months	Preventive
Power Line Carrier (PLC)	Preventive Maintenance	Every 24 Months	Preventive
Microwave Equipment	Preventive Maintenance	Every 24 Months	Preventive
Fiber Optic Equipment	Preventive Maintenance	Every 2 to 4 years (Depending on Network)	Preventive
Leased Line	Preventive Maintenance	Every 24 Months	Preventive
Pole-Type Recloser	Routine Inspection	Visual - Annually, and Operational Test - Every 36 to 72 months	Preventive
Pole-Type Regulators	Routine Inspection/Test	Every 24 months	Preventive
Critical (Hospital/Nursing Home) Network Transformers/Protectors	Routine Inspection	Every 2 to 3 years	Preventive
Distribution and Subway Network Transformers/Protectors	Routine Inspection	Condition based – Every 3 to 10 years based on location and type of service	Preventive
Underground Network Transformers/Protectors	Routine Long Inspection	Every 5 years de-energized (Staggered w/Short Inspection so visits are 2.5 years apart). Inspection cycle for some locations may differ and be between 2 - 10 years based on: 1) criticality - hospital locations are inspected more frequently; 2) location type - sidewalk/roadway location or roof top/basement; and 3) installation type - junction box type installation.	Preventive
Underground Network Transformers/Protectors	Routine Short Inspection	Every 5 years energized (Staggered w/Long Inspection so visits are 2.5 years apart)	Preventive

Equipment	Inspection	Periodicity	Type
Capacitor Banks – Pole Mounted	Routine Inspection	Every 2 to 4 years	Preventive
Distribution Pad mounted Transformers / Switchgear	Routine Inspection	Every 10 to 20 years	Preventive
Pipe-Type Cable Joint Sleeves in Manholes	Periodic Inspection	Every 5 to 10 years	Preventive
Wood Poles	Wood Pole Inspection, Remedial Treatment and Restoration	*Every 10 years (starting in 2015)	Preventive
Power Line Over Navigable Waterway – Overhead Clearance	Routine Inspection	Not to exceed 5 years	Preventive
High Voltage Transmission Structure Aviation Warning Lighting	Periodic Inspection	Annually	Preventive
High Voltage Transmission Structure Grounding	Periodic Inspection	Inspect Grounding System on a 5 – 10 year interval	Preventive
Microwave Tower and Aviation Warning Lighting	Periodic Inspection	Annual or as per Federal Aviation Administration (FAA) recommendation	Preventive
High Voltage Transmission Line Comprehensive Inspection	Aerial Inspection	HV system will be inspected over a six year period.	Preventive
Cathodic Protection	Substation Inspection and Manhole Survey	Condition based – Various intervals (based upon type of work involved)	Preventive
Cable Oil and Gas Alarms	Annual Inspection	Annually	Preventive
Fluid Pressurizing Plants for High-Pressure Pipe-Type Cables	Operational Test And Inspection	Every 1 to 2 weeks (chart replacement), Every 1 to 2 years (operational test)	Preventive

Table 1.3-C includes the current book value of equipment. Current book values have been categorized by direct and allocable plant. The use of FERC Mass Asset Accounting does not allow any specific asset to be identified and linked to its accumulated depreciation and remaining useful life or to link it to the maintenance method applied to the equipment as assets are depreciated by account.

Potomac Electric Power Company			
DC Commission Order No. 16091			
Paragraph 46			
DC Distribution Plant, Reserve, Net Book Value - 2014			
As of 02/19/15			
DC DISTRIBUTION PLANT	**Book Cost**	**Reserve**	**Net Book Value**
E-3601-Land	59,509,919	-	59,509,919
E-3602-Land Rights	567,557	116,473	451,085
E-3610-Structures and Improvements	62,332,303	24,461,397	37,870,906
E-3620-Station Equipment	394,822,881	123,075,668	271,747,213
E-3640-Poles, Towers, and Fixtures	104,197,741	26,271,380	77,926,361
E-3650-O/H Conductors and Devices	116,561,557	31,972,839	84,588,718
E-3660-U/G Conduit	663,800,530	257,705,979	406,094,551
E-3670-U/G Conductors and Devices	671,411,774	219,056,506	452,355,267
E-3680-Line Transformers	421,377,223	133,621,557	287,755,666
E-3691-O/H Services	12,427,510	683,447	11,744,063
E-3692-U/G Services	92,675,017	54,164,664	38,510,353
E-3693-U/G Cable Services	143,704,655	57,758,069	85,946,585
E-3700-Meters	7,123,311	2,579,437	4,543,875
E-3701- AMI Meters	47,523,730	7,097,391	40,426,339
E-3711-Install on Customer Premises	1,367,203	1,251,078	116,125
E-3731-Overhead Street Lighting	46,403	(83,824)	130,227
E-3732-Underground Street Lighting	7,559,763	3,923,966	3,635,797
E-3734-Dusk to Dawn Street Lighting	46,509	25,609	20,900
Total DC Distribution Plant, Reserve, NBV	**2,807,055,586**	**943,681,636**	**1,863,373,950**

Table 1.3-C: Distribution Equipment Net Book Value

Overhead Feeder Inspection Program [22]

In 2012, Pepco initiated the Overhead Feeder Inspection program to evaluate feeder condition, identify future improvement opportunities, and remediate safety issues in the infrastructure of Pepco's overhead system to improve reliability.

The Overhead Feeder Inspection Program focuses on an individual feeder and follows that single feeder to its end, inspecting all of the different pieces of equipment along the feeder at one time. This provides the necessary field data and information to determine a feeder's general condition, compare it to performance data, and strategically implement the best solution or corrective actions to improve the feeder's overall reliability and avoid or mitigate future outage impacts.

Initially, Pepco set very aggressive targeted time frames for remediation of issues identified under this program. Based on the findings of Pepco's pilot effort in 2011 and consultation with the Company's contractor partner, who has experience implementing this type of program with several other utilities, Pepco learned that a more comprehensive approach to planning the remediation of conditions observed during inspections was needed. Further, the initial targeted time frames for remedial projects were out of sync with Pepco's REP planning and construction cycle. Typical project cycles for feeder improvement projects under the REP ran from 6 to 18 months depending on the scope of work identified. It simply was not possible to engineer, procure, and construct the added projects of the inspection program in the limited time periods specified.

Consequently, the prioritization of remedial work has been refined to require immediate or near term response on those issues that must be addressed to avoid imminent safety or reliability problems while less urgent conditions are required to be remediated within the normal design and build cycle for distributions projects. Finally, conditions which do not pose

[22] Order No. 16975 states the following at paragraphs 64 and 107:

> 64. *Decision: Pepco is directed to report on the Overhead Feeder Inspection Program in future Consolidated Reports as recommended by OPC and the Staff, including results of the inspections, actual and incipient failures detected and remediation actions taken to correct the nonconformance items recorded. In particular, as requested by OPC, Pepco is directed to report on replacement of lightning arresters.*
>
> 107. *Pepco is DIRECTED to report on the Overhead Feeder Inspection Program consistent with paragraph 64herein;*

a reliability or safety concern in either the near term or long term are identified for possible upgrade in conjunction with more urgent work scopes.

Repairs or upgrades to correct or eliminate conditions observed during inspections are scheduled under the following guidelines.

- Priority 1: A condition where upon inspection, a Pepco facility is deemed to present an imminent safety hazard to utility personnel and/or the public. In this case, steps shall be taken to immediately eliminate the hazard. Inspectors are required immediately notify Pepco and to stand by until relieved by Pepco personnel.
- Priority 2: A condition where upon inspection, a component of an overhead feeder is observed and confirmed to pose a threat to service reliability, but does not pose a direct public safety threat. Conditions under this category should be remediated within 90 days.
- Priority 3: A condition where damage or degradation exists on a component of an overhead feeder line, does not pose a direct public safety threat, and if left uncorrected, has the potential to affect service reliability under adverse system conditions. Conditions under this category should be remediated within 18 months.
- Priority 4: A condition that poses no threat to safety or reliability, but does not conform to current Pepco standards. Conditions under this category should be corrected when other work presents the opportunity to bring the condition to current standards.

Overhead Feeder Inspection Cycle

In 2014, Pepco re-evaluated the Overhead Feeder Inspection Program and decided to change the inspection strategy and program cycle, and the outcome of this decision was to implement a more aggressive two year cycle. Planning and scheduling for this acceleration slowed the inspection process in 2014, however, this change will result in approximately 50% of overhead feeders being evaluated in 2015, and ultimately result in all of Pepco's District of Columbia overhead feeders being inspected by approximately December of 2016. [23]

[23] The following table, Overhead Feeders Inspected 2011-2014, responds to the Commission's directive to Pepco to "provide in its 2015 Consolidated Report a table listing by year the overhead feeders that it has inspected under its Overhead Feeder Inspection Program, from the commencement of the Program through December 31, 2014, and, if known, the feeder numbers of the overhead feeders scheduled to be inspected by Pepco in 2015," *In The Matter of the Annual Consolidated Report of the Potomac Electric Power Company*, Formal Case No. PEPACR-2014-01, Order No. 17816 at P 355 (February 27, 2015).

Overhead Feeders Inspected 2011-2014

Feeder No.	Year	Feeder No.	Year	Feeder No.	Year	Feeder No.	Year
228	2011	97	2012	52	2013	82	2014
323	2011	118	2012	60	2013	133	2014
485	2011	308	2012	99	2013	490	2014
14008	2011	347	2012	117	2013	14006	2014
14133	2011	388	2012	120	2013	14017	2014
14136	2011	479	2012	122	2013	14200	2014
14145	2011	488	2012	133	2013	14767	2014
14150	2011	495	2012	144	2013	14769	2014
14200	2011	14006	2012	152	2013	15170	2014
14700	2011	14007	2012	164	2013	15174	2014
14701	2011	14014	2012	178	2013	15264	2014
14703	2011	14017	2012	227	2013	15701	2014
14717	2011	14093	2012	229	2013		
15009	2011	14135	2012	234	2013		
15166	2011	14766	2012	294	2013		
15170	2011	14767	2012	322	2013		
15172	2011	14768	2012	325	2013		
15174	2011	14769	2012	333	2013		
15175	2011	14890	2012	14005	2013		
15199	2011	14894	2012	14015	2013		
15701	2011	14896	2012	14035	2013		
15702	2011	14900	2012	14146	2013		
15705	2011	14945	2012	15010	2013		
15706	2011	15001	2012	15012	2013		
15707	2011	15011	2012	15021	2013		
15709	2011	15013	2012	15166	2013		
15943	2011	15014	2012				
15945	2011	15015	2012				
		15197	2012				
		15761	2012				
		15801	2012				

In 2014, 12 feeders were inspected as part of the Overhead Feeder Inspection Program, covering 2,752 poles. 81 conditions were identified and prioritized as follows:

No.	Classification	Condition	P1	P2	P3	P4
1	Animal Guard	Missing				
2	Arrester Equipment	Blown/Broken			6	
3	Arrester Line	Blown/Broken				
4	Capacitor					
5	Crossarm	Broken/Cracked	3	5	2	
6	Crossarm Brace	Broken		2	2	
7	Down Guy	P3-Broken | P3-STD				
8	Flyer					
9	Foreign Step					
10	Foreign Wire					
11	Fuse	Blown/Broken				
12	Ground					
13	Guy Guard					
14	Neutral Wire	Floating				
15	Overhead Guy	P3-Broken | P4-STD				
16	Pin/Insulator	Leaning/Loose	1	3	18	8
17	Pole	Split/Decayed/Broken			3	
18	Pole Top	Split/Decayed				
19	Primary Wire		5	1	17	
20	Recloser					
21	Regulator					
22	Riser	Loose/Broken			2	
23	Secondary Wire	P3-Floating | P4-STD				
24	Sectionalizer					
25	Service Wire	P3-Floating | P4-STD				
26	Spacer	Broken				
27	Step	NESC				
28	Streetlight					
29	Switch				2	1
30	Transformer	Leaning/Loose				
31	Vegetation					
32	Wooden Pin					
33	Woodpecker Holes					
	Total		**9**	**11**	**52**	**9**

Table 1.3-D: Overhead Feeder Inspection Program Priorities List

The conditions summarized in the table above, as observed during the overhead feeder inspection program in 2014, have been referred to the appropriate Engineering division for evaluation and implementation to address the conditions. Of the conditions identified on Table 1.3-D above, all P1 conditions identified were addressed. Remediation of all P2, P3, and P4 conditions identified in 2014 are pending, with all P2 conditions and P3 arrestor conditions scheduled to be remediated by April 17, 2015.

1.3.3 VEGETATION MANAGEMENT PROGRAM DETAIL

Each year, Pepco's system reliability is significantly impacted by trees and tree branches that have contacted, fallen on, or otherwise interfered with poles and wires, causing disruption of service. Due to the density of tree coverage in Pepco's District of Columbia service territory and public concerns relative to tree pruning, challenges exist when balancing the value of trees to customers and communities and the need for reliable electric service. The main objectives that the Vegetation Management (VM) program attempts to balance are safety, reliability, regulatory compliance, environmental stewardship, and customer satisfaction. Pepco's VM program includes all activities from tree pruning through tree removal, as appropriate, to reduce vegetation caused outages.

Pepco's VM priorities are:

- Achieving and maintaining a high degree of reliability across the entire electric system;
- Targeting areas of the electric system found to be most susceptible to outages and damage from trees;
- Performing cyclical pruning to maintain the stability of the system;
- Working with local stakeholders and property owners in the removal of hazard trees in close proximity to Pepco's electric lines;
- Communicating with customers through various media;
- Performing emergency tree and limb removal from electric lines; and
- Assuring that the VM work is performed consistently with good environmental stewardship.

Pepco's VM program in the District of Columbia includes:

- Scheduled two year cyclical maintenance or routine scheduled pruning;
- Unscheduled (non-cycle) maintenance operations; and
- Selective application of herbicide.

Pepco's VM process can be summarized in the following steps:

- Establish an annual VM plan strategy in accordance with regulatory requirements, International Society of Arboriculture Best Management Practices and Pepco VM goals;

- Plan Work – Inspect the feeder to develop a VM work plan that defines the work to be performed;
- Prune/Remove/Clear Trees – VM personnel engage qualified contractors and perform project management and contract administration to complete feeder maintenance as planned;
- Validate completion of work plan – Certified Arborist inspects to validate that work performed is completed in accordance with plan and American National Standards Institute (ANSI) standards; and
- Document and report progress.

Scheduled Pruning

Pepco's scheduled cycle tree maintenance program in the District of Columbia includes a comprehensive inspection by an International Society of Arboriculture (ISA) Certified Arborist to develop a work plan for each feeder on a two-year cycle in accordance with guidelines established in conjunction with the District of Columbia's Urban Forestry Administration (UFA) ANSI standards, and International Society of Arboriculture (ISA) Best Management Practices (BMPs).

Coordination with UFA

The UFA is responsible for the management of the majority of public space trees that grow in proximity to Pepco overhead facilities. Arborists from Pepco and UFA work to identify and eliminate hazardous tree conditions during cycle and unscheduled maintenance operations. Pepco also coordinates with natural resource managers from the National Park Service, the District of Columbia Department of Parks and Recreation, and private property owners.

Despite the good working relationship between Pepco and UFA, challenges remain, especially with respect to VM work associated with the so-called "legacy" trees. District of Columbia statutes and regulations from decades ago resulted in "legacy trees" that impact operations today and have historically limited the degree and technique of vegetation cutback from Pepco power lines. This has resulted in large trees growing through and in close proximity to conductors. Examples of the policies include the following:

1. Section 13 of "An Act for the Preservation of the Public Peace and the Protection of Property within the District of Columbia," approved July 29, 1892. (27 Stat. 324; District of Columbia Official Code § 22-3310) (Emphasis added.)

   1892: *"An act for the preservation of the public peace and the protection of property within the District of Columbia" …unlawful for any person willfully **top**, cut down, remove, girdle, **break, wound, destroy, or in any manner injure** ….any tree not owned by that person…"*

2. Policy produced by District of Columbia, June 9, 1960, "Trees in Public Space: Washington, DC," at pg. 17.

   1960: *"Utility lines must be cleared by the use of directional clearance methods only…..the removal of internal branches to permit passage of utility lines through the trees where necessary"*

Many of the older trees are in conflict with the Pepco distribution system such that the issues with the various trees cannot be resolved without cutting entire "legacy" trees down. No standardized practice or agreement currently exists to resolve these conflicts. Pepco continues to work with UFA to resolve these issues on a case-by-case basis and in accordance with the Vegetation Management Plan for Utility Tree Pruning – District of Columbia (2005 Plan).[24]

Mitigation and Tree Planting Programs

Pepco's tree planting funding mitigates removals and promotes "Right Tree Right Place" best management practices around utility space. In 2014 Pepco planted approximately 350 trees in Washington D.C., and contributed $17,239 to the D.C. Tree Fund.

Selective Application of Herbicide

Pepco's VM program includes an herbicide component. An herbicide plan is developed each year to control brush and sprout growth where trees have been previously cleared. Herbicide applications are used selectively on rights-of-way, easements and, when granted permission, on private property, throughout the Pepco system in the District of Columbia. The use of herbicides follows a systematic approach with the aim of supplementing manual or mechanical

[24] The 2005 Plan was produced as a result of a tree-trimming working group including members from the District Department of Transportation's Urban Forestry Administration and Pepco's Vegetation Management team. Pepco filed the 2005 Plan on March 17, 2005 in Formal Case No. 982.

tree/brush removal, re-establishing rights-of-way (ROW), carrying out aggressive wall pruning to remove undergrowth and overhangs, stop re-growth of incompatible species, maintain overall clearance and fight encroachment until the next cycle. The herbicides used on Pepco's ROW are extremely low in toxicity and are biodegradable. Most herbicides affect treated plants by inhibiting the production of chemicals which plants need to produce chlorophyll, or by inhibiting the formation of leaf-buds. Without chlorophyll production, or functional leaves, the treated plant exhausts its stored food supply and dies. Only herbicides registered by the U.S. Environmental Protection Agency (EPA) and D.C. Department of Environment (DOE) are applied in strict accordance with the label and under the regulation of United States Department of Agriculture (USDA). Pepco contract applicators are supervised by certified commercial pesticide applicators.

Customer Communication Materials

- Provide consistent notification to customers regarding Pepco's VM activities on their property and in their community;
- Provide information to customers explaining the VM program along with a schedule of trim and contact information;
- Make available Pepco forestry representatives to respond to inquiries as work is being done and scheduled;
- Encourage customers to access the Pepco website for more detailed educational material including links to American National Standards Institute (ANSI) A330 standards, Utility Arborist Association, and the "Right Tree, Right Place" program under the Arbor Day Foundation;
- Enable the planners to meet with customers and local officials, or correspond through mail, e-mail, and phone as needed;
- Enable work permits to be obtained in advance of scheduled work to allow work to continue in a coordinated and planned manner;
- Participate in community meetings; and
- Coordinate public awareness of Pepco's VM activities and programs through the use of door hangers that are placed on customer's door prior to start of VM work.

Below is a clip from the Company's 2014 communication materials related to its VM efforts in the District of Columbia. These materials are circulated to District of Columbia customers in accordance with pruning schedules, to inform customers about the planned pruning of trees on their property.

Customer Communications: VM

Pepco and the Arbor Day Foundation are offering free trees to help you conserve energy.

Trees are available on a first-come, first-serve basis from March 20 through June 6, while supplies last. Distribution is limited to two, 2-to-4 foot trees per customer. To get your free trees, visit www.arborday.org/Pepco today.

Properly planted trees help reduce energy use through summer shading and by slowing winter winds. As your trees grow, they will have the potential to lower energy bills by 15 to 30 percent.

pepco
Energy for a changing world.℠

To help you plant your tree in the right place, the Arbor Day Foundation offers you an online mapping tool that will:

- Map your house
- Show you the right trees for your area
- Locate the best place to plant them
- Calculate how much you can expect to save

To learn more about this program, please visit www.arborday.org/pepco

ENERGY-SAVING TREES

Arbor Day Foundation®

30906-I-0276

1.3.4 INDUSTRY COMPARISONS[25]

The Industry Comparisons section contains industry comparisons of transmission and distribution operations and performance. The comparisons of reliability indices are provided in Figures 1.3-A through 1.3-D in response to Commission directives in Formal Cases No. 766 and 982.

Institute of Electrical and Electronics Engineers (IEEE) Benchmarking Survey Results

Each year, Pepco participate in the annual Transmission and Distribution System Benchmarking Study conducted by IEEE. The 2013 Benchmarking Study was developed by IEEE using member companies' actual 2012 data and applying IEEE standards for determining Major Event Day exclusions. Included in this section are comparisons of 2013 SAIDI, SAIFI and CAIDI performance indices for the member utilities of the IEEE benchmarking survey.

Although Pepco's District of Columbia service territory did not participate separately in the study, the Company has calculated separate values for Pepco's District of Columbia territory in both 2013 and 2014, using equivalent Major Event Day exclusions, and has indicated both of these reliability results on the following charts. Note that while Pepco's 2014 reliability results that are reported in the following graphs are not directly comparable to the data used in the 2013 study, the Company's 2014 results clearly illustrate the significant improvement made by Pepco since 2013. See Figure 1.3-A through Figure 1.3-D.

[25] In Order No. 15568 paragraph 57, the Commission ordered the following:
57. Pepco IS DIRECTED to provide a report on the Electric Utilities Best Practices, consistent with Paragraph 50 of this Order. This report shall be included in that 2010 Consolidated Report; and shall include the best practices of the electric utility industry on improving reliability and outage restoration (from the Benchmarking Studies). Pepco shall submit a continuous improvement plan, including resourcing, specific performance targets, and milestone dates to achieve the reliability and outage restoration performance of the best (quartile) performing (comparable) utilities in the Benchmarking Studies.

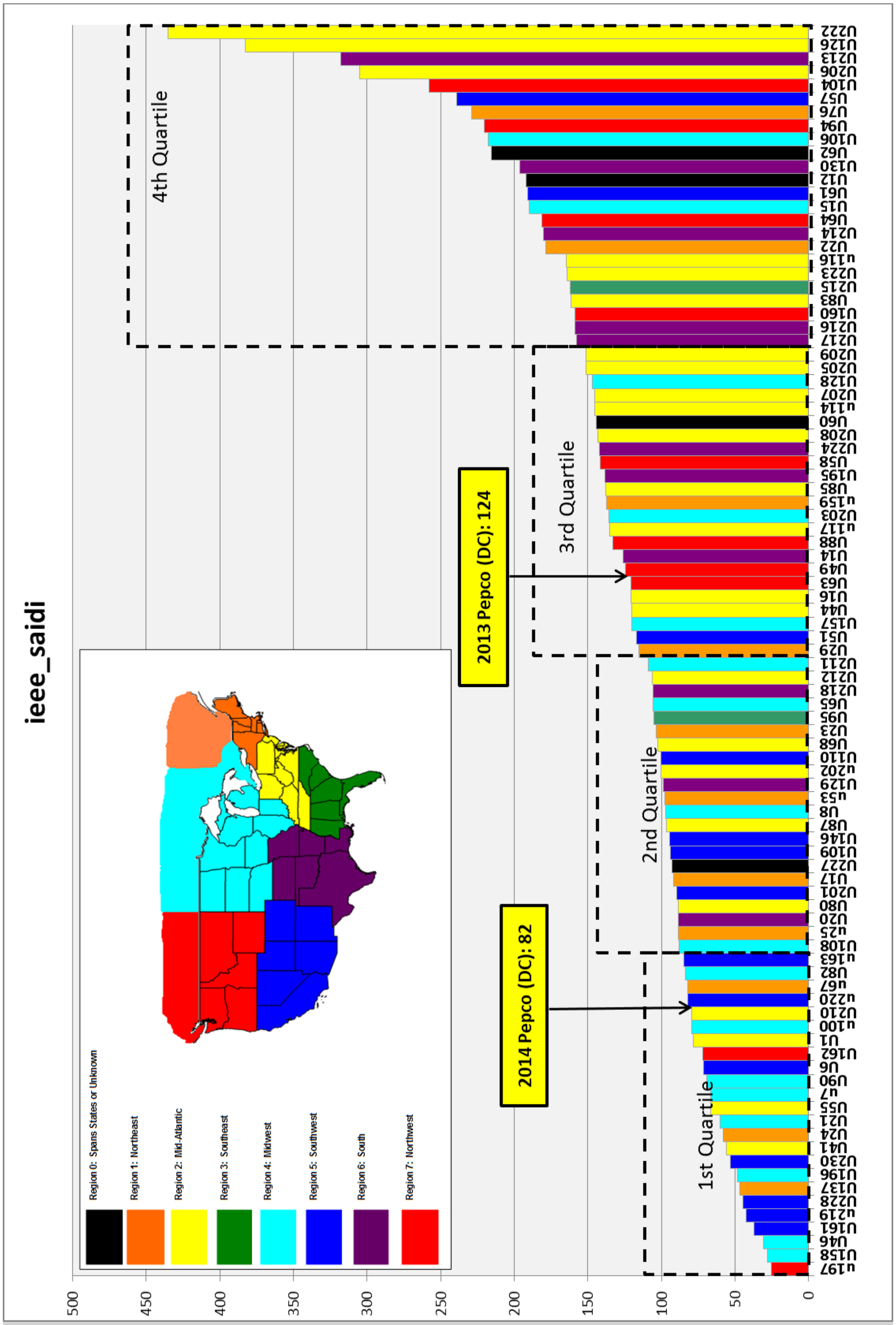

ieee_saidi
4th Quartile
3rd Quartile
2nd Quartile
1st Quartile
2013 Pepco (DC): 124
2014 Pepco (DC): 82
Region 0: Spans States or Unknown
Region 1: Northeast
Region 2: Mid-Atlantic
Region 3: Southeast
Region 4: Midwest
Region 5: Southwest
Region 6: South
Region 7: Northwest

Figure 1.3-A

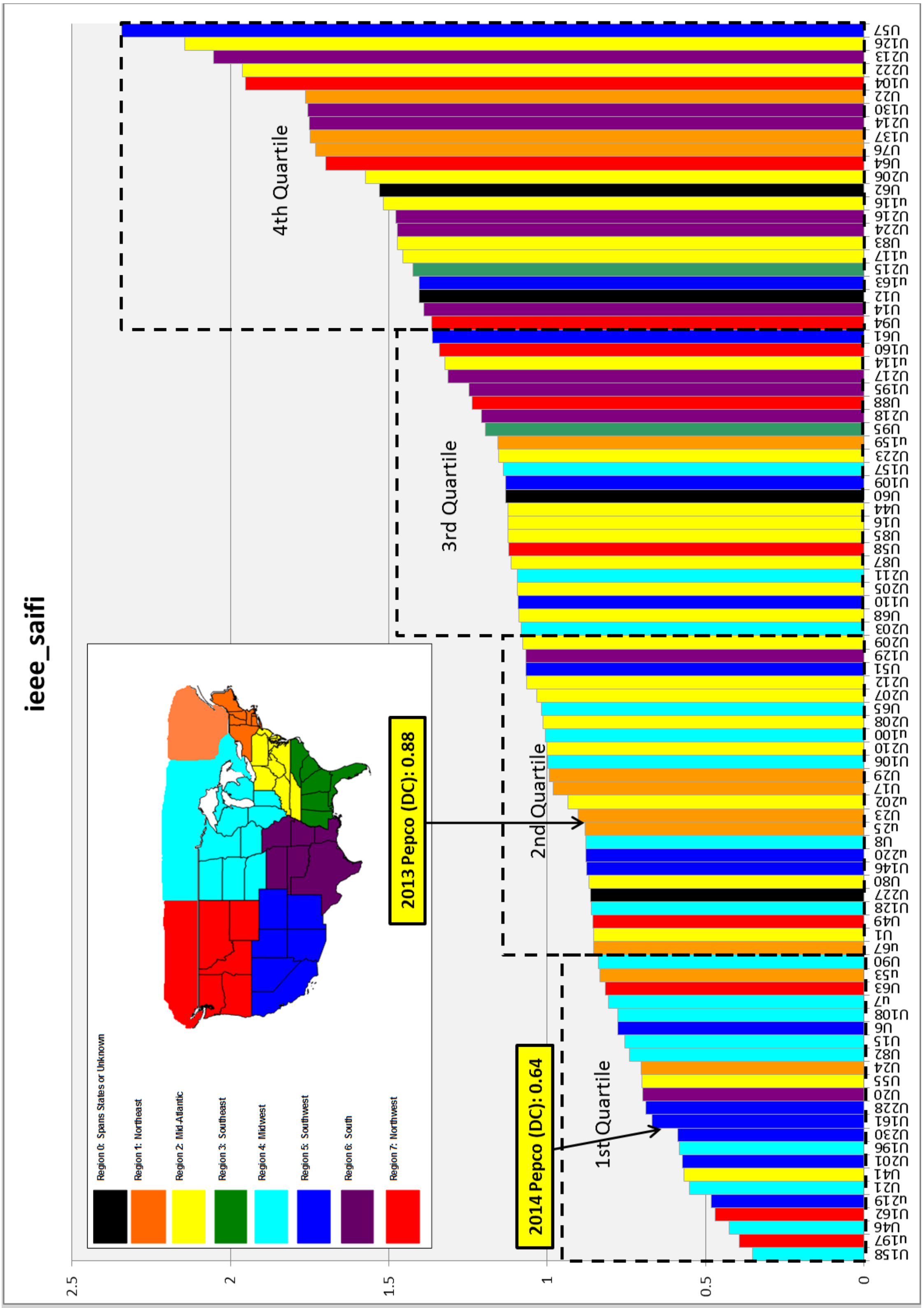

ieee_saifi
4th Quartile
3rd Quartile
2nd Quartile
1st Quartile
2013 Pepco (DC): 0.88
2014 Pepco (DC): 0.64
Region 0: Spans States or Unknown
Region 1: Northeast
Region 2: Mid-Atlantic
Region 3: Southeast
Region 4: Midwest
Region 5: Southwest
Region 6: South
Region 7: Northwest

Figure 1.3-B

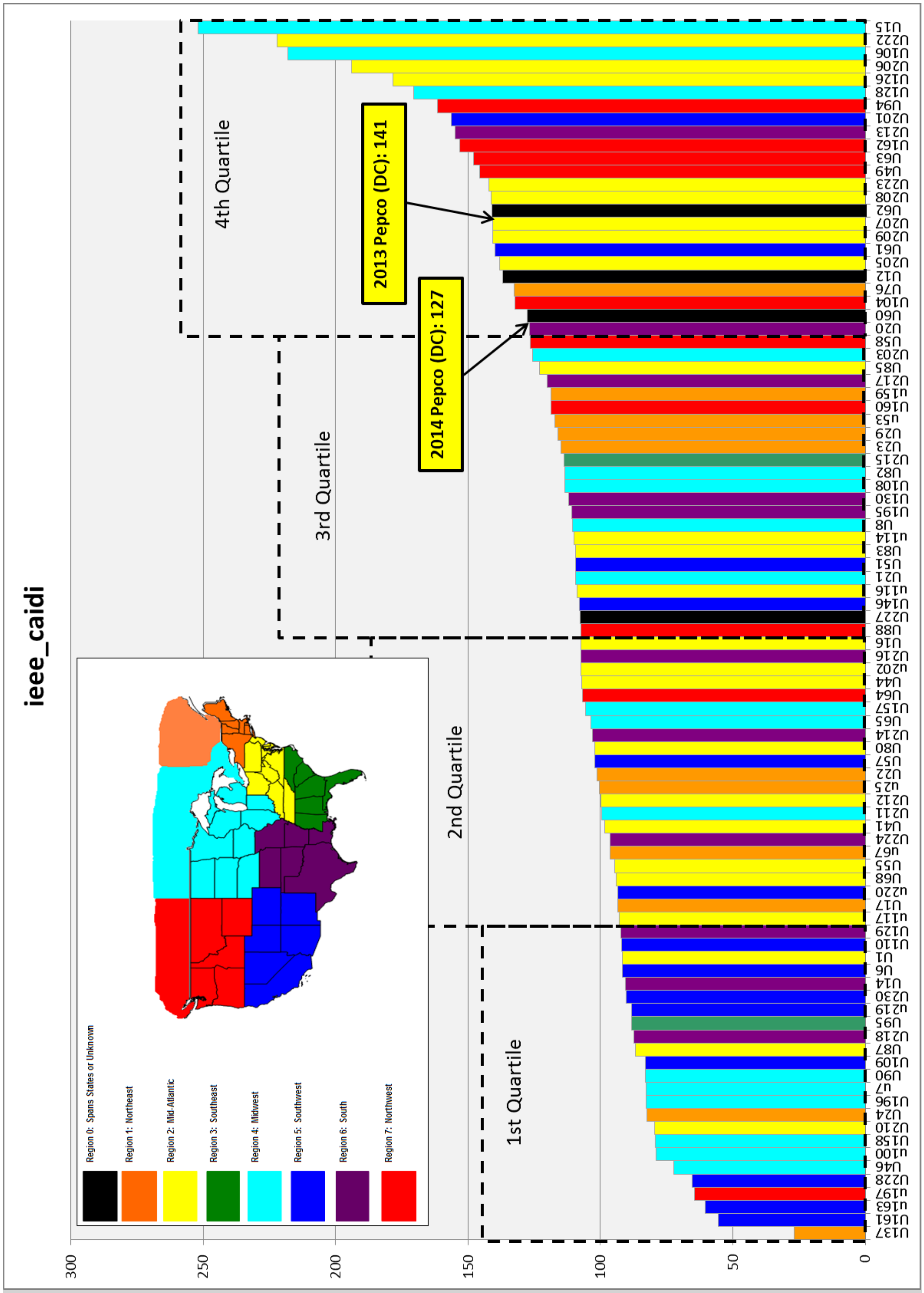

ieee_caidi
4th Quartile
3rd Quartile
2nd Quartile
1st Quartile
2013 Pepco (DC): 141
2014 Pepco (DC): 127
Region 0: Spans States or Unknown
Region 1: Northeast
Region 2: Mid-Atlantic
Region 3: Southeast
Region 4: Midwest
Region 5: Southwest
Region 6: South
Region 7: Northwest
300
250
200
150
100
50
0

Figure 1.3-C

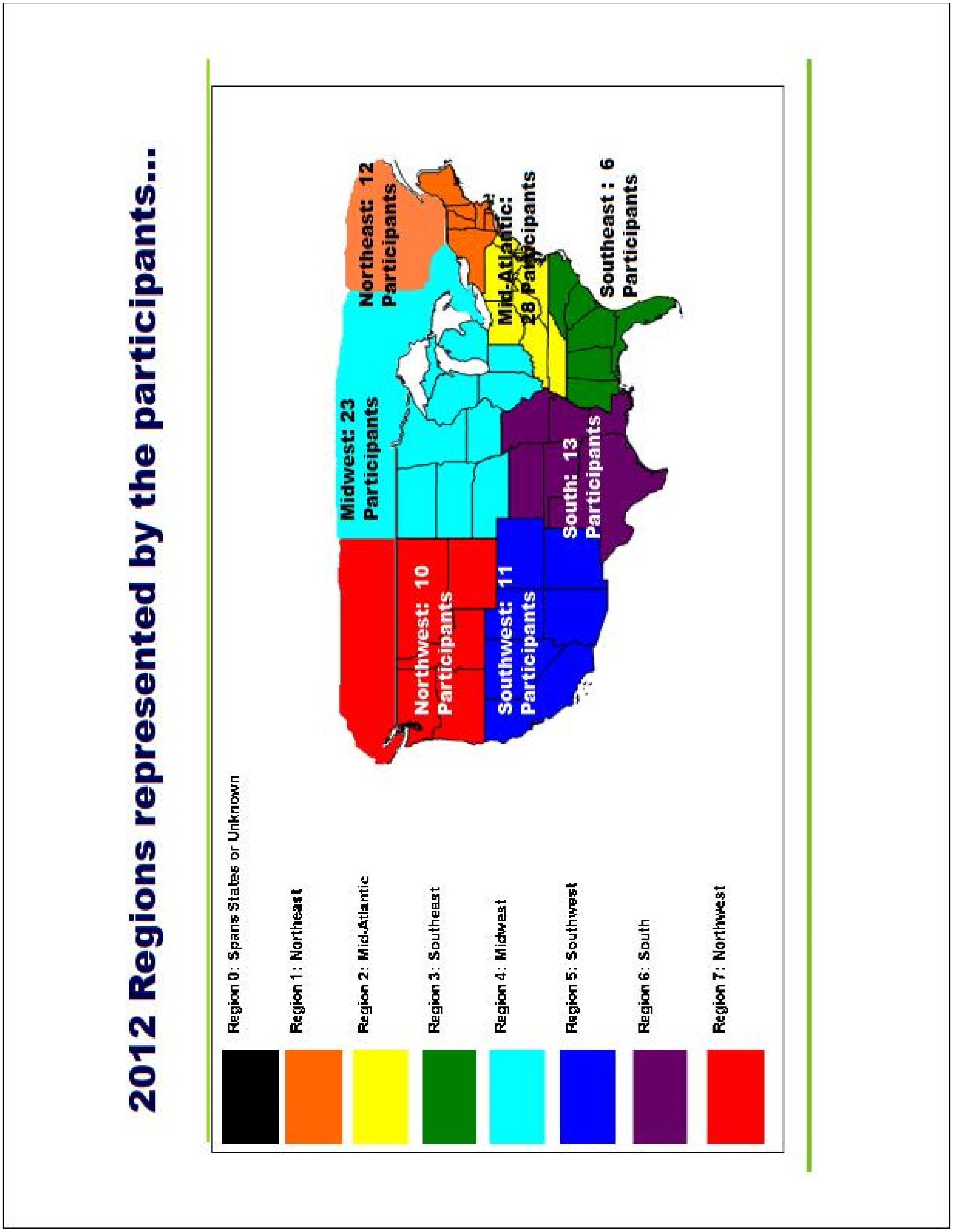

2012 Regions represented by the participants...
Region 0: Spans States or Unknown
Region 1: Northeast
Region 2: Mid-Atlantic
Region 3: Southeast
Region 4: Midwest
Region 5: Southwest
Region 6: South
Region 7: Northwest
Northeast: 12 Participants
Mid-Atlantic: 28 Participants
Southeast : 6 Participants
Midwest: 23 Participants
South: 13 Participants
Northwest: 10 Participants
Southwest: 11 Participants

Figure 1.3-D

1.3.5 BEST PRACTICES

Implementation of Twenty Best Practices[26,27,28,29]

[26] In Order No. 16091 paragraph 61, the Commission stated the following:

61. Pepco IS DIRECTED to include a "2011 Best Practices Report" in its 2011 Consolidated Report describing its on-going implementation of no fewer than twenty of the best practices identified in the 2009 Polaris Program, consistent with Paragraph 22 of this Order;

22. Decision. First, we conclude that Pepco has complied with the requirements of Paragraphs 32 and 52 of Order No. 15568. Second, as to the Staff's Recommendation that Pepco file a "Best Practices Report" from the PA Consulting's 2009 Polaris Transmission and Distribution Benchmarking Program, we agree that a report may be helpful in assuring that best practices continue to be implemented. Therefore, the Commission shall require that Pepco include in its 2011 Consolidated Report a section entitled "2011 Best Practices Report" in which Pepco shall describe its on-going implementation of no fewer than twenty of the best practices identified in the 2009 Polaris Program included in the 2010 Consolidated Report as Appendix 2D. The twenty best practices selected by Pepco should be those judged to have the most impact on reliability and outage restoration performance. Pepco shall report on all its activities during 2010 to implement these best practices, including data on staffing levels, expenses and results. This requirement is separate from the requirement to produce a "Continuous Improvement Plan," as is described more fully in Section IV.A.1.f.

[27] In Order No. 15632 issued in these proceedings, the Commission states at paragraph 5 the following:

5. Pepco shall file with the Company's annual Consolidated Reports to the Commission data on the Company's measures to continue to address each of the recommendations made by PA Consulting and the effectiveness of the Company's approaches to improve CAIDI and SAIDI to at least the average of PA Consulting benchmarks. This obligation shall begin with the 2010 Consolidated Report.

[28] Order No. 16623 states the following at paragraphs 29 and 52:

29. Decision: The Commission agrees with the Staff that the information provided in the 2011 Consolidated Report does not allow a complete assessment of Pepco's progress in implementing the twenty "best practices." Therefore, we direct Pepco to provide further information for each "best practice," including staffing levels, expenses and schedules and percentage of completion. In those cases where no incremental expenses or staffing occurred, we require Pepco to identify the other activities with which these best practices were combined "for efficiency" and provide expenses and staffing levels associated with those activities. In order to provide a comparative analysis, we require Pepco to provide budget vs. actual expenses and staffing levels for the period 2007 to 2011. We also require Pepco to provide an assessment of the progress it has made in fully implementing each best practice. In addition we require Pepco to identify whether and how each best practice has been incorporated within its Comprehensive Reliability Plan.[96] This information shall be included in the 2012 Consolidated Report.

52. Pepco is DIRECTED to prepare a report on best practices consistent with paragraph 29 herein;

[29] Order No. 16975 states the following at paragraphs 85 and 114:

85. Decision: The Commission finds that Pepco has failed to comply completely and explicitly with the requirement that it identify "whether and how each best practice has been incorporated within its Comprehensive Reliability Plan." While Pepco includes some of its best practices as part of the REP, it does not discuss each best practice, as required by Order No. 16623. The Commission agrees with OPC that "including these practices within the REP would be an effective means for improving reliability." Pepco is required to fully address the role that each best practice has in the REP in its 2013 Consolidated Report and in future Consolidated Reports. If a best practice is not part of the REP, then Pepco shall explicitly state that fact.

114. Pepco is DIRECTED to address the role each best practice has in the Reliability Enhancement Plan consistent with paragraph 85 herein;

Pepco continues to follow the best practices discussed in the 2014 Consolidated Report. The status, maturity/implementation levels, staffing impacts and REP drivers remain unchanged.

Approximate Costs Attributable to the District of Columbia

Regarding the costs of implementing best practices, Pepco must provide the following explanations:

1. **Cost allocation across companies and jurisdictions:** Many of the activities associated with the best practices described herein are performed by centralized teams supporting all of PHI's companies or teams supporting Pepco system-wide. Budgets and expenditures of departments that serve all of PHI are not directly attributable to one jurisdiction or another.
2. **Redirection of resources:** The implementation of some best practices by these teams did not necessarily require additional resources, but rather either required the allocation of additional duties or a shift in duties from previous practices to the newly-identified best practices. Further, activities supporting the best practices are only a subset of all work done by these departments, and the activities of many of the primary personnel involved in executing and advancing these best practices are allocated to general overhead accounts.
3. **Reported best practices costs:** The Company has attempted to allocate estimated resource hours and associated activity based costs in these centralized functions to the District of Columbia where possible. (See Table 1.3-E.) Where defined expenditures for process and reliability improvement exist, Pepco cites these expenditures in the attached table.

Best Practice #	Activity Supporting Best Practices	Average Hourly ATP*	Approximate Costs Attributable to District of Columbia															
			2007		2008		2009		2010		2011		2012		2013		2014	
			Hours	Cost	Hours	Cost	Hours	Cost	Hours	Cost	Hours	Cost	Hours	Cost	Hours	Cost	Hours	Cost
1-4	Reliability Centered Maintenance (RCM) Planning	$ 96.00	2000	$ 192,000.00	2000	$ 192,000.00	2000	$ 192,000.00	2000	$ 192,000.00	2500	$ 240,000.00	2500	$ 240,000.00	2500	$ 240,000.00	2500	$ 240,000.00
	Eqipment Condition Assessment (ECA)	$ 96.00	1500	$ 144,000.00	1500	$ 144,000.00	2000	$ 192,000.00	2000	$ 192,000.00	2000	$ 192,000.00	2040	$ 195,840.00	2040	$ 195,840.00	2040	$ 195,840.00
	Dissolved Gas Analysis (DGA)	$ 96.00	0	$ -	250	$ 24,000.00	400	$ 38,400.00	500	$ 48,000.00	500	$ 48,000.00	500	$ 48,000.00	500	$ 48,000.00	500	$ 48,000.00
5	Priority Feeder Analysis	$ 96.00	80	$ 7,680.00	80	$ 7,680.00	80	$ 7,680.00	120	$ 11,520.00	120	$ 11,520.00	200	$ 19,200.00	200	$ 19,200.00	200	$ 19,200.00
6	QA for VM work	$ 85.00	2000	$ 170,000.00	2000	$ 170,000.00	2000	$ 170,000.00	2000	$ 170,000.00	2000	$ 170,000.00	2000	$ 170,000.00	2000	$ 170,000.00	2000	$ 170,000.00
7	Responsible Engineer Assignments	$ 96.00	0	$ -	0	$ -	1200	$ 115,200.00	3000	$ 288,000.00	5000	$ 480,000.00	5500	$ 528,000.00	5500	$ 528,000.00	5500	$ 528,000.00
7	Large Project Management	$ 125.00	2000	$ 250,000.00	2000	$ 250,000.00	2000	$ 250,000.00	2000	$ 250,000.00	2000	$ 250,000.00	2000	$ 250,000.00	2000	$ 250,000.00	2000	$ 250,000.00
8	WMIS/SAP PM Integration	$ 96.00		$ -		$ -		$ -	500	$ 48,000.00	1200	$ 115,200.00	1200	$ 115,200.00	1200	$ 115,200.00	1200	$ 115,200.00
9	Critical Customer Analysis	$ 85.00	88	$ 7,480.00	88	$ 7,480.00	88	$ 7,480.00	88	$ 7,480.00	122	$ 10,370.00	122	$ 10,370.00	122	$ 10,370.00	122	$ 10,370.00
10	ETR Process Improvement	$ 96.00		$ -		$ -		$ -		$ -	1600	$ 153,600.00	1500	$ 144,000.00	1500	$ 144,000.00	1500	$ 144,000.00
11	Shift coverage adequacy	Please see narrative for explanation of impacts																
12	Ongoing revision of Stepped restoration processes (Control Center allocation)	$ 85.00	200	$ 17,000.00	200	$ 17,000.00	200	$ 17,000.00	200	$ 17,000.00	200	$ 17,000.00	200	$ 17,000.00	200	$ 17,000.00	200	$ 17,000.00
13	SCADA upkeep O&M increment	$ 90.00	2000	$ 180,000.00	2000	$ 180,000.00	2000	$ 180,000.00	2000	$ 180,000.00	2000	$ 180,000.00	2000	$ 180,000.00	2000	$ 180,000.00	2000	$ 180,000.00
14-17	VM Program Management including hazard tree removal, monitoring preventative vs corrective efforts, maintaining specifications, and utilization of cycle based trimming	$ 85.00	1000	$ 85,000.00	1000	$ 85,000.00	1000	$ 85,000.00	1000	$ 85,000.00	1000	$ 85,000.00	1000	$ 85,000.00	1000	$ 85,000.00	1000	$ 85,000.00
18	Maintaining Metrics for VM	$ 85.00	125	$ 10,625.00	125	$ 10,625.00	125	$ 10,625.00	125	$ 10,625.00	125	$ 10,625.00	125	$ 10,625.00	125	$ 10,625.00	125	$ 10,625.00
20	Feeder Trimming Prioritization	$ 96.00	60	$ 5,760.00	60	$ 5,760.00	80	$ 7,680.00	80	$ 7,680.00	80	$ 7,680.00	80	$ 7,680.00	80	$ 7,680.00	80	$ 7,680.00

* The average fully loaded activity based cost for resources performing or the activity for 2007-2014

Table 1.3-E: Approximate Costs Attributable to the District of Columbia

ECA Team[30][31]

Pepco completed four quarterly ECA meetings in 2014. As a result of the ECA, Pepco replaced two large power transformers (TR) (Southwest 3 TR, Southwest 4 TR) and a smaller power transformer (12th Street 1 TR).

and is in the process of replacing another larger power transformer (New Jersey Avenue 4 TR). For 2015, Pepco is scheduled to replace seven more power transformers [O Street #1 TR (DC), Palmer Corner #3 TR (MD), Suitland #2 TR (MD), Norbeck #2 & #4 TRs (MD), and Rossmoor #1 & #2 TRs (MD)].

Pepco also repaired four Transformer Load Tap Changers (LTCs) (Twenty Second Street #4 TR; Florida Avenue #2 TR and #4 TR; Tenth Street #2 TR) and conducted 32 LTC Inspection/Test PM during the year 2014.

Pepco replaced one circuit breaker in the District of Columbia (Buzzard Point 1B 13843) as a direct result of the ECA process. In addition, Pepco is scheduled to replace up to eighteen large substation circuit breakers budget in the District of Columbia from 2015-2018.

Pepco has also replaced six station battery banks (Fifty Third Street, Alabama Avenue # 1 & 2, Southwest, and Benning #1 & 2) in the District of Columbia in 2014 as a result of the ECA process.

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[30] Order No. 16975 states the following at paragraphs 39 and 98:

39. *Decision: …Specifically, the Commission directs Pepco to report on the recommendations and actions taken by the ECA team, including membership lists, meeting dates and minutes, analyses of impact of the ECA team on maintenance or replacement policies and asset management strategy and tactics. We also require Pepco, to the extent not already included, to report on costs for recommended equipment replacements and the projected benefits of those replacements, as OPC suggests. Further, the Commission directs Pepco to provide an explanation of how the work of the ECA team relates to other Pepco reliability initiatives and include a discussion of the equipment failure analysis as part of future years' Consolidated Reports.*
98. *Pepco is DIRECTED to include a report on the results of its Equipment Condition Assessment work consistent with paragraph 39 herein;*

[31] The ECA minutes have been modified in response to the Commission's directive "to include a brief description of the project status *(i.e.*, whether it is deferred, completed or ongoing)," *In The Matter of the Annual Consolidated Report of the Potomac Electric Power Company*, Formal Case No. PEPACR-2014-01, Order No. 17816 at P 231 (February 27, 2015).

Included at the end of this section are the ECA membership lists, meeting dates and minutes (which include the analyses) for four quarters of 2014.

A discussion of costs and benefits, as required by Order No. 16975, is provided below.

ECA driven projects generally consist of planned projects to replace large, high cost, long lead time primary components within substations. Targets for these projects are usually selected by condition based criteria such as dissolved gas in oil analysis. However, due to certain external drivers (such as load, location, environment and system criticality), these replacements may also be triggered by historic performance of a component. These projects are primarily driven by Pepco's need to manage contingency risk and do not result from cost / benefit analysis. Replacements are usually in-kind or upgrades depend on component availability at the time. System emergencies can alter the prioritization of these projects.

The utility's obligation to serve requires substation design criteria which provides redundancy and risk management. Although substation component failures are rare in comparison to feeder components, the loss of a critical substation asset could result in long term outages affecting thousands of customers. The provision of redundant components, backup sources, and minimization of single points of failure in substation designs reduces this risk and generally allows Pepco to perform routine maintenance and upgrades without the need for planned outages. This redundancy also allows Pepco to manage contingencies and continue service despite the loss of a major substation component. As such, substation reliability is maintained by keeping both the primary and redundant assets in good working condition. Therefore, condition and criticality of assets predominantly drives substation reliability programs and many projects in the substation reliability category do not directly translate to improvements in outage frequency and duration. This concept is known as Reliability Centered Maintenance (RCM), the principles of which dictate that predictive maintenance activities serve to identify failing assets prior to catastrophic failure.

Substation assets are inspected under various inspection programs, including visual, infrared, and oil sampling where applicable. Based on observed condition and potential system risk, assets are cleared for normal duty, scheduled for closer monitoring, scheduled for maintenance, selected for immediate replacement, or added to prioritized programmatic replacement programs, as appropriate. Pepco's ECA process is the vehicle used to identify substation assets for condition-driven replacement in order to maintain the reliability of the substation. The ECA process cooperatively analyzes major equipment condition, makes major repair / replace decisions utilizing various subject matter experts and through consensus, prioritizes candidates for replacement on a quarterly basis.

Substation assets such as transformers, breakers, and larger components typically have long lead times and must be ordered well in advance (months to years) of anticipated need. For this reason, a number of replacement projects are kept in the project pipeline at any given time. This allows Pepco to substitute one project for another in situations where long lead times would subject the system and customers to significant reliability risk. Projects are engineered and built using standard designs and approved equipment.

Generally, substation reliability projects cannot be translated into measurable or forecasted SAIDI or SAIFI benefits. The presence of redundant systems within substations reduces or eliminates the direct threat to customer reliability from the loss of a single asset. However, the failure of such assets reduces the security of supply to feeders and elevates the risk of large scale customer outages. Given the potential for customer impacts along with the long replacement cycle of major substation assets, Pepco replaces these assets proactively based on condition assessment and the desire to manage such contingency risk.

PHI Pepco-DC Region Equipment Condition Assessment

Meeting Minutes - 1Q 2014 (4/28/14)

Transformers

Work Priority:

- Sub 21 L Street – 2 TR – $2.0 million estimated cost. DC; Distribution Substation. Serves feeders: 14501, 14507, 14502, 14508, 14504, 14511, 14503, 14510, 14505, 14509, 14506, and 14512. (Keep monitoring oil and gas)

- Sub 126 12th Street – 3 TR – $1.3 million estimated cost. DC; Distribution Substation. Serves feeders: 370, 218, 371, 232, 230, and 233. (Keep monitoring oil and gas)

2014 Capital Work:

- Sub 18 Southwest – 3 TR (Replace) – $4.4 million actual cost. DC; Distribution Substation. Serves feeders: 15619, 15307, 15294, 15613, 15607, 15301, 15302, 15309, 15620, 15298, 15604, 15604, 15871, 15303, 15621, 15296, 15611, 15308, 15615, 15624, 15605, 15299, 15311, 15875, 15306, 15305, 15623, 15601, 15297, 15310, 15309, 15606, 15610, 15295, 15616, 15874, 15622, 15312, 15304, 15603, 15609, 15614, and 15872. (Working on it)
- Sub 18 Southwest – 4 TR (Replace) – $4.4 million estimated cost. DC; Distribution Substation. Serves feeders: 15619, 15307, 15294, 15613, 15607, 15301, 15302, 15309, 15620, 15298, 15604, 15604, 15871, 15303, 15621, 15296, 15611, 15308, 15615, 15624, 15605, 15299, 15311, 15875, 15306, 15305, 15623, 15601, 15297, 15310, 15309, 15606, 15610, 15295, 15616, 15874, 15622, 15312, 15304, 15603, 15609, 15614, and 15872. (Working on it)
- Sub 161 New Jersey – 4 TR (Replace) – $2.1 million estimated cost. DC; Distribution Substation. Serves feeders: 496, 495, 345, 499, 348, 347, 479, 349, and 494. (Plan to be done this year)

2017 Capital Work:

- Sub 38 Harrison – 1 TR (Trend) – $1.3 million estimated cost. DC; Distribution Substation. Serves feeders: 14501, 14628, 14894, 14891, 14352, 14898, 14900, 14629, 14895, 14899, 14893, 14896, 14897, 15930, 14351, 14890, and 14892. (Keep monitoring oil and gas. Will be retired in 2017)
- Sub 126 12th Street – 1 TR (Replace) – $1.3 million actual cost. DC; Distribution Substation. Serves feeders: 370, 218, 371, 232, 230, and 233. (Keep monitoring oil and gas. Will be retired in 2017)

Action Items:

Substation Engineering Action Items:

- Sub 150 Twining City 3 TR, need update
- CVG092 Old Naval Hospital 1 TR, on hold per customer

Asset Performance & Reliability Action Items:

- Blue Plains 23106 and 23107, sponsor the replacements in 5 years budget
- Sub 2 O St. 1 TR, sponsor a replacement in 10 years plan

Chemistry Lab Action Item:

- Sub 126 12th St. 1 TR, sample oil

Distribution Engineering Action Item:

- CVG120 DC Village B-1413 Feeder 14758, need an update

Load Tap Changers

Work Priority:

- Sub 129 Van Ness – 1 TR – $3.5 million estimated replacement cost. DC; Distribution Substation. Serves feeders: 14150, 14149, 14147, 15867, 14301, 14321, 14144, 14625, 14142, 14328, 14145, 14324, 14302, 14143, 14139, 14322, 14132, 14148, 14306, 14134, 14133, 14624, 14303, 14141, 14329, 14325, 14140, 14323, 14304, 14330, 14136, 14626, 14327, 14305, 14146, 14135, 14326, 15943, 15944, 15945, 15946, 15947, 15948, 15949, and 15950. (Keep monitoring oil and gas)
  Trend

2014 Capital Work:

- ~~Sub 52 Tenth Street – 2 TR. **Completed**~~
- Sub 52 Tenth Street – 4 TR. (On going)
- Sub 146 Oliver Street – 1 TR – $1.3 million estimated cost. DC; Distribution Substation. Serves feeders: 128 and 467. (On going)

Action Items:

Asset Performance & Reliability Action Item:

- Sponsor Sub 150 Twinning City 3 TR, sponsor a replacement in 10 years plan

Breakers

2014 Capital Work:

- Sub 42 Buzzard – 1B 13843 – $300K estimated cost. DC, Circuit breaker. Serve feeder 13843. (Keep monitoring oil and gas)
- Sub 42 Buzzard – K2-32 – $300K estimated cost. DC, Circuit breaker. (Keep monitoring oil and gas)

2017 Capital Work:

- Sub 190 Fort Slocum – 3B 69054, $175,000 estimated cost. DC, Circuit breaker. Serve feeder 69054. (Put it in 2017 budget)

Action Items:

Asset Performance & Reliability Action Items:

- O Street Sub 2 – Sponsor four breaker replacements in capital budget
- Tenth Street Sub 52 – Sponsor four breaker replacements in capital budget

Substation Engineering Action Item:

- Buzzard Point Sub 42 – Budgeted 5 years replacements of eight breakers

Meeting Attendees:

[Names redacted and replaced with department and job title.]

- Asset Performance: Mgr Asset Performance NERC, Sr Supervising Engineer NERC, Lead Engineer NERC, Engineer 2 NERC, Supervising Chemist NERC
- Electric Maintenance: Sr Engineering Associate NERC
- Pepco Distribution Planning: Sr Supervising Engineer NERC, Lead Engineer NERC
- Pepco Substation Engineering: Sr Supervising Engineer NERC, Engineer 2 NERC, Manager of Substation Engineering – Pepco, Technical Assistant A NERC

- Pepco-System Operations: Sr System Operator NERC, System Operations Work Coordinator NERC, Mgr Control Room Ops NERC
- Substation Eng T&D: Mgr Substation Engineering NERC
- Corporate Insurance: Finance & Treasury Manager NERC

PHI Pepco-DC Region Equipment Condition Assessment

Meeting Minutes - 2Q 2014 (7/15/14)

Transformers

Work Priority:

- Sub 21 L Street – 2 TR – $2.0 million estimated cost. DC; Distribution Substation. Serves feeders: 14501, 14507, 14502, 14508, 14504, 14511, 14503, 14510, 14505, 14509, 14506, and 14512. (Keep monitoring oil and gas)
  Trend oil
- Sub 126 12th Street – 3 TR – $1.3 million estimated cost. DC; Distribution Substation. Serves feeders: 370, 218, 371, 232, 230, and 233. (Keep monitoring oil and gas)
  Trend oil
- CVG092 Old Naval Hospital 1 TR (Trend) (Keep monitoring oil and gas)

2014 Capital Work:

- ~~Sub 18 Southwest – 3 TR (**Work Completed**) – $4.5 million actual cost. DC; Distribution Substation. Serves feeders: 15619, 15307, 15294, 15613, 15607, 15301, 15302, 15309, 15620, 15298, 15604, 15604, 15871, 15303, 15621, 15296, 15611, 15308, 15615, 15624, 15605, 15299, 15311, 15875, 15306, 15305, 15623, 15601, 15297, 15310, 15309, 15606, 15610, 15295, 15616, 15874, 15622, 15312, 15304, 15603, 15609, 15614, and 15872.~~
- ~~Sub 18 Southwest – 4 TR (**Work Completed**) – $3.5 million actual cost. DC; Distribution Substation. Serves feeders: 15619, 15307, 15294, 15613, 15607, 15301, 15302, 15309, 15620, 15298, 15604, 15604, 15871, 15303, 15621, 15296, 15611, 15308, 15615, 15624, 15605, 15299, 15311, 15875, 15306, 15305, 15623, 15601, 15297, 15310, 15309, 15606, 15610, 15295, 15616, 15874, 15622, 15312, 15304, 15603, 15609, 15614, and 15872.~~
- ~~Sub 126 12th Street – 1 TR (**Work Completed**) – $1.3 million actual cost. DC; Distribution Substation. Serves feeders: 370, 218, 371, 232, 230, and 233.~~
- Sub 161 New Jersey – 4 TR (Replace) – $2.1 million estimated cost. DC; Distribution Substation. Serves feeders: 496, 495, 345, 499, 348, 347, 479, 349, and 494. (Plan to be done this year)

2017 Capital Work:

- Sub 38 Harrison – 1 TR (Trend) – $1.3 million estimated cost. DC; Distribution Substation. Serves feeders: 14501, 14628, 14894, 14891, 14352, 14898, 14900, 14629, 14895, 14899, 14893, 14896, 14897, 15930, 14351, 14890, and 14892. (Keep monitoring oil and gas. Will be retired in 2017)

Other Work:

- Sub 83 Blue Plains Reactor (R)-23106 and R-23107 replacement in next 5 years
- Sub 2 O St. 1 TR replacement in next 10 years

Action Items:
Substation Engineering Action Item:

- Sub 150 Twining City 3 TR, need an update

Load Tap Changers

Work Priority:

- Sub 129 Van Ness – 1 TR – $3.5 million estimated replacement cost. DC; Distribution Substation. Serves feeders: 14150, 14149, 14147, 15867, 14301, 14321, 14144, 14625, 14142, 14328, 14145, 14324, 14302, 14143, 14139, 14322, 14132, 14148, 14306, 14134, 14133, 14624, 14303, 14141, 14329, 14325, 14140, 14323, 14304, 14330, 14136, 14626, 14327, 14305, 14146, 14135, 14326, 15943, 15944, 15945, 15946, 15947, 15948, 15949, and 15950. (Scheduled Preventive Maintenance)
  Trend

2014 Capital Work:

- ~~Sub 10 Florida Avenue – 2 TR and 4 TR. (**Completed**)~~
- ~~Sub 124 Twenty Second Street – 4 TR. (**Completed**)~~
- Sub 146 Oliver Street – 1 TR (Replace the transformer) – $1.3 million estimated cost. DC; Distribution Substation. Serves feeders: 128 and 467. (Plan to be done this year)

Action Items:
Asset Performance & Reliability Action Items:

- Sponsor Sub 150 Twinning City - 3 TR in 10 years replacement plan
- Sponsor Sub 2 O Street – 1 TR replacement

Breakers

2014 Capital Work:

- Sub 42 Buzzard – K2-32 – $300K estimated cost. DC, Circuit breaker. (On going)

2017 Capital Work:

- Sub 190 Fort Slocum – 3B 69054 $175,000 estimated cost. DC, Circuit breaker. Feeder 69054 (Put in 2017 budget)

Action Items:
Asset Performance & Reliability Action Items:

- O Street Sub 2 – Sponsor four breaker replacements in capital budget
- Tenth Street Sub 52 – Sponsor four breaker replacements in capital budget

System Operations Action Item:

- Sub 42 Buzzard – K2-32 breaker, provide an outage schedule to replace the breaker.

Batteries

Work Priority:

- Sub 13 Harvard Street – Battery 1 – $95,000 estimated cost for replacement. DC. Battery (Plan to be done this year)
- ~~Sub 48 Fifty Third Street – Battery 1 **(Completed)**~~
- ~~Sub 136 Alabama Avenue – Battery 2 **(Completed)**~~

Meeting Attendees:

[Names redacted and replaced with department and job title.]

- Asset Performance: Mgr Asset Performance NERC, Sr Supervising Engineer NERC, Lead Engineer NERC, Engineer 2 NERC, Supervising Chemist NERC
- Electric Maintenance: Consulting Engineer NERC, Sr Engineering Associate NERC, Manager of Electric Maintenance NERC
- Pepco Distribution Planning: Sr Supervising Engineer NERC, Lead Engineer NERC
- Pepco Substation Engineering: Sr Supervising Engineer NERC, Engineer 2 NERC, Manager of Substation Engineering, Technical Assistant A NERC
- Pepco-System Operations: Sr System Operator NERC, System Operations Work Coordinator NERC, Mgr Control Room Ops NERC
- Corporate Insurance: Finance & Treasury Manager NERC
- Power Delivery Process Managers: Process Owner Maintenance NERC
- Asset Management: Chief Engineer NERC

PHI Pepco-DC Region Equipment Condition Assessment

Meeting Minutes - 3Q 2014 (10/22/14)

Transformers

Work Priority:

- Sub 21 L Street – 2 TR – $2.0 million estimated cost. DC; Distribution Substation. Serves feeders: 14501, 14507, 14502, 14508, 14504, 14511, 14503, 14510, 14505, 14509, 14506, and 14512. (Keep monitoring oil and gas. Put it in the budget to be replaced)
  Trend oil
- Sub 126 12th Street – 3 TR – $1.3 million estimated cost. DC; Distribution Substation. Serves feeders: 370, 218, 371, 232, 230, and 233. (Keep monitoring oil and gas)
  Trend oil
- CVG092 Old Naval Hospital B-0040, 1 TR. (On going)
  Trend oil

2014 Capital Work:

- Sub 161 New Jersey – 4 TR (Replace) – $2.1 million estimated cost. DC; Distribution Substation. Serves feeders: 496, 495, 345, 499, 348, 347, 479, 349, and 494. (Plan to be done this year)

2017 Capital Work:

- Sub 38 Harrison – 1 TR (Trend) – $1.3 million estimated cost. DC; Distribution Substation. Serves feeders: 14501, 14628, 14894, 14891, 14352, 14898, 14900, 14629, 14895, 14899, 14893, 14896, 14897, 15930, 14351, 14890, and 14892. (Keep monitoring oil and gas. Will be retired in 2017)

Other Work:

- Sub 83 Blue Plains Reactor (R)-23106 and R-23107 replace in next 5 years
- Sub 2 O St. 1 TR replacement in 10 years

Action Items:
Substation Engineering Action Items:
- Sub 150 Sponsor Twining City Sub 150 T3 – need update on status
- CVG120 DC Village B-0413 – 14758 feeder need update on replacement progress

Asset Performance & Reliability Action Item:
- Sub 2 O Street 1TR – Sponsor transformer replacement in 10 year plan

Load Tap Changers

Work Priority:
- Sub 129 Van Ness – 1 TR – $3.5 million estimated replacement cost. DC; Distribution Substation. Serves feeders: 14150, 14149, 14147, 15867, 14301, 14321, 14144, 14625, 14142, 14328, 14145, 14324, 14302, 14143, 14139, 14322, 14132, 14148, 14306, 14134, 14133, 14624, 14303, 14141, 14329, 14325, 14140, 14323, 14304, 14330, 14136, 14626, 14327, 14305, 14146, 14135, 14326, 15943, 15944, 15945, 15946, 15947, 15948, 15949, and 15950. (PM completed)
  Trend

2014 Capital Work:
- Sub 146 Oliver Street – 1 TR (Replace the transformer) – $1.3 million estimated cost. DC; Distribution Substation. Serves feeders: 128 and 467. (On going)

Action Items:
Substation Engineering Action Items:
- Sub 013 Harvard Street 8 TR, need update and status
- Sub 070 Fort Chaplain 4 TR, need update and status
- Sub 133 12th and Irving 3 TR, need update on low oil status
- Sub 197 I Street 4 TR, need update and status

Asset Performance & Reliability Action Items:
- Sponsor Sub 150 Twinning City - 3 TR in 10 years replacement plan
- Sponsor Sub 2 O Street – 1 TR replacement

Electric Maintenance Action Items:
- Investigate Sub 133 12th & Irving St. - 3 TR, investigate low oil

Breakers

2014 Capital Work:
- Sub 42 Buzzard – K2-32 – $300K estimated cost. DC, Circuit breaker. (On going)

2017 Capital Work:
- Sub 190 Fort Slocum – 3B 69054 $175,000 estimated cost. DC, Circuit breaker. Feeder 69054 (To be replaced in 2017)

Action Items:
Asset Performance & Reliability Action Items:
- O Street Sub 2 – Sponsor four breaker replacements in capital budget
- Tenth Street Sub 52 – Sponsor four breaker replacements in capital budget

System Operations Action Items:
- Sub 42 Buzzard E-5136;E-5137;E-6041;E-5043;E-5042;E-5063;E-6049;E-6050; K2-32 breakers – Need update outage schedule to proceed with planned Fall, 2014 breaker replacements.

Batteries

Work Priority:

- Sub 13 Harvard Street – Battery 1 – $95,000 estimated cost for replacement. DC. Battery (Plan to be done this year)

Meeting Attendees:

[Names redacted and replaced with department and job title.]

- Asset Performance: Mgr Asset Performance NERC, Sr Supervising Engineer NERC, Lead Engineer NERC,
- Electric Maintenance: Consulting Engineer NERC, Sr Engineering Associate NERC, Manager of Electric Maintenance NERC
- Pepco Distribution Planning: Sr Supervising Engineer NERC,
- Pepco Substation Engineering: Sr Supervising Engineer NERC, Engineer 2 NERC, Manager of Substation Engineering, Pepco, Technical Assistant A NERC
- Pepco-System Operations: Sr System Operator NERC, System Operations Work Coordinator NERC, Mgr Control Room Ops NERC
- Corporate Insurance: Finance & Treasury Manager NERC
- AM Project Management; Engineer 3
- Pepco Transmission Planning: Sr Supervising Engineer NERC
- Pepco Distribution Engineering : Sr Supervising Engineer NERC

PHI Pepco-DC Region Equipment Condition Assessment

Meeting Minutes - 4Q 2014 (2/4/15)

Transformers

Work Priority:

- Sub 126 12th Street – 3 TR – $1.3 million estimated cost. DC; Distribution Substation. Serves feeders: 370, 218, 371, 232, 230, and 233. (Keep monitoring oil and gas. Will be retired in 2017)
- CVG092 Old Naval Hospital B-0040, 1 TR. (On going)
  Trend oil

2014 Capital Work:

- Sub 161 New Jersey – 4 TR (Replace) – $2.1 million estimated cost. DC; Distribution Substation. Serves feeders: 496, 495, 345, 499, 348, 347, 479, 349, and 494. (Working on it)

2015 Capital Work:

- Sub 2 O St. - 1 TR (Replace) - $3.5 million estimated cost. DC; Distribution Substation. Serves feeders: 14390, 14691, 14365, 14366, 14377, 14652, 14374, 14398, 14367, 14391, 14693, 14396W, 14396R, 14399, 14363, 14368, 14392, 14395, 14696, 14364, 14429, 14376, 14428, 14375, 14360, 14370, 14394, 14397W, 14397R, 14694, 14372, 14362, 14371, 14400, 14393, 14373, 14427, 14695, 14369, and 14361. (Put it in budget for 2015)

2017 Capital Work:

- Sub 38 Harrison – 1 TR (Trend) – $1.3 million estimated cost. DC; Distribution Substation. Serves feeders: 14501, 14628, 14894, 14891, 14352, 14898, 14900, 14629, 14895, 14899, 14893, 14896, 14897, 15930, 14351, 14890, and 14892. (Keep monitoring oil and gas. Substation will be retired in 2017)
- Sub 40 North Capitol Street – 1 TR (Trend) – $1.3 million estimated cost. DC; Distribution Substation. Serves feeders: 481, 482, 484, 485, 488, 489, 490, and 491.
  (Convert 4kV to 13kV and transformer will be retired.)
- Sub 40 North Capitol Street – 3 TR (Trend) – $1.3 million estimated cost. DC; Distribution Substation. Serves feeders: 481, 482, 484, 485, 488, 489, 490, and 491.
  (Convert 4kV to 13kV and transformer will be retired.)
- Sub 40 North Capitol Street – 4 TR (Trend) – $1.3 million estimated cost. DC; Distribution Substation. Serves feeders: 481, 482, 484, 485, 488, 489, 490, and 491.
  (Convert 4kV to 13kV and transformer will be retired.)
- Sub 150 Twining City – 3 TR - (Trend) – $1.3 million estimated cost. DC; Distribution Substation. Serves feeders: 496, 495, 345, 347, 479, 349, and 494. (Will be replaced in 2017)

Other Work:

- Sub 83 Blue Plains Reactor (R)-23106 and R-23107 (Plan to be replaced in the next 5 years)
- Sub 21 L Street – 2 TR – $2.0 million estimated cost. DC; Distribution Substation. Serves feeders: 14501, 14507, 14502, 14508, 14504, 14511, 14503, 14510, 14505, 14509, 14506, and 14512. (Keep monitoring oil and gas. Transformer will be replace in 10 years)
-

Action Items:

Substation Engineering Action Items:

- CVG092 Old Naval Hospital – Awaiting customer comment. Sub Eng will follow up
- CVG120 DC Village B-0413 – Awaiting customer comment. Sub Eng will follow up

Asset Performance & Reliability Action Item:

- Sub 2 O Street 1TR – Sponsor transformer replacement in 10 year plan

Load Tap Changers

Work Priority:

- Sub 70 Fort Chaplin - 1 TR – $1.3 million estimated replacement cost. DC; Distribution Substation. Serves feeders: 369, 167, 205, and 97. (Keep monitoring oil and gas.)
  Trend oil

2017 Capital Work:

- Sub 150 Twinning City – 3 TR (Replace the transformer) - $1.3 million estimated cost. DC; Distribution Substation. Serves feeders: 496, 495, 345, 347, 479, 349, and 494. (Will be replaced in 2017)

2019 Capital Work

- Sub 13 Harvard Street – 913 TR (Replace the transformer) – $2.0 million estimated cost. DC; Distribution Substation. Serves feeders: 14723, 15985, 14057, 15986, 14729, 14782, 14724, 14728, 14722, 14725, 14726, 14783, 14727, and 14054. (Will be replaced in 2019)

Action Item:

Asset Performance & Reliability Action Item:

- Sub 92 Nebraska 1TR – Sponsor transformer replacement in 2018

Breakers

2014 Capital Work:

- ~~Sub 042 Buzzard E – 4080 breaker. Completed~~

2015 Capital Work:

- Sub 042 Buzzard E - 5136; E-5137; E-6041; E-5043; E-5042; E-5063; E-6049; E-6050 breakers (Will be replaced in 2015)
- Sub 190 Fort Slocum – 3B 69054 $175,000 estimated cost. DC, Circuit breaker. Feeder 69054 (Will be replaced in 2015)

2016 Capital Work:

- Sub 2 O Street, breakers: 1B, 2B, 3B and 4B. (Put in a budget to be done in 2016)
- Sub 52 10^{th} Street, breakers: 1B, 2B, 3B and 4B. (Put in a budget to be done in 2016)

Future SPCC Work:

- Sub 42 Buzzard – K2-32. DC, Circuit breaker.
- Sub 42 Buzzard – CKT 7B 3-4. DC, Circuit breaker.

Action Item:

Asset Performance & Reliability Action Item:

- Sub 83 Blue Plains Reactor (R)-23106 and R-23107 evaluate to replace the breakers along with transformers.

Batteries

Work Priority:

- Sub 13 Harvard Street – Battery 1 – $95,000 estimated cost for replacement. DC. Battery. (Working on it)
- ~~Sub 18 Southwest – Battery 1 – DC. Battery. Completed~~
- ~~Sub 136 Alabama Avenue – Battery 1 – DC. Battery. Completed~~
- ~~Benning – Battery 1 – DC. Battery. Completed~~
- ~~Benning – Battery 2 – DC. Battery. Completed~~

Action Items:

Substation Engineering Action Items:

- Sub 13 Harvard Street – Battery 1, Need update
- Sub 25 Champlain - Battery 1, Need update

Meeting Attendees:

[Names redacted and replaced with department and job title.]

- Asset Performance: Sr Supervising Engineer NERC, Lead Engineer NERC, Engineer 1 NERC, Engineer 2 NERC, Supervising Chemist NERC
- Electric Maintenance: Consulting Engineer NERC, Sr Engineering Associate NERC,
- Pepco Distribution Planning: Sr Supervising Engineer NERC, Lead Engineer NERC

- Pepco Substation Engineering: Supervising Engineer NERC, Sr Engineer NERC, Manager of Substation Engineering, Technical Assistant A NERC, Lead Engineer NERC
- Pepco-System Operations: Sr System Operator NERC, System Operations Work Coordinator NERC
- Corporate Insurance: Finance & Treasury Manager NERC
- Power Delivery Process Managers: Process Owner Maintenance NERC
- Substation Eng T&D: Mgr Substation Engineering NERC

1.3.6 RELIABILITY ENHANCEMENT WORK PLAN

Consolidated Report and Reliability Enhancement Plan[32]

The REP provides a comprehensive strategic framework for improving the reliability of the Company's distribution system, and assigns metrics for evaluating the successes and assessing necessary strategic changes to improve system performance. As of 2015, Pepco has incorporated the REP elements, their processes, and the lessons learned from their implementation into its normal Reliability, Load, and Vegetation Management programs. In future reports, progress on the REP elements will be reflected in their respective sections, thereby avoiding redundancy and reducing potential confusion.

The following section explains each of the elements of the Reliability Enhancement Work Plan in detail. Examples of projects not included in the REP are customer-driven work (e.g., the connection of new customers), emergency response work, and other general projects (e.g., information technology projects). Matrices of costs, budgets, and timelines for REP activity follow. This section concludes with a detailed explanation of the REP Performance Metrics that the Company will use to assess its progress with respect to the REP.

The projects outlined within this plan are designed to both reduce outages where historically outages have occurred and to prevent future reliability problems. Mitigation of future reliability problems can be achieved in multiple ways, such as replacement of specific types of equipment that are demonstrating an increased failure rate or proactive replacement of entire systems as is done with the 4 kV conversion program. This conversion program replaces equipment that has reached the end of its useful life and without replacement would result in a decreased reliability performance for that equipment. The work on priority feeders is performed to reduce outages on the feeders that have demonstrated poor performance over a past twelve-month period.

[32] In Order No. 16623 issued on Pepco's 2011 Consolidated Report, the Commission states the following at paragraphs 47 and 61:

47. *We are also concerned about the relationship between the Consolidated Report and activities Pepco is undertaking pursuant to its Reliability Enhancement Plan. We need to be clear on which Distribution Projects are part of Pepco's normal on-going improvement projects, and which are part of the "enhancement." Therefore, we require the Pepco provide a discussion in the 2012 Consolidated Report which identifies each subset of those projects and includes detailed project costs and schedules, which, where appropriate, correspond to the Reliability Enhancement Plan.*
61. *Pepco IS **DIRECTED** to provide an explanation of the relationship between its Consolidated Report and its Reliability Enhancement Plan consistent with paragraph 47;*

Other projects are designed to add new capacity, maintain system voltages or replace facilities based on information gained from inspections or system modeling, with the goal of maintaining continued system reliability. In all of these cases, the system enhancements are to prevent future outages from occurring. In some cases, a project will provide both a reduction in the types of outages experienced in the past as well as prevention of future outages. These projects generally involve equipment replacement or installation of modern automation equipment. Several different terms have been used in the past to describe this collection of initiatives. Going forward to reduce confusion, and to be able to explain this work to Pepco customers, the common term of Reliability Enhancement Plan (REP) is used across Pepco.

Reliability Enhancement Work Plan (2015-2019)

1. Introduction

Pursuant to Commission Order No. 15568, Pepco was directed to "submit a continuous improvement plan, including resourcing, specific performance targets and milestone dates to achieve the reliability and outage restoration performance of the best (quartile) performing (comparably) utilities in the Benchmarking Studies." As such, Pepco submitted its Comprehensive Reliability Plan[33] for the District of Columbia.

The current REP strategy in the District of Columbia is comprised of the following initiatives:

- VM;
- Feeder Improvement;
- Underground Residential Distribution (URD) Cable Replacement and Enhancement;
- DA; and
- Load Growth/Conversions.

[33] Since the initial order that required the filing of the Company's Comprehensive Reliability Plan (CRP) the Company has developed and filed with the Commission a Reliability Enhancement Plan (REP). These terms are interchangeable.

2. VM

Pepco's VM program is an important part of Pepco's REP. Due to the density of tree coverage in Pepco's service territory and public concerns relative to tree pruning, challenges exist when balancing the value of trees to customers and communities and the need for reliable electric service. The main objectives that the VM program attempts to balance are safety, reliability, regulatory compliance, environmental stewardship, and customer satisfaction. Pepco's VM program includes all activities from tree pruning through tree removal, as appropriate, to reduce vegetation caused outages.

2.1 Standard VM

Reliability and Feeder Selection Process

Pepco's VM program in the District of Columbia is performed on a two-year cycle. Each overhead feeder in the District of Columbia is scheduled for pruning once every two years. In addition to the feeders to be pruned based on the two-year cycle, the annual VM cycle includes feeders in the Feeder Improvement program where the installation of new equipment requires the removal of additional vegetation.

Regulatory Compliance and Benefits of Cycle-Based Pruning

VM strategies are performed on the list of feeders to assure that all feeders are trimmed on an established cycle. In the District of Columbia, the trim cycle is at least once every two years.

Cycle-based pruning refers to a pruning plan that is based on a pre-set, consistent cycle. The amount of vegetation cleared is based on the average re-growth of the species, so that adequate clearance from conductors can be maintained by re-visiting the same spans on a consistent cycle, with some variation based upon the characteristics of the vegetation, the construction of the feeder and past jurisdictional requirements.

VM for Feeder Improvement

Each year, Pepco selects distribution feeders for further remediation under the Feeder Improvement program, including Priority Feeders, and feeders, based on their feeder performance during the previous 12 months. Selected feeders are inspected and, where appropriate, VM work is performed. VM for feeder improvement projects is identified and planned to clear and resolve vegetation conflicts related to the feeder improvement project.

2.2 VM Program Components

Pepco's VM program in the District of Columbia is comprised of several components whose objective is the removal of those vegetation hazards that have the greatest impact on system reliability, including:

1. Removal of hazard and weak species trees which threaten overhead distribution feeders;
2. Removal of overhanging limbs where possible; and
3. Removal of undergrowth to provide increased access to off-road poles.

The VM program prioritizes the removal of limbs that overhang the mainline three-phase distribution lines wherever possible. For example, overhanging limbs frequently cause damage to facilities resulting in outages when the limbs fall and come in contact with overhead feeder lines. Pepco targets overhangs in the wire zone, and proceeds to remove the overhanging limbs in situations in which Pepco has the right to do so.

Similarly, just as overhanging tree limbs above a circuit present risk to the system, so does unmanaged undergrowth. Fast growing trees, vines, invasive species, and shrubs growing under the substation supply lines and mainline distribution system are removed, mowed, or treated with herbicides for public safety, accessibility, and reliability reasons. Where possible, Pepco allows and encourages the growth of low-growing species of vegetation.

The removal decision is made based on the circumstances, as often times undergrowth is low quality, invasive, and opportunistic in nature. Moreover, clearing of undergrowth has benefits because it allows for increased sight lines and access along roadways. The removal of low growing vegetation allows for healthy understory growth or promotes compatible maintenance. Controlling incompatible vegetation allows more growing space for low-growing grass and permits more selective and lower disturbance rates as natural competition between plant species – and the activity of wildlife – promotes biological controls.

Hazard Trees

Pepco's District of Columbia VM program defines hazard trees as dead, dying, or mechanically damaged trees within physical reach of Pepco facilities. As such, not all trees that are within the reach of the overhead lines are defined as hazard trees. Professional foresters and International Society of Arboriculture Certified Arborists identify trees that threaten the reliability of the system and work with the owners or controlling authority of the trees to achieve safe and timely removal of the trees before they can cause outages. However, the owner or controlling authority often have a higher risk tolerance when considering the corrective action and urgency of hazard trees; that is, UFA or others may tolerate a condition to persist that Pepco considers hazardous.

When they are identified, tree risk assessments are performed on trees with the following characteristics:

- Any tree that constitutes a serious line or facility threat;
- Trees or limbs with included bark, weak limb attachments, and mechanical damage;
- Trees under low level primary circuits that have been topped with no clearance for further foliage growth;
- Badly diseased, dead, or dying trees;
- Trees growing in shallow soil or on an unstable earthen bank which may be subject to wind throw;
- Trees that for any other reason are such that adequate clearance cannot be obtained; and
- Trees requiring more than 25% of crown removal to obtain proper two year clearance requirement or limb overhang removal.

Pepco plans to submit updates to its work on hazard trees in conjunction with its quarterly status reports on the District of Columbia VM Work Plan.

Weak Species

Pepco targets trees for removal which are identified as weak species of trees, including:

- White Pine;
- Tulip Poplar;
- Red Maple;
- Silver Maple;
- Northern Red Oak;
- Virginia Pine; and
- Black Locust.

Removal of overhanging limbs

The VM program specifies the removal of limbs that overhang the mainline three phase distribution lines wherever possible. Overhanging limbs can cause a problem as they break and fall into the lines causing outages. Pepco targets overhangs in the wire zone, and proceeds to remove the overhanging limbs if Pepco has the rights to do so. Within the District of Columbia the Company must also comply with the special trimming and removal regulations for the elm trees that may be infected with Dutch Elm disease. This adds another level of complexity as these trees can only be trimmed during short periods of the year and any limbs removed require special disposal techniques.

3. Feeder Improvement

Annually, Pepco employs a three-step method for determining the group of feeders to be included in the feeder improvement program:

1. Identification of the poorest performing feeders pursuant to Commission standards (Previously this step used the CPI method. Beginning with the 2013 Priority Feeders, the System Performance Contribution (SPC) method described in Section 2.4.1.1 is used.);
2. Identification of the poorest performing feeders based on the CPI method. (Previously this step used feeder contribution to SAIFI); and
3. Identification of feeders serving customers that have experienced outages above a Pepco-determined threshold based on available program budget.

3.1 Priority Feeder Program

Each year Pepco reviews the performance of its distribution feeders. The feeders are ranked from the most to the least reliable according to several criteria over a rolling 12-month period from October 1 of each year through September 30 of the following year. A group of the least reliable feeders is selected for improvements over the ensuing calendar year. Detailed investigations are performed to determine the cause of outages and necessary corrective actions to reduce the number of outages.

Pepco develops a Priority Feeder list in compliance with Commission standards, which require mitigation efforts for the poorest performing 2% of its feeders.

In addition Pepco extends its list of feeders for improvement beyond the Commission-required 2% Priority Feeders. This allows for more detailed inspections, enables more aggressive and longer-term improvements, and provides more flexibility when determining corrective actions. Thus, the feeder improvement program not only captures a greater number of at risk feeders, but it entails a larger array of mitigation and preventive options that Pepco may deploy.

3.2 Ranking and Selection Criteria

Identification of the Priority Feeders – New/SPC Method and CPI Method

Pepco uses a blended performance ranking, known as the SPC method, based on an individual feeder's contribution to SAIFI and contribution to SAIDI to evaluate and rank feeder performance in order to identify the Priority Feeders needing improvement. The resulting index value is used to rank and identify the feeders that contribute the most to system reliability issues and therefore may require corrective measures to improve their future reliability.

Prior to 2013, Pepco used another ranking system known as CPI to determine worst performing feeders. Statistical analysis by Pepco indicated that the CPI methodology could be improved upon and simplified by replacing it with an alternative methodology, which ultimately yielded a better selection of Priority Feeders. This alternative methodology was presented to the Productivity Improvement Working Group (PIWG) in the Fall of 2012 along with the supporting analysis. The new blended performance methodology became the primary tool for selection of Priority Feeders. However, to address concerns including continuity of existing programs such as tracking of repeat Priority Feeders, Pepco has produced the Priority Feeder list using the new methodology as well as a CPI-Selected Feeder list using the historical CPI methodology. Pepco is performing remediation work on all feeders selected. This resulted in a total of 17 feeders selected, including 16 from the new Priority Feeder method and an additional one feeder identified by CPI. Pepco is working on the additional feeder selected by CPI under the REP Feeder Improvement program in lieu of the largest contributors to SAIFI.

Feeders with a High Number of Outages

The third tier of the Feeder Improvement list is composed of the feeders, or sections of a feeder, which serve customers who have experienced a high number of outages. The purpose of including these sections of feeders on the Feeder Improvement list is to target specific trouble areas that may affect relatively small number of customers but cause high levels of customer outages both during storms as well as during non-storm conditions. Also, feeders with devices that have experienced multiple operations over the course of a rolling 12-month period may be referred to the Feeder Improvement program for investigation and possible remediation.

Combined, these measures provide Pepco with a comprehensive view of the performance of its feeder assets. Once these feeders and locations are identified, three steps are involved from the completion of feeder selection to completed work:

- Field inspection and preliminary scope of work development;
- Detailed design defining the final scope of work, material to be upgraded or replaced; and
- Construction and inspection of work performed.

3.3 Remediation Process Going Forward

Pepco will continue to execute the Feeder Improvement program with the objective to address customer reliability issues. Selected feeders are assigned to engineers for analysis and evaluation in order to identify and design circuit reliability improvements. Pepco gathers and reviews system performance data on the selected feeders, checks for potential overloads and imbalances, and provides feeder maps and field inspection request forms to the designated field inspection crews.

Based on the field inspection results, the information is reviewed, evaluated and analyzed in order to recommend appropriate corrective actions. Remediation can be both tactical and strategic, and there is significant overlap of remediation options among the various REP initiatives.

Tactical Remediation Efforts

Proposed corrective actions may include, but are not limited to, the following activities:

- Installing animal guards;
- Replacing blown lightning arrestors,

- Replacing deteriorated poles/cross arms,
- Re-tensioning slack spans and installing spacers,
- Replacing deteriorated insulators,
- Replacing transformers and other distribution equipment based on observed condition,
- Installing of new lateral tap fuses,
- Installing sectionalizing devices,
- Performing VM work, including tree removals,
- Replacing missing or damaged grounds and guys,
- Checking for appropriate fuse installation and resizing fuses for fuse coordination in response to fuse inspection results,
- Installing tree wire in areas where vegetation cannot be effectively managed,
- Replacing underground cable in duct or direct buried cable,
- Re-routing overhead feeders to avoid potential fault sources, and
- Adding an automatic sectionalization and restoration scheme to a feeder.

Strategic Remediation Efforts

In cases where sufficient reliability improvement has not been obtained from past corrective actions and a feeder has repeated on the feeder improvement listing, Pepco will examine more extensive options for addressing performance.

3.4 Identifying and Tracking Specific Feeder Initiatives [34]

Feeder reliability improvements are typically achieved through the application of multiple initiatives or activities, such as the Tactical Remediation Efforts.

These activities are selected and applied based on several factors, including causes of historic outages as well as the observed condition of the feeder and presence of potential future fault sources or exposures including the age and condition of the equipment currently installed along the feeder. All of these initiatives are available to Pepco when determining how to address a selected feeder**.** As can be expected, there are times when multiple activities can address the same fault sources, such as re-tensioning slack spans and VM. As such, it would be impossible to isolate which activity would be directly responsible for the benefits achieved in order to accurately track feeder improvement costs within the REP by initiative.

Although there may be instances when a fault source is addressed by one specific activity, in which case it could be possible to track feeder improvement costs to that activity, the likelihood of this occurring throughout the year is rare, and the value of tracking so few instances would not warrant the effort and expense, or produce any statistically meaningful information.

[34] Order No. 16975 states the following at paragraphs 87, 91, 115 and 117:

87. *The "Feeder Improvement Program" is a part of the REP and, according to OPC, includes three initiatives: Priority Feeders, Poorest Performing Feeders Based on Contribution to SAIFI, and Feeders Experiencing Outages above a Pepco-determined Threshold. OPC suggests that the Work Order Number (Work Breakdown Structure element) be used to track individually the three initiatives. The Commission believes that OPC's recommendation has value; however, we do not read the REP work breakdown structure as containing three distinct feeder improvement initiatives as identified by OPC. Therefore, rather than adopting OPC's recommendation at this time, we shall require Pepco to identify specific feeder improvement initiatives, if any, in the 2013 Consolidated Report and report on the feasibility of tracking feeder improvement costs within the REP by initiative as recommended by OPC.*
97. *Decision: The Commission is concerned that, if this recommendation were applied to every feeder, as well as every initiative, the effort would be overly burdensome. As discussed above, it is not clear that Pepco has specific feeder "initiatives" as identified by OPC. Therefore, we direct Pepco to comment on OPC's recommendation in the 2013 Consolidated Report when it comments on the feasibility of tracking feeder improvement costs by initiative.*
115. *Pepco is DIRECTED to identify feeder improvement initiatives consistent with paragraph 87 herein;*
117. *Pepco is DIRECTED to comment on the feasibility of tracking reliability improvements by feeder and initiative consistent with paragraph 91 herein;*

Additionally, the measure and inclusion of cost/benefits per feeder or per individual initiative would potentially act to reduce the field of options available to apply in feeder performance improvement. Some activities will not be as efficient or economical as others mathematically. For example, the planned replacement of URD cables would always rank higher in cost than simply repairing a cable after a failure. This analysis would overlook the benefits of cable replacement and elimination of future cable failures. However, the potential exclusion of these activities based on their relative inefficiency at the feeder or activity level would mean that the best overall portfolio of remedies could not be used in system level improvement.

As such, Pepco agrees with the Commission's previous conclusions and believes that this requirement would not only be overly burdensome, but would potentially serve to exclude some currently used activities that exhibit lower cost benefit, but are nevertheless necessary to improve system performance.

As noted above, when multiple initiatives are used to address the same fault sources, it would be impossible to isolate which initiative would be directly responsible for benefits achieved, making it impossible to accurately track feeder improvement costs within the REP by initiative. Consequently, Pepco does not believe that it is practical or feasible for it to track feeder improvement costs by initiative on a feeder by feeder basis and that the better way to evaluate performance is to measure the reliability of groups of feeders where improvement initiatives have been performed. Comparison of system performance among different periods of time accurately identifies the benefits gained by the reliability work performed in total and not by individual activity.

4. Underground Residential Distribution (URD) Cable Replacement and Enhancement

Pepco began installing underground residential infrastructure in the 1960s. Within the District of Columbia, the use of URD cable was not implemented until new housing developments were developed that allowed space for the installation of direct buried cables outside of the road ROW. Much of this type of cable is installed in a conduit manhole system, which provides increased protection to the cables and access to replace individual sections of cables. Today, those older URD cables are reaching or have reached their end of useful life and will need to be replaced or enhanced. The need for this work will continue at varying levels into the future, as additional URD cable reaches the end of its useful life. If URD cable is not enhanced or replaced, there is a heightened risk of cable failure and outages. Due to the increase in the number of URD cable failures within the District of Columbia, an engineering strategy for a formal URD cable replacement program was implemented in 2012. This program, like all reliability programs, will be evaluated each year to determine the proper level of funding. This elevated level of effort would allow Pepco to transition its current URD cable strategy to one of proactive replacement and renewal.

In order to implement a planned URD cable replacement program, Pepco expanded its program to identify, analyze, and initiate corrective actions for the mitigation of URD cable failures as well as enhance the integrity of the URD system in terms of reliability, safety, and cost.

4.1 Background

Installation of Pepco's underground residential infrastructure started in the 1960s, and saw a rapid increase into the 1970s to comply with rules mandating the use of underground cable in new residential developments.

Although the cables installed were expected to have an average lifespan of 40 years or more, the factors influencing the performance of the cable and consequent issues were still being discovered at the time. For example, the types and purity of the materials used in the cable's semiconductor often resulted in early cable failures by compromising the capability of the semiconductor. These unforeseen issues have required innovative efforts to mitigate their impact and reduce reliability issues.

Initially, URD cables used an insulation material known as high molecular weight polyethylene (HMPE). In the mid-1970s, the insulation material was changed from HMPE to cross link polyethylene (XLPE) for new installations, which has proven to be more reliable. In the 1980s, Pepco replaced XLPE with an improved material, ethylene propylene rubber (EPR), which is the current material used for all new URD installations.

Pepco's URD cable replacement and enhancement program effort is focused on selected areas that have experienced cable failures, or where cable failures may be expected. The program has only a limited impact on system-wide measures of reliability. This is due to the small number of customers that are generally impacted when a cable failure occurs and the system design that allows the customers to be restored to service before repairing the failed cable. However, the program is important to reduce the number of customers and neighborhoods experiencing multiple interruptions due to aging URD cable, which generally occur during high load periods. Combined with other REP reliability efforts, this project will contribute to overall system reliability improvement and increase customer satisfaction in those communities.

4.2 Strategy

The URD cable system is analyzed regularly to determine priority subdivisions. Pepco then identifies feeders for replacement or enhancement, analyzes potential remediation options, and implements corrective actions. This work contributes to the mitigation of URD cable failures and maintains the integrity of the URD system, in terms of reliability, safety and cost.

This process involves the following components:

- Obtain URD outage history and determine number of failures within the subdivision, cause of the failure, number of customers, and location of the event;
- Acquire available information on age of the cable, type of cable, and design of the subdivision; and
- Use established criteria for URD cable replacement to determine priority areas.

4.2.1 Cable Replacement

There are two sub-categories to replacement work: spot primary replacement and subdivision primary replacement.

Spot Primary Replacement consists of segment replacement performed on primary feeders on which three or more failures have been experienced and/or deteriorated neutrals have been identified.

Subdivision Primary Replacement uses established criteria for scoring subdivisions to replace entire primary cables that have experienced three or more failures in the last 12 months. The primary candidates are compiled into a list of priority areas. In older subdivisions, feeders will also be reengineered to the current standards of achieving load balancing and loop feed design. Pepco uses a scoring methodology to prioritize subdivisions for cable replacement or cable refurbishment. The selection criteria include consideration of recent cable failure history, number of customers served, system design, cable design and cable vintage.

4.2.2 Cable Life Enhancement

There is also an option to inject silicone-based rehabilitation liquid into the cable to extend the life expectancy of the cable, sometimes referred to as “curing.” To perform a URD cable enhancement, the program requires the following characteristics to be met:

- At least 50% of the original full size neutral must be remaining;
- Should not have multiple splices (more than 2 per stretch); and
- Splices have to be able to allow curing (e.g., no taped slices).

4.2.3 Installation of Lightning Arresters

URD cable and its associated infrastructure must be protected from lightning that could cause further damage to cable and other underground assets on the line. Pepco is enhancing this protection scheme on its URD feeders/extensions so that existing installations meet new standards, based on the following criteria:

1. All silicon carbide arresters are being replaced with Metal-Oxide Varistor (MOV) arresters at the cable riser pole;
2. All cable/loop open points are inspected to verify that they have MOV arresters; and
3. All "midpoints," defined as "the transformer adjacent to the open point in each loop," are inspected to verify that they have MOV arresters.

4.2.3 URD Cable Replacement and Enhancement Progress

In 2014, Pepco replaced or enhanced 4.2 miles of URD cable, and the program replaced or enhanced a total of 91.3 miles in the District of Columbia.

5. Distribution Automation[35]

Pepco recognizes the benefits of deploying smart grid technology to improve infrastructure reliability, enhance customer experience, and provide enhanced interaction levels with the grid. In late 2009, Pepco was awarded a Department of Energy SGIG grant to match its smart grid spending. DA is one aspect of Pepco's comprehensive smart grid strategy. Pepco's DA approach involves installing advanced control systems, ultimately across the distribution system, to automatically identify and isolate faults in real time and promptly restore service to customers in the unaffected parts of the system. The goal of this DA strategy is to deploy technology that will enhance reliability by improving speed of isolation of trouble spots on the system, in coordination with automated restoration capability. Pepco's DA efforts include the following three elements:

[35]In Order No. 12804 paragraph 53 E, the Commission ordered the following:

53. The 2003 PIP is hereby APPROVED, provided that PEPCO:

(e) Provide to the PIWG, quarterly status reports on the new Technology Initiatives being undertaken by Pepco. An annual status report should be included in the 2004 and future PIPs. The status reports should include current accomplishments, plans for the future, and anticipated completion dates.

- Fault identification and isolation: DA can isolate critical pieces of the infrastructure to minimize customer impact in a fault area and/or allow for quicker restoration;
- Service restoration: DA can significantly reduce the duration of outages experienced by customers through automated isolation of faulted areas and restoration of customers unaffected by the fault; and
- System/Data management: DA can provide accurate and real-time information regarding the overall integrity of the distribution system, which allows for targeted deployment of corrective maintenance and upgrade measures for critical assets.

5.1 Selection and Prioritization

To identify the distribution feeders for inclusion in its ASR scheme, Pepco evaluates the lockout history of individual substation breakers, circuit breakers and downstream automatic circuit reclosers. Pepco prioritizes its plan considering factors such as reliability improvement, customer impact, and cost efficiency. Selection criteria for ASR deployment include:

- Identifying feeders with three or more lockouts over the most recent two year period;
- Identifying distribution feeders with tie points to other feeders that meet planning criteria; and
- Focusing efforts on 13 kV feeders, as they carry four to five times more load than 4 kV feeders.

Feeders are grouped into ASR schemes based on their proximity to other qualifying feeders. This grouping produces synergies by using the same substation equipment to control multiple feeders. Pepco prioritized this list of feeders by ranking them by number of lockouts over a two year period.

5.2 Integration of DA with Existing Systems

DA designs must integrate with existing or developing systems, such as the central operation systems (*e.g.,* EMS, OMS) and consider interfacing with other smart grid systems such as AMI or Direct Load Control devices. These and other key linkages need to be mapped and considered in all design plans.

The overall smart grid network and infrastructure design includes a fiber-optic/microwave network, a wireless broadband network, and a wireless mesh network. The wireless mesh network leverages the mesh network installed for the AMI system; additional radios are only installed at the DA device to communicate with the network.

The DA devices connect to the overall Pepco network through the wireless mesh network. Pepco has a signed short term contract with a public wireless provider to provide broadband services and is currently evaluating and testing longer-term solutions for a private broadband network. Pepco has constructed and continues to expand its fiber optic network, which is used for communications between substations, and between substations and the control centers.

6. Load Growth/4 kV Conversions

Pepco's load growth management program plays a significant role in both maintaining reliability and validating that future demand can be met under adverse conditions and during peak load conditions. Pepco uses PJM estimates, in addition to internal data, to calculate growth trends and produce a load growth forecast for its substations. Pepco's distribution and subtransmission networks have been designed with N-1 redundancy. The redundancy built into the system means that Pepco can lose one subtransmission line or substation transformer and still be able to serve peak load with the remaining facilities. Maintaining and improving this resiliency is critical to Pepco's total system reliability as well as the capability to effectively implement and accurately measure other REP initiatives.

Pepco has a process in place to effectively identify and relieve equipment overloads and system voltage violations through the planning process. Feeder and substation loads are monitored continuously through Pepco's SCADA system with system operators being alerted to substation operational abnormalities including feeder or transformer overloads.

6.1 Load Growth Forecasting

Planning for future load growth starts with the development of load growth projections. Short-term, summer-peak forecasts are developed for three years to allow adequate time to complete routine 4 kV and 13 kV construction work. Long range forecasting (four to ten years) is used to develop advance plans for large 4 kV and 13 kV construction projects that require more than two or three years to complete, to develop routine and advance plans for 34.5 kV to 230 kV construction work, and to identify future capital projects in the construction budget forecast process. Planning for upgrades to the transmission system is completed in conjunction with PJM using five- and ten-year load projections.

Distribution load growth in Pepco territories is studied by regions or areas. Substations within an area are studied to establish load growth on that substation and to determine the appropriate actions required to meet the system planning criteria. This load review determines an area and substation load growth trend based on data collected over several years. Information from area developers, demolition of existing facilities, and discussion with local officials are additional data sources that are used in developing individual feeder and substation forecasted loads. If load growth is extensive in a particular area, new load will be supplied from the existing 13 kV system infrastructure due to capacity limitations associated with the 4 kV system. Distribution load growth studied within an area is based on the load factors, historical trends, and AMI data that were established for that area.

Network load growth in underground network areas is studied in a similar fashion to other types of load on the system. Trends are developed from historical load information over the past several years. When load growth is projected to cause a particular network system to exceed the group capacity or individual feeder capacity, load transfers to other area networks are examined. In designing network transfers, the available capacity of the substation, load distribution on network feeders or spot networks are studied to determine, based on geographical considerations, the available load that can be transferred to the other network. Secondary networks associated with the load to be transferred must be examined to validate that adequate capacity and appropriate secondary cable systems exist and that no secondary cable ties are maintained between the networks. Design criteria associated with the operation of the network must also be examined for proper separation of one network from another. Load flow studies are conducted biennially (addressing approximately half of the system each year) to confirm adequate capacity of cables and transformers.

6.2 Load Management and Customer Density

Reliable electric system design requires a thorough understanding of load growth trends. Whenever substantial new loads are added or systems are reconfigured to incorporate new services, Pepco follows engineering design and planning practice to model the addition of new load to determine its impact on the system.

Pepco uses power flow and GIS systems to model system loading in an effort to predict and identify overload situations and to develop recommendations for their mitigation, so that single contingencies (i.e., loss of a substation power transformer and/or its associated supply feeder) will not overload the system. A comprehensive engineering process exists for gathering data, developing model inputs, and correcting any load violations generated. This process also includes updating any new loads and system modifications in the model so that the latest system configuration is reflected both presently and up to ten years forward for transmission planning.

2015 Work Plan [36]

The tables provided in Attachment A reflect the required capital budget and spending information for REP and Non-REP reliability improvement projects, as well as the 2015 REP work plan organized by REP project categories.

These tables contain identifying information for each District of Columbia project organized by their project category as set forth in the REP: (1) VM; (2) Feeder Improvements; (3) URD Cable Replacement and Enhancement; (4) DA; and (5) Load Growth/Conversions.

The identifying information for each of the projects includes:

1. The location and subdivision for each project;
2. The Feeder ID;
3. The Work Breakdown Structure (WBS) number, which is the number that the Company uses for the organization of projects for budgeting and scheduling purposes; and
4. The quarter in which the Company expects the project to be complete and providing service to its District of Columbia customers.

[36] Order No. 16975 states the following at paragraphs 48 and 100:

48. *Decision: The Commission concurs with the position taken by Staff and OPC that it is critical to understand the difference between Pepco's Reliability Enhancement Plan and its normal, on-going reliability improvement projects in the District. Pepco's response fails to provide the necessary clarity on whether the REP is in lieu of or in addition to on-going reliability projects. The Commission therefore requires Pepco to include in future years' Consolidated Reports a clear statement as to which elements of the REP are separate from the Company's normal, on-going reliability improvement projects. In particular, we direct Pepco to respond to the issue raised by OPC about the appropriateness of including load growth projects as reliability enhancement projects in the Reliability Enhancement Plan. We further direct Pepco to identify the amounts budgeted for the elements of the REP for the years 2010 through 2013. We also direct Pepco to identify the amounts budgeted for non-REP reliability improvement projects, specifically including and identifying load growth projects, for those years. We believe this information is necessary and useful in conducting a year by year comparison of the elements of the REP with non-REP reliability improvement projects and to better distinguish between the projects and we direct Pepco to file this information in all future Consolidated Reports.*

100. *Pepco is DIRECTED to provide information on the Reliability Enhancement Plan consistent with paragraph 48 herein;*

Order No. 16975 states at paragraph 48:

> *"The Commission therefore requires Pepco to include in future years' Consolidated Reports a clear statement as to which elements of the REP are separate from the Company's normal, on-going reliability improvement projects."*

In response, Pepco notes that the work performed under the REP is not new to Pepco. Pepco continues to implement the projects within its work plan aimed at producing reliability improvements over a shorter period of time. In addition, Pepco's construction work plan is not static: it is continuously being reviewed, and appropriate changes are made to meet changing operating conditions. However, the type of work being performed does not change. The changes are to the locations where work is needed and the timing of completion of work.

The budgeted amounts and timing of completion reported below reflect the Company's estimate of the cost of each project and a consideration of the Company's ability to expedite higher priority projects to attain reliability improvements necessary to comply with EQSS reliability standards. Estimates are necessarily revised at the time the work is issued to construction based on field investigation and engineering surveys. The actual cost and timing reported reflect the final cost and time necessary to perform the work, and may vary from the project estimates due to permit restrictions, changes in scope of work during construction, or identification of unexpected obstructions that impact the ability to construct the new facilities as originally anticipated. However, the Company works to not exceed the total budgeted levels and estimated completion dates on any individual project. The Company strives to install the new facilities in the most efficient manner possible taking into consideration the variables associated with any construction project.

Order No. 16975 states the following at paragraphs 47 and 48:

> *47. Further, OPC believes that inclusion of load growth projects in the Reliability Enhancement Plan is incorrect and misleading. According to OPC, planning for growth and the need for adding capacity are an integral part of being an electric utility, not "reliability enhancement."…*
>
> *48. Decision: …In particular, we direct Pepco to respond to the issue raised by OPC about the appropriateness of including load growth projects as reliability enhancement projects in the Reliability Enhancement Plan.*

Load growth projects, also known as system improvement projects, are appropriately included in the REP because the goal of load growth projects is to ensure the electric system has adequate capacity to reliably supply existing demand and future load growth. As discussed in the Company's comprehensive reliability plan filed in September 2010 (REP), the three major components of system planning are:

1. Voltage and Reactive Support
2. Ratings of Facilities
3. Reliability

The voltage and reactive support criterion ensures that proper voltage levels are maintained throughout the electric system for overall reliability of service. Failure to maintain proper voltage levels could potentially cause customer's equipment to trip or go offline, in effect resulting in an outage to that customer.

The ratings-of-facilities criterion ensures that the equipment on the electric system does not exceed its operating ratings. Operating levels exceeding ratings will shorten the life expectancy and therefore the reliability of the equipment (transformers, substation breakers, conductors, etc.). The equipment will fail more quickly, which can cause an outage.

The reliability criterion ensures that each Pepco substation in the District of Columbia has sufficient capacity so that any one component (e.g., a substation transformer and/or its associated supply feeder) can be out of service without suffering loss of customer load or overloading any remaining equipment. In addition, the radial distribution system is designed so that under peak load conditions any feeder can be backed up through manual switching operations at the substation. Failure to implement the reliability criterion will increase the frequency and duration of outages in the event of equipment failure.

Failure to address the three major criteria will result in power quality issues or shorten equipment life, which ultimately will result in an outage, harming Pepco's overall service reliability.

Work Plan Tables

The tables included as Attachment A align the elements of the REP with a detailed presentation of the various projects required to complete this plan, along with schedules, work status, budgets, and for previous periods, actual spending. The work plan presented outlines the work to be performed during 2015. It should be recognized that many projects have multi-year durations and therefore may have started in 2014 (or earlier) and will be completed in 2015 or may start in 2015 but will not complete until 2016 or later.

Note, in its response to Staff's comments on the 2013 Consolidated Report, Pepco indicated that it will specifically identify those substation reliability projects that are a direct result of Pepco's ECA program.[37] These projects are indicated with an * symbol.

37 Pepco's Response to the "Staff Report on the Potomac Electric Power Company's 2013 Consolidated Report: Productivity Improvement Plan, Comprehensive Plan, Manhole Event Report," filed August 14, 2013, at 2.

REP PERFORMANCE METRICS

1. Performance Measures

Pepco will measure the progress of its reliability improvement through a number of different metrics. Pepco's District of Columbia annual system-wide SAIDI and SAIFI will continue to be tracked and reported in accordance with the Commission's EQSS requirements, including the revised standards for 2013-2020. In addition, the REP initiatives will be tracked by physical measures, such as miles of feeders on which VM has been performed and number of ASR systems installed. Finally, Pepco has developed metrics applicable specifically to the REP initiatives to provide insight on the contribution of the elements of the REP to enhanced reliability as described herein.

The table below summarizes the REP initiatives and the specific metrics to be applied to the initiatives. The remaining portion of this Exhibit describes the Company's measurement methods and applies them to the REP initiatives, with a comparison of 2014 results to the 2010 baseline.

Initiative	Description	Metrics
Feeder Improvement	Program to address equipment, vegetation, weather, and animal-related interruptions which negatively impact reliability performance. These projects involve installing, removing, and replacing reclosers, switches, conductors, animal guards, lightning arresters and other equipment deemed necessary on the worst performing, top SAIFI contributing, and high customer interruption feeders to maintain safe operation and improve reliability.	Annual cumulative SAIFI/SAIDI performance for all feeders included within the feeder improvement as well as feeders where DA has been installed and feeders are undergrounded.
DA	Program to address system reliability by deploying technology. These projects involve installing advanced control systems across the distribution system in order to automatically identify and isolate faults in real time and restore service to customers in the unaffected parts of the system.	
VM	Program to address vegetation, designed to maintain appropriate clearance on the system, remediate trouble spots (e.g., Priority Feeders), and remove the vegetation hazards that have the greatest impact on system reliability.	Annual tree related SAIFI/SAIDI performance for all feeders.
URD Cable Replacement and Enhancement	Program to address reliability of the underground residential infrastructure. These projects involve replacing or rejuvenating URD cable in order to minimize URD failures.	Annual number of URD cable failures.
Conversions	Program to upgrade aging 4 kV infrastructure to 13 kV and retire 4 kV substations.	Amount of load converted.
Load Growth	Program to address increasing load demands to maintain reliability and to ensure that future demands can be met under adverse conditions. These projects involve adding or upgrading feeders in order to reliably supply new customers and support increased usage required by existing customers.	Operate substations within design loading criteria.

2. Reporting Process

Previously, because 2010 was the year the REP was implemented, Pepco used 2010 as the base year on which to track REP performance. However, given the notable reliability improvement reflected in every REP metric, the Company will begin reporting the reliability metrics on a rolling five-year basis. The five-year rolling reporting will allow the following charts to better reflect the trends of the data. The Company will continue to track progress on each REP initiative using the metrics described herein. Due to weather and other variables, including the timing of completion of projects throughout the plan year, the metrics produced by the REP initiatives in any one quarter or year may not necessarily reflect the actual reliability improvement generated by the initiatives individually or in total. Furthermore, the sum contribution of the improvements included in the REP may not equal the system wide reliability measures (and may show greater or lesser gains in reliability). This difference may be due to the many variables that affect the electric distribution system, the fact that the various REP metrics are measuring only subsets of the entire system, different physical components than the system wide measurements, and because the REP metrics are based on different factors than the District of Columbia system wide reliability measures. As further experience is gained with the metrics specific to the REP initiatives described herein, Pepco may present revised metrics or applications, while keeping in mind the desirability of maintaining data that can be usefully tracked over time to the greatest extent reasonably possible.

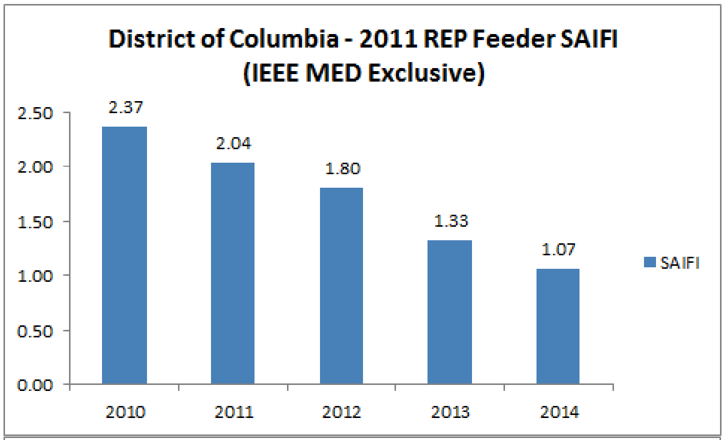
3. Feeder Improvement and DA

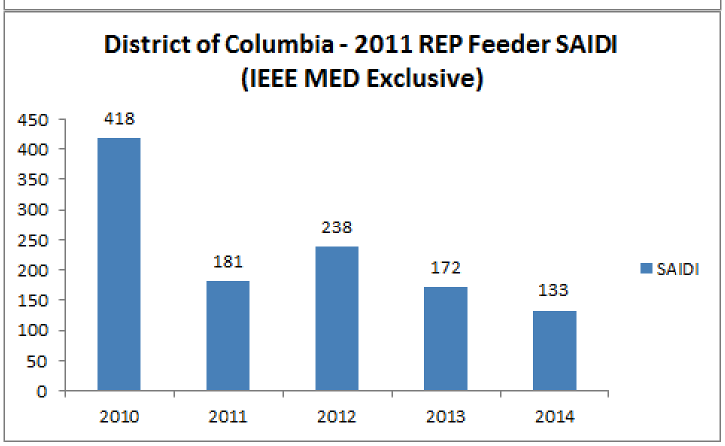
Pepco will track the cumulative SAIFI and SAIDI for (a) all feeders included in the feeder improvement program, and (b) all feeders that have had DA installed. This metric will be measured on an annual basis and improvement will be shown on a rolling five-year basis. These initiatives are grouped in a common measurement tool because multiple enhancement techniques are typically combined on a single feeder to achieve the desired outcome and are not readily measured in isolation.

Charts 1A-D below illustrate the reliability based progress achieved between 2010 and 2014 relative to feeder improvement and DA (with no feeder undergrounding yet undertaken). Data is measured excluding major event days (MED) determined in accordance with the IEEE Std™

1366-2003 IEEE Guide for Electric Power Distribution Reliability Indices because this data reflects operations under design or "normal" conditions, and so provides the measure of conditions which are susceptible to control by the utility.

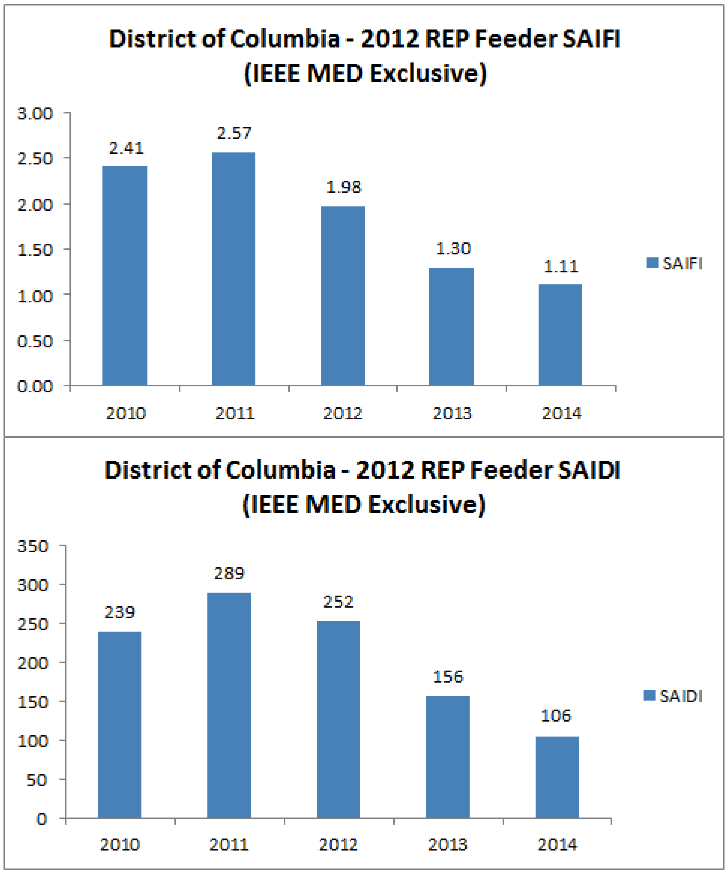
Chart 1-A





2011 REP Feeders

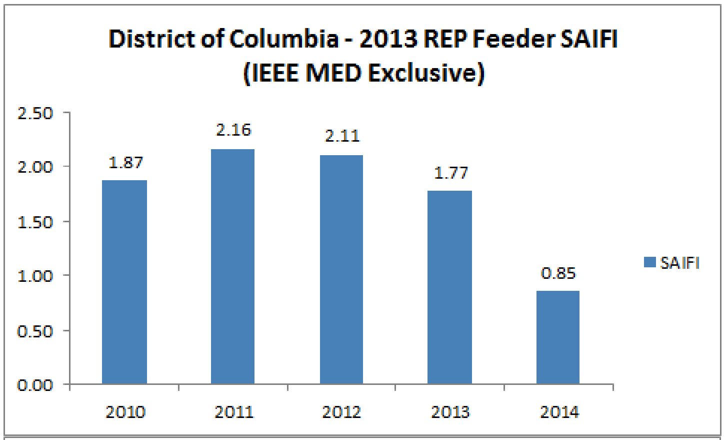
Chart 1-B



2012 REP Feeders

Chart 1-C

2013 REP Feeders



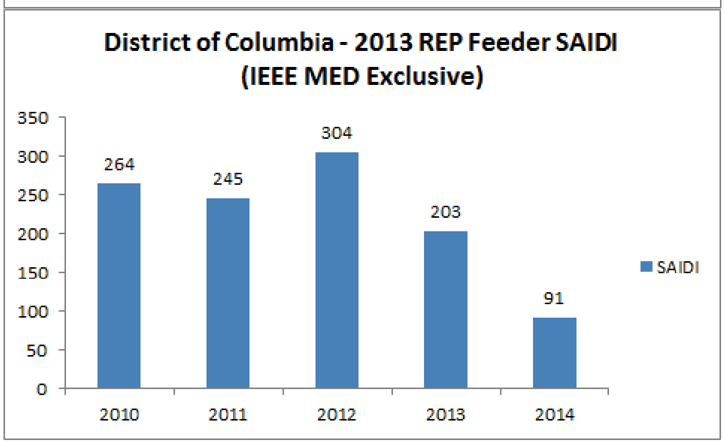
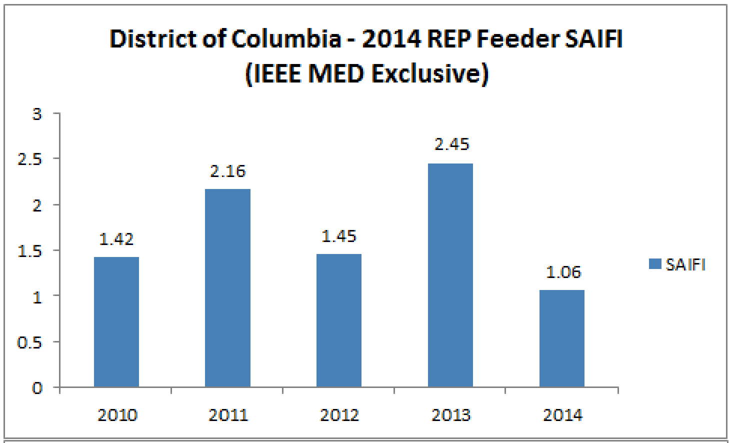
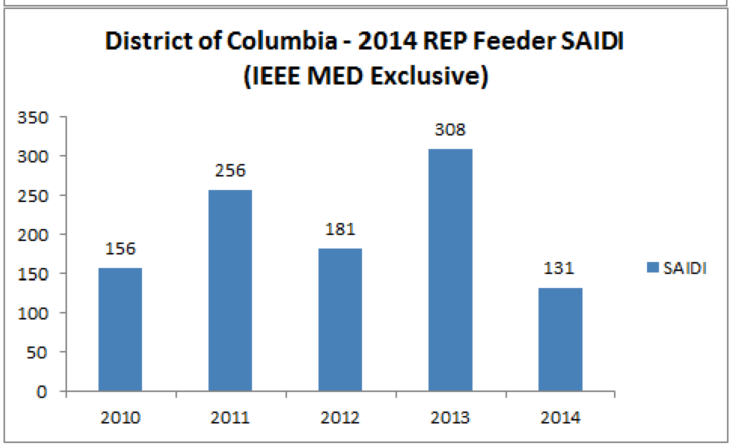


Chart 1-D



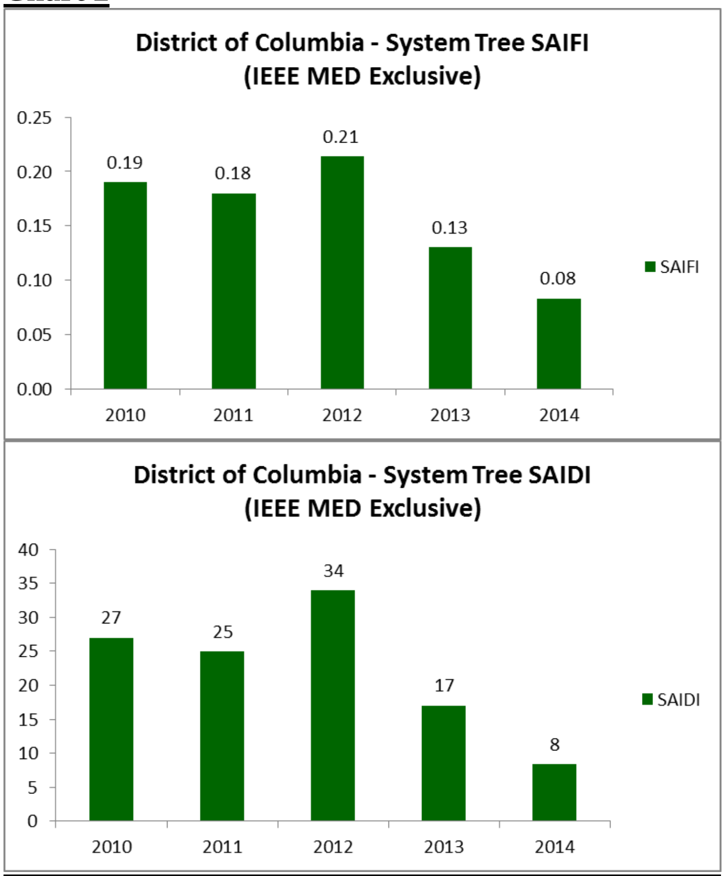


2014 REP Feeders

4. VM

Pepco uses District of Columbia system tree SAIFI and SAIDI to measure the progress of VM. Tree SAIFI and SAIDI measures the level of vegetation-caused outages on the affected feeders. This metric is reported on an annual basis as recorded within Pepco's OMS. This measure is shown on an MED-on an MED exclusive basis.

Chart 2



5. URD Cable Replacement

Pepco monitors URD cable performance through tracking and recording the number of URD cable failures. Due to the increase in the number of URD cable failures within the District of Columbia, an engineering strategy for a formal planned cable replacement program was implemented in 2012. Progress is measured by identifying the number of annual URD cable faults on a system basis. URD cable faults make a relatively small contribution to system wide SAIFI and SAIDI, but are a recurring factor in customer satisfaction with respect to reliability for the customers that are experiencing repeated outages due to failing cable, particularly due to "blue sky" failures.

Chart 3 provides a comparison of 2010 through 2014 URD cable failures.

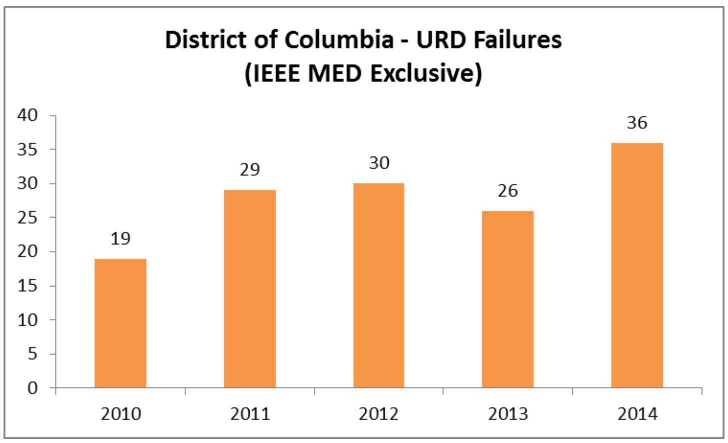


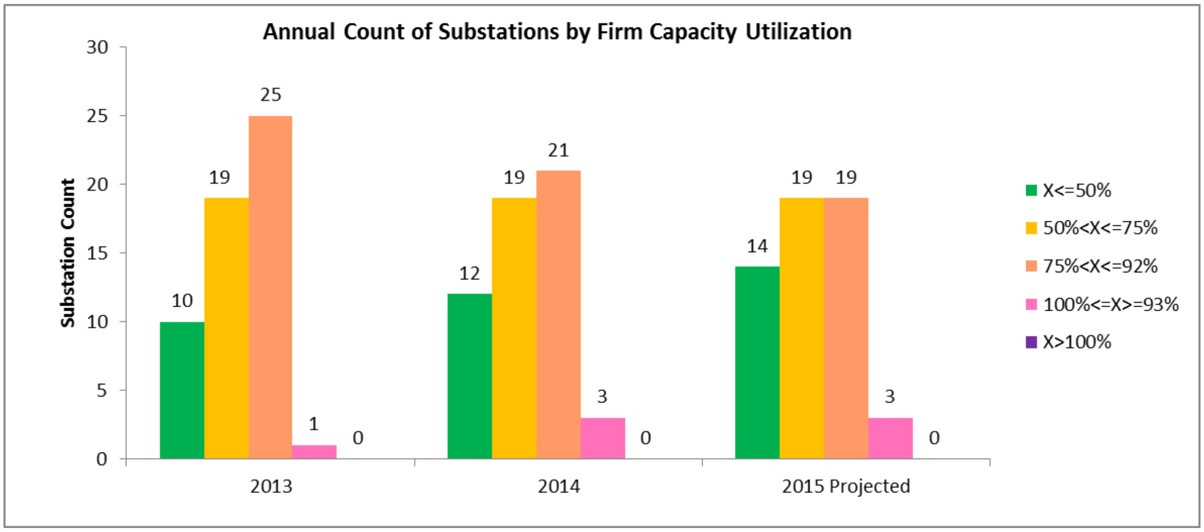
Chart 3

6. Load Growth

Pepco's system planning process is designed to meet customer load growth and to maintain the required ability to transfer load and maintain continuity of service under various operating conditions, including but not limited to operating conditions that warrant transfer of load between feeders and/or substations due to abnormal circumstances commonly referred to as N-1, a description of redundancy. Pepco monitors and measures success of its load growth planning efforts by maintaining normal loading limits established under system design criteria. Performance levels for this metric is based on annual reporting of overall substation conformity with normal loading criteria. Load growth projects do not lend themselves to ready measurement by metrics such as SAIDI and SAIFI. Instead, load growth is measured at the substation level by percentage of firm capacity used. Firm capacity is a design criterion that allows a substation to supply the full load of all the customers supplied from that station when one supply line to that station is out of service and includes within in it a margin of error to allow for planned and unplanned conditions. Thus, during normal conditions, a substation operated at a capacity above 100% does not necessarily represent a reliability threat but does indicate the need for analysis and planning to address the condition. Unlike other reliability measures, which are difficult to forecast with any precision due to the large number of variables (e.g., weather, dig-ins, vehicle accidents, animal damage), it is more feasible to forecast substation capacity usage since the variables are relatively stable and predictable (e.g., substation capacity and load growth). In addition, substation additions are longer-term projects that require several years of planning and construction; therefore, decisions to construct new substations must be made well in advance of the actual need and require decisions to be made on forecasted load and not actual load conditions.

Chart 4 provides a comparison of 2013 substation firm capacity usage to 2014 substation firm capacity usage and a forecast of 2015 for this measure.

Chart 4



Note: 2013-2014 substation loads from analyzed historical peak loadings.
2015 predicted substation loads based on 2014 peak historical substation loadings.

7. Forecasting Model for System Wide District of Columbia Reliability Performance

Pepco employs a statistical modeling program to project and evaluate the expected reliability performance of the electric system based on the impacts of the REP. Specifically, this model provides a probabilistic range of estimated SAIFI and SAIDI improvement values for the District of Columbia as a function of carrying out the elements of the REP.

The model is based on forecasted reliability improvement from three components of the REP: VM, feeder improvement work, and DA implementation. The balance of the REP project categories are expected to contribute to additional improvements in reliability performance. However, Pepco will update this model as actual data becomes available.

The forecasted results are illustrated in Chart 5 (SAIFI) and Chart 6 (SAIDI) below.

Chart 5

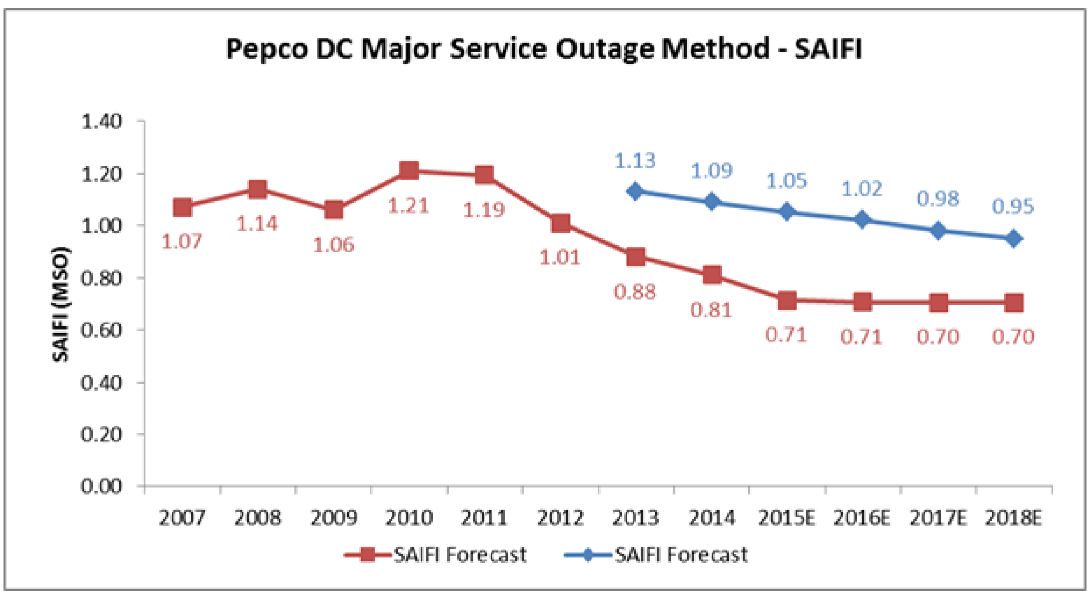
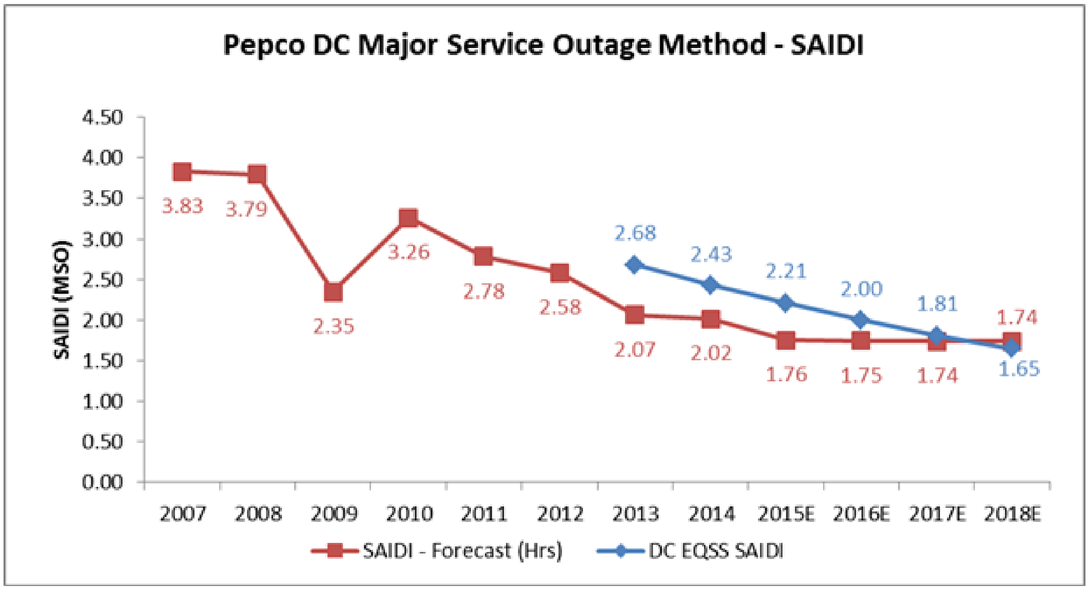


Chart 6



1.3.7 STORM READINESS

Pepco's mandate is to provide safe and reliable electric service. This is the basis for all Company contingency operations, including storm restoration, and is the foundation for the Storm Restoration Objective of safely restoring electric service to the greatest number of customers in a minimum amount of time. The Pepco District of Columbia Major Service Outage Restoration Plan (MSO Plan) uses these principles to assess damage across the entire Pepco service area and to establish restoration guidelines for preparedness, pre-storm planning, storm response, communications, and post-storm evaluations.

The PHI Crisis Management Plan and the MSO Plan necessarily modifies the normal corporate organization, in accordance with the National Incident Management System's (NIMS) Incident Command System structure, and manages this amended structure to accomplish storm restoration and emergency response. The Pepco Regional Incident Management Team (IMT) assigns personnel to this temporary structure to efficiently restore customer service. The overall governing principle of the Pepco IMT is to match resources to restoration requirements. The Pepco IMT is flexible in order to adjust resources to the various types of restoration efforts that may be required and to enable restoration activities to be prioritized to restore the largest number of customers first across Pepco's service territory. All Company resources, including Operations, Logistics, Planning &Analysis, and Finance and Administration are dedicated to customer service and the storm restoration effort.

Each branch of the Pepco IMT has the ability to expand or contract staffing for the response effort as necessary. Storm positions are activated based on the support or response functions required for efficient restoration. Pre-established storm duties are maintained for each storm position. The Staging Area branch of the IMT is activated under unique circumstances. The increased number of customer calls during storms requires additional staffing at the Customer Operations Call Center to answer customer inquiries and to supplement the automated entry of customer outage information. In the event of a major storm, Pepco's High-Volume Call Answering (HVCA) System can be activated to take the high volume of outage calls Pepco expects in the immediate aftermath of a major storm. This HVCA system is capable of answering more than 100,000 calls per hour to reduce the incidence of busy signals and hold times, and is most efficient in the early stage of the restoration process. Once the initial outage reports are in, the Company disables the automated call system and staffs the Pepco call center with additional employees who are trained to assist call center representatives in handling the increased volume of calls. All areas in the Customer Care Group, in performing their second roles are required to provide support to the Call Center. Additional personnel across the Company provide assistance through their incident response role assignments and help to relay accurate information between customers and operations.

Communication requirements for internal as well as external groups are identified in advance, planned for, and monitored for effectiveness during storm response. Accurate, timely and coordinated communications provide a vital link in the restoration response. Approximately 48 hours in advance of a significant major storm with predicted multi-day outages, Pepco notifies customers who are enrolled in Pepco's Emergency Medical Equipment Notification Program so they can prepare to implement their contingency plans in the event of power outages. Pepco also notifies regulatory and government officials and emergency management agencies of its storm preparations and to discuss any special concerns. Operational communications coordinate field restoration activities. Communication roles in the PHI Crisis Management Plan and the MSO Plan provide for a proactive and flexible communication strategy.

The Storm Restoration Objectives are to safely restore electric service to the largest number of customers in a minimum amount of time. This requires advance planning and pre-storm preparation. Advance planning during non-storm conditions enables operational readiness for restoration activities. In addition to drills and exercises designed to lead employees through a variety of emergency scenarios, Pepco also works with local emergency management agencies and a cross-section of community, government and business leaders in a collaborative effort to review restoration plans and practices to develop more effective ways to improve Pepco's response.

In addition, Pepco actively pursues a public education and awareness campaign that includes initiatives such as the "Weathering the Storm" brochure, available in English and Spanish, and a series of fact sheets based on the brochure that are available in English, Spanish, Russian, Italian, Chinese, Korean and Vietnamese. These publications and additional brochures contain information about the Company's Emergency Medical Equipment Notification Program, tree trimming, and portable generator safety, all of which are available upon request as well as on Pepco's Web site. A series of videos including "What to do if the Lights Go Out", "How Power is Restored", and "Tree Management" are available through the Web site or upon request. These materials and information provided in Pepco's monthly newsletter that is mailed to customers with their bill provide information that help families and individuals prepare in advance for any emergency situation and are a significant component of Pepco's advance planning efforts. Additional preparedness information, as well as neighborhood outage maps, with information regarding each outage event, including the ETR, is also available on the Pepco web site.

Pre-storm preparation is the process of preparing for mobilization before a storm occurs. When a significant major storm threatens, Pepco begins preparations, when possible, by reviewing Pepco's inventory of storm repair materials and notifying vendors of the potential need for material procurement. To plan for sufficient staffing, Pepco informs employees of the pending storm and the potential for activation of their incident response second role assignments. The Company also alerts Pepco contractors and discuss plans for possible aid from the utilities within Pepco's participating mutual assistance groups. Both advance planning and pre-storm preparation activities enable a state of preparedness to transition smoothly to IMT operations and to minimize restoration time.

After a storm affects the electric system, assessment and restoration begins. Damage Assessment requires an on-going evaluation of the substations shut down, distribution feeders locked out, and feeders with damaged segments, as well as the areas and the number of customers affected. This continual process enables efficient and appropriate allocation of restoration resources. The IMT is activated to provide customer communications and to coordinate the mobilization of crews for system repairs. Since damage assessment is on-going and storm levels may change in intensity, the restoration strategy may be modified throughout the effort, and the level of mobilization may be adjusted to meet restoration requirements.

Adequate supplies of materials, tools, and equipment are necessary for restoration to proceed safely and efficiently. Logistics include procuring, maintaining, and transporting restoration resources, personnel and materials. Departments are responsible for determining logistics requirements on an on-going basis and maintaining procedures.

When major reconstruction work or significant outside resources is required for system restoration, a staging area may be established. Staging Areas are defined as sites where crews and materials are temporarily stationed in severely damaged areas of the service territory. Staging areas are set up to respond to specific restoration efforts with assigned crews and on-site materials. Sites are selected for their accessibility, parking, and space to store materials needed for reconstruction and restoration of customer service.

During major outage events of extended duration Pepco can use resources from other PHI companies, if available, or request mutual assistance from one of several regional and national mutual assistance groups in which it participates. These groups meet periodically to review policies, procedures and work practices to ensure continued ability to provide mutual assistance between electric utility companies. Post-event evaluations following major service outages contribute to continuous improvements to the Pepco District of Columbia Major Service Outage Restoration Plan. Response activities are most likely to improve when recommendations are linked and incorporated into the plan and departmental support procedures. These links serve as the vehicle to enhance response plan capability. Trained personnel are essential for successful execution of storm response duties. Additional training requirements may be highlighted as a result of debriefings or drills.

Further, during major outage events, Pepco uses its Automated Metering Infrastructure (AMI) to enhance storm restoration efforts. For example, during Hurricane Sandy, 1,092 events were removed from the restoration queue by using AMI's capability to "ping" meters to help determine whether a customer has electric service. This application of Pepco's AMI network contributes to reducing restoration times, and avoiding costs, without necessitating phone calls to customers and it also materially reduces the number of truck rolls needed to verify customer restoration, helping ensure that crews are dispatched efficiently.

Drills and Functional Exercises

In 2014, Pepco participated and conducted multiple drills and exercises.

Pepco Emergency Management held a “Preparedness Tabletop Exercise” on December 17, 2014 with Emergency Management Agency (EMA) Directors and their key staff to review the year’s, procedures, available tools and coordination between Pepco and the Local EMAs. In addition, in 2014 the Pepco Emergency Preparedness worked with DC HSEMA and HHS staff to review the list of all critical facilities in the District. The critical facility lists are compared for accuracy on an annual basis to ensure both the Pepco and DC HSEMA have the necessary information to correctly, address and prioritize these critical facilities during major events. The Pepco IMT and CIC also conducted quarterly leadership meetings to review recent events and areas for process improvement. A drill of Pepco’s Emergency Satellite Communications equipment was conducted at the Pepco Benning Service Center on May 8, 2014.

Furthermore, in 2014 Pepco participated in external exercises, drills and seminars by providing subject matter expertise. Pepco participated in the District Hurricane Functional Exercise attended the District Response Plan Development: ESF #14-Damage Assessment meetings, the DC Water and Energy Nexus Review Meetings, the DC Infrastructure and Lifeline Systems Recovery Discussions, was part of the DC Hurricane Exercise Planning Team, the Council of Governments (COG) Winter Weather Briefing Exercise, and the COG Emergency Preparedness Council meeting. Pepco’s Emergency Management and Government Affairs teams facilitated a meeting with the D.C. AARP and key nursing home groups to discuss restoration priorities. These exercises, drills, seminars, meetings and task force included many District of Columbia stakeholders and key agencies

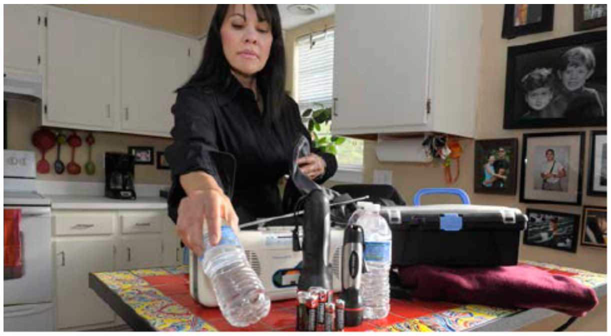
Pepco’s Emergency Management, Safety, Substation, and Underground Departments played key roles in the planning, security and activities for the African Leaders Summit as well as The State of the Union Address. Pepco was a contributor to the development of many of these forums as well as a participant.

Pepco actively participates in the District of Columbia Local Emergency Planning Council. Additionally, an Emergency Management Meeting for Key Accounts and government agencies was conducted on June 25, 2014 covering topics including emergency preparedness, restoration process, communications and coordination.

In conjunction with the MSO Plan, Pepco may also activate PHI's Crisis Management Plan. PHI's Crisis Management Plan defines the management structure and outlines response activities for extensive emergencies, including unplanned events that can cause significant injuries to employees, customers or the public; cause physical, environmental or technological damage; or that can shut down the business or disrupt operations. This plan also provides general guidelines allowing PHI and Pepco sufficient flexibility to respond to any emergency condition promptly and effectively.

LINES: Storm Preparation

Pepco is committed to achieving high quality communications with customers related to storms and power restoration. The Company's quarterly LINES publication provides information to customers regarding this topic. A clip from the Winter 2014 newsletter containing storm preparation communications is included below.



Winter storms are more frequent in a changing world and restoring power safely takes time. Here's how you can prepare so you'll stay safe and connected when severe weather strikes.

Before a Storm Strikes

- Assemble an emergency storm kit containing bottled water, non-perishable foods, blankets, flashlights and extra batteries, first-aid kit and prescription medications, special medical or infant supplies, hand tools and other essential items
- Purchase a battery-powered carbon monoxide detector for your home if you plan to use an alternative source of heat
- Develop and practice an emergency plan with everyone in your household
- Fill your bathtub with water if your water supply depends on electricity
- Make sure cell phones are charged
- Protect and unplug electronic equipment
- Ensure your Pepco contact information is up to date by calling 202-833-7500
- Download our mobile app (pepco.com/mobileapp) so you can get the latest news, report outages, access outage maps of your area, get restoration estimates and call us through a direct dial link should the power go out

If Power Goes Out

- If possible, gather in a central room that has an alternative source of heat such as a fireplace or wood stove
- Keep refrigerator and freezer doors shut
- Let the sun warm rooms during the day and close shades or curtains at night to keep warmth in
- Dress in loose layers for warmth and flexibility
- If using a portable generator during a power outage, always operate it outside and away from doors and windows to prevent deadly carbon monoxide fumes from entering the home
- If the indoor temperature drops to 55 degrees Fahrenheit or below, open your faucets slightly so they constantly drip to prevent pipes from freezing
- When conditions are safe, check on elderly or home-bound neighbors

Heating Without Power – Dos and Don'ts

- DO keep children and pets away from any open flames
- DO use a carbon monoxide detector to keep you and your family safe – carbon monoxide is not only colorless and odorless, it is deadly
- DO use sleeping bags and other cold weather gear to stay warm
- DON'T use a gas range for heating a room
- DON'T use a generator indoors or in any area without proper ventilation
- DON'T use charcoal to heat or cook indoors

For other tips and information, visit pepco.com/storm.

PART 2: 2014 PIP

SECTION 2.1 – REQUIREMENTS

On November 1, 1982, in Order No. 7668, the Commission adopted final rules regarding the submission of an annual PIP in Formal Case No. 766. These rules are codified in Title 15 of the District of Columbia Municipal Regulations, Chapter 5, Rules 502.1 and 502.2. In 1982 the Commission also directed the Company to establish the PIWG, consisting of representatives from the Commission Staff, the Office of the People's Counsel (OPC), and Pepco to provide a setting for communication among all parties and Commission Staff during the developmental stage of the first annual PIP. With the divestiture or transfer to an affiliate of all of Pepco's generating stations, the primary focus of the PIP and PIWG has shifted instead to transmission and distribution operations, performance, and reliability.[38] Later, Order No. 16623 emphasized a focus on reliability for the Consolidated Report.

SECTION 2.2 – PIWG

As discussed above, the PIWG has evolved over the years since its establishment, but continues to serve as a standing committee for collaboration among the Commission Staff, the OPC, and Pepco. The PIWG meetings address issues of interest to the Commission or PIWG members. Agendas and meeting frequency are determined according to issues of immediate concern to PIWG members and according to directives of the Commission. The PIWG generally meets no more frequently than monthly, but at least once per quarter. A discussion of the items on the next meeting's agenda usually occurs at the end of each

[38] In Order No. 15152 on the 2008 Consolidated Report paragraphs 68 the Commission stated the following:

> *68. The Productivity Improvement Working Group, which includes OPC, provided a reasonable definition of a productivity improvement project in 2006. Specifically, the PIWG states:*
>
> > *T&D productivity improvement projects were considered those projects that will increase T&D system efficiency by reducing losses and improve[ing] system reliability, and which may defer more costly additions to the electric system. (Footnote: F.C. No. 766, Decision on Consideration of OPC's T&D Productivity Improvement Working Group in Response to Commission Order No. 13754, filed July 6, 2006 ("2006 PIWG Report"), at 2.)*
>
> *The power serving the District's Standard Offer Service customers is now procured through a wholesale procurement process by PEPCO and, as such, productivity improvement is applicable only to transmission and distribution issues. We find the PIWG's definition of a productivity improvement project workable and adopt it here.*

PIWG meeting. The agenda for the next meeting is also included in meeting minutes, which are circulated to PIWG members for comment before filing with the Commission.

2014 PIWG Activities

The PIWG met eight times in 2014. The 2014 PIWG meeting dates and meeting minutes filing dates are as follows:

2014 PIWG Meeting Dates and Meeting Minutes Filing Dates

Meeting Date	Filing Date of the Meeting Minutes (See Formal Case No. 766)
January 28	February 7
February 25	March 7
April 15	April 25
May 27	June 6
July 14	July 24
September 30	October 7
October 28	November 7
December 2	December 12

Table 2.2-A

Topics discussed at each PIWG meeting in 2014 are included in Table 2.2-B below.

2014 PIWG Topics

	First Quarter			Second Quarter			Third Quarter			Fourth Quarter		
Items	28-Jan	25-Feb	March	15-Apr	27-May	June	14-Jul	August	30-Sep	28-Oct	November	2-Dec
Quarterly Status Reports												
o Manhole Events	X	X	No Meeting Scheduled		X	Meeting Postponed		Meeting Postponed	X		Meeting Postponed	X
o Manhole Inspections	X	X			X				X			X
o Quality Control Program Results	X	X							X			X
o Non-Major Outage Reports	X	X			X				X			X
o Incident Reporting (Injuries)	X	X			X				X			X
o PIP Projects	X	X			X				X			X
Order No. 12735 Implementation (FC 991)												
o Annual Failure Analysis Summary					X							
Review 2014 Consolidated Report Filing Layout	X											
Other												
Transmission Update		X	Meeting Postponed			Meeting Postponed		Meeting Postponed	X		Meeting Postponed	
Smart Inverter Pilot										X		
Maryland Plug-in Vehicle Pilot Program	X											
DC United Soccer Stadium		X										
Reliability Status												
DC HSEMA Outage Information Access				X								
Maryland Plug-in Vehicle Pilot Program				X			X					
Substation Projects				X								

Table 2.2-B

SECTION 2.3 – PIP

In Order No. 16623 on the 2011 Consolidated Report, the Commission stated the following in paragraph 8: "As a preliminary matter, we note our continuing concern with the reliability of the Pepco electrical distribution system… It is through the prism of these [reliability] efforts that we consider the Pepco Consolidated Report." In accordance with the Commission's focus in Order No. 16623 and the guidance of the PIWG, the Company presented its 2014 PIP projects, with a strong emphasis on reliability.

The 2014 PIP projects were as follows:

- 4 kV Distribution Substation Automation Projects
- 4 kV to 13 kV Conversion Projects
- DA Projects
- Priority Feeder Projects

2.3.1 PIP PROJECT STATUS

The year-end 2014 status of the 2014 PIP Projects is included in Table 2.3-A. PIP projects are contained within the Company's REP. To avoid repetition, detail regarding work completed in 2013 and work continuing into 2015 is contained in Section 2.3.2.

Item	Description	PIP Project Year	Spent To Date	2014 Project Amounts[1] (x1000)		Cost Variance Actual from Budget	Project Status
				Budget	Actual		
1	4 kV Distribution Substation Automation Projects	2014	$4,707	$785	$523	($262)	The substation automation work at 12th street Sub 126, G Street Sub 28, Oliver Street Sub 146 was completed. The substation automation engineering was completed at Twining City Sub 150, 53rd Street Sub 48, and Chesapeake Street Sub 181. The construction began at Sub 150 on January 2015 and will continue at Sub 181 on Fall 2015 and at Sub 48 on Spring 2016.
2	4 kV to 13 kV Conversion Projects	2014	$73,785	$24,947	$24,527	($420)	Georgetown Sub.12; Harvard Sub. 13; N Capitol Sub. 40; 12th St Sub. 126; Anacostia Sub. 8; 23rd St Sub. 131; Harrison Sub. 38
3	Distribution Automation Projects[2]	2014	$15,148	$6,794	$3,889	($2,905)	The scope for ASR projects is currently being modified to account for DC PLUG project. In the interim, an alternate plan for completion in 2016 has been formulated. This and some delay in RMS equipment delivery accounts for the majority of the under-expenditures in 2014. RMS-Sub 212 Northeast network awaiting completion of network split--EC[3] Q2 2015; Sub 18 Central Network RMS moved to EC[3] Q3 2015.
4	Priority Feeder Projects[4]	2014	$9,912	$15,842	$9,912	($5,930)	**Expected Completions:** 2014 feeders: OH feeders 14031, 15085 and UG feeder 53 - Q1 2015. 2013 carry over feeders: OH feeder 15166 -Q1 2015. 2014 feeders 15009, 15173, 15867, 14753, 14136, 15171,15021, 15199, 14717, 14758, 15130, 212, 15207R; 2013 carry over feeders 14786, 14788, 14014, 15801, 14787, 15707, 14009; 2012 carry over feeders 166, 141, 15702 - **Work complete as of Q4 2014.**

Note: 1) Project amounts are for 2014 only. 2) Values are net, after DOE reimbursements. 3) EC stands for Expected Completion, including integration with IT systems. 4) Priority Feeder Projects "Spent to Date" is for the current year.

Table 2.3-A

2.3.2 PIP PROJECT DETAIL

Detail addressing each of the 2014 PIP projects – including work completed in 2014, work forthcoming in 2015, and longer-term plans – is provided below.

2.3.2.1 4 kV Distribution Substation Automation Projects

This reliability improvement work is not included in the REP.

Status: In 2014, at G Street Sub. 28, transformer #2 secondary protection and alarm installation work was completed. Also, additional automation work was completed on the existing transformers#1 and #4 secondaries. At Oliver Street Sub 146, automation work was completed including the installation of feeder and transformer breaker protection relays as well as the Digital Remote Terminal Unit (DRTU).

2015 Plan: Based on current system needs, Pepco will continue to focus on automating transformer secondaries, including the installation of feeder, bus-tie, and transformer breaker protection relays at Twining City Sub 150 and Chesapeake Street Sub 181. The engineering and equipment procurement for Fifty-third Street Sub 48 automation work will be completed and the installation of this equipment is scheduled for Spring 2016. The estimated expenditure for 2015 is $702,982. A full discussion of current and planned substation automation work is provided in Section 1.3.1 of this report.

2.3.2.2 4 kV to 13 kV Conversion Projects[39 40]

These projects are included in the REP Load Growth program.

Background: The 4 kV distribution system supplies load throughout various neighborhoods in the District of Columbia. The 4 kV system has provided an effective and reliable supply to Pepco customers for many years. However, the 13 kV system is capable of supplying a greater density of load and generally produces less electrical losses. Therefore, as load density increases locally, or the system requires more maintenance and replacement becomes the best economic alternative, the 4 kV system is gradually being replaced with a 13 kV distribution system.

Magnitude of the Conversion: There are presently 150 megawatts of 4 kV load on the system, mostly in the District of Columbia. Over the next ten years, approximately 54 megawatts (including growth) will be converted to 13 kV service. Allowing for load growth, approximately 110 megawatts are projected to remain on the 4 kV distribution system by 2024. This 4 kV load will be located primarily in Wards 3, 7 and 8 where the load is served by substations that have either multiple transformers or are networked together through the feeder primaries. These remaining 4 kV areas are considered reliable

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[39] In Order No. 16091 at paragraphs 50, 53, and 64, the Commission stated the following:

50. *Decision. We agree with the Staff recommendation and require Pepco to provide justification for any deviations from the plan schedules and annual budgets for 4 kV to 13 kV conversion projects in its Consolidated Reports, excluding minor deviations of less than 5%. This information may be provided in the discussion of "Reliability Projects."*
53. *Decision. …we have not adopted the Staff's "replace or rebuild" recommendation. However, we agree that future Consolidated Reports should contain detailed schedules and budgets for Reliability Projects, as well as justification for deviations from those schedules and budgets. We shall require Pepco to submit such schedules in future Consolidated Reports.*
64. *Pepco IS DIRECTED to provide detailed schedules and budgets for conversion projects, as well as justification for any non-minor deviations from these , consistent with Paragraphs 50 and 53 of this Order;*

[40] Commission Order No. 16623 states the following:

32. *Staff Recommendation: Require Pepco to provide and submit a report as to whether the budgets and schedules for each of the four 4 kV to 13 kV conversion projects have undergone non-minor deviations from previous plans. Include the justification for such deviations.*
33. *We accept the Staff's recommendation and direct Pepco to include a complete update in the 2012 Consolidated Report, including changes in budgets and schedules and justification for each non-minor deviation.*
54. *Pepco is DIRECTED to provide a report of conversion projects consistent with paragraph 33;*

due to the shortness of the feeders and the availability of ready backup. Areas that are going to be maintained and not converted will involve upgrading of substantial transformer equipment and other supporting equipment.

<u>Areas Scheduled for Conversion:</u> Areas supplied by the following substations are scheduled to have conversion work performed in the next ten years:

• Georgetown Sub. 12	NW	Underground conversion
• Harvard Sub. 13	NW	Underground conversion
• North Capitol Sub. 40	NE	Overhead conversion
• Twelfth Street Sub. 126	SW	Underground conversion
• Anacostia Sub. 8	SE	Overhead conversion
• Fort Carroll Sub. 130	SE	Overhead conversion
• G Street Sub. 28	NE	Underground conversion, proposed for 2017

The 2014 PIP Project "4 kV to 13 kV Conversion Projects" includes all but the last of the conversion projects listed above.

All of the projects described below are multi-year projects with multiple phases. Five of the seven projects were initiated prior to 2014, and the seventh (G Street Sub. 28) is currently scheduled to commence in 2017. Dollars spent on these projects may fluctuate over the years to account for project phasing. The 2015 budget is lower the 2014 budget because the 4 kV conversions at Harrison Sub. 38 are scheduled for completion in the first half of 2015 and proposed conversion work at Anacostia Sub. 8 will be completed during the course of the DC PLUG initiative. The Anacostia conversion work is scheduled to be completed during the course of the DC PLUG initiative because much of the Anacostia 4 kV load will be converted to Feeder 15177, which was selected to be placed underground. The overall budget for the 4 kV conversion projects is still in line with the Company's long term conversion plan.

Status: In 2014 Pepco spent $24,856,000 on its 4 to 13 kV conversion projects, $2,284,000 less than the budget of $27,140,000. The deviation between the 2014 budget and actual expenditures is due to a combination of work being delayed by permitting and work time restrictions finding conduit breakdowns that slowed work and a cost-saving scope changes through discovery of usable empty conduits in the field.

Convert load at Georgetown Sub. 12 from 4 kV to 13 kV and retire 4 kV Substation

A modernization of this area infrastructure started in 2001. It includes the 4 to 13 kV conversions that will ultimately retire the 4 kV radial distribution system supplied from Georgetown Sub. 12. The 4 to 13 kV conversion has been completed for the area between M Street to the south, P Street to the north, Wisconsin Avenue to the west and 27th Street, NW to the east, by extending the two 13 kV distribution feeders from Georgetown Sub. 12. In addition, conversions along M Street, Prospect Street, and N Street west of Wisconsin Avenue were completed in 2010 and 2011. Conversions continued along O and P Streets west of Wisconsin Avenue and concluded in 2012. Conversions of the area north of P Street and east of Wisconsin Avenue were largely completed in 2014. The remainder of this section plus the section west of Wisconsin Avenue and north of P Street are scheduled to be completed in the 2015 timeframe. The section south of M Street NW identified as Phase 6, which has long and lightly loaded feeders, will be converted to Georgetown 13 kV feeders in the 2016-2017 timeframe.

Existing Configuration: The 4 kV underground radial distribution system serves mostly residential and some small commercial loads. Moderate load growth is anticipated for this isolated area but there are basically no external ties to deliver this power. The existing underground infrastructure, conduit and cable are in need of remediation with a history of extended outages due to limited transfer capability and circuit configuration and conduit construction that limits the size of cable that can be installed and provides limited physical protection to the cables.

The Georgetown 4 kV substation was rebuilt in the 1980s however the 4 kV underground infrastructure is the original construction and is nearing its full capacity.

Proposed Enhancement: Convert all 4 kV load to 13 kV distribution feeders

Status: Project is in progress. The trunks of three 13 kV feeders were extended along Wisconsin Avenue from N Street to Reservoir Road, NW. Two half loops have been built and 3 MVA of load has been converted to 13 kV operation. Conduit has been built along Q Street, Reservoir Road, 34th Street and 35th Street, NW. The 2014 budget for this project was $4,902,000 and approximately $7,009,000 was actually spent in 2014. The deviation between 2014 budget and actual was due to a significant amount of conduit being constructed that was not initially anticipated. The current project in-service date is June 2017.

Georgetown Sub. Conversion:

2015 – 2019 Budget (Figures in Thousands of Dollars)

2015	2016	2017	2018	2019	Total
$5,462	$4,715	$5,000	$0	$0	$15,176

Convert load at Harvard Sub. 13 from 4 kV to 13 kV and retire 4 kV Substation

This project is recommended to initiate infrastructure upgrades to the existing 4 kV system in the Upper Shaw and Harvard/Columbia Heights areas. Two 13 kV Feeders were extended from Florida Avenue Sub. 10 in 2011 to provide capacity for the conversion and to allow load to be transferred to Sub. 10 from Sub. 13. Existing 13 kV Feeders from Sub. 13 and new 13 kV Feeders from Sub. 25 will be used to convert the final portion of 4 kV load starting in 2015.

The current phases of conversion extended two new feeders from Florida Avenue Sub. 10 along Florida Avenue and Barry Place to convert 4 kV load in the area bounded by U Street NW to the south, 13th Street NW to the west, Harvard Street NW to the north and 7th Street NW to the east. This phase was largely completed in 2014. Pepco plans to have the remaining 4 kV load south of Harvard Street and west of 7th Street plus the 4 kV load east of 7th Street and south of Harvard Street largely converted in 2015. Pepco also plans to complete the mainline extension of the aforementioned new feeders from Champlain Sub. 25 in 2015 and plan to convert 4 kV load to these feeders beginning in 2016.

Existing Configuration: The existing 4 kV underground distribution system serves residential and small commercial loads. Modest load growth is anticipated for this area which is isolated from the rest of the system and has no external ties. The existing underground system experiences feeder overloads, voltage deficiencies and a greater than average number of underground cable outages due to the age and condition of the cable and limited transfer and switching capabilities.

Proposed Configuration: Convert 4 kV load to 13 kV distribution feeders and retire Harvard Sub. 13 which currently operates at 4 kV.

Status: The building of conduit and extension of main trunk of the two 13 kV feeders out of Florida Avenue has been completed and the building of conduit and extension of laterals to convert 4 kV load was begun in 2012 and four 4 kV feeders, about 3 MVA of load, has been converted in the area bounded by 11th Street, V Street, Georgia Avenue, and Euclid Street, NW. The 2014 budget for this project was $7,337,000 and approximately $3,120,000 was spent in 2014. Actual spending was below budget because duct breakdowns found in the field required reengineering and permitting. The extension of the two new Champlain feeders has been delayed due to delays in permits being issued. And, the half loop job from Sherman Avenue and Barry Place, NW is being redesigned due to new large commercial loads at 8th and V Streets, NW. The current project in-service date for the entire project and final retirement of the substation is December 2018.

Harvard Sub. Conversion:

2015 – 2019 Budget (Figures in Thousands of Dollars)

2015	2016	2017	2018	2019	Total
$6,184	$5,477	$7,165	$7,925	$0	$26,751

Convert load at North Capitol Sub. 40 from 4 kV to 13 kV and retire 4 kV Substation

This project relates to an extension of existing and new 13 kV feeders to convert all 4 kV load served by North Capitol Street Sub. 40 to 13 kV.

The North Capitol Street 4kV system serves mostly residential and small commercial customers in the Manor Park, Fort Totten, and Petworth neighborhoods. The first phase of this project will convert load from portions of North Capitol Sub. 40 Feeders 482 and 485 along 4th Street, NW between Buchanan and Hamilton Streets, NW to Fort Slocum Sub. 190 - 13kV Feeders 15006, 15012 and 15015. This phase was completed in 2013. 2014 saw the completion of conversions along Hamilton Street, NW, Hawaii Avenue, NE and Fort Totten Drive, NE.

Existing Configuration: The North Capitol Sub. 40 4 kV system is an isolated area on the Pepco distribution system that is not connected to any other 4kV substations or systems. Recent substation inspections have revealed deteriorating circuit breakers. The Allis Chalmers switchgear necessitates the salvage of spare parts from like equipment because the original equipment manufacturer is no longer in business and other manufacturers no longer supply parts for this equipment.

Proposed Configuration: Convert all 4 kV loads to 13 kV distribution feeders and retire North Capitol Sub. 40 - 4 kV.

Status: The project is underway. As of the end of 2014, several 13 kV trunk extensions have been completed and approximately 5 MVA of 4 kV load has been converted to 13 kV. The 2014 budget for this project was $2,406,000 and approximately $1,852,000 was actually spent in 2014. The deviation of budget to actual was because some engineering and construction resources were directed to other projects. The current in-service date for the rest of the conversion project is December 2017.

North Capitol Sub. Conversion:

2015 – 2019 Budget (Figures in Thousands of Dollars)

2015	2016	2017	2018	2019	Total
$1,107	$1,117	$2,401	$0	$0	$4,625

Convert load at 12th Street Sub. 126 from 4 kV to 13 kV and retire 4 kV Substation

This project will extend two 13 kV feeders and install two 13 kV transformers to 4 kV step-down transformers in order to convert or transfer all 4 kV load supplied by 12th Street Sub. 126.

The 12th Street 4 kV system serves residential and small commercial customers in Southwest area and National Park Service buildings, street lights and traffic signals in the National Mall area. The conversion and retirement of the 12th Street Sub. 126 will be done in two phases. Phase 1 will construct an 8 way conduit bank from 2nd and C street SW to the vicinity of 7th and Maryland Avenue SW. It will involve the construction of approximately 1.0 miles of 8-way conduit bank. Phase 2 will involve extending Feeders 15294 and 15295 to two new three way switches. Loops will then be extended from the switches to supply load around the National Mall and Southwest Waterfront. The last phase will require extending Feeders 15294 and 15295 to two new 3-way switches and extending laterals to the area of Hanes Point, the Tidal Basin and the 14th Street Bridge.

Existing Configuration: The 12th Street Sub. 126 contains oil circuit breakers that will be removed based on the review of condition and reliability. Both the 13 kV/4 kV transformers are identified as in need of eventual replacement. These oil circuit breakers are no longer manufactured and the manufacturer no longer provides spare parts. As part of the conversion process, this substation will be retired. Economic analysis concluded the least cost plan was to convert most of the load and transfer the rest to two 13/4 kV unit type transformers rather than replace the transformers and circuit breakers and maintain the substation switchgear and related infrastructure.

Proposed Configuration: Convert all 4 kV loads to 13 kV distribution feeders and retire Twelfth Street Sub. 126 – 4 kV including the transformers and oil circuit breakers.

Status: The extension of two 13 kV feeders from oil-switches on Maryland Avenue and 6th Street SE to 2nd and D Street SW was completed in 2013. Conduit and tap-holes have been constructed and cable extended and 0.2 MVA of load converted in 2014. The 2014 budget for this project was $4,201,000. Approximately $5,592,000 was spent in 2014. The difference between the 2014 budget and actual amounts was due to Pepco construction being able to install large amounts of conduit in the area in and around the National Mall. The current project in-service date is December 2017.

12th Street Sub. Conversion:

2015 – 2019 Budget (Figures in Thousands of Dollars)

2015	2016	2017	2018	2019	Total
$4,968	$6,744	$4,000	$0	$0	$15,712

Convert Load at Anacostia Sub. 8 from 4 kV to 13 kV and Retire 4 kV Substation

The project relates to the extension of 13 kV feeders from Alabama Avenue Sub. 136 in order to convert all 4 kV load from Anacostia Sub. 8 4 kV and retire the Anacostia Sub. 8 – 4 kV substation.

The Anacostia Sub. 8 4 kV system supplies residential and small commercial load in the Anacostia, St. Elizabeth's, Barry Farm, and Buena Vista neighborhoods in Southeast Washington, D.C. New and existing 13 kV overhead feeders from Alabama Avenue Sub. 136 will be extended in order to convert all 4 kV load.

Existing Configuration: Anacostia Sub. 8 is supplied by two 34 kV feeders from Buzzard Point Station B. Converting 4 kV load from Anacostia Sub. 8 will also relieve load from Buzzard Point Station B 13 kV substation which is approaching its firm capacity. Review of the equipment at Anacostia Substation and the 34 kV supplies indicated the need to replace all of this equipment for long term reliability. Instead of rebuilding this station, conversion of the 4 kV load and transfer of the 13 kV load to Alabama Avenue Substation will allow the retirement of the station and supplies and improve the overall reliability of the distribution system in this area.

<u>Proposed Configuration:</u> Convert all 4 kV loads to 13 kV distribution feeders and retire Anacostia Sub. 8 – 4 kV.

<u>Status:</u> Much of the Anacostia 4 kV load has been converted over the past several years as part of the 23rd Street and Anacostia 4 kV conversion projects. Construction for the Anacostia 4 kV conversion project began in 2012 and about 1.2 MVA load has been converted to 13 kV. The 2014 budget for this project was $0 and approximately $34,000 was spent in 2014. There was a small amount of money spent in 2014 to complete the first phases of recommended conversions. The next phases are being engineered and work should begin in 2015 on the 0.4 MVA of load that is being converted to overhead Feeder 15173. The work to convert the remaining 1.7 MVA to Feeder 15177 is being moved into the scope of the DC PLUG initiative. Feeder 15177 is in the 2nd group of feeders to be undergrounded. Pepco determined that the most prudent course of action was to convert the 4 kV portions at the same time that they are being undergrounded with the rest of Feeder 15177. This course of action reduces costs overall and is more efficient because Pepco is not first upgrading the 4 kV overhead to 13 kV overhead and then undergrounding it. It is anticipated that all the undergrounding/conversion work on Feeder 15177 will be completed in 2017 and Anacostia Sub. 8 would be retired at that time.

Anacostia Sub. Conversion:

2015 – 2019 Budget (Figures in Thousands of Dollars)

2015	2016	2017	2018	2019	Total
$245	$0	$0	$0	$0	$245

Convert load at Harrison Sub. 38 from 4 kV to 13 kV and retire 4 kV Substation

This project was recommended in 2012 to initiate infrastructure upgrades to the existing 4 kV system in the Chevy Chase and Friendship Heights areas. Substantial construction began in 2013. One 13 kV feeder will be extended from Van Ness Sub. 129 in 2014 to provide capacity for converting three out of the six 4 kV feeders. The other three feeders will be transferred to existing Oliver Street Sub. 146.

This work is being done to facilitate the retirement of the two 4 kV transformers and the 4 kV switchgear at Harrison Sub. 38. A project was proposed in 2011 to build a substation that would replace Harrison Sub. 38. Pepco's current plan is to rebuild Harrison Sub. 38 on the current substation site, but as a 13 kV substation only. The building and switchgear at Harrison Sub. 38 are in deteriorated condition as is one of the 4 kV transformers. A decision was made not to replace the Harrison 4 kV substation requiring that load be converted or transferred to other substations. The 52 year old 4 kV transformer at Oliver Street Sub. 146 was replaced in 2013 which has increased capacity at that substation increasing capacity to facilitate the transfers.

Existing Configuration: The existing 4 kV underground distribution system serves residential and small commercial loads. Low load growth is anticipated for this area. Harrison Sub. 38 and Oliver Street Sub. 146 are part of the Northwest District of Columbia 4 kV primary system so most all 4 kV feeders are served from two substations.

Proposed Configuration: Convert about half of the 4 kV load to 13 kV distribution feeders, transfer the other half to Oliver Street Sub. 146 and retire the 4 kV substation at Harrison Sub. 38.

Status: Construction began in 2013 to extend a new feeder from Van Ness Sub. 129 to facilitate the 4 kV conversions and to build conduit on Western Avenue to enable new feeders to be extended from Oliver Street Sub. 146 so that three Harrison feeders can be resupplied out of that substation. The 2014 budget for this project was $5,294,000. Approximately $6,584,000 was spent in 2014. The difference between budget and actual spending occurred because more conduit needed to be constructed than initially anticipated. The current in-service date is June 2015.

Harrison Sub. Conversion:

2015 – 2019 Budget (Figures in Thousands of Dollars)

2015	2016	2017	2018	2019	Total
$1,650	$0	$0	$0	$0	$1,650

Convert load at Fort Carroll Sub. 130 from 4 kV to 13 kV and retire 4 kV Substation

This project was recommended in 2013 to initiate infrastructure upgrades to the existing 4 kV system in the Congress Heights area. Construction is scheduled to begin in 2014. This project will extend existing feeders from NRL Sub. 168 and Alabama Avenue Sub. 136 to convert the load from three 4 kV feeders. Two other 4 kV feeders out of Fort Carroll Sub. 130 were converted in the past few years as part of other conversion projects.

This work is being done to facilitate the retirement of the single 4 kV transformer and the 4 kV switchgear at Fort Carroll Sub. 130 because the switchgear at Fort Carroll Sub. 130 was assessed to be in a deteriorated condition and in need of replacement. Pepco determined that since this substation was to be retired at some point in the future, it was most economical to convert the 4 kV load and retire this substation in 2015 rather than replace the switchgear and then convert load and retire the substation at a later date.

Existing Configuration: The existing 4 kV overhead distribution system serves residential and small commercial loads. Low load growth is anticipated for this area.

Proposed Configuration: This project proposes to extend existing feeders from NRL Sub. 168 and Alabama Avenue Sub. 136 to convert the load from three 4 kV feeders. Two other 4 kV feeders out of Fort Carroll Sub. 130 were converted in the past few years as part of other conversion projects.

Status: Construction began in 2014 and some overhead preparatory work has been completed. The 2014 budget for this project was $4,235,000. Approximately $664,000 was spent in 2014. The difference between budget and actual spending occurred because savings were found during the engineering of the project and delays in obtaining some permits reduced the amount of work that was completed in 2014. The project is scheduled to be completed by June 2016.

Fort Carroll Sub. Conversion:

2015 – 2019 Budget (Figures in Thousands of Dollars)

2015	2016	2017	2018	2019	Total
$2,248	$493	$0	$0	$0	$2,741

2.3.2.3 DA PROJECTS

These projects are included in the REP DA program.

DA is the conversion of a manually operated distribution system with limited available status information and limited control to a system that not only is fully automated but also performs operations totally independent of any human intervention. Advancements in technologies have made these automation activities practical for the lower voltage systems and will significantly change the way the Company will respond to outages and operate and restore the electric system.

Status: All DA ASR projects for 19 feeders under the SGIG program have been completed. New ASR plans for 5 feeders are planned for installation in 2015, with activation planned for 2015. See Attachment A for details of the DA ASR plans.

A full discussion of current and planned DA work is provided in Section 1.3.1 of this report.

2.3.2.4 PRIORITY FEEDER PROJECTS

These projects are included in the REP Feeder Improvement program.

Status: In response to the Commission’s focus on preventing repeat Priority Feeders, Pepco has adjusted its feeder remediation strategy to a more comprehensive approach. Instead of focusing on locations where previous failures have occurred, the entire feeder is reviewed to address potential locations for future failures. During this review of the 2014 Priority Feeders, including detailed field inspections, Pepco identified additional opportunities to increase feeder reliability based on infrastructure conditions. The actual expenditure of the 2014 Priority Feeder Projects is $9,912,324. A more detailed description of the work can be found in Section 2.4.1.

An extensive discussion of the 2015 Priority Feeder projects is contained in Section 2.4.1 of this report.

SECTION 2.4 – PERFORMANCE

2.4.1 PRIORITY FEEDERS & AGGRESSIVE INITIATIVES

2.4.1.1 FEEDER PERFORMANCE AND AGGRESSIVE INITIATIVES [41]

[41] Order No. 16975 states the following at paragraphs 58 and 59, 60, and 105:

58. *Decision: …We therefore require Pepco to provide in the 2013 Consolidated Report, the information recommended by the Staff including an explanation of any discrepancies between work planned and work completed…. In Order No. 15941, the Commission required Pepco to provide specific information regarding any 4 kV feeder that has appeared on the Priority Feeder List three times or any 13 kV feeder that has appeared on the Priority Feeder List four times. On June 13, 2012, Pepco filed a report pursuant to that Order, providing information on two 13 kV feeders, 14717 and 14768. The Commission believes it is necessary to expand the scope of Pepco's reporting on feeder improvement to include any feeder that has appeared on the priority feeder list more than twice. Therefore, we require Pepco to provide the information required in paragraph 13 of Order No. 15941 in the future Consolidated Reports for any feeder appearing more than twice on the Priority Feeder List….*

59. *In future Consolidated Reports, Pepco shall include the following information about each feeder on the Priority Feeder List:*

    (1) a detailed description of outages, including causes and corrective actions taken;

    (2) the SAIDI, SAIFI, number of interruptions, and number of hours of customer interruptions for that feeder for each year beginning with the year the feeder first appeared on the Priority Feeder list;

    (3) a map showing the feeder service area, including affected neighborhoods;

    (4) an analysis of why past corrective actions failed;

    (5) Pepco's proposed solution to the feeder's reliability problem, including an explanation of options considered with the cost/benefit analysis of each and justification for the option recommended;

    (6) a cost/benefit analysis of the solution, including budget and cash flows by year, as well as any impact on the revenue requirement; and

    (7) a detailed justification for its aggressive feeder remediation measure of replacing open wire secondary with triplex secondary conductor.

60. *The Commission notes that in recent PIWG meetings, Pepco has indicated its intention to change the methodology which it uses to determine Priority Feeders. A change in methodology would diminish the value of the Priority Feeder List in determining historically poorly performing feeders and would lessen our ability to track and compare the historical data. Therefore, we require Pepco to provide two Priority Feeder Lists, using both the historical (CPI) and any new methodologies in the 2013, 2014 and 2015 Consolidated Reports. In addition, the Commission requires Pepco to provide the information required by paragraph 13 of Order No. 15941 for any feeder appearing more than twice on the Priority Feeder List using either the historical or any new method.*

105. *Pepco is DIRECTED to provide information on Priority Feeders consistent with paragraphs 58-60 herein;*

Feeder Performance[42]

Each year Pepco analyzes the performance of its feeders to determine the relative ranking of each feeder from the best to the least reliable. From this ranking, Pepco selects the least reliable two percent (2%) of its feeders (excluding the feeders selected through the prior year's study) to analyze and identify actions which likely will improve the reliability of the feeders, and therefore the system.

Beginning in 2013, the Company began using the SPC a method that provides greater system performance improvement potential (the "New Method"). The New Method value is calculated by the summation of 75% of the SAIFI and 25% of the SAIDI for each feeder.

In addition to the New Method to select Priority Feeders, Pepco uses CPI to rank the performance of its distribution feeders. Feeders that would have been selected as Priority Feeders using the CPI method are reported to the Commission in this report as "CPI-Selected Feeders" and are included in the Company's Feeder Improvement category of its REP program. CPI is determined by evaluating four measurements of reliability: number of interruptions (NI), number of hours of customer interruptions (CHI), SAIFI, and SAIDI. A description of the design of CPI can be found in Section 4.4 of this report.

The 2014 Priority Feeders and the CPI-Selected Feeders were selected using outage data from October 1, 2012 through September 30, 2013. Excluded from this annual study are the Priority Feeders from the prior year, which typically would not show the full results of corrective actions until a full year following the completion of the corrective actions.

The 2014 Priority Feeders were selected after September 30, 2013, at which time there were 796 feeders (4 kV and 13 kV) in the District of Columbia. Sixteen feeders represent

[42] The Electricity Quality of Service Standard D.C.M.R. 3603.6 states the following:

> *3603.6 The utility shall continue the current reporting of the worst performing (lowest two (2) percent) feeders (utility methodology) and corresponding corrective action plans, with the action taken in year 1 and the subsequent performance in year 2 in the annual Consolidated Report.*

approximately 2% of Pepco's current District of Columbia feeder count. Figures 2.4-A1 and 2.4-A2 contains maps of the 2014 Priority Feeders.

In addition, as of January 1, 2013, Pepco began changing the way feeders are counted in a jurisdiction (District of Columbia or Maryland), a modification that was originally presented at the September 2012 PIWG Committee Meeting. However, as of the time of the 2013 Priority Feeder selection, feeder reliability was still being tracked according to the old method of feeder classification in which feeders were assigned to a jurisdiction based upon the area in which the substation resides. Pepco's new method of counting feeders, which will assign each individual feeder to the jurisdiction where the majority of customers reside, took effect for selection of the 2014 Priority Feeders.

Cost/Benefit Discussion

Order No. 16975 requires that Pepco provide the following in this and future Consolidated Reports (paragraph 59, item 6):

> *(6) a cost/benefit analysis of the solution, including budget and cash flows by year[43], as well as any impact on the revenue requirement;*

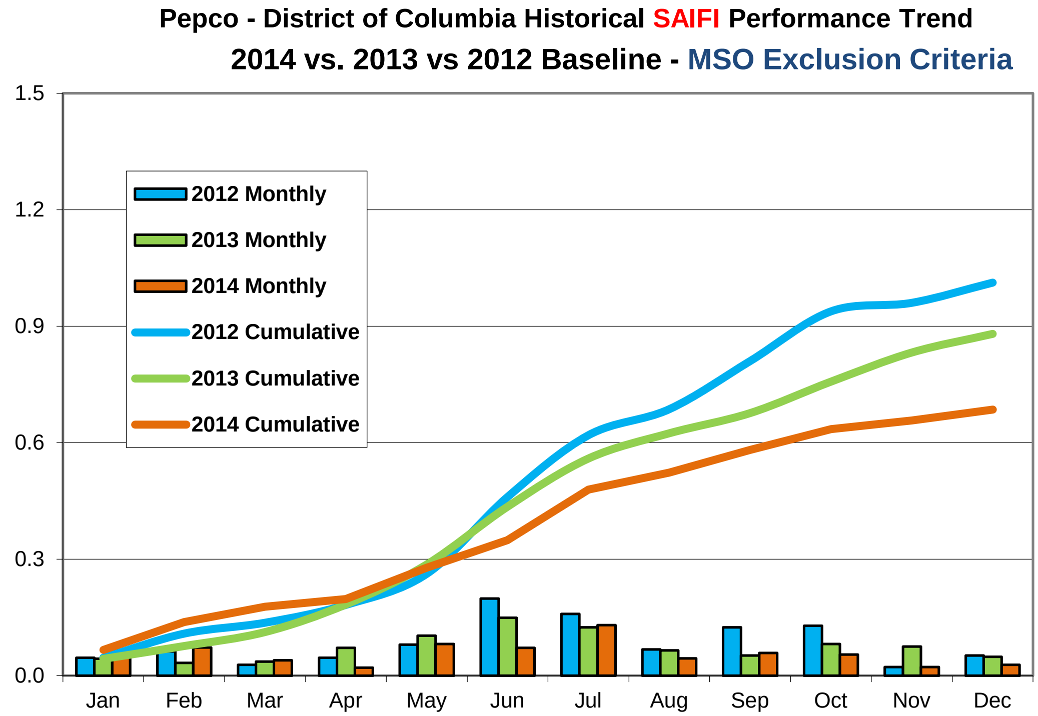
The measurement of benefits associated with feeder reliability projects generally depends on the outage history of the feeder and the likelihood that a portfolio of remediation activities will reduce or totally eliminate similar outages for the same or similar cause. Simply allocating a portion of the previous customer interruptions or customer minutes of interruption prior to the remediation activity is a way of qualifying the relative cost / benefit of individual remedial efforts. This is, however, not a dependable method of forecasting future feeder or aggregate system reliability because no remediation tactic is all inclusive of every possible outage cause. Likewise, this approach assumes all other inputs to system reliability are held constant (same weather, same animal events, same tree faults, etc.), which is unlikely.

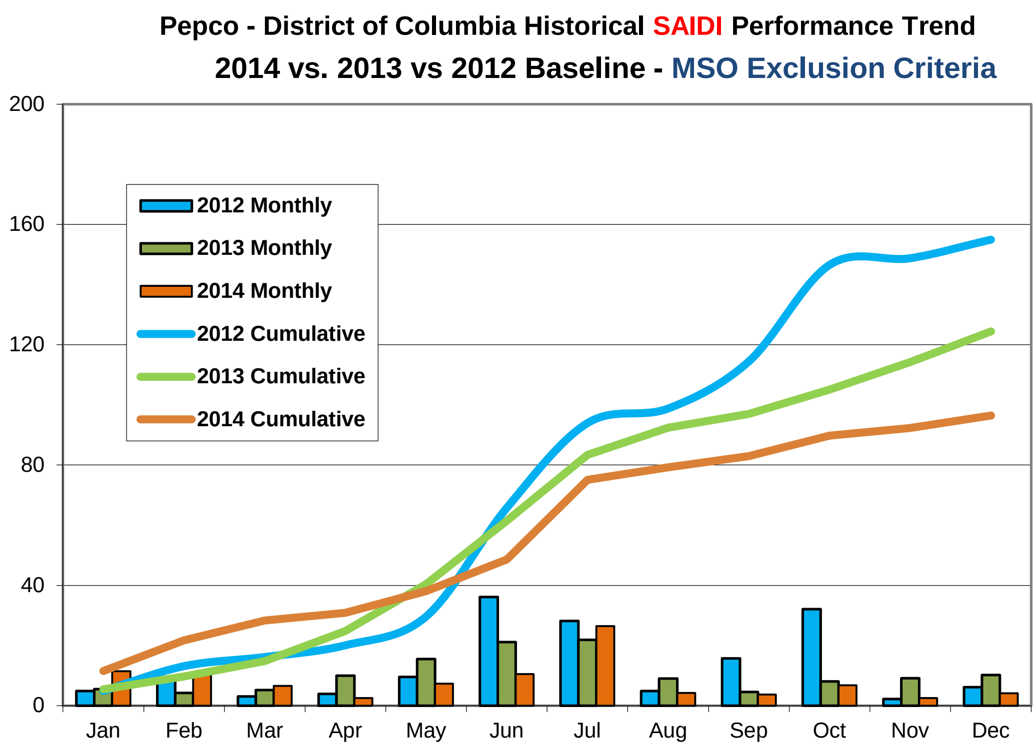
[43] The budget and cash flow discussion is provided in Section 2.4.1.2 below on a feeder by feeder basis.

Similarly, the measure and inclusion of cost/benefit per feeder or per individual initiative would potentially serve to reduce the field of options available to apply in feeder performance improvement. Some activities are not as efficient or economical as others based on a simple mathematical evaluation. However, the potential exclusion of these activities based on their relative inefficiency at the feeder or activity level would mean that the best overall portfolio of remedies could not be utilized in system level improvement. Further, with the advances in sectionalization technology, standard cost benefit analysis could drive a utility to employ only mitigation efforts rather than more appropriate but costly fault elimination tactics. Pepco evaluates each of these options and implements mitigation as well as elimination techniques when evaluating work to improve reliability of a feeder.

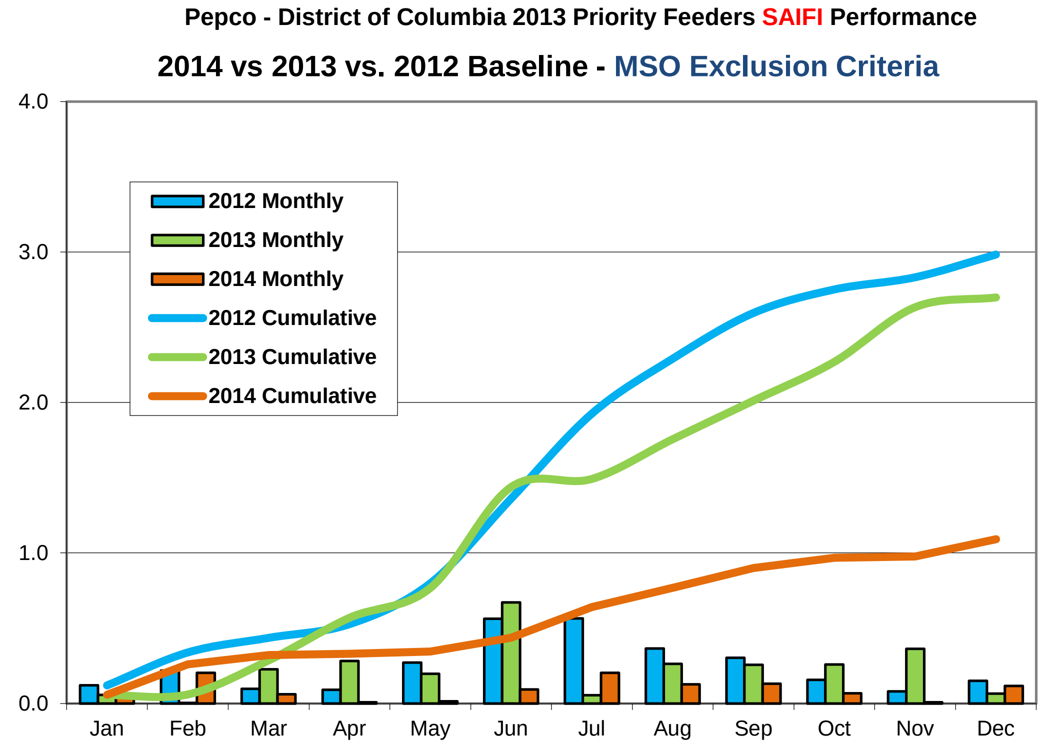
The method to evaluate benefit for an electric distribution feeder is a measure of the improvement in reliability performance. This comparison is made between the feeders' historical reliability performance before corrective action is taken and the reliability performance after the corrective work has been completed. The following figures show the improvement in both overall system performance and in the priorities feeders where work was performed during 2014. In all cases improvement is shown year over year and customers are experiencing fewer outages and shorter duration when outages do occur. These results indicate that the REP and Priority Feeder programs are working and realizing positive results. The Company will continue these efforts to select new feeders each year and identify the appropriate corrective actions to take in order to improve overall reliability.

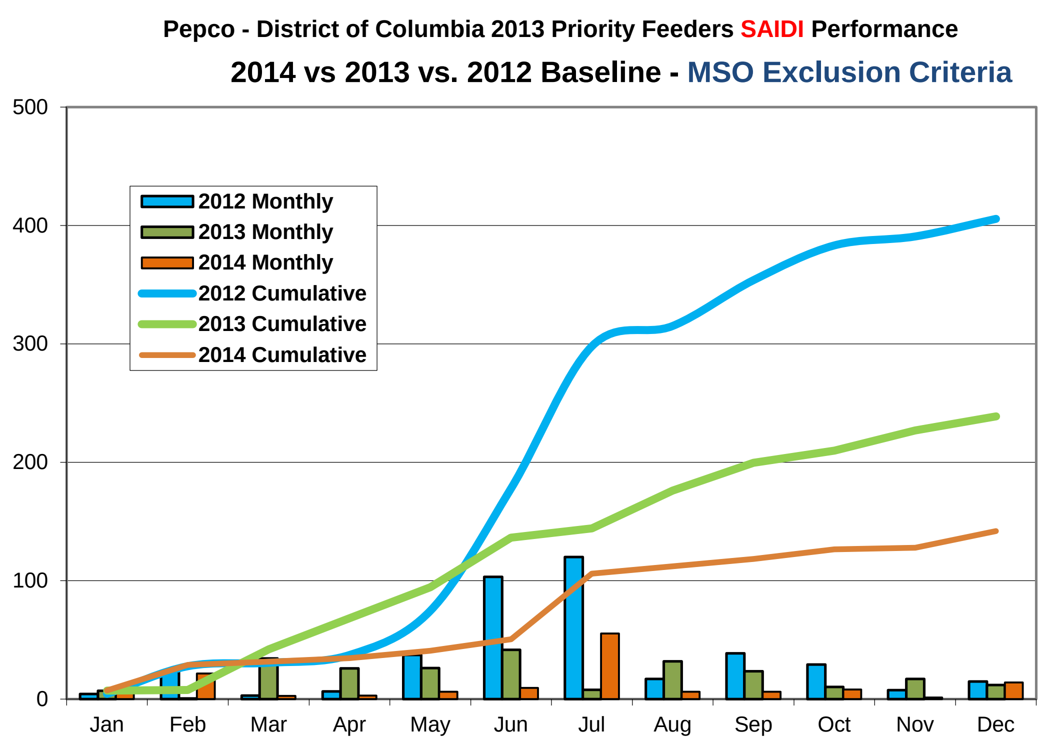
District of Columbia Historical SAIFI and SAIDI Performance





2013 Priority Feeders SAIFI and SAIDI Performance





In addition, as addressed in the REP Metrics discussion, Pepco has employed a statistical modeling program to project and evaluate the expected reliability performance of the electric system based on the impacts of the REP. Specifically, this model provides a probabilistic range of estimated SAIFI and SAIDI improvement values for the District of Columbia as a function of carrying out the elements of the REP.

The model is based on forecasted reliability improvement from three components of the REP: VM, feeder improvement work, and DA implementation. The improvement levels for each of these activities are based on the actual reliability performance during 2011-2013. The balance of the REP project categories are expected to contribute to additional improvements in reliability performance.

The forecasted results are illustrated in the Charts 5 and 6 in the REP Metrics discussion.

The charts show that the expenditures planned in the next five years alone will not achieve both SAIDI and SAIFI EQSS goals. Various process improvements will also be needed to achieve the SAIDI results towards the end of the five year period. In addition natural variations due to storms can have great impact on the yearly results and therefore the Company needs to strive for better than the minimum performance in order to achieve the stated standards.

Aggressive Initiatives[44]

The priority feeder program is an enhanced initiative including both reliability work routinely performed on the selection of priority feeders supplemented with more aggressive initiatives.

Aggressive initiatives may include the following:

- Installation of tree wire in close configuration construction to replace bare wire through heavily treed areas where aggressive tree trim and standard cross-arm construction would have limited success or is restricted by ordinance or property owners.
- Installation of PAC for use as the main trunk of the feeder with the existing mainline reconfigured as fused laterals.
- Installation of automatic circuit reclosers (ACR) in loop scheme configuration to automatically sectionalize faulted sections of the feeder and provide automatic backup to unfaulted sections.
- Installation of remote operated load break switches into the loop scheme configuration with the automatic circuit reclosers.

Pepco's proposed aggressive initiatives to its underground distribution feeders are:

4 kV System

In addition to performing Very Low Frequency (VLF) testing and manhole inspections, the process of correcting identified issues also includes the following:

- Installation of tap-holes (switch points) at key locations to improve the ability to isolate problems as well as improving the ability to restore customers following each event.

[44] In Order No. 15152 paragraph 73, the Commission ordered the following:

> *73. Pepco is DIRECTED to investigate the viability of the "aggressive" initiatives for all least performing feeders, to file a progress report regarding the implementation of these initiatives where viable as part of the 2009 Consolidated Report, and to file quarterly progress reports thereafter, consistent with paragraph 62 of this Order;*

In Order No. 15809 paragraph 11, the Commission ordered the following:

> *11. Pepco IS DIRECTED to include in its 2011 Consolidated Report a plan for development and application of "aggressive initiatives" to its underground distribution feeders;*

- Perform a review of the failure history of the area for each failure and comparison of failure locations to replacement history. Perform proactive cable replacement of stretches that were not previously replaced in the area.

Regarding Commission's recommendation (per Order No. 16975) to add switch points to 4kV feeders, over time these 4kV feeders will be converted to 13kV, in which the loop alternate feed design is inherent. In the interim, all of the 4kV systems have back up supply for trunk outages. And for lateral outages, Pepco is replacing cable, installing tap holes, and ultimately converting all current underground 4kV feeders to 13kV feeders.

13 kV System

In addition to performing VLF testing and manhole inspection, correcting identified issues include the following:

- Perform a review of the failure history of the area for each failure and compare failure locations to replacement history. Perform proactive cable replacement of stretches that were not previously replaced in the area.
- Replace all of the problem sections of cable.

For various reasons, not all of the "Aggressive Initiatives" are applied to the Priority Feeders. For example, if a particular feeder is completely underground, installing tree wire, PAC, ACR and remote operated load-break switches would not be applicable as these types of equipment are not used on underground feeders. Similarly, if a feeder is already equipped with remote switching capabilities and the switches are functioning properly, then simply increasing the number of remotely operated switches will generally not yield improvement. Further, if the predominant outage cause for a feeder is not tree-related, installing tree wire along the previous outage locations, will not yield performance improvement.

Order No. 16975 states the following at paragraph 58:
58. …In addition to the information required by paragraph 13 of Order No. 15941, the Commission also requires that Pepco provide detailed justification for its aggressive feeder

remediation measure of replacing open wire secondary with triplex secondary conductor, as recommended by the OPC response.

Explanation for replacing open wire secondary conductors with triplex conductors: Triplex conductors are less susceptible to mechanical damage such as trees, winds, etc. It increases the distance between the primary and neutral conductors which reduces the opportunity for primary related tree outages. Other miscellaneous upgrades will also be performed such as pole, hardwire, and equipment replacements due to deterioration. Upgrading will significantly reduce future equipment failures. Should damage occur, restoration is faster with the triplex conductors. Therefore, the customers will experience lower number of outages as well as a shorter duration of outages. The cost to replace open wire secondary conductors with triplex conductors is $40,000 per mile.

2.4.1.2 2014 PRIORITY FEEDER PROGRAM

Order No. 16975 requires that Pepco provide the following in this and future Consolidated Reports (paragraph 59, item 1):

(1) a detailed description of outages, including causes and corrective actions taken;

Note, modifications may be made to these plans depending on the work associated with the DC PLUG initiative.

2014 2% Priority Feeder Program - District of Columbia - Corrective Actions Proposed vs. Completed/ Pending Completion				
Rank	**Feeder**	**Proposed Corrective Actions, as filed in the 2014 Consolidated Report**	**Detailed Corrective Actions - Completed/ Pending Completion**	**Explanation of Variances/ Comments**
1	14717	• Upgrading approximately 1,900 feet of secondary wire • Upgrading approximately 102 feet of bare wire • Upgrading/replacing approximately 28 poles • Upgrading/replacing approximately 15 transformers • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	• Upgrading 331 feet of primary tree wire • Upgrading 2,255 feet of secondary wire • Upgrading 1,365 feet of bare wire • Upgrading/replacing 21 Poles • Upgrading/replacing 35 cross arms • Upgrading/replacing 6 transformer • Upgrading/replacing 38 fuses • Upgrading/replacing 1 gang switch • Installing 70 lightning arresters • Installing 393 animal guards • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	The proposed corrective actions were based on high level inspection. Additional opportunities to improve system reliability were identified based on further detailed field inspection. This work was completed in 4th quarter of 2014.
2	14758	• Upgrading approximately 17,932 feet of secondary wire • Upgrading approximately 4,128 feet of bare wire • Upgrading/replacing approximately 6 poles • Upgrading/replacing approximately 2 transformers • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	• Upgrading 216 feet of primary tree wire • Upgrading 416 feet of secondary wire • Upgrading 11,089 feet of bare wire • Upgrading/replacing 9 poles • Upgrading/replacing 13 cross arms • Upgrading/replacing 10 fuses • Upgrading/replacing 7 transformers • Installing 3 lightning arresters • Installing 212 animal guards • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	The proposed corrective actions were based on high level inspection. However, corrective actions were further defined following a detailed field investigation. This work was completed in 3rd quarter of 2014.
3	15207R	• Upgrading approximately 4,760 feet of underground cable • Upgrading/replacing approximately 3 oil switches • Performing inspection of underground oil switches, including cables and fuse boxes • Performing inspection of tap modules.	• Upgrading/replacing 1 transformer • Performing inspection of underground oil switches, including cables and fuse boxes • Performing inspection of tap modules.	The proposed corrective actions were based on the initial outage analysis. However, corrective actions were further defined after the detailed field inspection. This work was completed in 3rd quarter of 2014.
4	15085	• Upgrading approximately 12,670 feet of secondary wire • Upgrading approximately 953 feet of bare wire • Upgrading/replacing approximately 36 poles • Upgrading/replacing approximately 32 transformers • Upgrading/replacing approximately 2 gang switches • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	• Upgrading 3,416 feet of primary tree wire • Upgrading 11,163 feet of secondary wire • Upgrading 3,167 feet of bare wire • Upgrading/replacing 49 poles • Upgrading/replacing 44 cross arms • Upgrading/replacing 3 gang switches • Upgrading/replacing 53 fuses • Upgrading/replacing 31 transformers • Installing 18 lightning arresters • Installing 107 animal guards • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	The proposed corrective actions were based on high level inspection. Additional opportunities to improve system reliability were identified based on further detailed field inspection. This work is currently in Construction and scheduled for completion in 1st quarter of 2015.
5	14136	• Upgrading approximately 51 feet of secondary wire • Upgrading/replacing approximately 2 poles • Upgrading/replacing approximately 3 transformers • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	• Upgrading 125 feet of secondary wire • Upgrading 151 feet of bare wire • Upgrading/replacing 1 Pole • Upgrading/replacing 6 cross arms • Upgrading/replacing 1 transformer • Upgrading/replacing 8 fuses • Installing 1 lightning arrester • Installing 48 animal guards • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	The proposed corrective actions were based on high level inspection. Additional opportunities to improve system reliability were identified based on further detailed field inspection. This work was completed in 4th quarter of 2014.
6	14031	• Upgrading approximately 6,534 feet of primary tree wire • Upgrading approximately 31,807 feet of secondary wire • Upgrading approximately 14,645 feet of bare wire • Upgrading/replacing approximately 242 Poles; • Upgrading/replacing approximately 109 transformers • Upgrading/replacing approximately 5 gang switches • Upgrading/replacing approximately 1 ACR • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	• Upgrading 7,193 feet of primary tree wire • Upgrading 11,006 feet of secondary wire • Upgrading 6,296 feet of bare wire • Upgrading/replacing 83 Poles • Upgrading/replacing 105 cross arms • Upgrading/replacing 64 transformers • Upgrading/replacing 2 gang switches • Upgrading/replacing 1 ACR • Upgrading/replacing 92 fuses • Installing 26 lightning arresters • Installing 308 animal guards • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	The proposed corrective actions were based on high level inspection. However, corrective actions were further defined following a detailed field investigation. This work is currently in Construction and scheduled for completion in 1st quarter of 2015.

2014 2% Priority Feeder Program - District of Columbia - Corrective Actions Proposed vs. Completed/ Pending Completion				
Rank	Feeder	Proposed Corrective Actions, as filed in the 2014 Consolidated Report	Detailed Corrective Actions - Completed/ Pending Completion	Explanation of Variances/ Comments
7	15199	• Upgrading approximately 23,457 feet of secondary wire • Upgrading approximately 129 feet of bare wire • Upgrading/replacing approximately 120 poles • Upgrading/replacing approximately 50 transformers • Upgrading/replacing approximately 1 SF6 switch • Upgrading/replacing approximately 1 ACR • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	• Upgrading 796 feet of primary tree wire • Upgrading 32,270 feet of secondary wire • Upgrading/replacing 1 ACR • Upgrading/replacing 1 SF6 switch • Upgrading/replacing 90 poles • Upgrading/replacing 20 cross arms • Upgrading/replacing 89 fuses • Upgrading/replacing 37 transformers • Installing 20 lightning arresters • Installing 278 animal guards • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	The proposed corrective actions were based on high level inspection. However, corrective actions were further defined following a detailed field investigation. This work was completed in 4th quarter of 2014.
8	15130	• Upgrading approximately 504 feet of primary tree wire • Upgrading approximately 22,993 feet of secondary wire • Upgrading approximately 22,703 feet of bare wire • Upgrading/replacing approximately 82 poles • Upgrading/replacing approximately 103 transformers • Upgrading/replacing approximately 4 gang switches • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	• Upgrading 1,160 feet of primary tree wire • Upgrading 22,352 feet of secondary wire • Upgrading 3,332 feet of bare wire • Upgrading/replacing 68 poles • Upgrading/replacing 65 cross arms • Upgrading/replacing 1 ACR • Upgrading/replacing 4 manual switches • Upgrading/replacing 164 fuses • Upgrading/replacing 73 transformers • Installing 28 lightning arresters • Installing 403 animal guards • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	The proposed corrective actions were based on high level inspection. However, corrective actions were further defined following a detailed field investigation. This work was completed in 4th quarter of 2014.
9	15021	• Upgrading approximately 164 feet of secondary wire • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	• Upgrading 80 feet of secondary wire • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	The proposed corrective actions were based on high level inspection. However, corrective actions were further defined following a detailed field investigation. This work was completed in 3rd quarter of 2014.
10	15171	• Upgrading approximately 2,060 feet of secondary wire • Upgrading approximately 7,446 feet of bare wire • Upgrading/replacing approximately 38 poles • Upgrading/replacing approximately 25 transformers • Upgrading/replacing approximately 2 ACRs • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	• Upgrading 797 feet of primary tree wire • Upgrading 2,000 feet of secondary wire • Upgrading 5,658 feet of bare wire • Upgrading/replacing 58 poles • Upgrading/replacing 99 cross arms • Upgrading/replacing 1 ACR • Upgrading/replacing 15 manual switches • Upgrading/replacing 95 fuses • Upgrading/replacing 72 transformers • Installing 18 lightning arresters • Installing 316 animal guards • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	The proposed corrective actions were based on high level inspection. Additional opportunities to improve system reliability were identified based on further detailed field inspection. This work was completed in 4th quarter of 2014.
11	15009	This feeder was a Priority feeder in 2012 and the work was completed in 1st Quarter 2014. No additional work was proposed.	2012 Priority Feeder work completed in 1st quarter 2014: • Upgrading 16,603 feet of primary treewire • Upgrading 64,225 feet of secondary wire • Upgrading/replacing 279 poles • Upgrading/replacing 69 cross arms • Upgrading/replacing 1 gang switch • Upgrading/replacing 1 manual switch • Upgrading/replacing 117 fuses • Upgrading/replacing 77 transformers • Installing 55 lightning arresters • Installing 223 animal guards • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	This work was completed in 1st quarter of 2014.
12	14753	• Upgrading approximately 11,968 feet of secondary wire • Upgrading approximately 3,315 feet of bare wire • Upgrading/replacing approximately 23 poles • Upgrading/replacing approximately 4 transformers • Upgrading/replacing approximately 3 ACRs • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	• Upgrading 442 feet of primary tree wire • Upgrading 12,683 feet of secondary wire • Upgrading 2,693 feet of bare wire • Upgrading/replacing 45 poles • Upgrading/replacing 69 cross arms • Upgrading/replacing 1 gang switch • Upgrading/replacing 25 transformers • Upgrading/replacing 3 ACRs • Installing 16 lightning arresters • Installing 198 animal guards • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	The proposed corrective actions were based on high level inspection. Additional opportunities to improve system reliability were identified based on further detailed field inspection. This work was completed in 4th quarter of 2014.

2014 2% Priority Feeder Program - District of Columbia - Corrective Actions Proposed vs. Completed/ Pending Completion				
Rank	**Feeder**	**Proposed Corrective Actions, as filed in the 2014 Consolidated Report**	**Detailed Corrective Actions - Completed/ Pending Completion**	**Explanation of Variances/ Comments**
13	15173	• Upgrading approximately 80 feet of secondary wire • Upgrading/replacing approximately 1 ACR • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	• Upgrading 84 feet of secondary wire • Upgrading/replacing 1 ACR • Upgrading/replacing 1 pole • Upgrading/replacing 1 cross arm • Upgrading/replacing 1 transformer • Installing 24 animal guards • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	The proposed corrective actions were based on high level inspection. Additional opportunities to improve system reliability were identified based on further detailed field inspection. This work was completed in 3rd quarter of 2014.
14	15867	• Upgrading approximately 4,324 feet of secondary wire • Upgrading approximately 541 feet of bare wire • Upgrading/replacing approximately 75 poles • Upgrading/replacing approximately 35 transformers • Upgrading/replacing approximately 4 ACRs • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	• Upgrading 505 feet of primary tree wire • Upgrading 3,935 feet of secondary wire • Upgrading 3,042 feet of bare wire • Upgrading/replacing 3 ACRs • Upgrading/replacing 1 gang switch • Upgrading/replacing 46 poles • Upgrading/replacing 49 cross arms • Upgrading/replacing 54 fuses • Upgrading/replacing 32 transformers • Installing 17 lightning arresters • Installing 170 animal guards • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	The proposed corrective actions were based on high level inspection. Additional opportunities to improve system reliability were identified based on further detailed field inspection. This work was completed in 4th quarter of 2014.
15	212	• Upgrading/replacing approximately 20 transformers • Performing inspection of underground oil switches, including cables and fuse boxes • Performing inspection of tap modules.	• Upgrading/replacing 9 transformers • Performing inspection of underground oil switches, including cables and fuse boxes • Performing inspection of tap modules.	The proposed corrective actions were based on high level inspection. However, corrective actions were further defined following a detailed field investigation. This work was completed in 4th quarter of 2014.
16	53	• Upgrading/replacing approximately 15 transformers • Performing inspection of underground oil switches, including cables and fuse boxes • Performing inspection of tap modules.	• Upgrading/replacing 4 transformers • Performing inspection of underground oil switches, including cables and fuse boxes • Performing inspection of tap modules.	The proposed corrective actions were based on high level inspection. However, corrective actions were further defined following a detailed field investigation. This work is currently in Construction and scheduled for completion in 1st quarter of 2015.
17	CPI-00177	• Upgrading approximately 5,320 feet of secondary wire • Upgrading/replacing approximately 7 poles • Upgrading/replacing approximately 3 transformers • Upgrading/replacing approximately 1 gang switch • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	• Upgrading 5,108 feet of secondary wire • Upgrading/replacing 8 poles • Upgrading/replacing 10 cross arms • Upgrading/replacing 5 fuses • Upgrading/replacing 3 animal guards • Performing thermal vision of overhead facilities and necessary upgrades • Performing inspection and tree trimming in accordance with the EIVM Plan	This work is currently in Construction and scheduled for completion in 1st quarter of 2015. In addition, this feeder is being converted to a 13kV feeder 15177, which is a 1st year DC PLUG feeder.

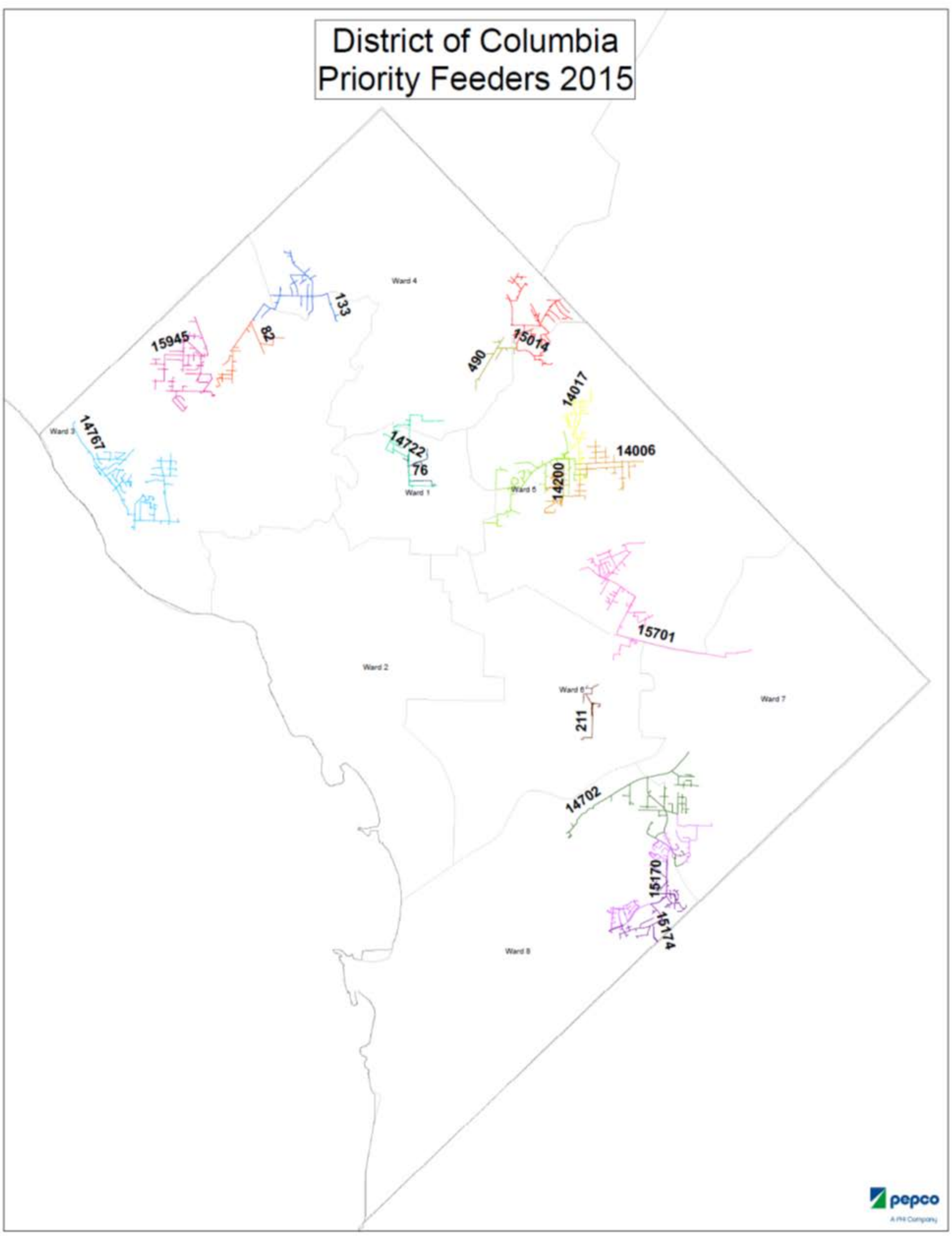

District of Columbia
Priority Feeders 2015
Ward 4
Ward 3
Ward 1
Ward 5
Ward 2
Ward 6
Ward 7
Ward 8
133
82
15945
14767
490
15014
14017
14006
14722
76
14200
15701
211
14702
15170
15174
pepco

Figure 2.4-A1

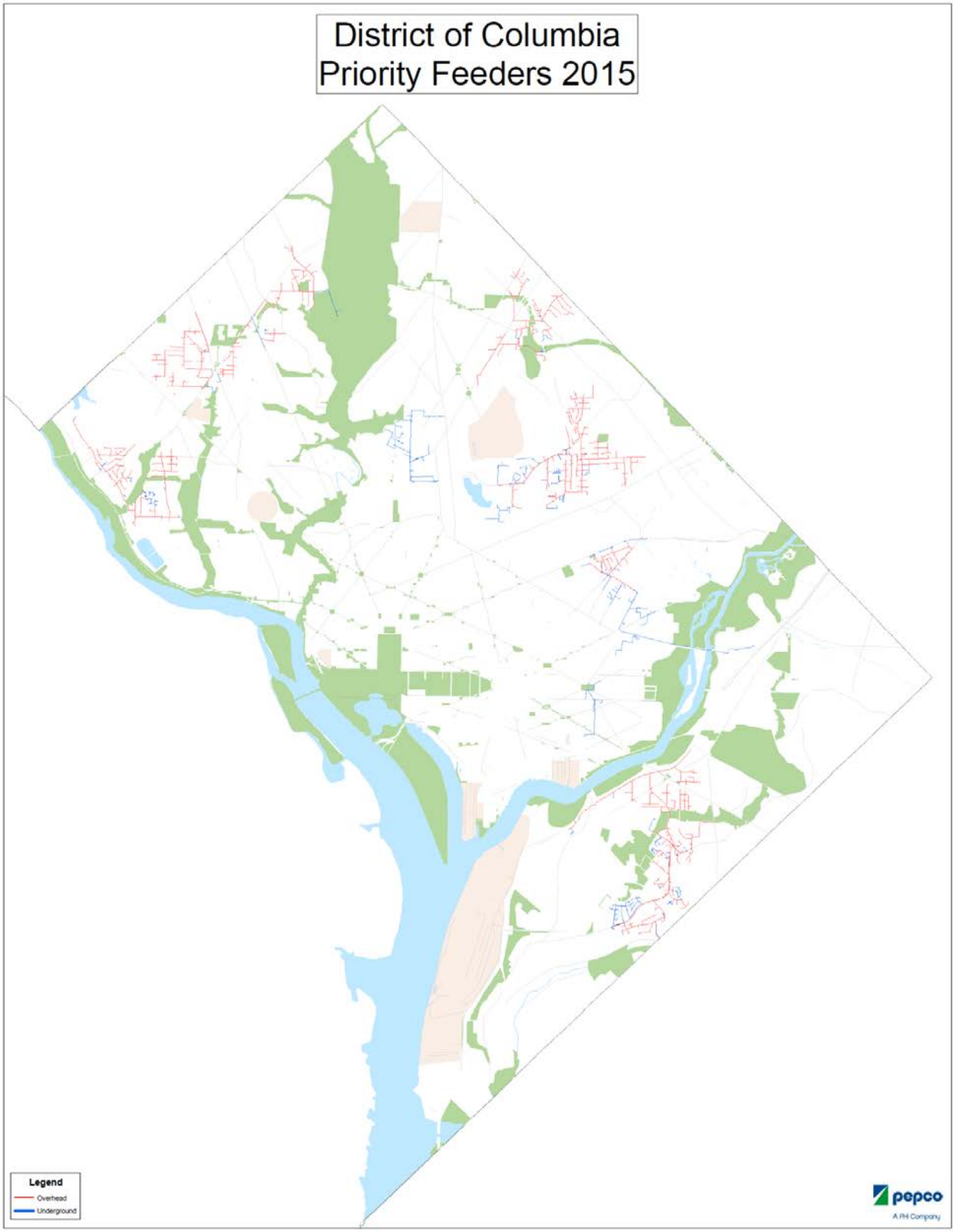

District of Columbia
Priority Feeders 2015
Legend
Overhead
Underground
pepco
A PHI Company

Figure 2.4-A2

2014 Priority Feeder Program - District of Columbia

Rank	Feeder No.	Sub No.	Neighborhood(s)	Customers	System MED Exclusion		Repeat Priority Feeder
					SAIDI (min.)	SAIFI	
1	53	13	Brookland, Columbia Heights	419	663.79	2.93	
2	15867	129	Cleveland Park, Forest Hills, Massachusetts Avenue Heights, North Cleveland Park Rock Creek Park 2, Woodley	634	421.68	2.67	
3	15130	15	Fort Dupont Park, Marshall Heights	1,916	269.36	3.67	
4	15021	190	Brightwood, Chillum, Petworth, Shepherd Park	2,077	46.06	2.05	
5	15009	190	Brightwood, Chillum	1,402	110.17	2.50	2005, 2009, 2012
6	15207R	52	Old City 2	1,424	1,238.00	2.29	
7	15173	136	Randle Heights	519	223.19	4.92	
8	212	28	Old City 1	565	435.86	2.77	
9	14753	168	Congress Heights, DC Village	801	375.74	3.74	
10	14136	129	Cleveland Park, Glover Park, North Cleveland Park, Observatory Circle	1,022	264.20	5.13	2010, 2012
11	14031	134	Hillcrest	1,175	489.36	3.72	
12	15171	136	Congress Heights, Randle Heights	1,436	242.79	2.18	
13	15085	59	Congress Heights, Randle Heights	1,561	441.51	3.34	
14	15199	27	Brightwood, Shepherd Park, Takoma Park	1,969	173.24	2.15	2001, 2004, 2010, 2012
15	14717	7	DC Stadium, Deanwood, Lily Ponds	2,023	413.86	3.38	2001, 2003, 2009, 2012
16	14758	168	Bolling Air Force Base, Congress Heights, DC Village	2,110	156.47	3.29	2003, 2012

2014 CPI-Selected Feeders (Feeder Improvement Program) - District of Columbia

Rank	Feeder No.	Sub No.	Neighborhood(s)	Customers	System MED Exclusion		Repeat Priority Feeder
					SAIDI (min.)	SAIFI	
1	15207R	52	Old City 2	1,424	1,238	2.29	
2	14717	7	DC Stadium, Deanwood, Lily Ponds	2,023	414	3.38	2001, 2003, 2009, 2012
3	15085	59	Congress Heights, Randle Heights	1,561	442	3.34	
4	14031	134	Hillcrest	1,175	489	3.72	
5	14136	129	Cleveland Park, Glover Park, North Cleveland Park, Observatory Circle	1,022	264	5.13	2010, 2012
6	15130	15	Fort Dupont Park, Marshall Heights	1,916	269	3.67	
7	15173	136	Randle Heights	519	223	4.92	
8	14753	168	Congress Heights, DC Village	801	376	3.74	
9	15867	129	Cleveland Park, Forest Hills, Massachusetts Avenue Heights, North Cleveland Park Rock Creek Park 2, Woodley	634	422	2.67	
10	14758	168	Bolling Air Force Base, Congress Heights, DC Village	2,110	156	3.29	2003, 2012
11	212	28	Old City 1	565	436	2.77	
12	15171	136	Congress Heights, Randle Heights	1,436	243	2.18	
13	15199	27	Brightwood, Shepherd Park, Takoma Park	1,969	173	2.15	2001, 2004, 2010, 2012
14	15009	190	Brightwood, Chillum	1,402	110	2.50	2005, 2009, 2012
15	177	8	Anacostia	322	204	2.38	
16	15021	190	Brightwood, Chillum, Petworth, Shepherd Park	2,077	46	2.05	

Note: There are no feeders listed above repeated from the 2013 Priority Feeder Program.

Table 2.4-A

Proposed Corrective Actions for 2015 Priority Feeders and CPI-Selected Feeders[45]

The following information provides an overview of the outages and proposed corrective actions for the 2015 Priority Feeders and the CPI-Selected Feeder and detailed information regarding the equipment related events.

Pepco's OMS assigns event numbers based on length of time between interruptions. Therefore, during the trouble locating and restoration process, more than one event number may be generated and counted. For the sections explains equipment failures, for mainline feeders, line fuses and transformers, the events were grouped by incidents.

* The Other category includes: Contractor, Employee, Equipment Hit, Load Shed, Salt, Secondary, Source, Tap, Vandalism etc.

[45] Actual equipment failures may be more or less than the number shown because a single event may give rise to more than one equipment failure and due to OMS limitations that do not allow a single unique case to be identified in each line.

2015 Priority Feeders

1 - Feeder 00211

This feeder was not a 2% Priority Feeder previously.

Feeder 211 - Year 2015 (IEEE MED Exclusive)	
Year	2015
SAIFI	7.60
SAIDI	13.58
CHI	8,452
NI	9

2015 Priority Feeder- Analysis and Corrective Actions

Description of Major Event Exclusive Outages (October 1, 2013 through September 30, 2014):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 9
Total number of customer interruptions during Non-Major Event Days = 4,726

- Mainline events contributed to 100% of the total number of events, which accounted for 100% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 6 – Equipment Failure
- 3 – Unknown

The 6 equipment failures occurred as the result of the following 6 incidents: 4 cable failures and 2 joint failures.

Corrective Actions Addressed by the Feeder Program:

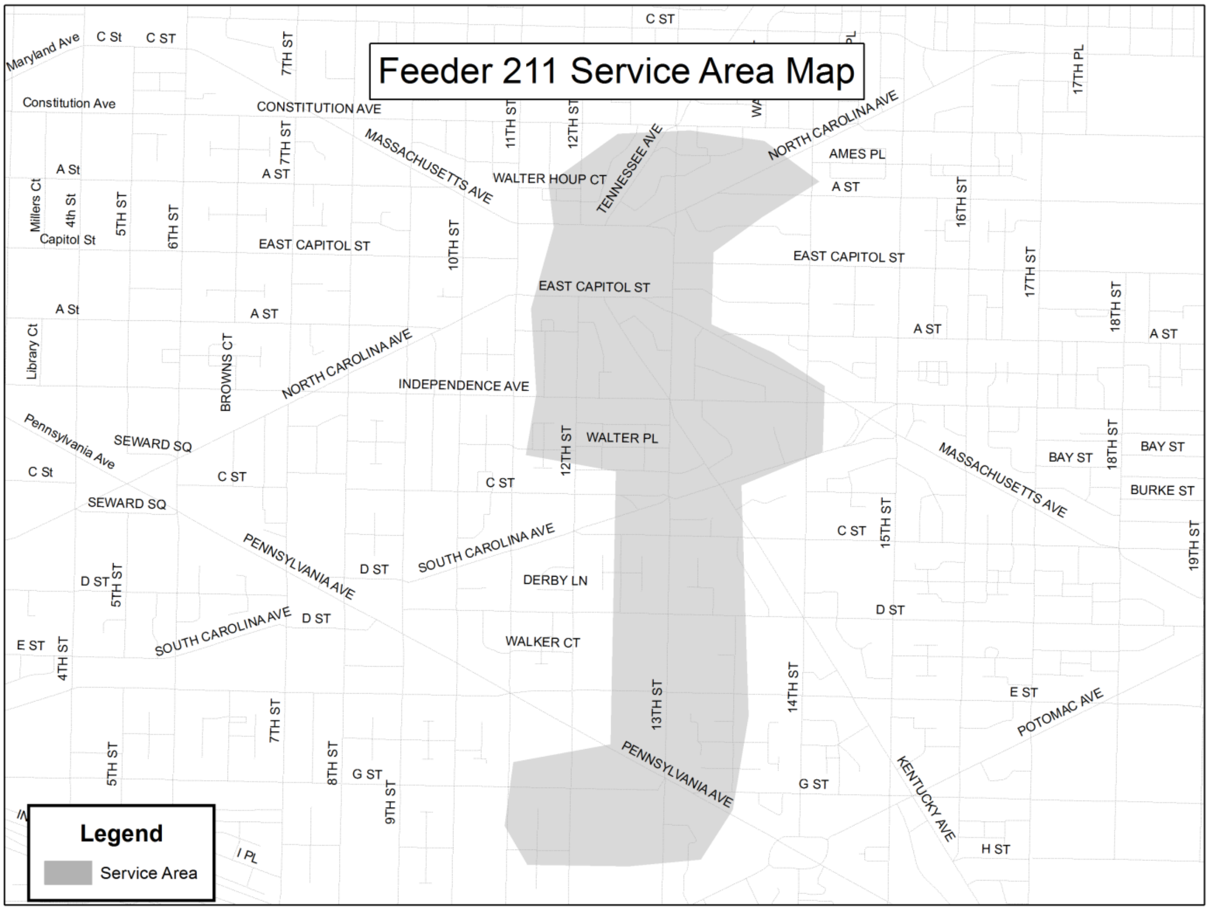
Review of the outage history, feeder map, and past corrective actions identified the following option for consideration:

- Install/replace approximately:
  - 3 Transformers
  - 10 Joints
  - 10 elbows

The work locations include:
Independence Avenue and Kentucky Avenue

Total Project Cost Estimate: $274,392

2015 Cash Flow: $274,392



2 - Feeder 00076

This Feeder was a 2% Priority Feeder in 2011.

Feeder 76 - Year 2011 - 2015 (IEEE MED Exclusive)					
Year	2011	2012	2013	2014	2015
SAIFI	6.58	1.69	0.13	0.79	4.88
SAIDI	33.79	9.94	0.80	1.10	53.57
CHI	15,105	4,572	391	494	23,359
NI	19	9	3	6	11

Priority Feeder in 2011

Description of Major Event Exclusive Outages (October 1, 2009 through September 30, 2010):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 19
Total number of customer interruptions during Non-Major Event Days = 2,942

- Mainline events contributed to 42% of the total number of events, which accounted for 86% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 6 – Equipment Failure
- 2 – Other*

The 6 equipment failures occurred as the result of the following 6 incidents: 3 joint failures, 1 cable failure, 1 switch failure, and 1 transformer failure.

- Localized transformer events contributed to 58% of the total number of events, which accounted for 14% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 8 – Equipment Failure
- 2 – Load
- 1 – Other*

The 8 equipment failures occurred as the result of the following 8 incidents: 4 cable failures, 2 joint failures, 1 transformer failure, and 1 service cable failure.

Corrective actions performed in 2011:

Performed primary and/or secondary cable replacement, performed Very Low Frequency (VLF) cable testing, performed substation relay tests; performed load studies on remaining transformers, and secondary cable, upgrading as necessary.

Analysis of Past Corrective Actions

The scope of work of the previous corrective actions did not solve the incidents caused by deteriorating infrastructure. Past corrective actions did not adequately address all of the reliability issues on this feeder.

2015 Priority Feeder – Analysis and Corrective Actions:

Description of Major Event Exclusive Outages (October 1, 2013 through September 30, 2014):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 11
Total number of customer interruptions during Non-Major Event Days = 2,129

- Mainline events contributed to 73% of the total number of events, which accounted for 93% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 8 – Equipment Failure

The 8 equipment failures occurred as the result of the following 8 incidents: 7 cable failures and 1 burned switch.

- Localized transformer events contributed to 27% of the total number of events, which accounted for 7% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 3 - Equipment Failure

The 3 equipment failures occurred as the result of the following 3 incidents: 2 cable failures and 1 joint failure.

Corrective Actions Addressed by the Priority Feeder Program:

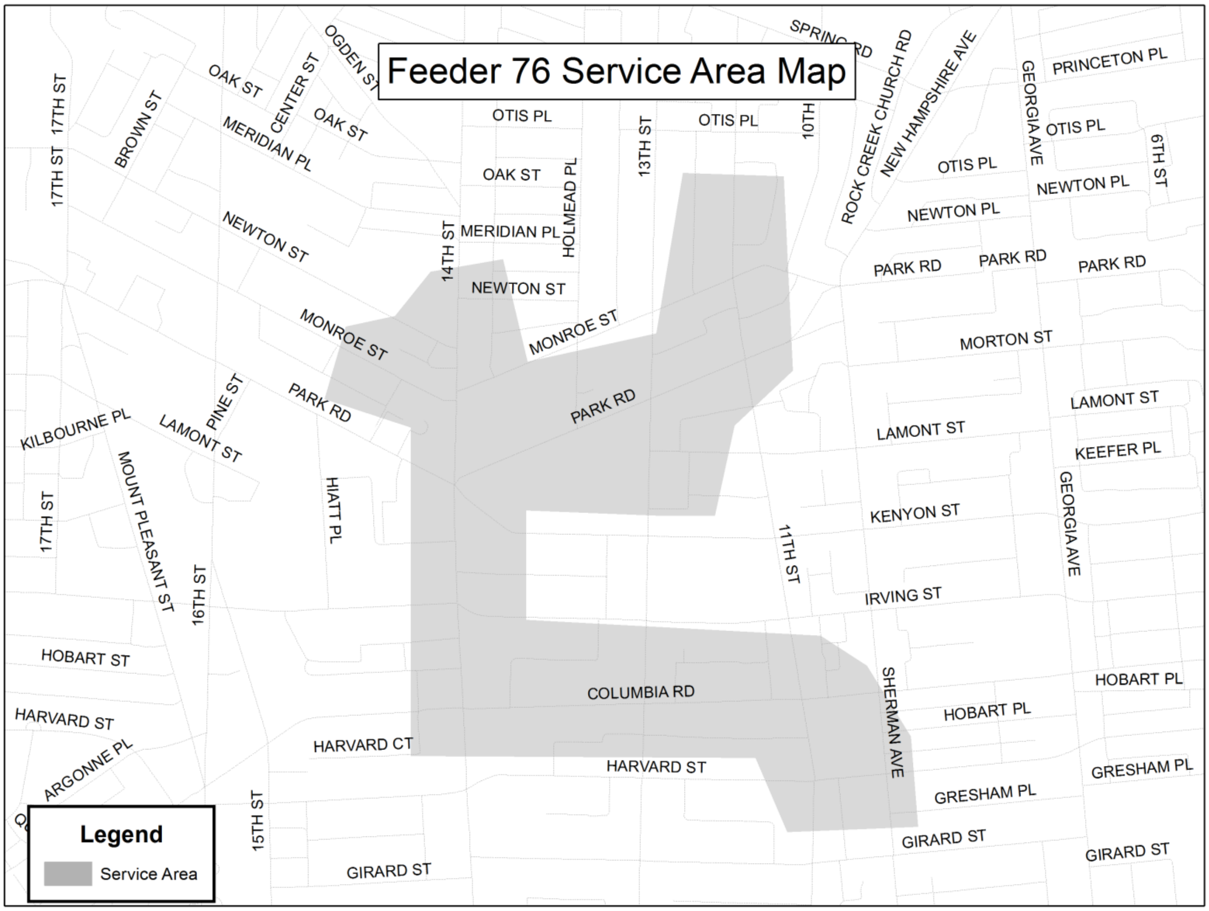
This feeder is scheduled for 4kV to 13kV conversion during 2015. As part of the conversion project, the following work is proposed for this year:

- Install approximately:
  - 5,700 feet of conduit
  - 22 new tap holes
  - 2 oil switches
  - 10,500 feet of underground cable
  - 35 transformers

The work locations include:
Monroe Street, 14^{th} Street, Park Road and 11^{th} Street

Total Project Cost Estimate: $2,000,000

2015 Cash Flow: $2,000,000



3 - Feeder 15174

This feeder was a 2% Priority Feeder in 2010 and 2013.

Feeder 15174 - Year 2010 - 2015 (IEEE MED Exclusive)						
Year	2010	2011	2012	2013	2014	2015
SAIFI	2.16	1.10	1.12	3.10	4.04	2.12
SAIDI	4.34	1.08	2.84	4.03	3.76	2.44
CHI	9,786	2,582	6,565	9,409	8,528	5,324
NI	17	16	19	19	22	9

Priority Feeder in 2010

Description of Major Event Exclusive Outages (October 1, 2008 through September 30, 2009):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 17
Total number of customer interruptions during Non-Major Event Days = 4,872

- Mainline events contributed to 18% of the total number of events, which accounted for 93% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 1 - Unknown
- 2 - Tree

- Fuse events contributed to 6% of the total number of events, which accounted for 2% of the total number of customer interruptions.

In summary, the cause for the fuse event was due to:

- 1 - Unknown

- Localized transformer events contributed to 76% of the total number of events, which accounted for less than 5% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 4 - Equipment Failure
- 4 – Tree
- 2 - Animal
- 1 – Weather
- 2 – Unknown

The 4 equipment failures occurred as the result of the following 4 incidents: 1 failed transformer, and 3 cable failures.

Corrective actions performed in 2010:
Replaced/Installed 29 cross arms, and 30 animal guards. Installed 3 SF6 and 1 manual operated gang operated switch. Performed thermal vision inspection of overhead facilities. No problems were identified. Performed tree trimming.

Priority Feeder in 2013

Description of Major Event Exclusive Outages (October 1, 2011 through September 30, 2012):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 20
Total number of customer interruptions during Non-Major Event Days = 7,238

- Mainline events contributed to 15% of the total number of events, which accounted for 97% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 1 - Equipment Failure
- 1 – Tree
- 1 – Other*

The 1 equipment failure occurred as the result of the following incident: a wire down due to loose jumper.

- Fuse events contributed to 10% of the total number of events, which accounted for 1% of the total number of customer interruptions.

In summary, the cause for the fuse event was due to:

- 1 - Equipment Failure
- 1 - Other*

The 1 equipment failure occurred as the result of the following incident: 1 cable failure.

- Localized transformer events contributed to 75% of the total number of events, which accounted for 2% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 3 - Unknown
- 3 – Equipment Failure
- 3 - Animal
- 1 – Tree
- 5 – Other*

The 3 equipment failures occurred as the result of the following 3 incidents: 2 secondary connections burnt off and 1 faulty transformer.

Corrective actions performed in 2013:

Replaced/Installed 3,934 feet of primary tree wire, 11,389 feet of primary bare wire, 5,156 feet of mainline secondary, 16 poles, 24 cross arms, 20 fuse cutouts, 19 transformers, 6 lightning arrestors, and 55 animal guards.

Analysis of Past Corrective Actions

Past corrective actions did not adequately address all of the reliability issues on this feeder.

2015 Priority Feeder- Analysis and Corrective Actions

Description of Major Event Exclusive Outages (October 1, 2013 through September 30, 2014):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 9
Total number of customer interruptions during Non-Major Event Days = 4,616

- Mainline events contributed to 33% of the total number of events, which accounted for 98% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 2 – Unknown
- 1 – Weather

- Fuse events contributed to 11% of the total number of events, while accounting for less than 1% of the total number of customer interruptions.

In summary, the cause for the fuse event was due to:

- 1 – Equipment Failure

The 1 equipment failure occurred as the result of the following incident: 1 blown cutout.

- Localized transformer events contributed to 56% of the total number of events, which accounted for 2% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 1 - Equipment Failure
- 1 – Weather
- 2 – Animal
- 1 – Unknown

The 1 equipment failure occurred as the result of the following incident: 1 overloaded transformer.

Corrective Actions Addressed by the Priority Feeder Program:

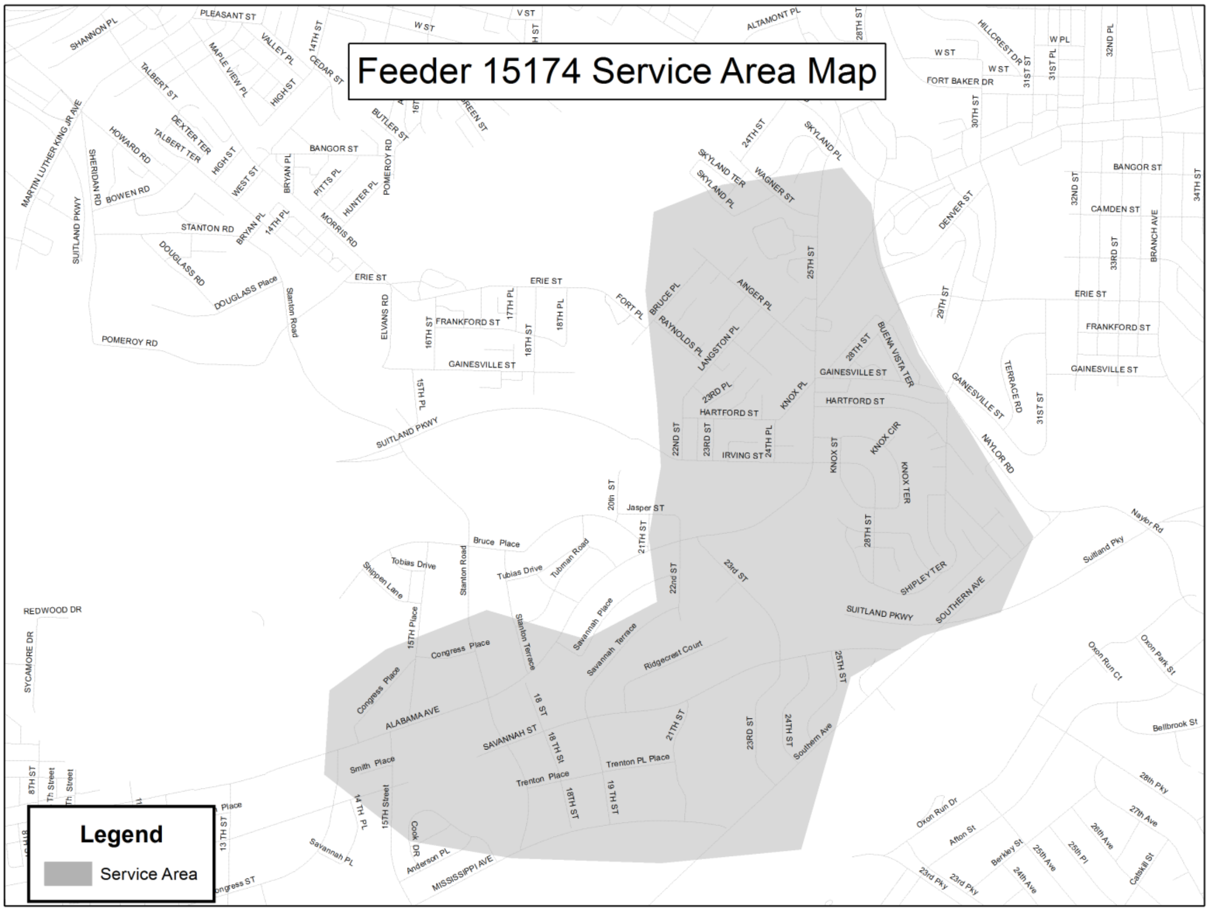
Review of the outage history, feeder map and past corrective actions identified the following option for consideration:

- ❖ Install/replace approximately:
  - 300 Animal Guards
  - 15 Cross Arms
  - 10 Transformers
  - 5 poles
- ❖ Perform inspection and tree trimming in accordance with the VM Plan
- ❖ Perform thermal vision of overhead facilities and necessary upgrades

The work locations include:
Savanah Street, Anger Place, Ridgecrest Road, Stanton Road, 23rd Street, 25th Street, Alabama Avenue SE, Hartford Street, Buena Vista Terrace, Shipley Terrace and Trenton Place

Total Project Cost Estimate: $301,830

2015 Cash Flow: $301,830



4 - Feeder 15701

This feeder was a 2% Priority Feeder in 2003, 2005, 2010.

Feeder 15701 - Year 2001 - 2015 (IEEE MED Exclusive)											
Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
SAIFI	0.08	0.13	0.24	0.38	1.25	2.19	0.46	4.28	1.66	0.15	1.37
SAIDI	0.29	0.46	0.98	2.87	5.04	3.04	1.63	2.51	3.01	0.81	2.81
CHI	944	1,534	3,186	7,930	14,097	8,552	4,232	6,430	8,258	2,272	8,173
NI	32	36	33	34	31	37	35	28	22	24	30

<u>Priority Feeder in 2003</u>

Description of Major Event Exclusive Outages (October 1, 2001 through September 30, 2002):

Data is unavailable

Corrective actions performed in 2003:

Performed manhole inspections - no problems found, installed 2 animal guards, 1 fuse, re-tensioned wires at 1 location, replaced 2 cross-arms, transferred load, replaced 2 transformers.

Priority Feeder in 2005

Description of Major Event Exclusive Outages (October 1, 2003 through September 30, 2004):

Data is unavailable

Corrective actions performed in 2005:

Install/Replace 2 cross arms, 13 fuse cutouts, 3 lightning arrestors, and 6 animal guards.

Priority Feeder in 2010

Description of Major Event Exclusive Outages (October 1, 2008 through September 30, 2009):

Total number of events during Non-Major Event Days (Major Event Exclusive) =37
Total number of customer interruptions during Non-Major Event Days = 6,171

- Mainline events contributed to 2% of the total number of events, which accounted for 78% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 1 – Unknown

- Localized transformer events contributed to 98% of the total number of events, which accounted for 22% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 8 - Equipment Failure
- 1 – Animal
- 1 - Employee
- 1 - Tree
- 3 – Weather
- 7 – Load
- 12 – Unknown
- 3 - Other*

The 8 equipment failures occurred as the result of the following 8 incidents: 4 cable failures, 2 meter box failure, 1 failed transformer and 1 failed fuse.

Corrective actions performed in 2010:

Install/Replace 47 feet of primary tree wire, 1 ACR, 6 lightning arrestors, and 18 animal guards.

Analysis of Past Corrective Actions

The scope of work of the previous corrective actions did not solve the incidents caused by deteriorating infrastructure. Past corrective actions did not adequately address all of the reliability issues on this feeder.

<u>2015 Priority Feeder – Analysis and Corrective Actions</u>

Description of Major Event Exclusive Outages (October 1, 2013 through September 30, 2014):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 30
Total number of customer interruptions during Non-Major Event Days = 3,990

- Mainline events contributed to 13% of the total number of events, which accounted for 76% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 1 – Equipment Failure
- 3 – Animal

The 1 equipment failure occurred as the result of the following incident: 1 transformer failure.

- Fuse events contributed to 17% of the total number of events, which accounted for 15% of the total number of customer interruptions.

In summary, the cause for the fuse event was due to:

- 2 – Equipment Failure
- 2 – Animal
- 1 – Other*

The 2 equipment failures occurred as the result of the following 2 incidents: 1 cable failure and 1 blown fuse.

- Localized transformer events contributed to 70% of the total number of events, which accounted for 9% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 14 - Equipment Failure
- 1 – Employee
- 2 – Unknown
- 1 – Load
- 3 – Other*

The 14 equipment failures occurred as the result of the following 14 incidents: 7 cable failures, 1 loose secondary connection, 1 burned cutout, 2 joint failures, 2 meter failures, and 1 burned service.

Corrective Actions Addressed by the Priority Feeder Program:

Review of the outage history, feeder map and past corrective actions identified the following option for consideration:

- Install/replace approximately:
  - 496 feet of primary wire
  - 2,448 feet of bare wire
  - 4,979 feet of secondary wire
  - 18 poles
  - 32 cross arms
  - 77 fuses
  - 17 transformers
  - 16 lightning arresters
  - 219 animal guards

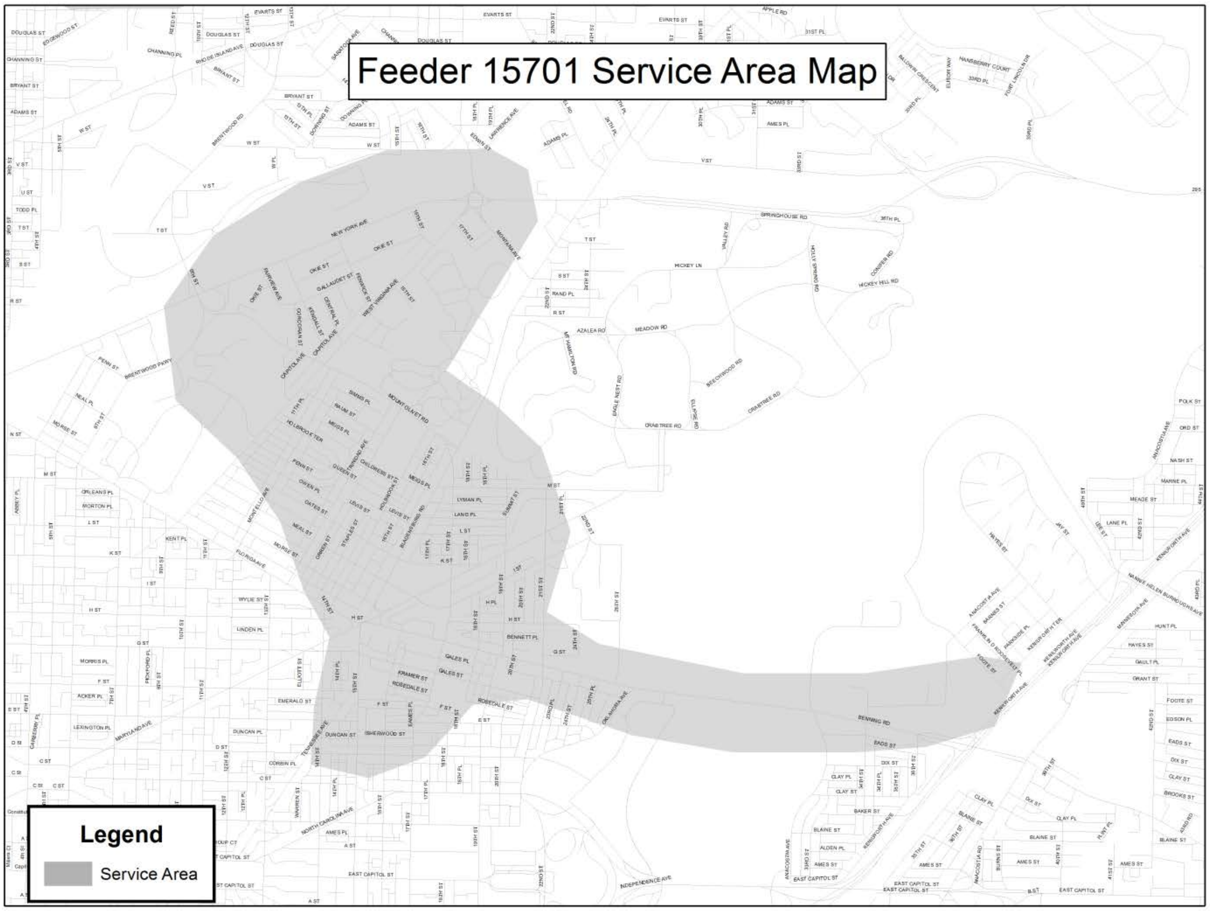
- Perform inspection and tree trimming in accordance with the VM Plan

- Perform thermal vision of overhead facilities and necessary upgrades.

The work locations include:
Mount Olivet Road, Corcoran Street, Kendall Street, Providence Street, Central Place, Fenwick Street, Gallaudet Street, Okie Street, West Virginia Avenue and Fairview Street.

Total Project Cost Estimate: $284,797

2015 Cash Flow: $284,797



5 - Feeder 14722

This feeder was not a 2% Priority Feeder previously.

Feeder 14722 - Year 2015 (IEEE MED Exclusive)	
Year	2015
SAIFI	2.11
SAIDI	6.21
CHI	10,181
NI	13

2015 Priority Feeder- Analysis and Corrective Actions

Description of Major Event Exclusive Outages (October 1, 2013 through September 30, 2014):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 13
Total number of customer interruptions during Non-Major Event Days = 3,459

- Mainline events contributed to 31% of the total number of events, which accounted for 92% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- ➢ 4 – Equipment Failure

The 4 equipment failures occurred as the result of the following 4 incidents: 2 blown joints and 2 failed switches.

- Localized transformer events contributed to 69% of the total number of events, which accounted for 8% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- ➢ 6 - Equipment Failure
- ➢ 1 – Employee
- ➢ 1 – Fire
- ➢ 1 – Load

The 6 equipment failures occurred as the result of the following 6 incidents: 4 cable failures, 1 transformer failure and 1 broken meter.

Corrective Actions Addressed by the Feeder Program:

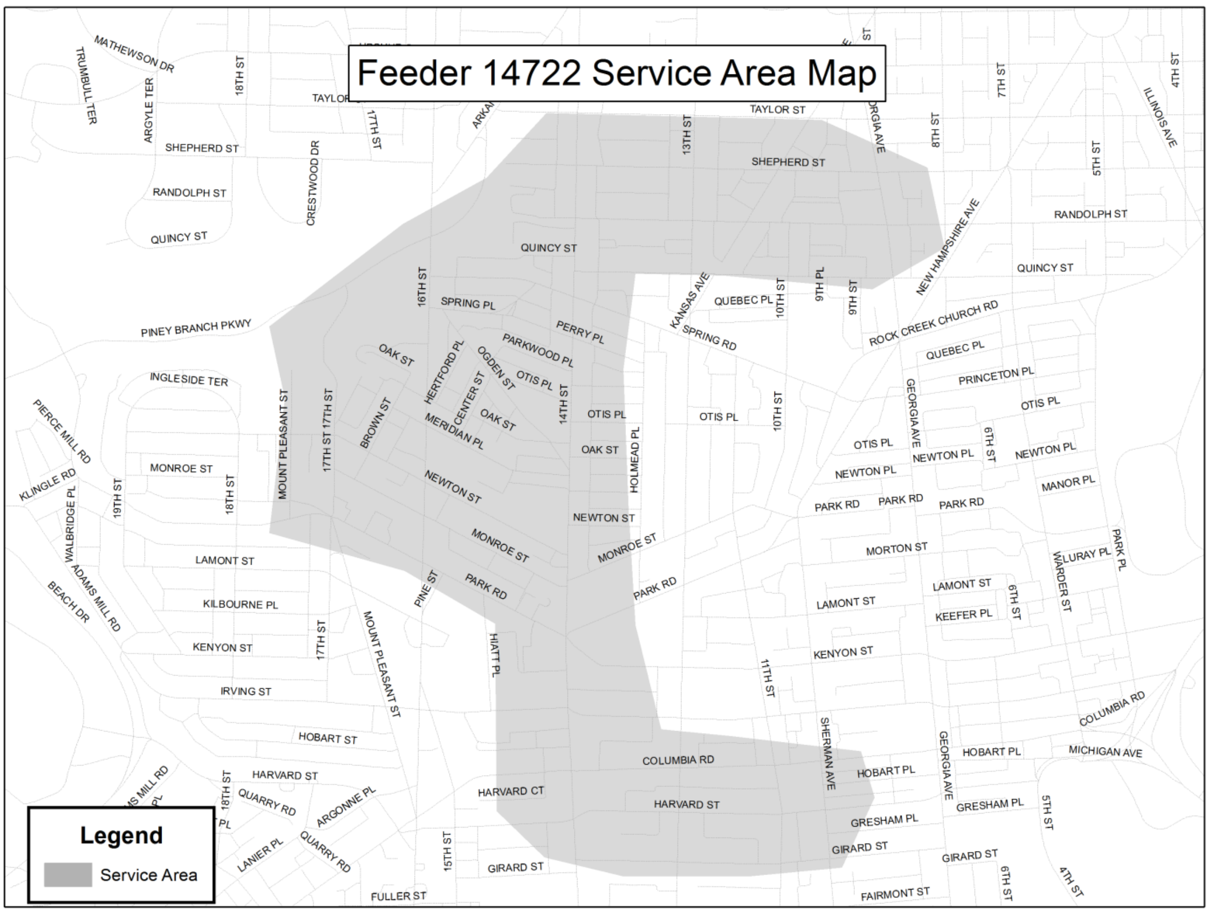
Review of the outage history, feeder map, and past corrective actions identified the following option for consideration:

- ❖ Install/replace:
  - 1 transformer
  - 1 manhole
- ❖ Perform inspection of underground oil switches, including cables and fuse boxes
- ❖ Perform inspection of tap modules
- ❖ Perform Very Low Frequency (VLF) cable testing as appropriate to identify necessary repairs and upgrades

The work locations include:
Kansas Avenue NW and Randolph Street NW.

Total Project Cost Estimate: $41,489

2015 Cash Flow: $41,489



6 - Feeder 15170

This feeder was a 2% Priority Feeder in 2006 and 2010.

Feeder 15170 - Year 2006 - 2015 (IEEE MED Exclusive)										
Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
SAIF	1.59	4.95	4.16	4.21	5.88	3.98	0.04	1.00	0.16	2.60
SAIDI	7.93	13.61	3.11	2.95	6.49	7.09	0.12	0.70	0.40	2.87
CHI	8,514	15,469	4,545	4,466	10,066	10,316	194	5,615	649	4,629
NI	11	24	24	36	24	24	9	39	11	22

Priority Feeder in 2006

Description of Major Event Exclusive Outages (October 1, 2004 through September 30, 2005):

Data is unavailable

Corrective actions performed in 2006:

Install/replace 6 lightning arresters and 4 animal guards

Priority Feeder in 2010

Description of Major Event Exclusive Outages (October 1, 2008 through September 30, 2009):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 24
Total number of customer interruptions during Non-Major Event Days = 9,112

- Mainline events contributed to 33% of the total number of events, which accounted for 95% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 5 – Trees
- 3 – Weather

- Fuse events contributed to 4% of the total number of events, which accounted for 2% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 1 – Equipment Failure

This 1 equipment failure occurred as a result of the following incident: 1 failed cable.

- Localized transformer events contributed to 63% of the total number of events, which accounted for 4% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 6 – Equipment Failure
- 2 – Trees
- 3 – Unknown
- 4 – Other*

The 6 equipment failures occurred as the result of the following 6 incidents: 5 service cable failures and 1 transformer failure.

Corrective actions performed in 2010:

Install/Replace 2,078 feet of primary tree wire, 3,006 feet of mainline secondary wire, 950 feet of secondary service wire, 9 poles, 9 cross arms, 1 fuse cutout, 3 transformers, 6 lightning arrestors, and 27 animal guards.

Analysis of Past Corrective Actions

Past corrective actions did not adequately address all of the reliability issues on this feeder.

2015 Priority Feeder – Analysis and Corrective Actions

Description of Major Event Exclusive Outages (October 1, 2013 through September 30, 2014):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 22
Total number of customer interruptions during Non-Major Event Days = 4,202

- Mainline events contributed to 9% of the total number of events, which accounted for 78% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 1 – Equipment Failure
- 1 – Weather

The 1 equipment failure occurred as the result of the following incident: 1 cable failure

- Fuse events contributed to 32% of the total number of events, which accounted 16% of the total number of customer interruptions.

In summary, the cause for the fuse event was due to:

- 6 – Equipment Failure
- 1 – Animal

The 6 equipment failure occurred as the result of the following 6 incidents: 6 cable failures.

- Localized transformer events contributed to 59% of the total number of events, which accounted for 6% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 13 – Equipment Failure

The 13 equipment failures occurred as the result of the following 13 incidents: 9 cable failures, 2 service cable failures, 1 fuse cutout failure, and 1 loose connection.

Corrective Actions Addressed by the Feeder Program:

Review of the outage history, feeder map, and past corrective actions identified the following option for consideration:

- Install/replace approximately:
  - 423 feet of primary tree wire
  - 875 feet of mainline secondary
  - 95 feet of secondary service wire
  - 11 poles
  - 3 cross arms
  - 47 fuse cutouts
  - 15 transformers
  - 210 animal guards

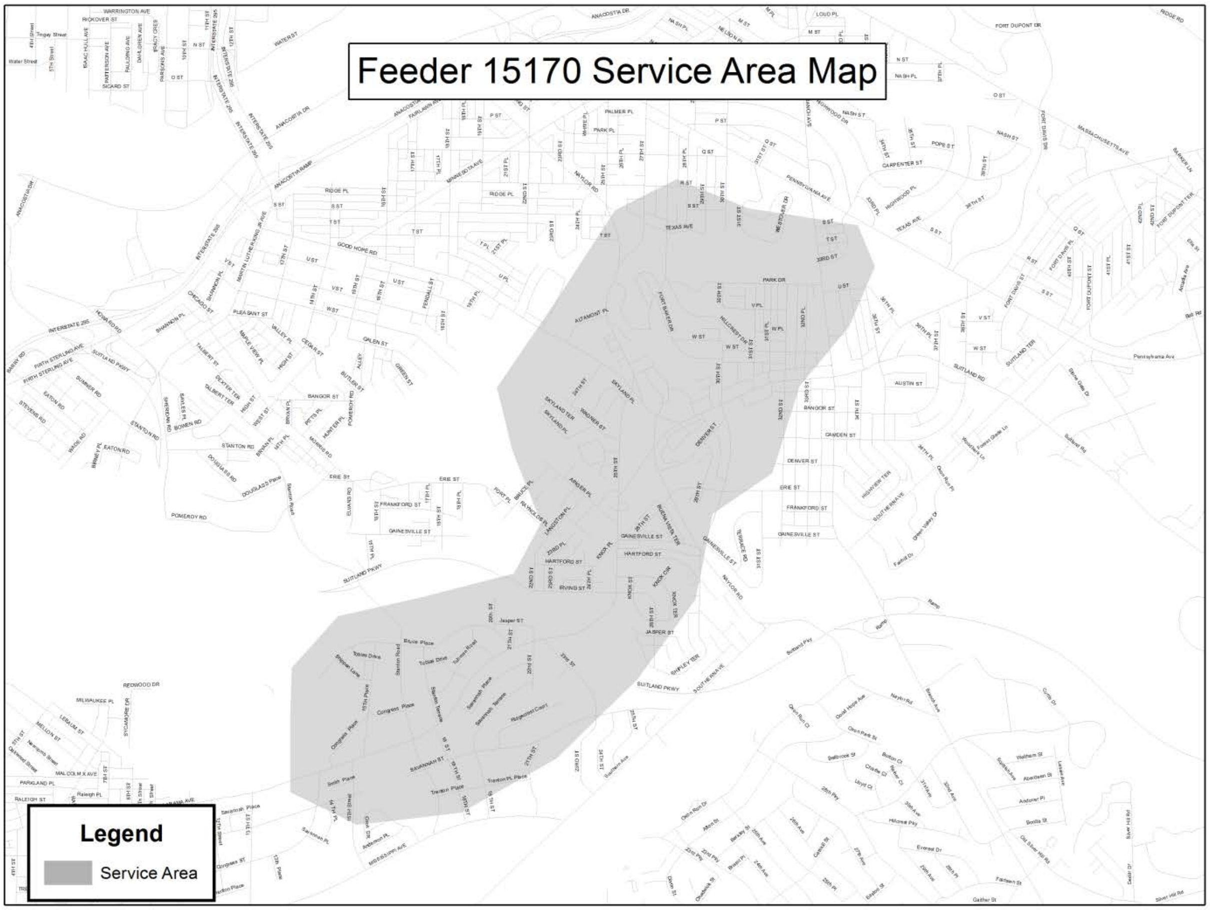
- Perform inspection and tree trimming in accordance with the VM Plan

- Perform thermal vision of overhead facilities and necessary upgrades

The work locations include:
Alabama Avenue, 25th Street, Naylor Road, Good Hope Road, Denver Street, 30th Street, Wagner Street SE, Skyland Place SE, Skyland Terrace SE, 24th Street SE, 29th Street SE, Akron Place SE, Fort Baker Drive SE and W Street SE

Total Project Cost Estimate: $359,807

2015 Cash Flow: $359,807



7 - Feeder 14006

This feeder was a 2% Priority Feeder in 2002 and 2013.

Feeder 14006 - Year 2002 - 2015 (IEEE MED Exclusive)											
Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
SAIFI	1.90	1.15	0.03	1.10	1.66	1.09	4.34	1.40	2.31	2.07	2.21
SAIDI	1.65	1.78	0.77	2.19	5.10	2.38	4.11	3.42	7.01	4.09	1.82
CHI	2,842	3,135	1,355	3,873	8,926	4,240	7,342	5,619	13,239	7,971	3,493
NI	15	17	12	21	25	15	38	25	48	21	18

Priority Feeder in 2002

Description of Major Event Exclusive Outages (October 1, 2000 through September 30, 2001):

Data is unavailable

Corrective actions performed in 2002:

Replace/installed 26 fuses and performed tree trimming.

Priority Feeder in 2013

Description of Major Event Exclusive Outages (October 1, 2011 through September 31, 2012):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 48
Total number of customer interruptions during Non-Major Event Days = 4,370

- Mainline events contributed to 6% of the total number of events, which accounted for 72% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 1 - Equipment Failure
- 1 – Weather
- 1 - Tree

The 1 equipment failure occurred as the result of the following incident: a burnt switch.

- Fuse events contributed to 15% of the total number of events, which accounted for 18% of the total number of customer interruptions.

In summary, the cause for the fuse event was due to:

- 1 - Equipment Failure
- 3 – Tree
- 3 - Weather

The 1 equipment failure occurred as the result of the following incident: a defective cutout.

- Localized transformer events contributed to 79% of the total number of events, which accounted for 10% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 9 - Equipment Failure
- 12 – Tree
- 6 - Animal
- 3 - Other*
- 2 – Load
- 4 – Weather

- 2 – Unknown

The 9 equipment failures occurred as the result of the following 9 incidents: 2 loose/open secondary connections, 2 secondary services off, 1 fuse burnout, 1 transformer failure, 2 wire failures and 1 burnt meter box.

Corrective actions performed in 2013:

Replaced/Installed 186 feet of primary tree wire, 1,500 feet of mainline secondary, 1,963 feet of secondary service, 16 poles, 9 cross arms, 1 gang switch, 6 fuse cutouts, 6 transformers, 6 lightning arrestors, and 29 animal guards.

Analysis of Past Corrective Actions

Past corrective actions did not adequately address all of the reliability issues on this feeder.

<u>2015 Priority Feeder – Analysis and Corrective Actions</u>

Description of Major Event Exclusive Outages (October 1, 2013 through September 30, 2014):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 18
Total number of customer interruptions during Non-Major Event Days = 4,234

- Mainline events contributed to 11% of the total number of events, which accounted for 92% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 1 – Animal
- 1 – Unknown

- Fuse events contributed to 17% of the total number of events, while accounting for less than 3% of the total number of customer interruptions.

In summary, the cause for the fuse event was due to:

- 1 – Equipment Failure
- 1 – Tree
- 1 - Animal

The 1 equipment failure occurred as the result of the following 1 incident: 1 blown lighting arrestor.

- Localized transformer events contributed to 72% of the total number of events, which accounted for 5% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 5 - Equipment Failure
- 4 – Tree
- 2 – Animal
- 1 – Load
- 1 – Other*

The 5 equipment failures occurred as the result of the following 5 incidents; 1 loose/open secondary connections, 1 burnt tap, 1 burnt splice, 1 failed transformer and 1 blown cutout.

Corrective Actions Addressed by the Feeder Program:

Review of the outage history, feeder map, and past corrective actions identified the following option for consideration:

- Install/replace approximately:
  - 3,150 feet of secondary wire
  - 340 Animal guards
  - 9 poles
  - 2 Cross Arms

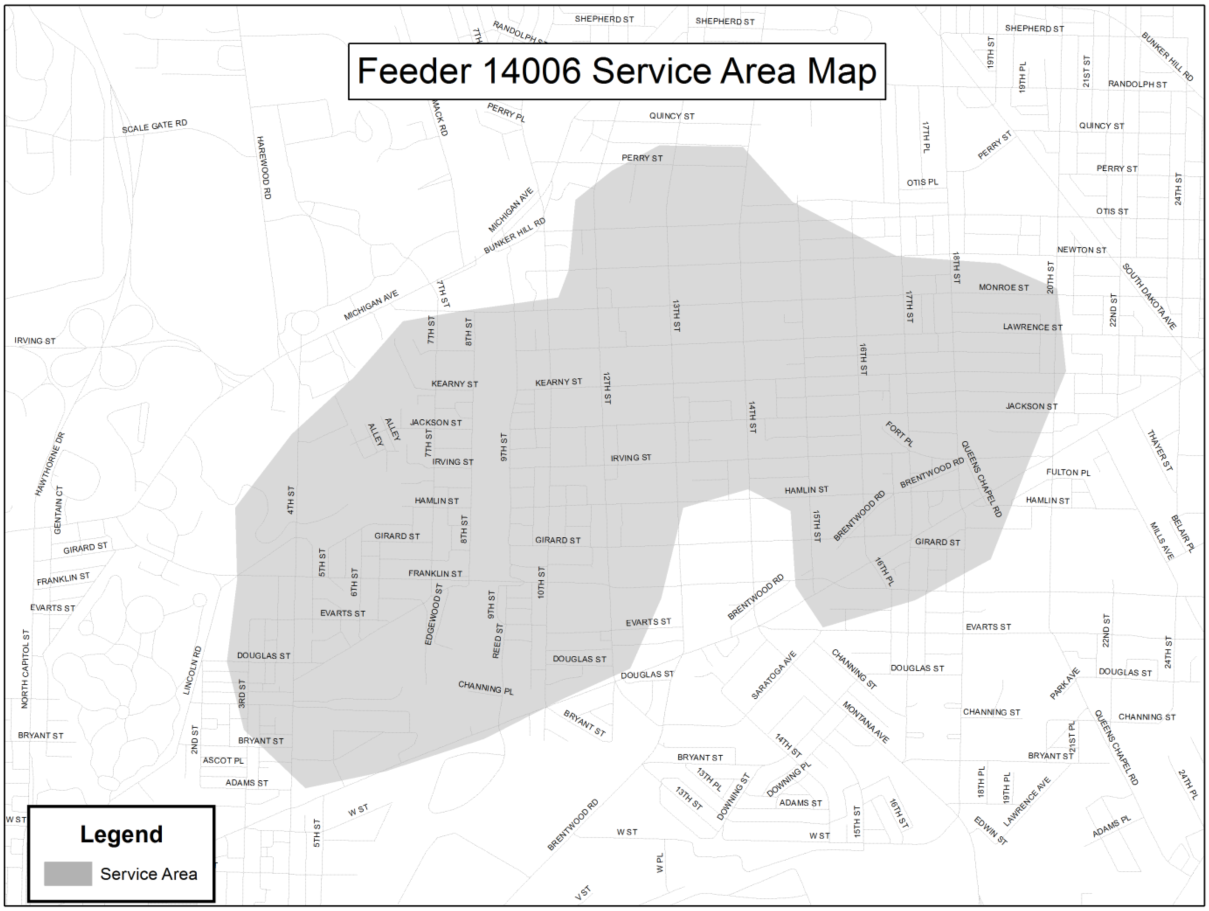
- Perform inspection and tree trimming in accordance with the VM Plan

- Perform thermal vision of overhead facilities and necessary upgrades

The work locations include:
4TH Street, 6th Street, 7th Street, 10th Street, 12th Street, 13th Street, 14th Street, 15th Street, 16th Street, 17th Street, 18th Street, Brentwood Road, Edgewood Street, Evarts Street, Franklin Street, Girard Street, Hamlin Street, Irving Street, Jackson Street, Kearny Street, Lawrence Street, Monroe Street, Newton Street and Otis Street.

Total Project Cost Estimate: $428,514

2015 Cash Flow: $428,514



8 - Feeder 15014

This feeder was a 2% Priority Feeder in 2009 and 2012.

Feeder 15014 - Year 2009 - 2015 (IEEE MED Exclusive)							
Year	2009	2010	2011	2012	2013	2014	2015
SAIFI	4.08	0.07	1.19	4.41	2.47	0.03	3.00
SAIDI	6.66	0.13	1.21	9.32	3.40	0.08	3.37
CHI	7,173	143	1,534	11,345	4,302	93	4,114
NI	22	17	32	16	17	7	13

<u>Priority Feeder in 2009</u>

Description of Major Event Exclusive Outages (October 1, 2007 through September 31, 2008):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 21
Total number of customer interruptions during Non-Major Event Days = 4,368

- Mainline events contributed to 14% of the total number of events, which accounted for 77% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 1 - Weather
- 2 – Unknown

- Fuse events contributed to 10% of the total number of events, which accounted for 19% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 1 – Tree
- 1 – Unknown

- Localized transformer events contributed to 76% of the total number of events, which accounted for 4% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 5 - Equipment Failure
- 1 – Load
- 1 – Animal
- 4 – Other*
- 5 – Unknown

The 5 equipment failures occurred as the result of the following 5 incidents: 1 burned fuses and 4 failed transformers.

Corrective actions performed in 2009:

Replaced/Installed 16 lightning arresters, 32 animal guards, 4 cross arms, 2 radios, 2 SF6 switches, and 144’ of tree wire.

Priority Feeder in 2012

Description of Major Event Exclusive Outages (October 1, 2010 through September 31, 2011):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 16
Total number of customer interruptions during Non-Major Event Days = 5,365

- Mainline events contributed to 31% of the total number of events, which accounted for 95% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 3 - Equipment Failure
- 1 - Unknown
- 1 - Weather

The 3 equipment failures occurred as the result of the following 1 incident: 1 rotten pole

- Fuse events contributed to19% of the total number of events, which accounted for 4% of the total number of customer interruptions.

In summary, the cause for the fuse event was due to:

- 2 – Animal
- 1 – Weather

- Localized transformer events contributed to 50% of the total number of events, which accounted for 1% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 2 - Equipment Failure
- 1 - Unknown
- 1 – Foreign Contact
- 1 - Weather
- 2 - Animal
- 1 - Other*

The 2 equipment failures occurred as the result of the following 2 incidents: 1 secondary bare wire failure and 1 burned cutout.

Corrective actions performed in 2012:

Install/Replace 18,062 feet of primary tree wire, 709 feet of primary bare wire, 15,709 feet of mainline secondary, 25,099 feet of secondary service, 132 poles, 59 cross arms, 130 fuse cutouts, 100 transformers, 4 lightning arrestors, and 265 animal guards.

Analysis of Past Corrective Actions

Past corrective actions did not adequately address all of the reliability issues on this feeder.

2015 Priority Feeder – Analysis and Corrective Actions

Description of Major Event Exclusive Outages (October 1, 2013 through September 2014):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 13
Total number of customer interruptions during Non-Major Event Days = 3,662

- Mainline events contributed to 31% of the total number of events, which accounted for 95% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 1 – Equipment Failure
- 1 – Unknown
- 2 – Tree

The 1 equipment failure occurred as the result of the following incident: 1 loose connection.

- Fuse events contributed to 15% of the total number of events, which accounted for 4% of the total number of customer interruptions.

In summary, the cause for the fuse event was due to:

- 1 – Tree
- 1 – Other*

- Localized transformer events contributed to 54% of the total number of events, which accounted for 1% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 1 - Equipment Failure
- 1 – Tree
- 4 – Animal
- 1 – Other*

The 1 equipment failure occurred as the result of the following incident: 1 broken meter.

Corrective Actions Addressed by the Priority Feeder Program:

Review of the outage history, feeder map and past corrective actions identified the following option for consideration:

- Install/replace approximately:
  - 714 feet of bare wire
  - 1,320 feet of secondary wire
  - 7 poles
  - 13 transformers
  - 1 gang switch

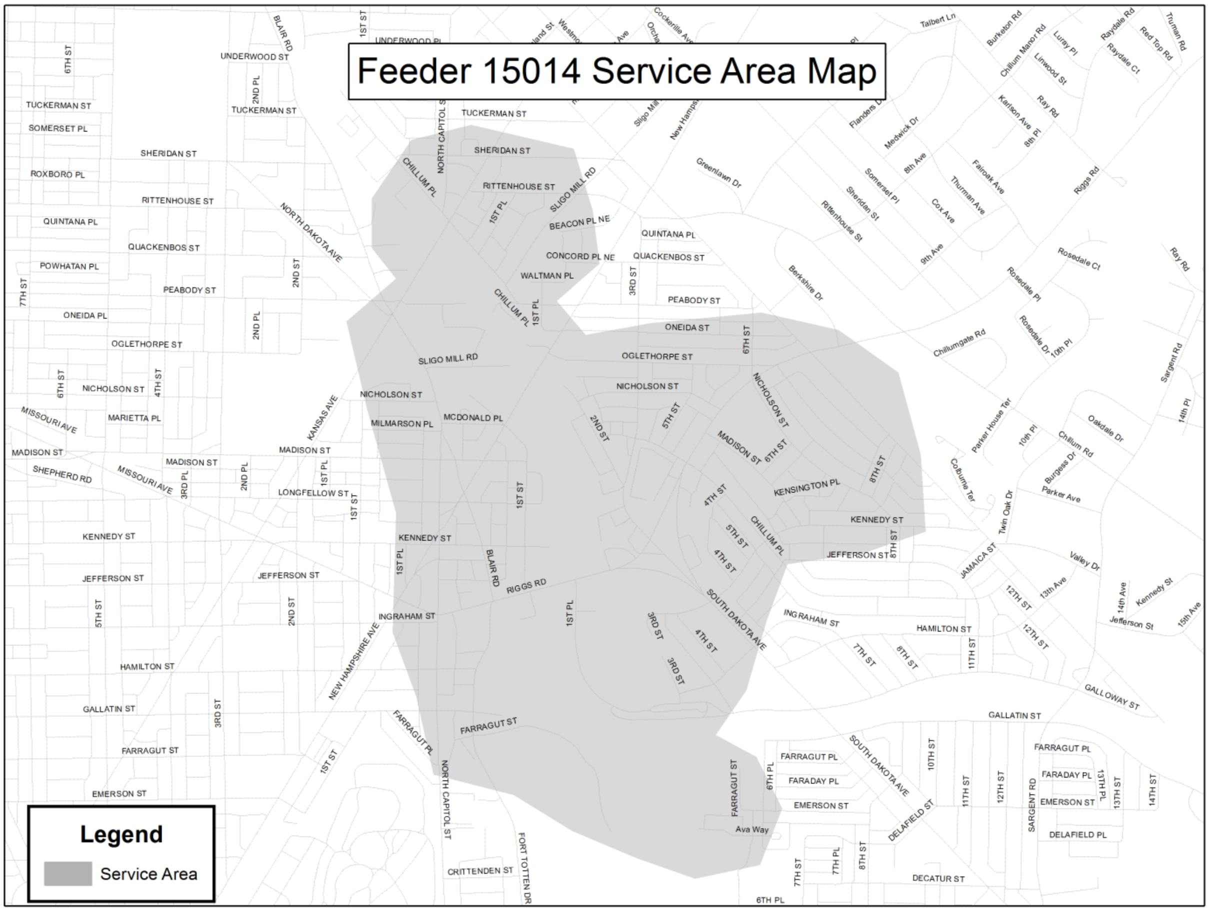
- Perform inspection and tree trimming in accordance with the VM Plan

- Perform thermal vision of overhead facilities and necessary upgrades

The work locations include:
Oglethorpe Street, Madison Street, Nicholson Street, Kensington Place, Chillum Place, First Place, Sligo Mill Road, Farragut Street, Kennedy Street, Rock Creek Road and Riggs Road

Total Project Cost Estimate: $304,123

2015 Cash Flow: $304,123



9 - Feeder 14702

This feeder was not a 2% Priority Feeder previously.

Feeder 14702 - Year 2015 (IEEE MED Exclusive)	
Year	2015
SAIFI	3.25
SAIDI	4.73
CHI	4,966
NI	17

2015 Priority Feeder – Analysis and Corrective Actions:

Description of Major Event Exclusive Outages (October 1, 2013 through September 30, 2014):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 17
Total number of customer interruptions during Non-Major Event Days = 3,409

- Mainline events contributed to 23% of the total number of events, which accounted for 95% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:
- 1 - Equipment Failure
- 3 - Weather

The 1 equipment failure occurred as a result of the following incident: 1 pole down

- Fuse events contributed to 12% of the total number of events, which accounted for less than 1% of the total number of customer interruptions.

In summary, the causes for the fuse events were as follows:
- 2 – Equipment Failure

The 2 equipment failures occurred as a result of the following 2 incidents: 1 loose connection and 1 damaged fuse holder.

- Localized transformer events contributed to 65% of the total number of events, which accounted for 5% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 6 - Equipment Failure
- 1 - Weather
- 1 – Overload
- 1 – Animal
- 2 - Unknown

The 6 equipment failures occurred as the result of the following 6 incidents: 3 burnt fuse, 1 loose connection, 1 transformer lead burnt, and 1failed meter.

Corrective Actions Addressed by the Priority Feeder Program:

Review of the outage history, feeder map, and past corrective actions identified the following option for consideration:

- Install/ replace approximately:
  - 275ft Primary tree wire
  - 7,268ft Primary bare wire
  - 742ft Secondary Triplex wire
  - 412ft Secondary Service Triplex wire
  - 27 Poles
  - 1 ACR
  - 3 Gang Switches
  - 3 Transformers

- 1 Capacitor
- 35 Cutouts
- 90 Lightning Arrestors
- 318 Animal Guards
- 88 Cross arms

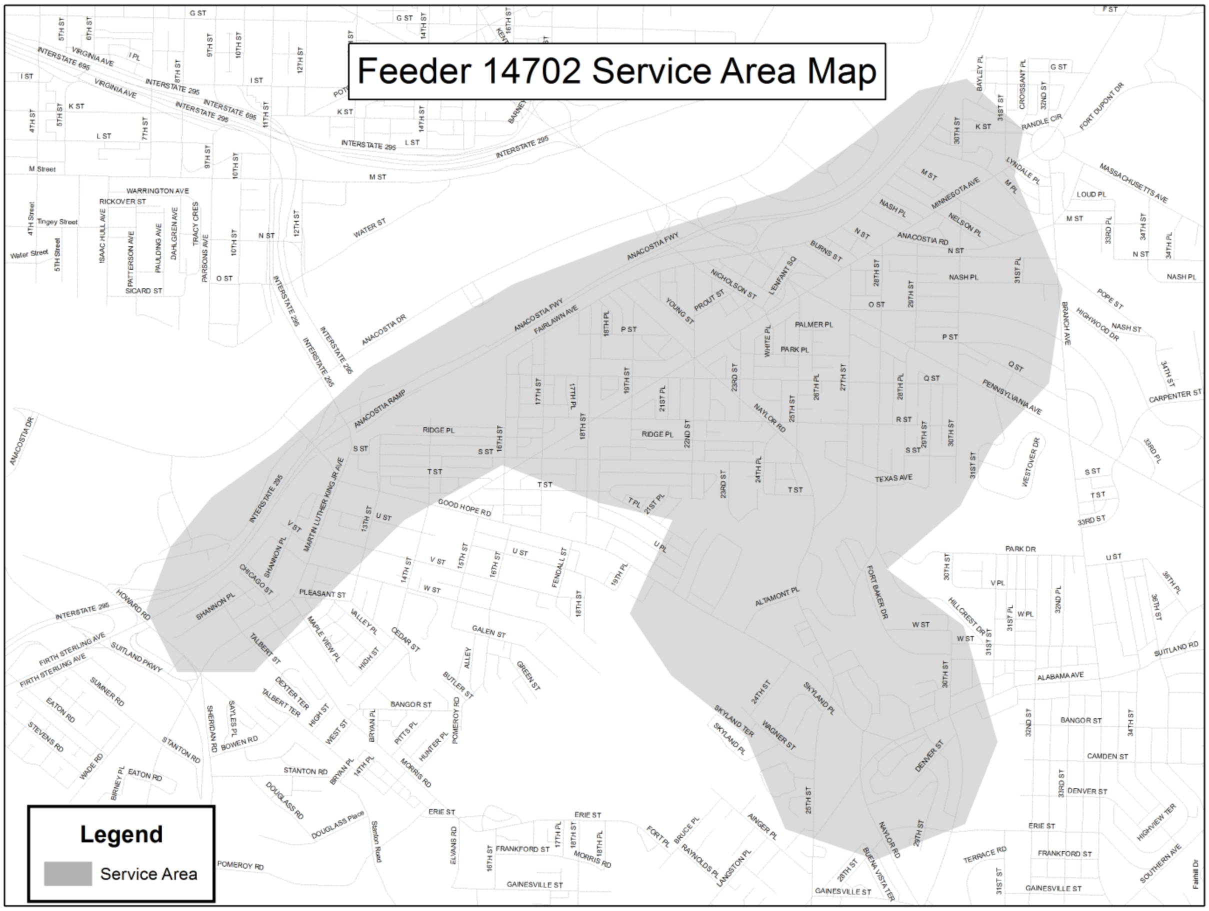
❖ Perform inspection and tree trimming in accordance with the VM Plan

❖ Perform thermal vision of overhead facilities and necessary upgrades

The work locations include:
Shannon Place SE, Railroad Avenue SE, Railroad Avenue, Good Hope Road SE, Fairlawn Avenue SE, N Street SE, 28th Street SE, O Street SE, 18th Street SE, R Street SE, 22nd Street SE, Minnesota Avenue SE, Naylor Road SE, S Street SE, Altamont Place SE, Anacostia Road SE, Nash Place, Palmer Place SE, Texas Avenue SE, Ridge Place SE, N Street SE, Q Street SE, S Street SE, T Street SE, Q Street SE, 24th Place SE, 25th Street SE, 27th Street SE, 28th Place SE, 29th Street SE, and 30th Street SE.

Total Project Cost Estimate: $780,000

2015 Cash Flow: $780,000



10 - Feeder 15945

This feeder was a 2% Priority Feeder in 2011 and 2013.

Feeder 15945 - Year 2011 - 2015 (IEEE MED Exclusive)					
Year	2011	2012	2013	2014	2015
SAIFI	5.89	1.05	3.13	0.53	2.07
SAIDI	7.67	0.33	6.08	3.18	1.58
CHI	9,510	402	7,433	3,925	1,950
NI	28	15	23	9	21

Priority Feeder in 2011

Description of Major Event Exclusive Outages (October 1, 2009 through September 30, 2010):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 28
Total number of customer interruptions during Non-Major Event Days = 7,298

- Mainline events contributed to 29% of the total number of events, which accounted for 99% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:
- 4 - Equipment Failures
- 1 - Unknown
- 3 – Tree

The 4 equipment failures occurred as the result of the following 4 incidents: 3 blown lighting arrestors and 1 failed switch.

- Localized transformer events contributed to 71% of the total number of events, which accounted for less than 1% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:
- 8 - Equipment Failures
- 1 - Unknown
- 1 - Overload
- 5 – Tree
- 5 - Animal

The 8 equipment failures occurred as the result of the following 8 incidents: 2 loose connections, 1 connection burned up, 1 switch failure, 3 failed cutouts, and 1 blown lighting arrestor.

Corrective actions performed in 2011:
Installed/ replaced 300 feet of primary wire, 100 feet of secondary wire, 8 poles, and 6 transformers. Performed tree trimming.

Priority Feeder in 2013

Description of Major Event Exclusive Outages (October 1, 2011 through September 30, 2012):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 23
Total number of customer interruptions during Non-Major Event Days = 3,834

- Mainline events contributed to 13% of the total number of events, which accounted for 96% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:
- 3 - Tree

- Fuse events contributed to 9% of the total number of events, which accounted for less than 1% of the total number of customer interruptions.

In summary, the cause for the fuse event was due to:

- ➢ 2 - Tree

- Localized transformer events contributed to 78% of the total number of events, which accounted for 4% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:
- ➢ 7 - Equipment Failure
- ➢ 1 - Overload
- ➢ 4 - Tree
- ➢ 2 - Weather
- ➢ 3 - Animal
- ➢ 1 - Other*

The 7 equipment failures occurred as the result of the following 7 incidents: 4 burnt/loose connections, 1 broken fuse, 1 failed transformer, and 1 burnt meter block.

Corrective actions performed in 2013:

Installed/ replaced 23 animal guards, 1 transformer and 1 fuse cutout. Performed tree trimming.

Analysis of Past Corrective Actions

The scope of work of the previous corrective actions did not solve the incidents caused by deteriorating infrastructure. Past corrective actions did not adequately address all of the reliability issues on this feeder.

<u>2015 Priority Feeder – Analysis and Corrective Actions</u>

Description of Major Event Exclusive Outages (October 1, 2013 through September 30, 2014):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 21
Total number of customer interruptions during Non-Major Event Days = 2,560

- Mainline events contributed to 14% of the total number of events, which accounted for 96% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:
- ➢ 3 – Equipment Failures

The 3 equipment failures occurred as a result of the following 3 incidents: 2 failed switches and 1 blown pothead.

- Fuse events contributed to 5% of the total number of events, while accounting for less than 1% of the total number of customer interruptions.

In summary, the cause for the fuse event was due to:
- 1 – Animal

- Localized transformer events contributed to 81% of the total number of events, which accounted for 4% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:
- 4 - Equipment Failures
- 6 – Tree
- 1 - Weather
- 3 – Animal
- 3 – Overload

The 4 equipment failures occurred as the result of the following 4 incidents: 1 broken pole top, 1 defective meter, 1 failed secondary cable, and 1 failed transformer

Corrective Actions Addressed by the Priority Feeder Program:
Review of the outage history, feeder map, and past corrective actions identified the following option for consideration:

- Install/ replace approximately:
  - 387 feet Primary Tree Wire
  - 601 feet Primary Bare Wire
  - 2,697 feet Secondary Wire
  - 9 Poles
  - 6 Transformers
  - 1 Gang Operated Switch
  - 2 ACRs
  - 112 Cutouts
  - 94 Lightning Arrestors
  - 179 Animal Guards
  - 13 Headguy
  - 7 Downguy

- Perform inspection and tree trimming in accordance with the VM Plan

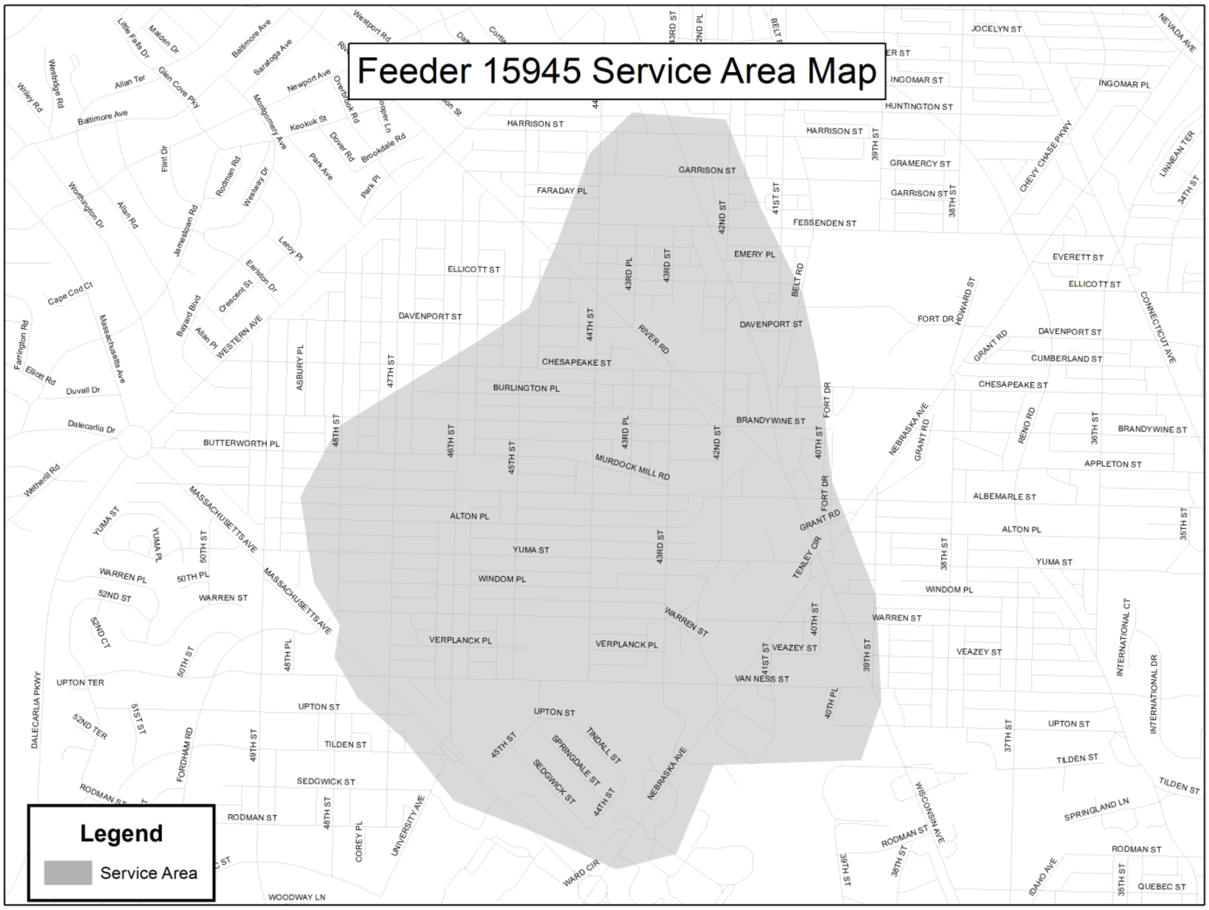
- Perform thermal vision of overhead facilities and necessary upgrades

The work locations include:
Nebraska Avenue NW, Van Ness Street NW, Warren Street NW, 42nd Street NW, River Road NW, 44th Street NW, Brandywine Street NW, 46th Street NW, Wisconsin Avenue, Yuma Street, 45th Street, Albemarle Street NW, Murdock Mill Road, Chesapeake Street

NW, Garrison Street NW, Ellicott Street NW, Davenport Street NW, Burlington Place NW, and Alton Place NW.

Total Project Cost Estimate: $550,000

2015 Cash Flow: $550,000



11 - Feeder 14200

This Feeder was a 2% Priority Feeder in 2009, 2011 and 2013.

Feeder 14200 - Year 2009 - 2015 (IEEE MED Exclusive)							
Year	2009	2010	2011	2012	2013	2014	2015
SAIFI	4.96	1.28	3.60	2.05	2.82	2.14	1.78
SAIDI	8.26	2.92	9.27	0.57	2.18	0.41	0.86
CHI	12,071	3,921	12,648	800	3,097	570	1,189
NI	13	15	28	13	30	7	23

Priority Feeder in 2009

Description of Major Event Exclusive Outages (October 1, 2007 through September 30, 2008):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 10
Total number of customer interruptions during Non-Major Event Days = 7,243

- Mainline events contributed to 50% of the total number of events, which accounted for 98% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 2 – Equipment Failures
- 2 – Unknown
- 1 – Employee

The 2 equipment failures occurred as a result of the following 2 incidents: 1 wire down and 1 cable failure.

- Localized transformer events contributed to 50% of the total number of events, which accounted for 2% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 2 – Equipment Failures
- 1 – Animal
- 2 – Unknown

The 2 equipment failures occurred as a result of the following 1 incident: 2 cable failures.

Corrective actions performed in 2009:

Install/Replace 11 animal guards, 11 lightning arresters, 1 SF6 switch, and tree wire.

Priority Feeder in 2011

Description of Major Event Exclusive Outages (October 1, 2009 through September 30, 2010):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 28
Total number of customer interruptions during Non-Major Event Days = 4,918

- Mainline events contributed to 14% of the total number of events, which accounted for 81% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 3 – Motor Vehicle
- 1 – Equipment Failure

The 1 equipment failure occurred as a result of the following incident: switching of capacitor bank.

- Fuse events contributed to 10% of the total number of events, which accounted for 3% of the total number of customer interruptions.

  - 3 – Equipment Failure

The 3 equipment failures occurred as a result of the following 3 incidents: 2 blown fuses and 1 cable failure.

- Localized transformer events contributed to 75% of the total number of events, which accounted for 16% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 6 – Equipment Failure
- 4 – Animal
- 4 – Motor Vehicle
- 3 - Load
- 3 – Unknown
- 1 – Tree

The 6 equipment failures occurred as the result of the following 6 incidents: 4 cable failures, 1 transformer failure, and 1 blown fuse.

Corrective actions performed in 2011:

Install/Replace approximately 2,358 feet of primary tree wire, 1,449 feet of mainline secondary wire, 210 feet of secondary service wire, 11 poles, 2 cross arms, 6 fuse cutouts, 2 transformers, and 9 animal guards. Performed inspection and tree trimming, in accordance with the Enhanced Integrated Vegetation Management (EVIM) plan; Performed load studies on transformers; Performed thermal vision inspection of overhead facilities.

Priority Feeder in 2013

Description of Major Event Exclusive Outages (October 1, 2011 through September 30, 2012):

Total number of events during Non-Major Event Days (Major Event Exclusive) =30
Total number of customer interruptions during Non-Major Event Days = 4,007

- Mainline events contributed to 10% of the total number of events, which accounted for 85% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 1 – Animal
- 1 – Tree
- 1 – Weather

- Fuse events contributed to 17% of the total number of events, which accounted for 10% of the total number of customer interruptions.

In summary, the causes for the fuse events were as follows:

- 2 – Animal
- 2 – Unknown
- 1 – Tree

- Localized transformer events contributed to 98% of the total number of events, which accounted for 22% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 13 - Equipment Failure
- 3 – Animal
- 3 – Other*
- 2 – Weather
- 1 – Unknown

The 13 equipment failures occurred as the result of the following 13 incidents: 5 failed meters, 2 blown fuse, 2 loose connections, 2 cable failures, 1 failed transformer and 1 service cable failure.

Corrective actions performed in 2013:

Install/Replace 166 feet of primary tree wire, 2,642 feet of primary bare wire, 1,109 feet of mainline secondary, 739 feet of secondary service, 16 poles, 19 cross arms, 1 ACR, 1 SF6 switch, 6 manual switches, 6 fuse cutouts, 5 transformers, 18 lightning arrestors, and 41 animal guards.

Analysis of Past Corrective Actions

Past corrective actions did not adequately address all of the reliability issues on this feeder.

2015 Priority Feeder- Analysis and Corrective Actions

Description of Major Event Exclusive Outages (October 1, 2013 through September 30, 2014):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 23
Total number of customer interruptions during Non-Major Event Days = 2,460

- Mainline events contributed to 13% of the total number of events, which accounted for 95% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 2 – Trees
- 1 – Motor Vehicle Accident

- Fuse events contributed to 4% of the total number of events, while accounting less than 1% of the total number of customer interruptions.

In summary, the cause for the fuse event was due to:

- 1 – Animal

- Localized transformer events contributed to 83% of the total number of events, which accounted for 5% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 11 – Equipment Failure
- 3 – Weather
- 2 – Animal
- 2 – Unknown
- 1 – Load

The 11 equipment failures occurred as the result of the following 11 incidents: 2 cable failures, 3 service cable failures, 3 blown fuses, 2 failed meters, and 1 transformer failure.

Corrective Actions Addressed by the Feeder Program:
Review of the outage history, feeder map, and past corrective actions identified the following option for consideration:

- Install/replace approximately:
  - 1,725 feet of secondary wire
  - 3 poles
  - 122 animal guards

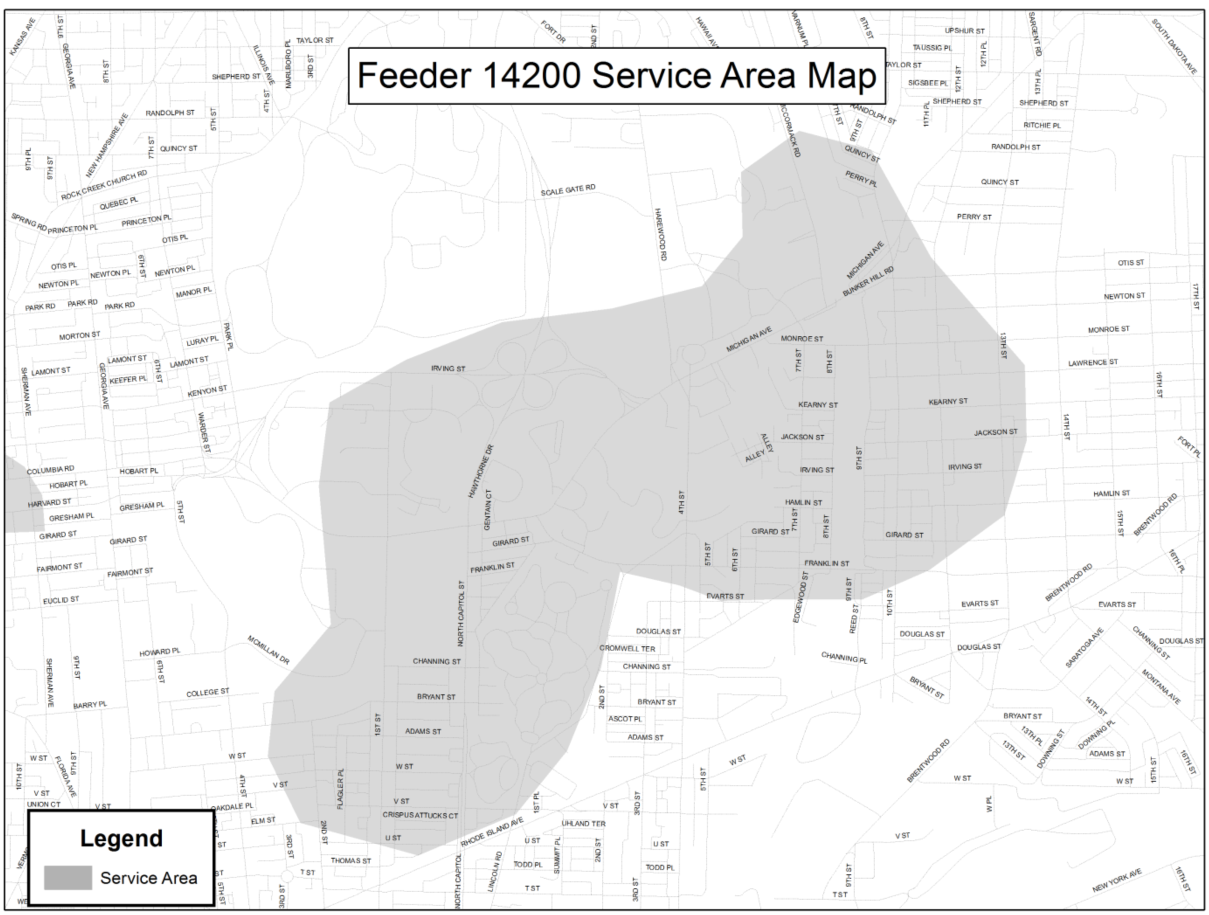
- Perform inspection and tree trimming in accordance with the VM Plan

- Perform thermal vision of overhead facilities and necessary upgrades

The work locations include:
4th Street, 8th Street, 9th Street, Evarts Street, Franklin Street, Girard Street, Jackson Street, John McCormack Road, Kearny Street, Lawrence Street, Michigan Avenue and North Capitol Street.

Total Project Cost Estimate: $164,657

2015 Cash Flow: $164,657



12 - Feeder 14017

This feeder was a 2% Priority Feeder in 2006.

Feeder 14017 - Year 2006 - 2015 (IEEE MED Exclusive)										
Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
SAIFI	5.56	1.82	0.15	6.91	1.07	0.26	0.04	0.24	1.20	1.75
SAIDI	5.88	5.79	0.96	17.07	1.26	0.57	0.03	0.25	2.06	1.48
CHI	5,433	5,288	873	15,177	1,123	520	31	233	2,095	1,957
NI	23	16	4	22	11	14	4	15	12	13

Priority Feeder in 2006

Description of Major Event Exclusive Outages (October 1, 2004 through September 30, 2005):

Data is unavailable

Corrective actions performed in 2006:

Install/Replace 114 feet of primary tree wire, 3 cross arms, 1 ACR, 13 lightning arrestors, and 20 animal guards.

Analysis of Past Corrective Actions

The scope of work of the previous corrective actions did not solve the incidents caused by deteriorating infrastructure. Past corrective actions did not adequately address all of the reliability issues on this feeder.

2015 Priority Feeder- Analysis and Corrective Actions

Description of Major Event Exclusive Outages (October 1, 2013 through September 30, 2014):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 13
Total number of customer interruptions during Non-Major Event Days = 2,311

- Mainline events contributed to 8% of the total number of events, which accounted for 99% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 1 – Equipment Failure

The 1 equipment failure occurred as the result of the following incident: 1 cable failure.

- Fuse events contributed to 15% of the total number of events, while accounting for less than 1% of the total number of customer interruptions.

In summary, the cause for the fuse event was due to:

- ➢ 2 - Animal

- Localized transformer events contributed to 77% of the total number of events, which accounted for 1% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- ➢ 8 - Equipment Failure
- ➢ 1 – Animal
- ➢ 1 – Other*

The 8 equipment failures occurred as the result of the following 8 incidents: 2 loose/open secondary connection, 1 burnt feeder block, 3 defective meters and 2 failed transformers.

Corrective Actions Addressed by the Feeder Program:

Review of the outage history, feeder map, and past corrective actions identified the following option for consideration:

- ❖ Install/replace approximately:
  - 7,685 feet of secondary wire
  - 1,424 feet of bare wire
  - 53 Transformers
  - 53 poles

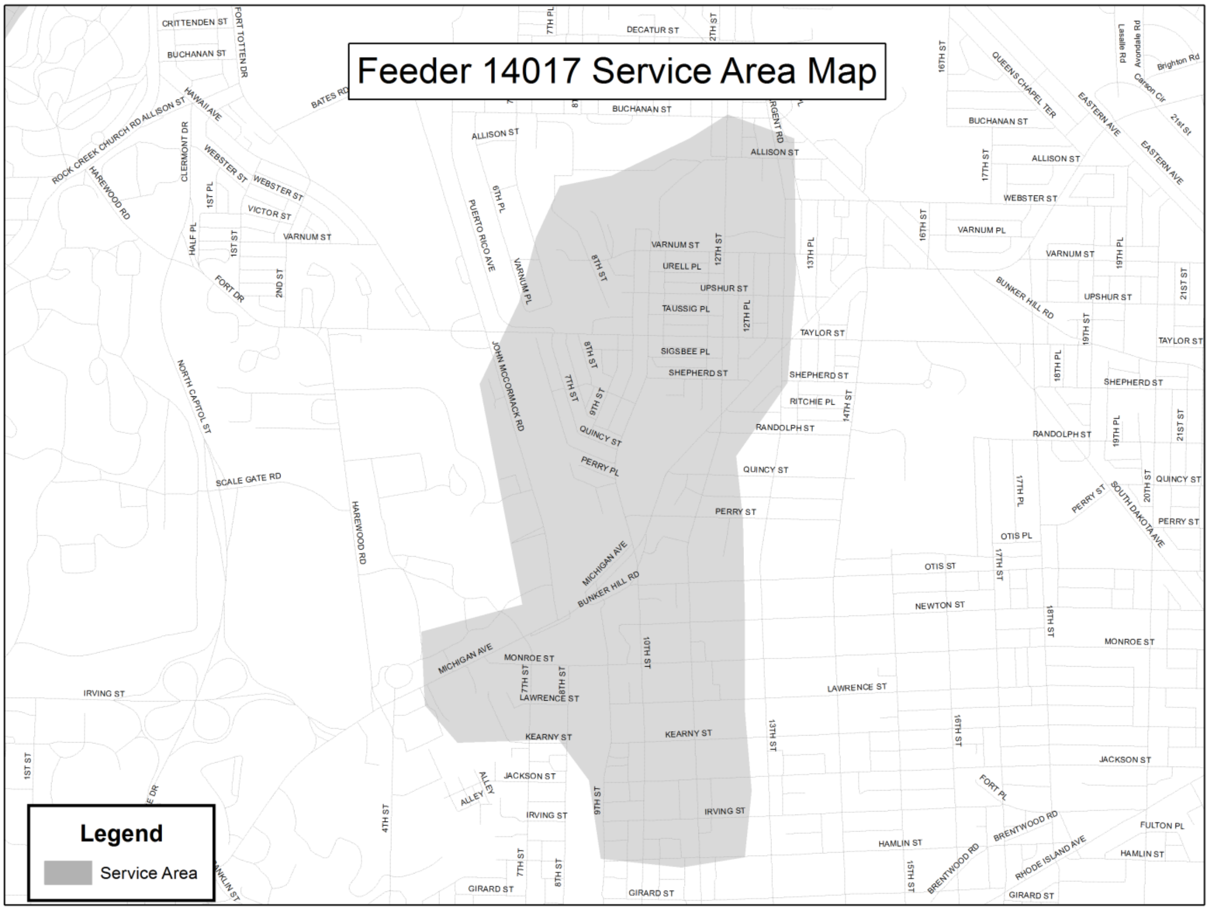
- ❖ Perform inspection and tree trimming in accordance with the VM Plan

- ❖ Perform thermal vision of overhead facilities and necessary upgrades

The work locations include:
10th Street, Monroe Street, Michigan Avenue, Perry Street, Quincy Street, 7th Street, Varnum Street, 12th Street, Taylor Street, Newton Street, Taussig Place NE, Upshur Street, National Child Daycare Association & Catholic Sisters Dining Hall, 8th Street, 9th Street and Our Lady Of Angels

Total Project Cost Estimate: $948,190

2015 Cash Flow: $948,190



13 - Feeder 00490

This feeder was not a 2% Priority Feeder previously.

Feeder 490 - Year 2015 (IEEE MED Exclusive)	
Year	2015
SAIFI	3.40
SAIDI	2.21
CHI	1,365
NI	10

<u>2015 Priority Feeder – Analysis and Corrective Actions:</u>

Description of Major Event Exclusive Outages (October 1, 2013 through September 30, 2014):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 10
Total number of customer interruptions during Non-Major Event Days = 2,095

- Mainline events contributed to 50% of the total number of events, which accounted for 99% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 2 – Equipment Failures
- 2 – Tree
- 1 – Other*

The 2 equipment failures occurred as the result of the following 2 incidents: 1 burnt tap and 1 failed switch.

- Localized transformer events contributed to 50% of the total number of events, which accounted for 1% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 2 - Equipment Failure
- 1 – Tree
- 1 – Load
- 1 – Other*

The 2 equipment failures occurred as the result of the following 2 incidents: 2 failed meters.

Corrective Actions Addressed by the Priority Feeder Program:

Review of the outage history, feeder map, and past corrective actions identified the following option for consideration:

- Install/replace approximately:
  - 534 feet of Primary wire
  - 1,266 feet of Bare wire
  - 3,092 feet of Secondary wire
  - 7 Transformers
  - 19 Animal Guards
  - 3 Lightning Arresters
  - 2 Gang Switches
  - 5 Down Guy
  - 11 Head Guy
  - 1 Cap Bank

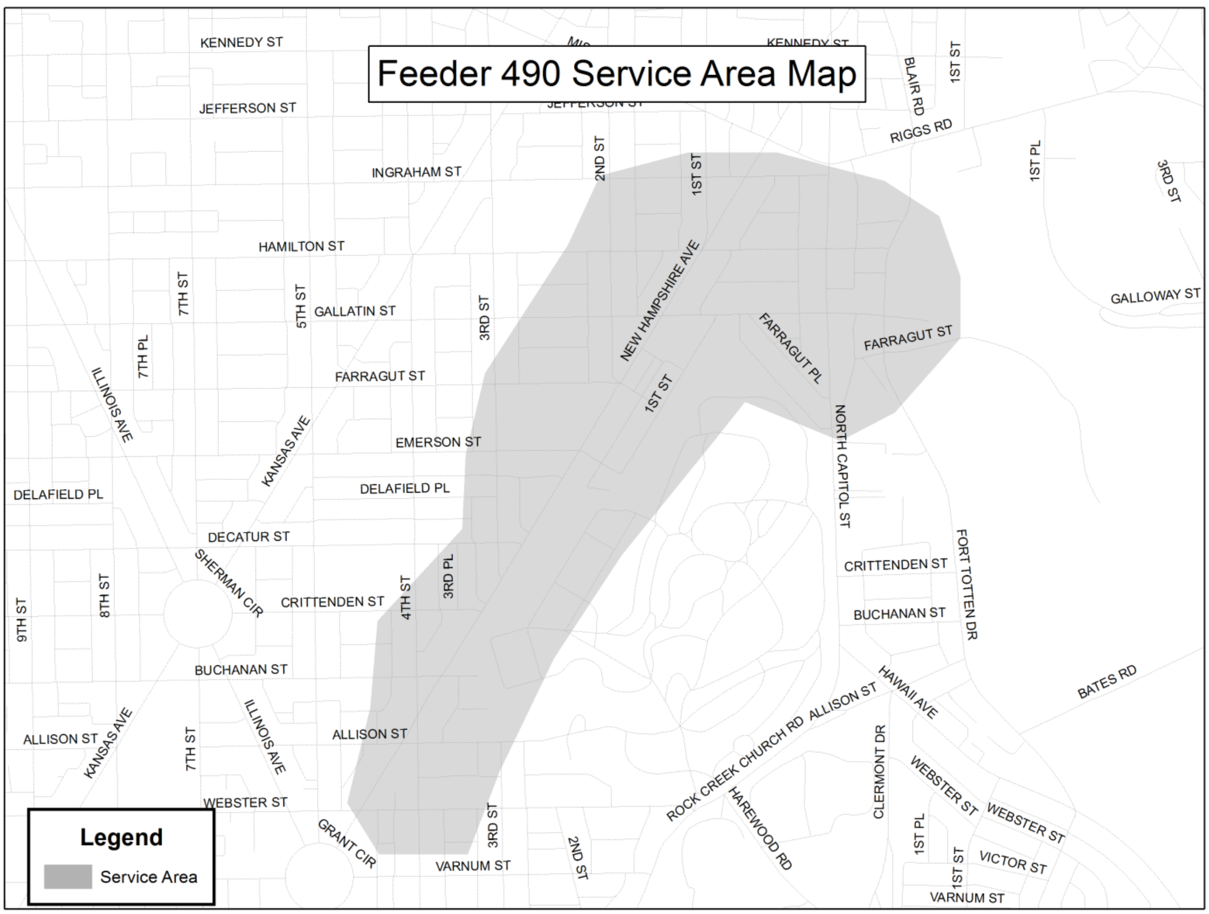
- 8 Fuses
- 23 poles

- ❖ Perform inspection and tree trimming in accordance with the VM Plan
- ❖ Perform thermal vision of overhead facilities and necessary upgrades

The work locations include:
New Hampshire Avenue NW, N (From Gallatin Street NW to Hamilton Street NW, 2nd Street NW, Ingraham Street NW, Farragut Street NW, Fort Totten Drive NE, North Capitol Street NW, 1st Street NW

Total Project Cost Estimate: $465,584

2015 Cash Flow: $465,584



14 - Feeder 14767

This feeder was a 2% Priority Feeder in 2002 and 2008.

Feeder 14767 - Year 2002 - 2015 (IEEE MED Exclusive)											
Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
SAIFI	3.53	0.30	1.35	7.78	1.85	1.80	4.34	3.82	0.71	0.20	1.75
SAIDI	3.99	168.60	1.67	37.38	6.59	7.66	6.13	3.38	1.86	0.72	3.03
CHI	3,065	2,599	1,687	39,029	6,870	7,947	6,326	3,615	1,907	738	3,132
NI	19	27	25	31	26	25	43	46	35	19	24

Priority Feeder in 2002

Description of Major Event Exclusive Outages (October 1, 2000 through September 30, 2001):
Data is unavailable.

Corrective actions performed in 2002:
Installed 24 line fuses, corrected wire slack, and performed tree trimming.

Priority Feeder in 2008

Description of Major Event Exclusive Outages (October 1, 2006 through September 30, 2007):
Data is unavailable.

Corrective actions performed in 2008:

Installed 18 animal guards, 20 lightning arresters, 2 cross arms, 2 new fuses, 2 load break switches and repositioned wire on cross arms to clear trees at 3 locations. Transferred 1.8MVA load to an adjacent area feeder. Performed tree trimming.

Analysis of Past Corrective Actions

The scope of work of the previous corrective actions did not solve the incidents caused by deteriorating infrastructure. Past corrective actions did not adequately address all of the reliability issues on this feeder.

2015 Priority Feeder – Analysis and Corrective Actions:

Description of Major Event Exclusive Outages (October 1, 2013 through September 30, 2014):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 24
Total number of customer interruptions during Non-Major Event Days = 1,812

- Mainline events contributed to 17% of the total number of events, which accounted for 92% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:
- 4 – Equipment Failures

The 4 equipment failures occurred as a result of the following 1 incident: 1 wire down.

- Fuse events contributed to 29% of the total number of events, which accounted for 5% of the total number of customer interruptions.

In summary, the causes for the fuse events were as follows:
- 1 – Equipment Failure
- 5 – Tree
- 1 – Animal

The 1 equipment failure occurred as a result of the following incident: 1 wire down

- Localized transformer events contributed to 54% of the total number of events, which accounted for 3% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:
- 7 - Equipment Failure
- 2 – Tree
- 1 - Weather
- 1 – Overload
- 2 – Other*

The 7 equipment failures occurred as the result of the following 7 incidents: 1 broken fuse, 3 burnt connections, 1 failed transformer, and 2 failed neutrals.

Corrective Actions Addressed by the Priority Feeder Program:

Review of the outage history, feeder map, and past corrective actions identified the following option for consideration:

- Install/ replace approximately:
  - 1,855 feet of primary Tree Wire
  - 801 feet of PAC
  - 23 Poles
  - 12 Transformers
  - 29 Cutouts
  - 47 Lightning Arrestors
  - 65 Animal Guards
  - 12 Head Guys

- 9 Down Guys

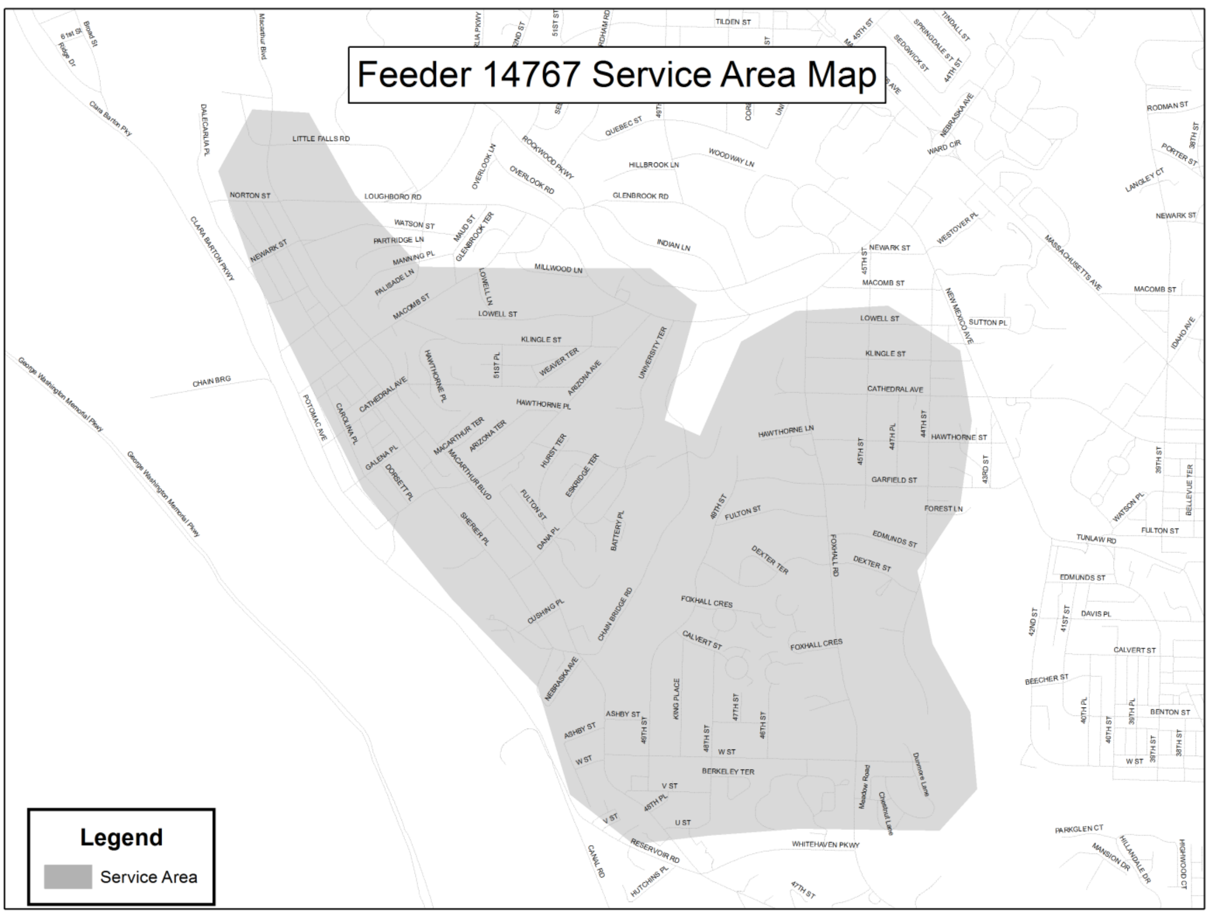
❖ Perform inspection and tree trimming in accordance with the VM Plan

❖ Perform thermal vision of overhead facilities and necessary upgrades

The work locations include:
MacArthur Boulevard NW, Ashby Street NW, Ashby Street NW, W Street NW, Foxhall Road NW, Galena Place, Arizona Avenue NW, Dana Place NW, V Street NW, 49th Street NW, 46th Street NW, Edmunds Street NW, Garfield Street NW, Hawthorne Lane NW and Cathedral Avenue NW.

Total Project Cost Estimate: $651,000

2015 Cash Flow: $651,000



15 - Feeder 00082

This feeder was a 2% Priority Feeder in 2007.

Feeder 82 - Year 2007 - 2015 (IEEE MED Exclusive)									
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015
SAIFI	1.40	1.53	0.00	2.01	0.80	0.16	0.06	0.20	3.17
SAIDI	14.06	2.34	0.01	6.24	3.62	0.82	0.19	0.41	5.50
CHI	8,631	1,400	5	3,797	2,206	496	114	245	1,929
NI	7	7	2	5	6	9	5	11	8

Priority Feeder in 2007

Description of Major Event Exclusive Outages (October 1, 2005 through September 30, 2006):

Data is unavailable.

Corrective actions performed in 2007:

Installed 6 animal guards, replaced 3 cross arms, and performed tree trimming.

Analysis of Past Corrective Actions

The scope of work of the previous corrective actions did not solve the incidents caused by deteriorating infrastructure. Past corrective actions did not adequately address all of the reliability issues on this feeder.

2015 Priority Feeder – Analysis and Corrective Actions:

Description of Major Event Exclusive Outages (October 1, 2013 through September 30, 2014):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 8
Total number of customer interruptions during Non-Major Event Days = 1,112

- Mainline events contributed to 38% of the total number of events, which accounted for 92% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 2 – Equipment Failure
- 1 - Unknown

The 2 equipment failures occurred as a result of the following 1 incident: 1 underground cable failure.

- Localized transformer events contributed to 62% of the total number of events, which accounted for 8% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 2 - Equipment Failure
- 1 – Overload
- 2 – Other*

The 2 equipment failures occurred as the result of the following 2 incidents: 1 damaged meter and 1 loose connection.

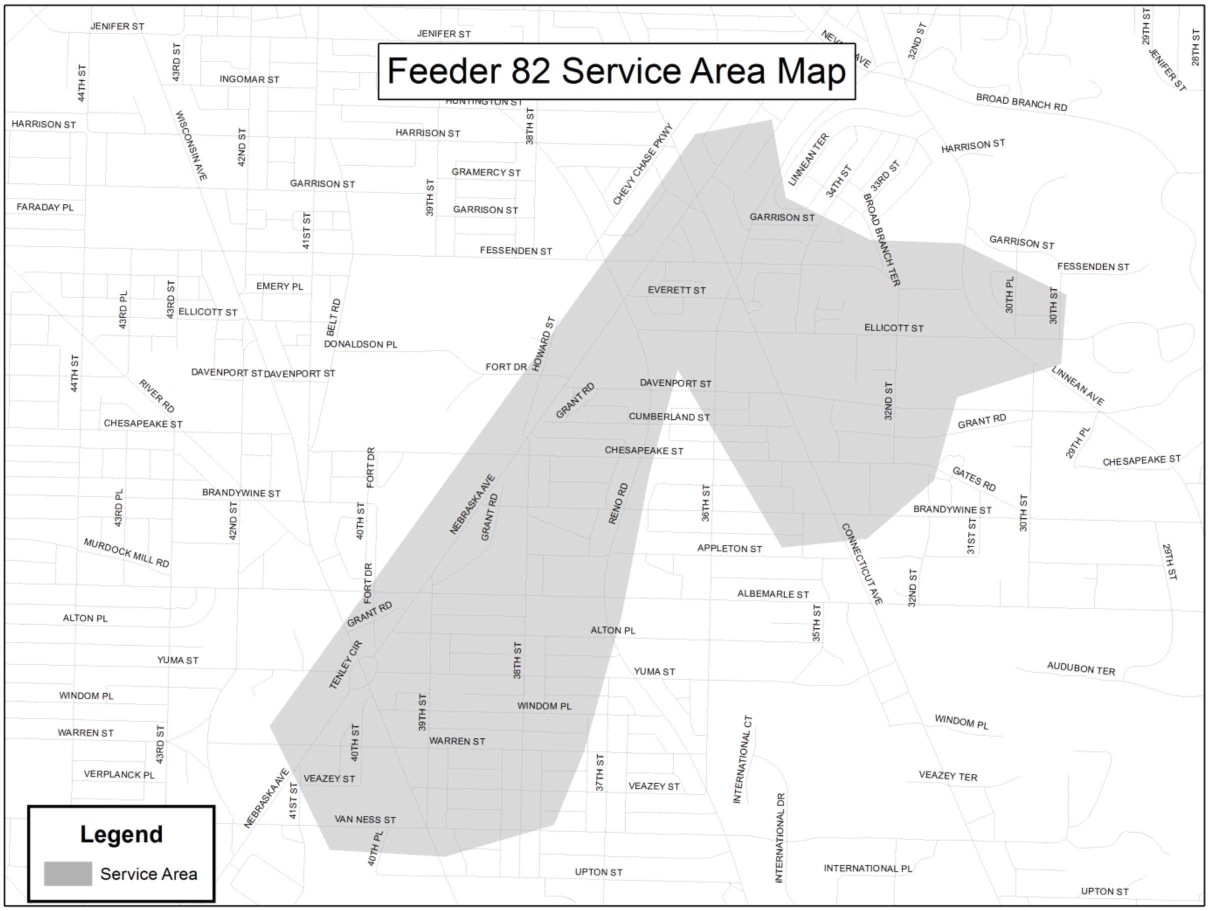
Corrective Actions Addressed by the Priority Feeder Program:
Review of the outage history, feeder map, and past corrective actions identified the following option for consideration:

- Install/ replace approximately:
    - 920ft of Secondary Triplex wires
    - 2000ft Secondary Service Triplex wires
    - 44 Poles
    - 12 Transformers
    - 3 Cutouts
    - 42 Animal Guards
    - 3 Lightning Arrestors
    - 7 Down Guys
- Perform inspection and tree trimming in accordance with the VM Plan
- Perform thermal vision of overhead facilities and necessary upgrades

The work locations include:
Windom Place NW, 38th Street NW, Cumberland Street NW, Nebraska Avenue NW, Davenport Street NW, 32nd Street NW, Ellicott Street NW, Yuma Street NW, Alton Place NW, Brandywine Street NW, Grant Road NW, 39 Street NW and Fessenden Street NW.

Total Project Cost Estimate: $481,000

2015 Cash Flow: $481,000



16 - Feeder 00133

This feeder was not a 2% Priority Feeder previously.

Feeder 133 - Year 2015 (IEEE MED Exclusive)	
Year	2015
SAIFI	2.12
SAIDI	4.43
CHI	2,110
NI	14

<u>2015 Priority Feeder- Analysis and Corrective Actions</u>

Description of Major Event Exclusive Outages (October 1, 2013 through September 30, 2014)

Total number of events during Non-Major Event Days (Major Event Exclusive) = 14
Total number of customer interruptions during Non-Major Event Days = 1,009

- Mainline events contributed to 22% of the total number of events, which accounted for 94% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 1 – Equipment Failure
- 2 – Trees

The 1 equipment failure occurred as the result of the following incident: 1 cable failure.

- Fuse events contributed to 7% of the total number of events, while accounting for less than 1% of the total number of customer interruptions.

In summary, the cause for the fuse event was due to:

- 1 – Other*

- Localized transformer events contributed to 71% of the total number of events, which accounted for 5% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 3 - Equipment Failure
- 4 – Tree
- 1 – Unknown
- 1 – Animal
- 1 – Load

The 3 equipment failures occurred as the result of the following 3 incidents: 1 loose secondary connection, 1 failed transformer and 1 cable failure.

Corrective Actions Addressed by the Priority Feeder Program:

Review of the outage history, feeder map and past corrective actions identified the following option for consideration:

- Install/replace approximately:
  - 10,008 feet of secondary wire
  - 5,487 feet of tree wire
  - 54 poles
  - 24 transformers
  - 1 capacitor
  - 1 gang switch

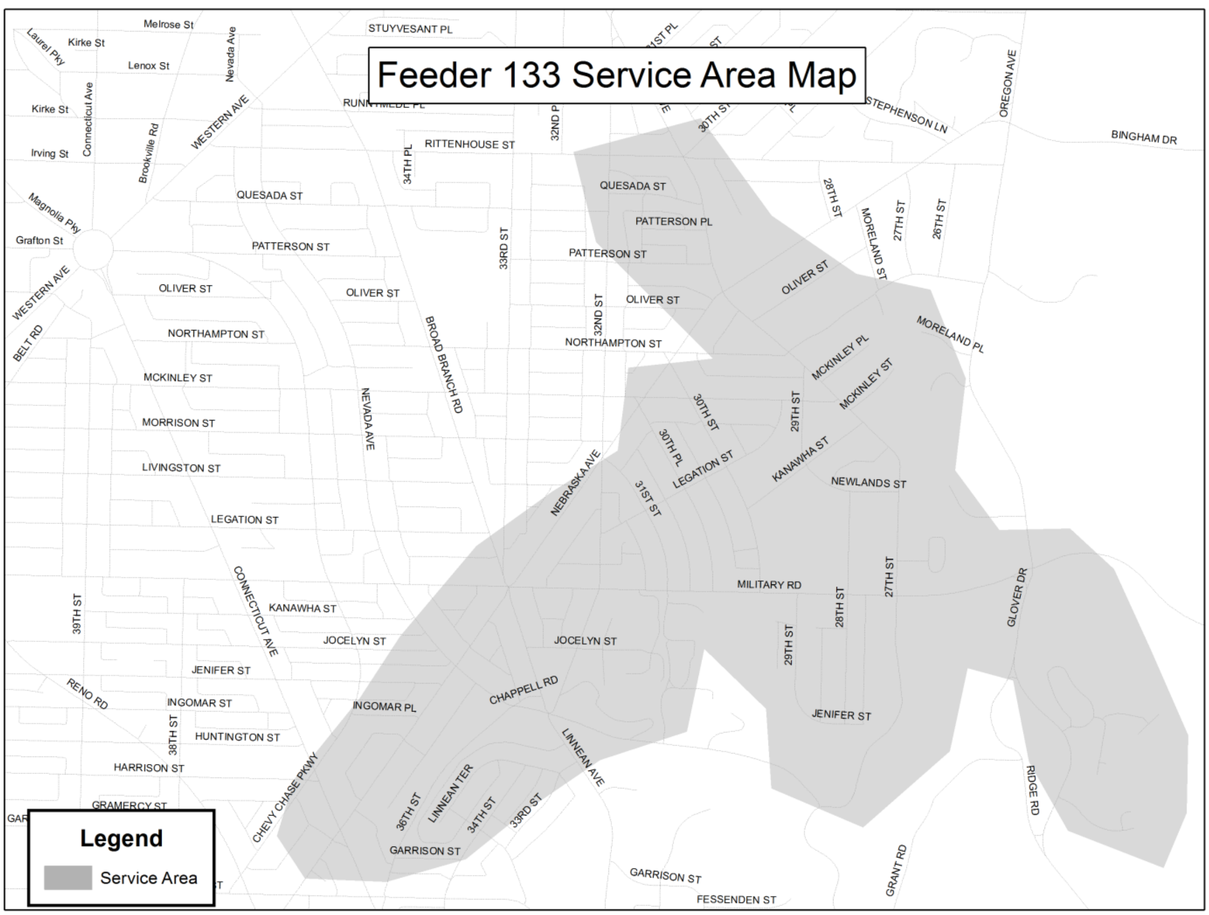
- ❖ Perform inspection and tree trimming in accordance with the VM Plan

- ❖ Perform thermal vision of overhead facilities and necessary upgrades.

The work locations include:
Jocelyn Street NW, 36th Street NW, 32nd Street NW, Legation Street NW, 30th Street NW, 30th Place NW,29th Street NW, 28th Street NW, Jenifer Street NW, 27th Street NW, Kanawha Street NW, McKinley Street NW, McKinley Place NW, Military Road, Nevada Avenue, Patterson Place NW, Quesada Street NW and Utah Avenue NW.

Total Project Cost Estimate: $756,656

2015 Cash Flow: $756,656



2014 CPI-Selected Feeders

In addition to Pepco's new method of ranking the performance of distribution feeders, Pepco is also using CPI to rank the performance of its distribution feeders. As discussed in the Feeder Improvement discussion of Section 1.3.6, the CPI was Pepco's prior method of identifying Priority Feeders. Feeders that would have been selected as Priority Feeders using the CPI method are included in the Company's Feeder Improvement category of its REP program for remediation. These CPI-selected feeders for inclusion in the Feeder Improvement REP program are identified below along with corrective action plans.

2015 Priority Feeders For Improvement (Data is based on October 1, 2013 through September 30, 2014)								
Feeder No.	Substation	Area / District	Customers Served	Number of Outages	Reliability Indices			
					SAIFI	SAIDI	CAIDI	CPI
76	Harvard 13	DC	436	11	4.88	3,214	658	0.78282
86	Harvard 4	DC	318	6	3.12	1,996	640	0.46172
211	"G" Street, SE 28	DC	622	9	7.60	815	107	0.38010
14722	Harvard 13	DC	1,639	13	2.11	373	177	0.21172
14702	Anacostia 8	DC	1,050	17	3.25	284	87	0.18419
15170	Alabama Avenue 136	DC	1,614	22	2.60	172	66	0.16570
15014	Fort Slocum 190	DC	1,219	13	3.00	202	67	0.15844
82	VeazeyEast 90E	DC	351	8	3.17	330	104	0.15359
490	North Capitol 40	DC	617	10	3.40	133	39	0.14853
15174	Alabama Avenue 136	DC	2,183	9	2.12	146	69	0.13393
14006	12th & Irving 133	DC	1,919	18	2.21	109	49	0.13349
14767	Little Falls 77	DC	1,034	24	1.75	182	104	0.13345
133	Quesada 89	DC	477	14	2.12	266	126	0.12148
15945	Van Ness 129	DC	1,236	21	2.07	95	46	0.11972
14200	12th & Irving 133	DC	1,388	23	1.78	51	29	0.10647
14017	12th & Irving 133	DC	1,323	13	1.75	89	51	0.09587
Average of 16 Selected Feeders in DC			697	14	2.57	305	119	n/a

Of the 16 feeders included in the CPI ranking for 2014, only Feeder No. 86, was not also ranked using the new SPC method.

<u>Feeder 177</u>

This was not previously a 2% Priority Feeder.

<u>2014 Priority Feeder – Analysis and Corrective Actions</u>

Description of Major Event Exclusive Outages (October 1, 2012 through September 30, 2013):

Total number of events during Non-Major Event Days (Major Event Exclusive) = 10
Total number of customer interruptions during Non-Major Event Days = 765

- Mainline events contributed to 20% of the total number of events, which accounted for 85% of the total number of customer interruptions.

In summary, the causes for the mainline events were as follows:

- 1 – Equipment Failure
- 1 – Lightning

This 1 equipment failure occurred as the result of 1 incident; a primary cable fault.

- Localized transformer events contributed to 85% of the total number of events, which accounted for 15% of the total number of customer interruptions.

In summary, the causes for the transformer events were as follows:

- 1 – Customer's service disconnected
- 4 – Equipment Failure
- 3 – Tree

These 4 equipment failures occurred as the result of the following 4 incidents; 1 defective cutout, 1 leaning pole, and 2 loose connections.

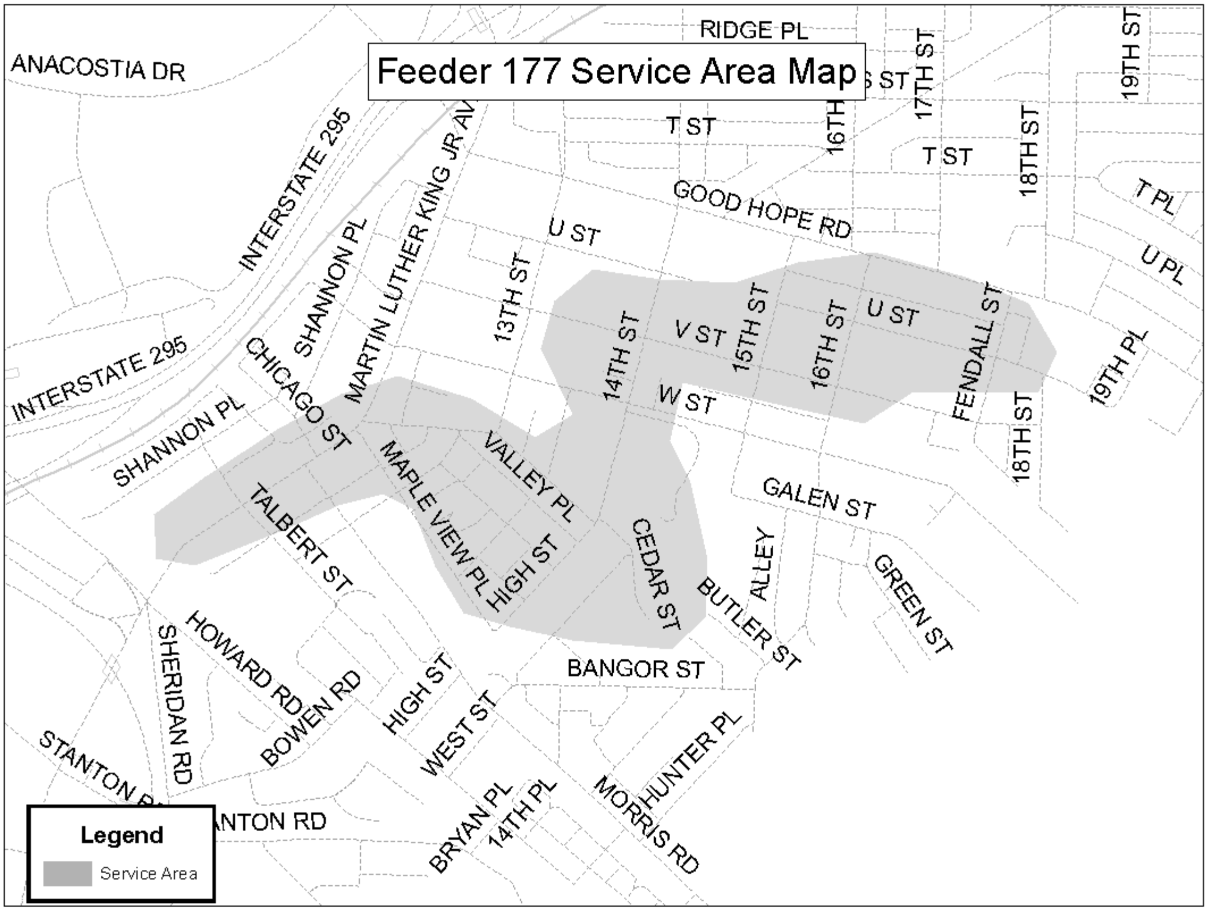
Corrective Actions Addressed by the Priority Feeder Program:

Review of the outage history, feeder map, and past corrective actions identified the following options for consideration:

- Install/replace approximately:
  - 5,320 feet of secondary wire;
  - 7 poles;
  - 3 transformers;
  - 1 gang switch
- Perform inspection and tree trimming in accordance with the VM Plan
- Perform thermal vision of overhead facilities and necessary upgrades

The work locations include:
Chester Street SE, High Street SE, Alley (between High Street and Mount View Place), Alley (off Chester Street), and V Street (between 15th and 16th Streets)

Total Project Cost Estimate: $138,555



2.4.1.3 Review of 2013 Priority Feeder Program (Least Reliable Feeders)

Activities conducted to improve the performance of each of the feeders in the 2013 Priority Feeder Program are identified in Table 2.4-B.

2013 2% Priority Feeder Program - District of Columbia - Completed/ Pending Completion Corrective Actions							
Rank	Feeder ID	Substation	Category		SPC	Completion Timeline	Corrective Actions
			OH	UG			
1	15705	Benning #7	72%	28%	0.04144	4th Quarter 2013	Install/replace 433 feet of primary wire, 274 feet of primary tree wire, 270 feet of secondary wire, 6,895 feet of secondary triplex/quadriplex, 192 feet of secondary service wire, 47 grounds, 110 animal guards, 40 lightning arresters, 17 poles, 137 fuses and 19 transformers
2	15707	Benning #7	92%	8%	0.03379	3rd Quarter 2014	Install/Replace 2,502 feet of primary tree wire, 6,582 feet of mainline secondary, 1,000 feet of secondary service, 42 poles, 56 crossarms, 88 fuse cutouts, 12 transformers, and 38 animal guards
3	15174	Alabama Avenue #136	67%	33%	0.02541	4th Quarter 2013	Install/replace 31,656 feet of primary bare wire with 477 ACSR, 855 feet of primary bare wire with 477 tree wire, 4,161 feet of primary bare wire with 1/0 ACSR, 1,839 feet of primary bare wire with 1/0 tree wire, 5,260 feet of secondary open wire with 4/0 triplex, 12 poles, 16 transformers, 64 fuses and 3 lightning arrestors
4	15710	Benning #7	77%	23%	0.0236	4th Quarter 2013	Install/replace 4,755 feet of primary wire, 493 feet of secondary triplex, 261 feet of primary tree wire, 609 feet of secondary service wire, 203 feet of secondary wire, 88 poles, 35 transformers, 91 fuses and 87 animal guards
5	14786	New Jersey Ave. #161	0%	100%	0.0232	1st Quarter 2014	Install/Replaced 34,916 feet of injected URD cable
6	14014	12th & Irving #133	92%	8%	0.02143	4th Quarter 2014	Install/Replace 9,610 feet of primary tree wire, 935 feet of primary bare wire, 50,856 feet of mainline secondary, 25,666 feet of secondary service, 291 poles, 132 crossarms, 1 ACR, 1 SF6 switch, 2 gang switches, 159 fuse cutouts, 111 transformers, 42 lightning arrestors, and 360 animal guards.
7	15166	Alabama Avenue #136	78%	22%	0.02038	1st Quarter 2015	Install/Replace 927 feet of primary tree wire, 216 feet of primary bare wire, 928 feet of mainline secondary, 2,000 feet of secondary service, 56 poles, 121 crossarms, 1 gang switch, 42 fuse cutouts, 18 transformers, 34 lightning arrestors, and 146 animal guards.
8	15801	Little Falls #77	92%	8%	0.01987	1st Quarter 2014	Install/Replace 9,676 feet of primary tree wire, 445 feet of primary bare wire, 104 feet of URD cable, 2,839 feet of mainline secondary, 5,940 feet of secondary service, 289 poles, 66 crossarms, 3 manual switches, 125 fuse cutouts, 82 transformers, 7 lightning arrestors, and 292 animal guards.
9	14006	12th & Irving #133	82%	18%	0.01867	3rd Quarter 2013	Install/replace 60 feet of primary tree wire, 1,600 feet of secondary triplex, 9 Poles, 2 animal guards and 6 lightning arrestors
10	14788	New Jersey Ave. #161	0%	100%	0.01589	1st Quarter 2014	Install/Replace 1,541 feet of underground cable.
11	15945	Central Avenue #185	95%	5%	0.01454	4th Quarter 2013	Install/replace 1 transformer and 21 animal guards.
12	14900	Harrison #38	71%	29%	0.01339	2nd Quarter 2013	Install/replace 21 animal guards.
13	14200	12th & Irving #133	51%	49%	0.01314	4th Quarter 2013	Install/replace 8,785 feet of primary tree wire, 10 poles, 20 animal guards and 3 SF6 switches
14	14787	New Jersey Ave. #161	0%	100%	0.01277	4th Quarter 2013	Enhancing 12,900 feet of cable by cable injection
15	14009	12th & Irving #133	46%	54%	0.01213	1st Quarter 2014	Install/Replace 4,820 feet of primary tree wire, 5,403 feet of mainline secondary, 4,653 feet of secondary service, 23 poles, 17 crossarms, 2 gang switches, 31 fuse cutouts, 12 transformers, and 10 animal guards.
16	14001	12th & Irving #133	0%	100%	0.01198	1st Quarter 2013	Enhancing 22,670 feet of cable by cable injection
17	CPI-00332	Congress Hights #64	89%	11%	CPI - 0.39520	4th Quarter 2013	Feeder reliability issues were addressed as part of the system conversion project completed in 4th quarter of 2013.
18	CPI-00325	Fort Carroll #130	94%	6%	CPI - 0.24990	4th Quarter 2013	Install/report 50 feet of primary wire, 81 feet of primary tree wire, 105 feet of secondary service wire, 60 feet of secondary wire, 2 poles, 9 transformers, 28 fuses and 29 animal guards
19	CPI-14890	Harrison #38	83%	17%	CPI - 0.23290	2nd Quarter 2014	Install/Replace 10,383 feet of primary tree wire, 443 feet of primary bare wire, 4,976 feet of mainline secondary, 2,589 feet of secondary service, 181 poles, 59 crossarms, 1 gang switch, 63 fuse cutouts, 43 transformers, 13 lightning arrestors, and 186 animal guards.
20	CPI-00147	Harvard #13	0%	100%	CPI - 0.19695	4th Quarter 2014	Install/Replace 16,395 feet of underground cable, 9 tapholes, 3 manholes and 15 transformers

Table 2.4-B

2013 High Priority Feeder Program: 2-Year Comparison (CPI vs. SPC)									
2013 Rank	2015 Rank	2015 Rank	Feeder	SAIFI		SAIDI (minutes)		CAIDI (minutes)	
CPI	CPI	SPC	No.	2013 List	2015 List	2013 List	2015 List	2013 List	2015 List
1	36	5	15707	2.32	1.82	562	96	242	53
2	599	314	332	10.02	0.00	464	0	46	0
3	54	23	15705	5.74	1.33	565	109	98	82
4	58	35	14786	4.56	1.37	704	200	154	146
5	8	2	14014	2.38	2.80	542	295	228	105
6	56	46	14788	2.62	0.84	762	282	291	337
7	40	15	14006	2.31	2.21	420	109	182	49
8	293	312	325	5.63	0.00	466	0	83	0
9	184	188	14890	3.27	0.06	373	7	114	116
10	151	135	14001	4.35	0.33	612	47	141	142
11	156	133	15801	3.77	0.21	354	43	94	204
12	17	1	15166	2.72	4.03	427	214	157	53
13	125	154	15710	3.27	0.07	316	13	97	183
14	52	26	15945	3.13	2.07	365	95	116	46
15	113	101	14900	2.46	0.29	350	67	142	229
16	6	71	147	3.99	4.17	546	1,512	137	362

Table 2.4-C

2.4.1.4 AGGRESSIVE CORRECTIVE ACTION PROGRAM

Annual Program for Repeat Priority Feeders[46]

The review of the 16 feeders selected for the 2% Priority Feeder initiative with previous year selections show that four feeders 14006, 14200, 15174, and 15945, which were in the 2013 Priority feeder Program reappear on the 2015 Priority Feeder Program. When a feeder repeats, additional aggressive corrective actions are implemented. All of the corrective actions listed in Section 2.4.1.2 will be completed in 2015.

Corrective action plans are based on an analysis of outage causes on a feeder. Tables 2.4-D1 through 2.4-D4 provide a comparison of the outage cause contributions for the 2015 Priority Feeders that were also identified as a Priority Feeder in 2013: feeders 14006, 14200, 15174, and 15945. The 2013 and 2015 Outage Cause Contributions are based on a rolling 12 month history performance, exclusive of Major Event Days, from October 1, 2011 to September 30, 2012 and October 1, 2013 to September 30, 2014, respectively.

Pepco Major Outage Cause Summary MED Exclusive DC Area - 12th & Irving 133 - FEEDER 14006 - 2013												
Cause	Events	Pct	Rank	Cust Out	Pct	Rank	Minutes	Pct	Rank	SAIFI	CAIDI	SAIDI
Animal	6	12.5%	4	96	2.2%	4	11,083	1.4%	4	0.051	115.5	5.87
Dig In	-	0.0%	9	-	0.0%	9	-	0.0%	9	0.000	-	-
Equipment Failure	11	22.9%	2	1,967	45.0%	1	254,142	32.0%	2	1.041	129.2	134.54
Equipment Hit	1	2.1%	8	30	0.7%	5	5,283	0.7%	5	0.016	176.1	2.80
Other*	2	4.2%	5	2	0.0%	7	261	0.0%	7	0.001	130.4	0.14
Overload	2	4.2%	5	30	0.7%	5	4,203	0.5%	6	0.016	140.1	2.22
Tree	16	33.3%	1	874	20.0%	3	50,364	6.3%	3	0.463	57.6	26.66
Unknow n	2	4.2%	5	2	0.0%	7	161	0.0%	8	0.001	80.6	0.09
Weather	8	16.7%	3	1,369	31.3%	2	468,823	59.0%	1	0.725	342.5	248.19
Sum	**48**	**100.0%**		**4,370**	**100.0%**		**794,320**	**100.0%**		**2.313**	**181.8**	**420.50**

Pepco Major Outage Cause Summary MED Exclusive DC Area - 12th & Irving 133 - FEEDER 14006 - 2015												
Cause	Events	Pct	Rank	Cust Out	Pct	Rank	Minutes	Pct	Rank	SAIFI	CAIDI	SAIDI
Animal	4	22.2%	3	2,011	47.5%	1	106,739	50.9%	1	1.048	53.1	55.62
Dig In	-	0.0%	7		0.0%	7	-	0.0%	7	0.000	-	-
Equipment Failure	6	33.3%	1	157	3.7%	3	28,576	13.6%	3	0.082	182.0	14.89
Equipment Hit	-	0.0%	7	-	0.0%	7	-	0.0%	7	0.000	-	-
Other*	1	5.6%	4	1	0.0%	6	62	0.0%	6	0.001	61.5	0.03
Overload	1	5.6%	4	24	0.6%	5	3,860	1.8%	5	0.013	160.8	2.01
Tree	5	27.8%	2	90	2.1%	4	8,421	4.0%	4	0.047	93.6	4.39
Unknow n	1	5.6%	4	1,951	46.1%	2	61,847	29.5%	2	1.017	-	32.23
Weather	-	0.0%	7	-	0.0%	7	-	0.0%	7	0.000	-	-
Sum	**18**	**100.0%**		**4,234**	**100.0%**		**209,505**	**100.0%**		**2.206**	**49.5**	**109.17**

Table 2.4-D1

Pepco
Major Outage Cause Summary MED Exclusive
DC Area - 12th & Irving 133 - FEEDER 14200 - 2013

Cause	Events	Pct	Rank	Cust Out	Pct	Rank	Minutes	Pct	Rank	SAIFI	CAIDI	SAIDI
Animal	6	20.0%	2	1,579	39.4%	1	30,340	16.3%	4	1.113	19.2	21.38
Dig In	-	0.0%	7	-	0.0%	7	-	0.0%	7	0.000	-	-
Equipment Failure	13	43.3%	1	112	2.8%	5	50,863	27.4%	2	0.079	454.1	35.84
Equipment Hit	-	0.0%	7	-	0.0%	7	-	0.0%	7	0.000	-	-
Other*	3	10.0%	3	3	0.1%	6	213	0.1%	6	0.002	71.0	0.15
Overload	-	0.0%	7	-	0.0%	7	-	0.0%	7	0.000	-	-
Tree	2	6.7%	6	682	17.0%	3	30,800	16.6%	3	0.481	45.2	21.71
Unknow n	3	10.0%	3	211	5.3%	4	63,238	34.0%	1	0.149	299.7	44.57
Weather	3	10.0%	3	1,420	35.4%	2	10,356	5.6%	5	1.001	7.3	7.30
Sum	**30**	**100.0%**		**4,007**	**100.0%**		**185,810**	**100.0%**		**2.824**	**46.4**	**130.94**

Pepco
Major Outage Cause Summary MED Exclusive
DC Area - 12th & Irving 133 - FEEDER 14200 - 2015

Cause	Events	Pct	Rank	Cust Out	Pct	Rank	Minutes	Pct	Rank	SAIFI	CAIDI	SAIDI
Animal	3	13.0%	2	3	0.1%	5	407	0.6%	5	0.002	135.7	0.29
Dig In	-	0.0%	8	-	0.0%	8	-	0.0%	8	0.000	-	-
Equipment Failure	11	47.8%	1	66	2.7%	3	21,690	30.4%	1	0.048	328.6	15.63
Equipment Hit	1	4.3%	6	1,411	57.4%	1	11,970	16.8%	4	1.017	8.5	8.62
Other*	-	0.0%	8	-	0.0%	8	-	0.0%	8	0.000	-	-
Overload	1	4.3%	6	1	0.0%	7	120	0.2%	7	0.001	-	0.09
Tree	2	8.7%	4	936	38.0%	2	18,758	26.3%	2	0.674	20.0	13.51
Unknow n	2	8.7%	4	2	0.1%	6	305	0.4%	6	0.001	152.6	0.22
Weather	3	13.0%	2	41	1.7%	4	17,992	25.3%	3	0.030	438.8	12.96
Sum	**23**	**100.0%**		**2,460**	**100.0%**		**71,243**	**100.0%**		**1.772**	**29.0**	**51.33**

Table 2.4-D2

Pepco
Major Outage Cause Summary IEEE MED Exclusive
DC Area - Alabama Avenue 136 - FEEDER 15174 - 2013

Cause	Events	Pct	Rank	Cust Out	Pct	Rank	Minutes	Pct	Rank	SAIFI	CAIDI	SAIDI
Animal	3	15.0%	3	57	0.8%	4	7,719	1.4%	5	0.024	135.4	3.30
Dig In	-	0.0%	7	-	0.0%	7	-	0.0%	7	0.000	-	-
Equipment Failure	5	25.0%	1	2,470	34.1%	1	191,011	33.8%	2	1.057	77.3	81.73
Equipment Hit	2	10.0%	5	10	0.1%	6	1,453	0.3%	6	0.004	145.3	0.62
Other*	5	25.0%	1	2,355	32.5%	2	57,902	10.3%	3	1.008	24.6	24.78
Overload	-	0.0%	7	-	0.0%	7	-	0.0%	7	0.000	-	-
Tree	2	10.0%	5	2,316	32.0%	3	267,480	47.4%	1	0.991	115.5	114.45
Unknow n	3	15.0%	3	30	0.4%	5	39,060	6.9%	4	0.013	1,302.0	16.71
Weather	-	0.0%	7	-	0.0%	7	-	0.0%	7	0.000	-	-
Sum	**20**	**100.0%**		**7,238**	**100.0%**		**564,625**	**100.0%**		**3.097**	**78.0**	**241.60**

Pepco
Major Outage Cause Summary MED Exclusive
DC Area - Alabama Avenue 136 - FEEDER 15174 - 2015

Cause	Events	Pct	Rank	Cust Out	Pct	Rank	Minutes	Pct	Rank	SAIFI	CAIDI	SAIDI
Animal	2	22.2%	2	33	0.7%	3	6,935	2.2%	3	0.015	210.2	3.18
Dig In	-	0.0%	5	-	0.0%	5	-	0.0%	5	0.000	-	-
Equipment Failure	2	22.2%	2	27	0.6%	4	6,902	2.2%	4	0.012	255.6	3.16
Equipment Hit	-	0.0%	5	-	0.0%	5	-	0.0%	5	0.000	-	-
Other*	-	0.0%	5	-	0.0%	5	-	0.0%	5	0.000	-	-
Overload	-	0.0%	5	-	0.0%	5	-	0.0%	5	0.000	-	-
Tree	-	0.0%	5	-	0.0%	5	-	0.0%	5	0.000	-	-
Unknow n	3	33.3%	1	2,305	49.9%	1	100,023	31.3%	2	1.056	43.4	45.82
Weather	2	22.2%	2	2,251	48.8%	2	205,559	64.4%	1	1.031	91.3	94.16
Sum	**9**	**100.0%**		**4,616**	**100.0%**		**319,419**	**100.0%**		**2.115**	**69.2**	**146.32**

Table 2.4-D3

Pepco Major Outage Cause Summary MED Exclusive DC Area - Van Ness 129 - FEEDER 15945 - 2013												
Cause	Events	Pct	Rank	Cust Out	Pct	Rank	Minutes	Pct	Rank	SAIFI	CAIDI	SAIDI
Animal	3	13.0%	3	23	0.6%	3	4,463	1.0%	4	0.019	194.0	3.65
Dig In	-	0.0%	7	-	0.0%	7	-	0.0%	7	0.000	-	-
Equipment Failure	7	30.4%	2	44	1.1%	2	6,036	1.4%	3	0.036	137.2	4.94
Equipment Hit	1	4.3%	5	5	0.1%	5	399	0.1%	6	0.004	79.9	0.33
Other*	-	0.0%	7	-	0.0%	7	-	0.0%	7	0.000	-	-
Overload	1	4.3%	5	15	0.4%	4	8,188	1.8%	2	0.012	545.8	6.69
Tree	9	39.1%	1	3,745	97.7%	1	426,322	95.6%	1	3.062	113.8	348.59
Unknow n	-	0.0%	7	-	0.0%	7	-	0.0%	7	0.000	-	-
Weather	2	8.7%	4	2	0.1%	6	549	0.1%	5	0.002	274.7	0.45
Sum	**23**	**100.0%**		**3,834**	**100.0%**		**445,956**	**100.0%**		**3.135**	**116.3**	**364.64**

Pepco Major Outage Cause Summary MED Exclusive DC Area - Van Ness 129 - FEEDER 15945 - 2015												
Cause	Events	Pct	Rank	Cust Out	Pct	Rank	Minutes	Pct	Rank	SAIFI	CAIDI	SAIDI
Animal	4	19.0%	3	18	0.7%	4	2,136	1.8%	5	0.015	118.7	1.73
Dig In	-	0.0%	6	-	0.0%	6	-	0.0%	6	0.000	-	-
Equipment Failure	7	33.3%	1	2,481	96.9%	1	96,736	82.8%	1	2.007	39.0	78.27
Equipment Hit	-	0.0%	6	-	0.0%	6	-	0.0%	6	0.000	-	-
Other*	-	0.0%	6	-	0.0%	6	-	0.0%	6	0.000	-	-
Overload	3	14.3%	4	26	1.0%	2	6,382	5.5%	3	0.021	-	5.16
Tree	6	28.6%	2	22	0.9%	3	7,895	6.8%	2	0.018	-	6.39
Unknow n	-	0.0%	6	-	0.0%	6	-	0.0%	6	0.000	-	-
Weather	1	4.8%	5	13	0.5%	5	3,736	3.2%	4	0.011	287.4	3.02
Sum	**21**	**100.0%**		**2,560**	**100.0%**		**116,884**	**100.0%**		**2.071**	**45.7**	**94.57**

Table 2.4-D4

2.4.2 RELIABILITY STATISTICS

Service Reliability Indices

SAIDI, SAIFI, and CAIDI are the specific indices used and provide information about both the duration and frequency of outages for customers. These indices are described as follows:

- **SAIDI -** System Average Interruption Duration Index. Designed to provide information about the average time (in aggregate) that the customers served in a predefined area are interrupted.
- **SAIFI -** System Average Interruption Frequency Index. Designed to give information about the average frequency of sustained interruptions per customer served in a predefined area.
- **CAIDI** - Customer Average Interruption Duration Index. Designed to provide information about the average time required to restore service to the average customer experiencing a sustained interruption.

Each index is calculated several times; once with all outage data and then according to the specific significant event exclusions specified. The expectation is that the indices calculated with significant event related outage data excluded will provide a reflection of system performance under normal operating conditions. The indices calculated with all outage data will provide a reflection of the impact of significant events on the system. It is important to note that a year-to-year comparison of reliability indices calculated with all outage data would not be appropriate. The indices during a year in which major storms impact an electric utility will be substantially different from the indices during a year with no major storms.

Service Outage Statistics[47,48]

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[47] In Order No. 16623 paragraphs 48, 62 and 63, the Commission stated the following:

48. *…Therefore, we hereby require that Pepco include reliability calculations using District of Columbia-only data and relying on a Major Service Outage exclusion in the 2012 Consolidated Report and in future Consolidated Reports. We also require that Pepco include in its 2012 Consolidated Report a revised version of its reliability calculations from the 2010 and 2011 Consolidated Reports using D.C.-only data and excluding Major Service Outages.* [See Table 2.4-F2] *Pepco shall also include calculations of reliability indices for the entire Pepco system using system-wide data and Major Event Day exclusions,* [See Table 2.4-E] *as well as reliability indices for Pepco D.C. using D.C.-only MEDs in the 2012 Consolidated Report and in future Consolidated Reports, so that we may make comparisons.* [See Table 2.4-F3] *For purposes of this requirement, the "reliability calculations" contained in the Consolidated Report include all calculations of SAIDI, SAIFI and CAIDI,* [See Tables 2.4-E through 2.4-F3] *discussion of failure rate data,* [Failure rate data analysis is based on all events, per PIWG decision in the October 18, 2011 PIWG meeting.] *and selection of Priority Feeders.* [The Priority Feeders were selected in October 2011 using prior methodology.] *(Footnote: Because the Aggressive Corrective Action Program requires the identification of feeders that have been listed as Priority Feeders in the past using system-wide, MED-excluding data, we will allow Pepco to continue to select ACAP feeders using that data. However, we require that a list of Priority Feeders using the new method of calculation be included in the 2012 Consolidated Report.)*
62. *Pepco is DIRECTED to include in the 2012 Consolidated Report reliability calculations using District of Columbia-only data and excluding Major Service Outages consistent with paragraph 48;* [See Table 2.4-F2.]
63. *Pepco is DIRECTED to include in the 2012 Consolidated Report a revised version of the reliability calculations contained in the 2010 and 2011 Consolidated Report using District of Columbia-only data and excluding Major Service Outages consistent with paragraph 48.*

[48] In Order No. 16700 issued February 12, 2012, paragraphs 10 and 11, the Commission stated:

10. *In establishing out new reliability performance standards, we decided that Pepco should be given a reasonable amount of time to "ramp up" to our new requirements. Therefore, we made the new SAIDI and SAIFI standards effective beginning in 2013. By replacing the prior rule with a new one, and giving Pepco a transition period, we created a "gap" in reliability measures. We saw no harm in a temporary suspension of reliability benchmarks, recognizing that the standards in effect for 2013 through 2020 would require significant improvement on Pepco's part, starting at once. For example, in order to meet our 2013 SAIDI target, Pepco must make either about a 9% improvement in both 2012 and 2013 or about an 18% improvement in 2013. Therefore, we saw no risk that Pepco would suffer a significant "backslide" in reliability because there were no effective standards in place for 2011 or 2012.*
11. *We do not believe that reestablishment (for the years 2011 and 2012) of the standards to which Pepco was previously held is necessary. (Footnote: We note that not all states have Electric Quality of Service Standards. For example, Pepco presently operates in Maryland without standards but is required to provide annual reliability indices pursuant to COMAR 20.50.07.06.) Nor has Pepco provided any reason for that reestablishment. Consequently, we decline to make the clarification that Pepco requests. However, we do expect that Pepco will continue to report on its reliability performance in its annual Consolidated Report and we concur with OPC in its suggestion that Pepco coordinate its data reporting so that Pepco calculations are a consistent "apples to apples" comparison from 2011 through 2013 and beyond. Therefore, as OPC has requested, we require Pepco to include in its annual report a description of its performance and a calculation of whether it would have met the appropriate SAIFI, SAIDI and CAIDI standards had they been in effect.*
14. *Pepco shall include in its 2012 and 2013 annual Consolidated Reports calculations of SAIDI, SAIFI, and CAIDI as described in paragraph 11.*

Presented in Table 2.4-E are the SAIDI, SAIFI and CAIDI values for the past five years. These reliability indices are provided for all sustained interruptions and all sustained interruptions excluding major events. A sustained interruption is defined as an interruption of five (5) minutes or greater.

Pepco System Indices 2010 - 2014					
(MED Exclusive - IEEE 1366-2003 Std, Pepco System Wide Based)					
SAIFI	**2010**	**2011**	**2012**	**2013**	**2014**
Sustained Outages	3.27	2.86	2.62	1.25	1.24
Sustained Less Major Storms	1.97	1.67	1.24	1.25	1.02
SAIDI (Hours)	**2010**	**2011**	**2012**	**2013**	**2014**
Sustained Outages	26.07	19.35	34.87	2.20	2.43
Sustained Less Major Storms	3.93	3.16	2.35	2.20	1.55
CAIDI (Hours)	**2010**	**2011**	**2012**	**2013**	**2014**
Sustained Outages	7.96	6.76	13.32	1.77	1.97
Sustained Less Major Storms	2.00	1.89	1.90	1.77	1.53

Table 2.4-E

District of Columbia Indices 2010 - 2014					
(MED Exclusive - IEEE 1366-2003 Std, Pepco System Wide Based)					
SAIFI	**2010**	**2011**	**2012**	**2013**	**2014**
Sustained Outages	1.55	1.69	1.57	0.88	0.69
Sustained Less MEDs	1.12	1.19	0.96	0.88	0.64
SAIDI (Hours)	**2010**	**2011**	**2012**	**2013**	**2014**
Sustained Outages	8.33	9.81	18.15	2.07	1.61
Sustained Less MEDs	2.68	2.68	2.21	2.07	1.36
CAIDI (Hours)	**2010**	**2011**	**2012**	**2013**	**2014**
Sustained Outages	5.39	5.79	11.55	2.35	2.34
Sustained Less MEDs	2.41	2.26	2.31	2.35	2.12

Table 2.4-F1

Tables 2.4-F2 and 2.4-F3 show annual indices for 2010 through 2014. Table 2.4-F2 shows performance indices Including and Excluding District of Columbia Major Service Outages, and Table 2.4-F3 shows performance indices Including and Excluding District of Columbia-only MEDs.

District of Columbia Indices 2010 - 2014
(Major Service Outage Criteria - DC Based)

SAIFI	2010	2011	2012	2013	2014
Sustained Outages	1.55	1.69	1.57	0.88	0.69
Sustained Less MEDs	1.21	1.19	1.01	0.88	0.69
SAIDI (Hours)	**2010**	**2011**	**2012**	**2013**	**2014**
Sustained Outages	8.33	9.81	18.15	2.07	1.61
Sustained Less MEDs	3.26	2.79	2.58	2.07	1.61
CAIDI (Hours)	**2010**	**2011**	**2012**	**2013**	**2014**
Sustained Outages	5.39	5.79	11.55	2.35	2.34
Sustained Less MEDs	2.69	2.34	2.55	2.35	2.34

Table 2.4-F2

District of Columbia Indices 2010 - 2014
(IEEE Std 1366-2003, DC Based)

SAIFI	2010	2011	2012	2013	2014
Sustained Outages	1.55	1.69	1.57	0.88	0.69
Sustained Less MEDs	1.26	1.26	1.14	0.88	0.69
SAIDI (Hours)	**2010**	**2011**	**2012**	**2013**	**2014**
Sustained Outages	8.33	9.81	18.15	2.07	1.61
Sustained Less MEDs	3.48	3.12	3.57	2.07	1.61
CAIDI (Hours)	**2010**	**2011**	**2012**	**2013**	**2014**
Sustained Outages	5.39	5.79	11.55	2.35	2.34
Sustained Less MEDs	2.76	2.49	3.12	2.35	2.34

Table 2.4-F3

Order No. 16975 states the following at paragraphs 62 and 106:

62. ***Decision:*** *The Commission directs Pepco to provide SAIDI and SAIFI statistics in the future Consolidated Reports calculated by both including and excluding cross-border feeders. Pepco shall identify which feeders it treats as "cross-border" for this purpose.*

106. *Pepco is* ***DIRECTED*** *to provide SAIDI and SAIFI information consistent with paragraph 62 herein;*

District of Columbia Reliability Inclusive and Exclusive of Cross-Border Feeders

2014 IEEE MED Exclusive**		
District of Columbia Reliability Statistics	SAIFI	SAIDI (Hours)
Excluding all cross-border feeders	**0.55**	**1.31**
Including all cross-border feeders	**0.70**	**1.38**
2014 DC MSO (& COMAR) Exclusive**		
District of Columbia Reliability Statistics	SAIFI	SAIDI (Hours)
Excluding all cross-border feeders	**0.57**	**1.44**
Including all cross-border feeders*	**0.75**	**1.67**
* Note - COMAR is a Maryland criteria and MSO is a DC criteria.		
MSO and COMAR are not compatible with each other.		
** No IEEE MEDs, MSO, or COMAR exclusions in 2013		

Table 2.4-F4

Comparison of Cross-Border Feeder Reliability Performance[49]

Pepco calculates reliability indices on a feeder level in the same way regardless of the location of a feeder. For feeders that have customers in both the District of Columbia and Maryland, the indices for these feeders are included for reporting purposes with the jurisdiction in which the majority of customers on these feeders reside. Because feeders may switch between jurisdictions over time, to make their impact on reliability performance clear, Pepco presents system reliability performance both with and without

[49] The following is in response to the Commission's directive to:

> [I]nclude in its 2015 Annual Consolidated Report an explanation of the metric or metrics it will use to report upon the reliability performance of its cross-jurisdictional feeders. This explanation is also to describe how Pepco's chosen metric(s) will allow reliability performance to be compared from year-to-year, when the jurisdictional status of a feeder changes between Maryland and the District .

In The Matter of the Annual Consolidated Report of the Potomac Electric Power Company, Formal Case No. PEPACR-2014-01, Order No. 17816 at P 241 (February 27, 2015).

both feeders assigned to the District of Columbia and Maryland, thereby allowing comparisons across different years.

In 2014, there were 29 feeders counted as District of Columbia feeders that also include Maryland customers (That is, the majority of customers on the feeder reside in the District of Columbia). These feeders are counted as part of the District of Columbia's reliability indices (IEEE Major Event Days excluded) in 2014 where SAIFI is 0.64 and SAIDI is 1.36 hours. If the 29 feeders were excluded from the 2014 District of Columbia reliability indices, then these indices will change. The SAIFI would decrease by 13.7% (0.55) and the SAIFI would decrease by 3.47% (1.31 hours).

Conversely, there are several customers in that reside in the District of Columbia that are served by feeders in which the majority of the customers on these feeders are located in Maryland. These feeders, 34 in total, are treated as Maryland feeders. They are currently used in the calculation of Pepco-Maryland's reliability indices and not counted towards those for the District of Columbia. If those 34 feeders were counted as District of Columbia feeders, the SAIFI for DC would increase by 8.7% (0.70) while the SAIDI would increase by 1.54% (1.38 hours) when excluding IEEE Major Event Days.

The Major Storm Outages (MSO) criteria used in the District of Columbia differs in its selection of excludable events from the Maryland storm criteria (COMAR or MED). Therefore the two criteria are not compatible with each other, making comparisons difficult. However, if all of the cross jurisdiction feeders were excluded then the SAIFI and SAIDI (MSO excluded) would decrease by 16.43% (0.57) and 10.5% (1.44 hours), respectively. If the cross jurisdiction feeders including the ones with predominately Maryland customers are incorporated into the District of Columbia's reliability indices, the SAIFI will increase by 9.32% (0.75) and the SAIDI by 4.1% (1.67 hours) when excluding MSO and MEDs.

PEPCO REGION

Cross Jurisdictional Serving Majority DC Customers

(Based on customers served, not physical presence)

Feeder No.	Substation Name	Substation No.	Substation Name	Substation No.	Construction		Designation
120	Chesapeake Street	181	-	-	OH	4-Wire	Radial Distribution
183	Chesapeake Street	181	-	-	OH	4-Wire	Radial Distribution
205	Seat Pleasant	30	Fort Chaplin	70	OH	4-Wire	4kV Primary Network
308	Harrison	38-6	Westmoreland	93	OH	4-Wire	4kV Primary Network
327	Fort Dupont	58	Texas Ave.	111	OH	4-Wire	4kV Primary Network
328	Fort Dupont	58	Fort Davis	100	OH	4-Wire	4kV Primary Network
333	Chesapeake Street	181	-	-	OH	4-Wire	Radial Distribution
366	Seat Pleasant	30	53rd Street, SE	48	OH	4-Wire	4kV Primary Network
368	53rd Street, SE	48	Fort Davis	100	OH	4-Wire	4kV Primary Network
372	Seat Pleasant	30	53rd Street, SE	48	OH	4-Wire	4kV Primary Network
388	53rd Street, SE	48	-	-	OH	4-Wire	Radial Distribution
451	Fort Davis	100	Texas Ave.	111	OH	4-Wire	4kV Primary Network
476	Quesada	89	Oliver Street	146	OH	4-Wire	4kV Primary Network
14014	12th & Irving	133	-	-	OH	4-Wire	Distribution
14015	12th & Irving	133	-	-	OH	4-Wire	Distribution
14016	12th & Irving	133	-	-	OH	4-Wire	Distribution
14031	Suitland	134	-	-	OH	4-Wire	Distribution
14035	Suitland	134	-	-	OH	4-Wire	Distribution
14261	Beech Road	159	-	-	OH	4-Wire	Distribution
14352	Harrison	38	-	-	UG	3-Wire	LVAC Network
14717	Benning	7	-	-	OH	4-Wire	Distribution
14758	N.R.L.	168	-	-	OH	4-Wire	Distribution
14890	Harrison	38	-	-	OH	4-Wire	Distribution
14893	Harrison	38	-	-	UG	3-Wire	LVAC Network
14900	Harrison	38	-	-	OH	4-Wire	Distribution
15085	St. Barnabas Road	59	-	-	OH	4-Wire	Distribution
15130	Walker Mill Road	15	-	-	OH	4-Wire	Distribution
15171	Alabama Avenue	136	-	-	OH	4-Wire	Distribution
15198	Takoma	27	-	-	OH	4-Wire	Distribution
15199	Takoma	27	-	-	OH	4-Wire	Distribution
15648	Little Falls	77	-	-	UG	3-Wire	High Voltage
15649	Little Falls	77	-	-	UG	3-Wire	High Voltage
15705	Benning	7	-	-	OH	4-Wire	Distribution

Note: Feeders with two source substations listed are 4 kV primary network feeders and are supplied from two substations.

Table 2.4-F5

PEPCO REGION
Cross Jurisdictional Feeders Serving Majority Maryland Customers

Feeder No.	Substation Name	Substation No.	Substation Name	Substation No.	Construction		Designation
152	Fort Dupont	58	Randle Highlands	71	OH	4-Wire	4kV Primary Network
365	53rd Street, SE	48	Fort Dupont	58	OH	4-Wire	4kV Primary Network
14032	Suitland	134	-	-	OH	4-Wire	Distribution
14033	Suitland	134	-	-	OH	4-Wire	Distribution
14102	Tuxedo	148	-	-	OH	4-Wire	Distribution
14263	Linden	156	-	-	OH	4-Wire	Distribution
14271	Linden	156	-	-	OH	4-Wire	Distribution
14593	Sligo	9	-	-	UG	3-Wire	LVAC Network
14595	Sligo	9	-	-	UG	3-Wire	LVAC Network
14768	Little Falls	77	-	-	OH	4-Wire	Distribution
14896	Harrison	38	-	-	OH	4-Wire	Distribution
14949	Wood Acres	154	-	-	OH	4-Wire	Distribution
14979	Grant Avenue	183	-	-	OH	4-Wire	Distribution
14987	Grant Avenue	183	-	-	OH	4-Wire	Distribution
15082	St. Barnabas Road	59	-	-	OH	4-Wire	Distribution
15086	St. Barnabas Road	59	-	-	OH	4-Wire	Distribution
15090	St. Barnabas Road	59	-	-	OH	4-Wire	Distribution
15094	Bladensburg	175	-	-	OH	4-Wire	Distribution
15100	Bladensburg	175	-	-	OH	4-Wire	Distribution
15131	Walker Mill Road	15	-	-	OH	4-Wire	Distribution
15132	Walker Mill Road	15	-	-	OH	4-Wire	Distribution
15200	Takoma	27	-	-	OH	4-Wire	Distribution
15264	Takoma	27	-	-	OH	4-Wire	Distribution
15501	Little Falls	77	-	-	UG	3-Wire	LVAC Network
15502	Little Falls	77	-	-	UG	3-Wire	LVAC Network
15503	Little Falls	77	-	-	UG	3-Wire	LVAC Network
15504	Little Falls	77	-	-	UG	3-Wire	LVAC Network
15505	Little Falls	77	-	-	UG	3-Wire	LVAC Network
15506	Little Falls	77	-	-	UG	3-Wire	LVAC Network

Note: Feeders with two source substations listed are 4 kV primary network feeders and are supplied from two substations.

Table 2.4-F6

2.4.3 NEIGHBORHOOD ANALYSIS

Starting with Order No. 16623, the Commission has required a specific focus on neighborhoods in the Consolidated Report. This section addresses each of the neighborhood subjects required by the Commission.

In response to the Commission's requirements for reporting the neighborhoods impacted by reliability issues and remediation work, Pepco developed a comprehensive list of the feeders serving District of Columbia customers and the neighborhoods served by each in May of 2012. In order to provide neighborhood identification that is both accurate and consistent from one submission to another, Pepco is now using assessment neighborhoods as defined by the District of Columbia Office of Tax and Revenue (OTR) Real Property Tax Administration (RPTA). This data is maintained by the District of Columbia and is available as a GIS file[50] allowing Pepco to programmatically identify the neighborhoods each Pepco feeder serves. These assessment neighborhoods are named somewhat differently from the neighborhood map posted in Wikipedia that was used to define neighborhoods for previous submissions, but that map was not maintained by the District of Columbia and was not available in GIS format. Pepco's previous approach to identifying neighborhoods required Pepco personnel to determine neighborhoods served by a feeder manually. Where neighborhoods reported in this 2015 Consolidated Report are inconsistent with previously identified neighborhoods associated with a given feeder, the differences are due to the Company's new automated approach to identifying neighborhoods served.

[50] The Company used the Assessment Neighborhoods shapefile "DCGIS.AsNbhdPly" located at http://data.dc.gov/Metadata.aspx?id=127 on May 15, 2012 to complete the GIS-based analysis associating each feeder with the assessment neighborhoods it serves.

Neighborhood Analysis Requirements

(A) Neighborhoods warranting infrastructure improvements due to increased load growth[51]

Response: See discussion for Neighborhood Item A below.

(B) Neighborhoods with decreased planned spending on 4 kV to 13 kV conversions[52]

(C) Neighborhoods with decreased planned spending on 4 kV to 13 kV conversions that are among previously identified Most Susceptible Neighborhoods[53]

(D) Explanation of how reduced conversion spending will improve reliability in Most Susceptible Neighborhoods[54]

Response: See discussion for Neighborhood Items B, C, and D below.

(E) Neighborhoods served by Priority Feeders[55]

Response: See Priority Feeder discussion.

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51 Order No. 16623 states the following at paragraph 35:

35. We find Pepco's explanation to be credible, but require further information on the neighborhoods in the District impacted by Pepco's changed plans. Specifically, we direct Pepco to identify those neighborhoods which warrant further infrastructure improvements due to increased load growth, including any explanation and data on Pepco's forecasts of load growth in those neighborhoods. (<u>Footnote:</u> In identifying neighborhoods, Pepco should use the methodology it used for defining and selecting neighborhoods in its May 20, 2011 submission to the Commission, or provide an explanation of why that methodology was not used. See F.C. Nos. 766, 982 and 991, Response of the Potomac Electric Power Company to Order No. 16347, May 20, 2011, Attachment 2.)…

52 Order No. 16623 states the following at paragraph 35:

…Similarly, we require Pepco to identify those neighborhoods where planned spending on 4 kV to 13 kV conversion projects has decreased…

53 Order No. 16623 states the following at paragraph 35:

…Further, we require that Pepco indicate if any of the neighborhoods it identifies pursuant to this paragraph is among the Most Susceptible Neighborhoods identified in Order No. 14626, Appendix A. (<u>Footnote:</u> See F.C. Nos. 766, 982, and 991, Order No. 16426, July 7, 2011, Appendix A.)…

54 Order No. 16623 states the following at paragraph 35:

If any of the neighborhoods identified in this paragraph is among those Most Susceptible Neighborhoods, Pepco is directed to provide a full explanation of how its changed plans will improve reliability in that neighborhood.

55 Order No. 16623 states the following at paragraph 46:

46. In connection with the second prong of our reliability efforts, our neighborhood initiative, we believe it is important to know whether any of the Priority Feeders are the feeders which serve the Most Susceptible Neighborhoods in the District. Beginning in the 2012 Consolidated Report, we require that Pepco identify the neighborhoods served by any Priority Feeders…

(F) Neighborhoods served by Repeat Priority Feeders[56]

Response: See Repeat Priority Feeder discussion.

(G) Neighborhoods served by equipment subject to failure data rate analysis[57]

Response: See Failure Data Rate Analysis discussion.

(H) Updated list of Most Susceptible Neighborhoods for Calendar Year 2011[58]

Response: See Neighborhood Item H, Most Susceptible Neighborhoods update below.

(I) Neighborhood information to be included in 2012 Consolidated Report[59]

Response: This information was included in the 2012 Consolidated Report as specified above.

(J) Directive to identify neighborhoods affected by changed plans[60]

Response: See discussion for Neighborhood Items A, B, C, and D below.

(K) Directive to provide information on neighborhoods[61]

Response: See discussion for Neighborhood Items E, F, G, H, and I.

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[56] Order No. 16623 states the following at paragraph 46:

> *…and any Repeat Priority Feeder (those in the ACAP program). (Footnote: In identifying neighborhoods, Pepco should use the methodology it used for defining and selecting neighborhoods in its May 20, 2011 submission to the Commission, or provide an explanation of why that methodology was not used. See F.C. Nos. 766, 982 and 991, Response of the Potomac Electric Power Company to Order No. 16347, May 20, 2011, Attachment 2.)...*

[57] Order No. 16623 states the following at paragraph 46:

> *…Further, we require that Pepco identify the neighborhoods served by any equipment subject to the failure data rate analysis proposed by Pepco at the October 18, 2011 PIWG meeting for inclusion in the 2012 Consolidated Report. (Footnote: See October 18, 2011 PIWG Meeting Minutes at 1.)…*

[58] Order No. 16623 states the following at paragraph 46:

> *We also require Pepco to update its list of Most Susceptible Neighborhoods to identify the neighborhood in each Ward experiencing the most frequent non-major outages in Calendar Year 2011.*

[59] Order No. 16623 states the following at paragraph 46:

> *…This information should be included in the 2012 Consolidated Report.*

[60] Order No. 16623 states the following at paragraph 55:

> *55. Pepco is DIRECTED to identify neighborhoods affected by changed plans consistent with paragraph 35;*

[61] Order No. 16623 states the following at paragraph 60:

> *60. Pepco is DIRECTED to provide information on neighborhoods consistent with paragraph 46;*

Neighborhood Item A.

Neighborhoods with Increased Load Growth

Pepco forecasts load by substation using identified PNB load to develop short term forecasts and uses trends plus knowledge of future planned development to develop a long term forecast for each substation in the Pepco system.

There are areas where Pepco anticipates above average load growth and these include the Mt. Vernon Square/Convention Center neighborhood (R.L.A.[62] (N.E.) assessment neighborhood), NoMa (R.L.A. (N.E.) assessment neighborhood), the Washington Navy Yard/Southwest (R.L.A. (S.W.) assessment neighborhood) neighborhood and the area around St. Elizabeth's Hospital.

Mt. Vernon Square/Convention Center and NoMa

Pepco added one new transformer to the existing Florida Avenue substation in 2014 and is planning to add capacity to the existing Northeast substation by adding a new substation transformer in 2016. These measures will address load growth in the Mt. Vernon Square/Convention Center (Old City 2 assessment neighborhood) and NoMa neighborhoods. Pepco is planning to build a new substation near the area of Mt. Vernon Square in 2020 to address load growth in the NoMa (R.L.A. (N.E.) assessment neighborhood) and the Mt. Vernon Triangle (Old City 2 assessment neighborhood) areas.

Washington Navy Yard/Southwest

Pepco is planning the proposed Waterfront substation to be built in 2017 in the Buzzard Point (Old City 1 assessment neighborhood) area to address load growth in the Washington Navy Yard and Southwest (R.L.A. (S.W.) assessment neighborhood) neighborhoods.

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[62] Redevelopment Land Agency.

St. Elizabeth's Hospital

Pepco is planning to add shunt reactors at its Alabama Avenue substation in 2015 that will increase existing substation capacity to serve load in the St. Elizabeth's Hospital area.

Columbia Heights

Pepco has installed a fourth transformer at Florida Avenue Sub. 10 in 2014 to increase capacity at that substation. Pepco is also planning to rebuild the Harvard 13 kV substation in 2021, increasing its capacity from 46.5 MVA to ultimately 210 MVA.

Neighborhood Items B, C, D.

Neighborhoods with Decreased Planned Spending on 4 kV to 13 kV Conversions

The neighborhoods served by Anacostia Sub. 8 (Anacostia and Randle Heights) will see less planned spending on conversions in 2015 because most of the next phase of conversion work has been moved to the DC PLUG initiative. This is because much of the 4 kV load in the next phase is to be converted to Feeder 15177 which has been identified as a feeder to be undergrounded in year two of the DC PLUG initiative. The 4 kV conversion work will be done in conjunction with the undergrounding of Feeder 15177, scheduled to be completed in the 2016-2017 timeframe. Randle Heights is identified as one of the most susceptible neighborhoods in 2014, but Anacostia has not been previously identified as a Most Susceptible Neighborhood.

The neighborhoods served by the Harrison 4 kV substation (Friendship Heights and Chevy Chase) will see less money spent on 4 kV conversions in 2015 because that project should be completed in the first half of the year. The neighborhoods served by the Anacostia 4 kV substation (Anacostia, Barry Farm, and Buena Vista) will see reduced spend on 4 kV conversions in 2015, but will benefit later as several of the 4 kV lines will be converted to a new underground feeder as part of the DC PLUG initiative. The neighborhoods served by the North Capitol 4 kV substation (Manor Park, Fort Totten, and Petworth) will see somewhat less spending on 4 kV conversions in 2015 as the next phase of conversions begins and resources are marshalled for that area.

Neighborhood Item F. [63]

Table 2.4-G lists the feeders that have appeared more than once on the 2% Priority Feeder list, the years they appeared, and the neighborhoods they serve.

[63] In Order No. 15941 issued on August 18, 2010, the Commission stated at paragraphs 13 and 16, the following:

13. *Beginning with the 2011 Consolidated Report, Pepco shall identify any feeders that have appeared more than once on the Priority Feeder List, by year from the first Priority Feeder List in 2002, so that it shall be apparent how many times each feeder has appeared on the Priority Feeder List…*
16. *Pepco IS DIRECTED to identify in its 2011 and successive Consolidated Reports, each feeder that has appeared more than once on the Priority Feeder List.*

	Feeder	Years Appeared on Priority Feeder List Since 2002	Neighborhoods
1	27	2007, 2009	Brookland, Columbia Heights, Ledroit Park
2	30	2006, 2011	Columbia Heights
3	53	2009, 2014	Brookland, Columbia Heights
4	76	2011, 2015	Columbia Heights
5	82	2007, 2015	Chevy Chase, Forest Hills, North Cleveland Park, Wakefield
6	166	2008, 2012	Georgetown
7	252	2004, 2006	N/A
8	14001	2011, 2013	Brookland, Eckington, Ledroit Park
9	14006	2013, 2015	Brookland, Woodridge
10	14007	2005, 2008	Brookland, Michigan Park, Woodridge
11	14008	2004, 2008, 2011	Brentwood, Woodridge
12	14014	2004, 2006, 2013	Brookland, Woodridge
13	14015	2004, 2009	Brookland, Michigan Park, Riggs Park, Woodridge
14	14017	2006, 2015	Brookland
15	14054	2004, 2007	Columbia Heights
16	14136	2010, 2012, 2014	Cleveland Park, Glover Park, North Cleveland Park, Observatory Circle
17	14200	2009, 2011, 2013, 2015	Brookland, Ledroit Park
18	14700	2004, 2010	Anacostia, Barry Farms, Hillcrest, Randle Heights
19	14701	2010, 2012	Anacostia, Barry Farms, Bolling Air Force Base, Congress Heights, St Elizabeths Hospital
20	14717	2007, 2009, 2012, 2014	DC Stadium, Deanwood, Lily Ponds
21	14729	2004, 2006	Columbia Heights, Petworth
22	14753	2009, 2014	Congress Heights, DC Village
23	14758	2012, 2014	Bolling Air Force Base, Congress Heights, DC Village
24	14767	2008, 2015	Berkley, Fort Drive, Kent, Palisades, Wesley Heights
25	14768	2005,2007, 2009, 2012	Spring Valley
26	14769	2007, 2011	N/A
27	14786	2007, 2013	Brentwood, Central Tri 3, Old City 1, Old City 2
28	14787	2005, 2008, 2013	Brentwood, Capitol Hill, Old City 1, Old City 2
29	14788	2007, 2013	Old City 1, Old City 2, RLA NE
30	14890	2008, 2011, 2013*	American University, Chevy Chase
31	14896	2007, 2011	Chevy Chase, Hawthorne
32	14900	2007, 2009, 2011, 2013	Chevy Chase, Hawthorne, Rock Creek Park 1
33	15009	2005, 2009, 2012, 2014	Brightwood, Chillum
34	15014	2009, 2012, 2015	Brookland, Chillum, Riggs Park, Takoma Park
35	15021	2005, 2014	Brightwood, Chillum, Petworth, Shepherd Park
36	15166	2010, 2013	Bolling Air Force Base, Congress Heights, Randle Heights, St Elizabeths Hospital
37	15170	2006, 2010, 2015	Barry Farms, Hillcrest, Randle Heights
38	15171	2005, 2014	Congress Heights, Randle Heights
39	15172	2006, 2010, 2012	Barry Farms, Randle Heights, St Elizabeths Hospital
40	15174	2010, 2013, 2015	Randle Heights
41	15197	2007, 2005	16th Street Heights, Brightwood, Columbia Heights, Crestwood, Petworth, Rock Creek Park 2
42	15199	2004, 2010, 2012, 2014	Brightwood, Shepherd Park, Takoma Park
43	15206	2008, 2010	Eckington, Ledroit Park, Old City 2
44	15701	2005, 2010, 2015	Brentwood, Old City 1, Trinidad
45	15702	2005, 2012	Capitol Hill, National Arboretum, Old City 1, Trinidad
46	15703	2004, 2006	DC Stadium, Old City 1, Trinidad
47	15705	2009, 2011, 2013	DC Stadium, Deanwood, Lily Ponds
48	15706	2009, 2011	Deanwood, Fort Dupont Park, Marshall Heights
49	15707	2007, 2010, 2013	Deanwood
50	15709	2004, 2006, 2008, 2010	Deanwood, Fort Dupont Park
51	15801	2005, 2008, 2010, 2013	Foxhall, Georgetown, Kent, Palisades
52	15867	2008, 2014	Cleveland Park, Forest Hills, Massachusetts Avenue Heights, North Cleveland Park, Rock Creek Park 2, Woodley
53	15943	2008, 2010, 2012	Berkley, Burleith, Foxhall, Georgetown, Glover Park, Observatory Circle, Palisades
54	15945	2011, 2013, 2015	American University, Chevy Chase

* 2013 CPI-Selected Feeder.

Table 2.4-G

<u>Neighborhood Item H.</u>

Most Susceptible Neighborhoods By Ward With Most Frequent Non-Major Outages In 2014

Most Susceptible Neighborhood Analysis

Pepco was directed to provide analysis regarding the neighborhoods in each District Ward which were most susceptible to outages as determined by outage data. In defining neighborhoods, as well as the capability of providing reliability measures at the neighborhood level, Pepco took the approach of determining the poorest performing feeder in each ward and identifying the neighborhood(s) served by that feeder. The feeder performance evaluation period is from October 1, 2013, to September 30, 2014, and is exclusive of major service outages.

The first analysis consists of determining the feeder in each ward that had the highest number of total customer interruptions (CI) during the evaluation period. As such, the selected feeders would represent the highest contributors to system SAIFI in their respective wards. Pepco refers to this characteristic of feeder performance as "contribution to SAIFI", denoting the impact a single feeder has on the overall performance of a given group of feeders—in this case, the District of Columbia electric distribution system. See Table 2.4-H1 below for the analysis by SAIFI contribution.

In addition, Pepco was directed to provide analysis using customer minutes of interruption (CMI) to identify the poorest performing feeder in each ward and identifying the neighborhood(s) served by that feeder. Pepco refers to this selection criteria as "contribution to SAIDI". As additionally ordered by the Commission for this analysis, Pepco has included scheduled or planned outages when computing CMI. However, it should be noted that planned outages on a feeder are generally taken in order to improve the reliability of the feeder. Such outages are typically planned for employee safety reasons or when no practical energized alternative exists. Pepco therefore cautions that the inclusion of planned outages in such analyses could have the effect of causing a feeder to be selected in subsequent analysis simply due to its efforts to remediate the initial condition. See Table 2.4-H2 below for the analysis by SAIDI contribution.

Ward No.	Feeder No.	Cross Border Feeder	Customers Served	Neigborhood(s)	OH,UG or OH/UG	Reliability Indices R12M Ending September 30, 2014 Exc MSO's				HPF	Historical MSN	Number of Outage Occurrences
						SAIFI	% Sys SAIFI	CAIDI	SAIDI	Status	Status	
Ward 1	76		436	Columbia Heights	UG	4.883	1.10%	658	3,214.34	2011,2015		11
Ward 2	15764		2136	Columbia Heights, Mt Pleasant, Old City 2	UG	1.208	1.33%	44	52.63			9
Ward 3	15945		1235	American, University Chevy Chase	OH	2.073	1.32%	46	94.64	2011,2013, 2015		21
Ward 4	15199	Y	1900	Brightwood, Shepherd Park, Takoma Park	OH/UG	2.463	2.41%	131	321.36	2001,2004, 2010,2011, 2014		26
Ward 5	14014	Y	2056	Brookland, Woodridge	OH	2.798	2.97%	105	294.92	2001,2004, 2006,2013	2013, 2014	33
Ward 6	211		622	Old City 1	UG	7.598	2.44%	107	814.92	2015		9
Ward 7	14717	Y	2057	DC Stadium, Deanwood, Lily Ponds	OH	2.623	2.78%	25	64.61	2001, 2003, 2007, 2008, 2011, 2014	2012	37
Ward 8	15166		1792	Bolling Air Force Base, Congress Heights, Randle Heights, St Elizabeths Hospital	OH/UG	4.03	3.73%	53	213.94	2010,2013		11

Table 2.4-H1

Ward No.	Feeder No.	Cross Border Feeder	Customers Served	Neigborhood(s)	OH,UG or OH/UG	Reliability Indices R12M Ending September 30, 2014 Exc MSO's				HPF	Historical MSN	Number of Outage Occurrences
						SAIFI	CAIDI	SAIDI	% Sys SAIDI	Status	Status	
Ward 1	76		436	Columbia Heights	UG	7.67	552	4,236.18	6.30%	2011,2015		11
Ward 2	15204R		1891	Old City 2	UG	0.979	441	431.69	2.78%		2014	27
Ward 3	14136		968	Cleveland Park, Glover Park, North Cleveland Park, Observatory Circle	OH/UG	1.925	311	599.34	1.98%	2010,2012, 2014		21
Ward 4	15021		2058	Brightwood, Chillum, Petworth, Shepherd Park	OH	1.635	236	386.31	2.71%	2005, 2014		16
Ward 5	14014	Y	2056	Brookland, Woodridge	OH	2.964	113	333.81	2.34%	2001,2004, 2006,2013	2013, 2014	33
Ward 6	211		622	Old City 1	UG	7.833	114	891.59	1.89%	2015		9
Ward 7	15130					2.366	76	178.61	1.15%			39
Ward 8	15166		1792	Bolling Air Force Base, Congress Heights, Randle Heights, St Elizabeths Hospital	OH/UG	4.232	64	271.76	1.66%	2010,2013		11

Table 2.4-H2

From the analyses above, contribution to SAIFI and contribution to SAIDI (including planned outages) combined yielded 12 unique feeders. Of the 12 feeders, 11 have had recent reliability work done or have been scheduled for corrective action as part of the 2015 REP. See summary below: [64]

- Feeders 76, 211 and 15945 are part of the 2015 Priority Feeder program;
- Feeder 15204R was part of the 2014 REP Feeder Improvement program;
- Feeders 14136, 15021, 15130, 15166, 15199 and 14717 were part of the 2014 Priority Feeder program;
- Feeder 14014 was part of the 2013 Priority Feeder program with corrective actions completed by the 4th quarter of 2014; and
- Feeder 15764 was not part of any program. However, its current reliability performance does not indicate the need for corrective actions. Pepco will continue to monitor its performance.

[64] Feeder Nos. 14136, 14014, 15130, and 15166 have all been selected to be placed underground as part of the DC PLUG initiative.

2.4.4 EQUIPMENT FAILURE RATES[65]

Pepco continues improvements to the quality of outage data. Outage data records are screened at multiple check points for accuracy. Control Center personnel review outage data daily for accuracy and make necessary edits to reflect actual circumstances. Asset Management staff performs several validation screens monthly to catch other data entry errors. Reliability Engineering staff periodically review outage data and field crew comments as part of reliability improvement programs and when questionable data is encountered and works with Control Center staff to resolve remaining issues.

Analysis of Top Three Equipment Failure Modes[66]

This information identifies and analyzes the top three equipment failure modes in the District of Columbia. In addition, it identifies feeders for corrective actions to remediate these failures in the future based on root cause determination where appropriate.

For the period October 2013 through September 2014 inclusive of MEDs, the District of Columbia experienced 1,108 events attributed to equipment failures resulting in customer outages. In comparison to the previous 12-month period, the number of customers impacted decreased by 0.5%, resulting in an improvement in SAIFI, SAIDI and CAIDI by 1%, 18% and 14%, respectively. Similarly, the customer minutes of interruption also decreased by 18%.

For purposes of this analysis, the following definitions are established.

[65] Order No. 16975 states the following at paragraphs 95 and 118:

85. *Decision: In its Comments, OPC identifies several instances in which outage data is inconsistent or erroneous. Pepco itself has identified several areas in which it can improve outage data quality. In an effort to ensure that the Commission and OPC is receiving accurate outage data, the Commission requires Pepco to report in its 2013 Consolidated Report on its efforts to improve the collection and accuracy of information regarding outages.*

114. *Pepco is DIRECTED to report on outage data quality improvement consistent with paragraph [95] herein.*

[66] In Order No. 16091, the Commission stated among other things, at paragraph 59, the following:

59. *…(5)…If data on failure rates for all variables is available for manhole events, Pepco shall include such information in its 2011 Consolidated Report. If such data is unavailable, we require the members of PIWG to discuss the need for and the availability of such data include in the 2011 Consolidated Report the PIWG conclusions and recommendations, if any.*

- Events – number of outage events
- CI – number of customers interrupted
- CMI – Customer minutes of interruption
- SAIFI – System Average Interruption Frequency Index
- SAIDI – System Average Interruption Duration Index
- CAIDI – Customer Average Interruption Duration Index

Table 2.4-I1 illustrates the aggregate impact of outages attributed to equipment failure and compares 2014 to 2013 results.

	12 Months Ending	Events	CI	CMI	Indices		
					SAIFI	**SAIDI**	**CAIDI**
Total Primary and Secondary Equipment	**Sep. 2014**	1108	94,741	15,181,349	0.363	60.61	167
	Sep. 2013	917	95,206	18,490,398	0.367	71.21	194

Table 2.4-I1 – Equipment Failure Rates

Replacement of Oil-Filled Switches in Pepco's 4kV System[67]

Pepco determined in 2012 that it would no longer install new 4kV oil-filled switches on its underground 4kV system. Since that time, Pepco has engaged in opportunistic replacement of oil-filled switches, replacing them with alternative devices whenever equipment condition or other relevant factors warrant removal.

[67] This section is intended to respond to the Commission's directive to " include information describing whether, in 2014, it conducted an investigation into programmatic replacement of oil-filled switches in its 4 kV system and, if such an investigation was conducted, the results of that investigation." *In The Matter of the Annual Consolidated Report of the Potomac Electric Power Company*, Formal Case No. PEPACR-2014-01, Order No. 17816 at P 367 (February 27, 2015).

Table 2.4-I2 details the reliability impacts of equipment categories tracked by Pepco.

Equipment Type	Event	(%)	CI	(%)	CMI	(%)	SAIFI	CAIDI	SAIDI
ACR	4	0.4%	1713	1.8%	73901	0.5%	0.007	43	0.28
AUTOTRANSFORMER	1	0.1%	1	0.0%	10	0.0%	0.000	10	0.00
BUSHING	10	0.9%	974	1.0%	526863	3.3%	0.004	541	2.02
CABLE	400	36.1%	32443	34.2%	6491710	41.0%	0.124	200	24.87
CAPACITOR	1	0.1%	656	0.7%	7161	0.0%	0.003	11	0.03
CONNECTION(I.E. LOOSE)	194	17.5%	18477	19.5%	1898590	12.0%	0.071	103	7.27
CROSSARM	9	0.8%	3838	4.1%	367880	2.3%	0.015	96	1.41
CUTOUT	34	3.1%	703	0.7%	97443	0.6%	0.003	139	0.37
DISTR. CKT. BREAKER	2	0.2%	28	0.0%	168	0.0%	0.000	6	0.00
ELBOW INSERT	10	0.9%	5231	5.5%	830506	5.3%	0.020	159	3.18
FUSE	84	7.6%	1757	1.9%	250463	1.6%	0.007	143	0.96
INSULATOR	1	0.1%	91	0.1%	9581	0.1%	0.000	105	0.04
JOINT FAILURE	31	2.8%	8792	9.3%	1692031	10.7%	0.034	192	6.48
LIGHTNING ARRESTOR	6	0.5%	175	0.2%	23313	0.1%	0.001	133	0.09
METER	76	6.9%	93	0.1%	14543	0.1%	0.000	156	0.06
METER-PRIMARY	2	0.2%	2	0.0%	1068	0.0%	0.000	534	0.00
MOLE	1	0.1%	18	0.0%	10681	0.1%	0.000	593	0.04
NONE	1	0.1%	1	0.0%	352	0.0%	0.000	352	0.00
PAC / SPACER CABLE	3	0.3%	1123	1.2%	114181	0.7%	0.004	102	0.44
POLE	4	0.4%	1141	1.2%	159378	1.0%	0.004	140	0.61
REGULATOR	1	0.1%	919	1.0%	5836	0.0%	0.004	6	0.02
RELAY	1	0.1%	1	0.0%	53	0.0%	0.000	53	0.00
SECTIONALIZER	1	0.1%	109	0.1%	25862	0.2%	0.000	237	0.10
SERVICE	71	6.4%	258	0.3%	98763	0.6%	0.001	383	0.38
SPLICE	2	0.2%	25	0.0%	6872	0.0%	0.000	275	0.03
SWITCH	15	1.4%	5696	6.0%	760829	4.8%	0.022	134	2.92
SWITCH - GANG OP	3	0.3%	1251	1.3%	44926	0.3%	0.005	36	0.17
TRANSFORMER	89	8.0%	4356	4.6%	1476769	9.3%	0.017	339	5.66
TRANSFORMER - PADMOUNT	3	0.3%	69	0.1%	22574	0.1%	0.000	327	0.09
TRANSFORMER - SUBSURFACE	18	1.6%	1212	1.3%	444971	2.8%	0.005	367	1.70
WIRE - BARE	12	1.1%	2115	2.2%	206985	1.3%	0.008	98	0.79
WIRE - COVERED	18	1.6%	1473	1.6%	154087	1.0%	0.006	105	0.59
Total Primaries and secondaries	**1,108**	**100.0%**	**94,741**	**100.0%**	**15,818,349**	**100.0%**	**0.363**	**166.96**	**60.61**

Table 2.4-I2 – Event Detail for Equipment Failures[68]

Based on the number of customers out, as shown above in highlighted rows, the top three classes of equipment failures contributing to SAIFI are cable, connection and joint failures, contributing to 63% of total customers impacted and to 63.7% total Customer Minutes of Interruptions due to equipment failures.

Cable Failure Analysis

Based on MED Inclusive OMS data, the District of Columbia experienced 400 outage causing cable failures during the period of analysis, which affected 32,443 customers contributing to 34% of the total customers affected due to equipment failure.

Months Ending	Mode of Failure: Cable Failure					
	Events	**Pct.**	**CI**	**Pct.**	**CMI**	**Pct.**
Sep. 2014	400	36%	32,443	34%	6,491,710	41%
Sep. 2013	281	31%	33,643	35%	8,141,970	44%

Table 2.4-J1 – Cable Failure Rates

Analysis of these 400 cable failure events as reported by OMS revealed that 53% of the customers impacted by cable failure can be attributed to 21 events, which affected 16 feeders. Out of the 16 feeders, 11 feeders have been identified as being part of an REP program. See summary below:

- Feeders 82, 117, 14017, 15085, 15170 and 15945 were selected as part of the 2015 Priority Feeder Program in the District of Columbia;
- Feeders 212, 14005 and 15130 were part of various programs in REP for 2014. Pepco expects reliability work done on these feeders will improve their performance in 2015;
- Feeders 309, 14731, 14786, 15206 and 15702 performance indices are either within or below the system average. No further actions are required at this time;
- Feeder 86 is part of Harvard conversion for 2016; and
- Feeder 14008 will be investigated further for possible addition to comprehensive work under REP for 2015.

Table 2.4-J2 – Event Detail for Cable Failures

Feeder	Substation	Neighborhood(s)	Date	CI	Cause	UG Miles	%UG	Cable Type	Comments
82	Veazey East 90	Chevy Chase, Forest Hills, North Cleveland Park,	10/14/2013	426	UG cable fault at or near getaway	3	52%	PILC	2015 Priority Feeder.
86	Harvard 13	Columbia Heights	3/22/2014	337	ML B-phase cable fault. All 3-phase xformers affected.	1.71	100%	1/0-1/C RL	Harvard conversion. First quarter 2016
117	Nebraska 92	Chevy Chase, Forest Hills	10/14/2013	304	Feeder tripped due to cable fault on feeder 82.	0.3	11%	N/A	2015 High Priority Feeder.
133	Nebraska 92	Chevy Chase, Forest Hills, Rock Creek Park 1	10/14/2013	477	Feeder tripped due to cable fault on feeder 82.	0.78	16%	N/A	2015 High Priority Feeder.
211	G street 28	Old City 1	11/27/2013	636	Feeder tripped due to cable fault . Manually closed, feeder held.	1.86	100%	1/0 RL	2015 High Priority Feeder.
211	G street 28	Old City 1	11/27/2013	636	Feeder tripped due to cable fault on C phase. Crew opened feeder to make permanent repairs.	1.86	100%	1/0 RL	2015 High Priority Feeder.
212	G street 28	Old City 1	11/29/2013	509	Cable fault	2.05	100%	PILC	2014 High Priority Feeder.
309	Veazeyeast 90e	Cleveland Park, North Cleveland Park	5/7/2014	503	Cable fault	2	48%	PILC	Permanent repairs were made. Low SAIFI feeder. No additional actions required.
14005	12th irving 133	Fort Lincoln, Woodridge	10/25/2013	350	Cable fault get-away HM	2.79	44%	500 KCM PILC	2014 HIGH SAIFI
14008	12th irving 133	Brentwood, Woodridge	9/11/2014	1021	Cable fault, under water.	2.98	41%	500 KCM PILC	Under investigation.
14017	12th irving 133	Brookland	10/12/2013	2291	Cable fault at get-away. Feeder was tie to 14006.	0.37	9%	600 EPR	2015 High Priority Feeder.
14731	Champlain 25	Kalorama, Mt Pleasant, National Zoological Park, Old City 2	11/13/2013	304	Cable fault	8.56	100%	#2 EPR	N/A
14731	Champlain 25	Kalorama, Mt Pleasant, National Zoological Park, Old City 2	3/5/2014	300	Cable fault	8.56	100%	#2 EPR	N/A
14786	New jersey 161	Brentwood, Central Tri 3, Old City 1, Old City 2	12/3/2013	1266	Cable fault	6.75	100%	500 KCM EPR	N/A
15085	St barnabas 59	Congress Heights, Randle Heights	5/1/2014	1578	Cable fault	4.33	37%	EPR	2015 High Priority Feeder.
15130	Walker mill 15	Fort Dupont Park, Marshall Heights	5/30/2014	106	Cable fault	3.7	35%	EPR	2014 High Priority Feeder.
15130	Walker mill 15	Fort Dupont Park, Marshall Heights	5/30/2014	1917	Feeder tripped while on maintenance mode.	3.7	35%	N/A	2014 High Priority Feeder.
15170	Alabama ave 136	Barry Farms, Hillcrest, Randle Heights	5/16/2014	1637	Single phase cable fault. Breaker was opened for safety reasons.	6.53	57%	EPR	2015 High Priority Feeder.
15206	Tenth st 52	Eckington, Ledroit Park, Old City 2	12/23/213	1293	Cable fault	7.6	100%	600 PILC	2013 PILC Strategy. Q1 2015
15702	Benning a23013 7	Capitol Hill, National Arboretum, Old City 1, Trinidad	2/8/2014	497	Cable fault	12.7	95%	#2 EPR	Permanent repairs were made. Low SAIFI feeder. No additional actions required.
15945	Van ness 129	Chevy Chase, American University	8/27/2014	1232	Cable failure at get-away pole.	0.36	5%	PILC	2015 High Priority Feeder.

Connection Failure Analysis

Based on MED Inclusive OMS data, the District of Columbia experienced 194 connection related outages for the period of October 2013 through September 2014. These events affected 18,477 customers, contributing to 20% of the total customers affected due to equipment failure.

Months Ending	Mode of Failure: Connection					
	Events	**Pct.**	**CI**	**Pct.**	**CMI**	**Pct.**
Sep. 2014	194	18%	18,477	20%	1,898,590	12%
Sep. 2013	158	17%	15,113	16%	1,442,009	8%

Table 2.4-K1 – Connection Failure Rates

Analysis of these events as reported by OMS revealed that 68% of the customers impacted by connection failures can be attributed to six events on six feeders. All six events occurred on the main trunk of the circuit.

Below is the summary and breakdown of these events:

- Two events were attributed to breaker operation, affecting a total of 3,012 customers on Feeders 14132 and 15199;
- One event was attributed to wire down, where faulty connections were found to be the root cause. This event affected a total of 1,981 customers on Feeder15707;
- One event was attributed to burned bypass on the ACR. Crew opened feeder to make final repairs. This even affected 1380 customers on feeder 15172; and
- Two events were attributed to a connections failure while crews were working on feeder 15166 and 14717. This event affected a total of 6,153 customers.

Table 2.4-K2 – Event Detail for Connection Failures

Feeder	Substation	Neighborhood(s)	Date	CI	Cause	Device
15166	Alabama ave 136	Bolling Air Force Base, Randle Heights, Congress Heights, St Elizabeths Hospital	10/8/2013	1818	Outrugger broke causing feeder to trip. Feeder was on MM	BRKR804368-754459-2_15166
14132	Van ness 129	American University, Cleveland Park, Glover Archbold Parkway, Glover Park, Spring Valley, Wesley Heights	5/6/2014	1111	Faulty connection on URD pole cause Pothead to burn tripping feeder	BRKR777403-420913-1_14132
15199	Takoma13 27	Brightwood, Shepherd Park, Takoma Park	6/3/2014	1901	Faulty connections on a OH xfr and URD pole cause Pothead to burn	BRKR800413-377769-4_15199
15172	Alabama ave 136	Barry Farms, Randle Heights, St Elizabeths Hospital	6/18/2014	745	Connection at ACR by-passe burned	Pole #804371-7531
15707	Benning a23013 7	Deanwood	6/22/2014	1981	Wire down due to faulty connection.	RCLR819389-190470_15707
14717	Benning a23013 7	DC Stadium, Deanwood, Lily Ponds	7/15/2014	4335	Tap burned while feeder was on MM. Feeder was tie to 15707	BRKR813387-876596-22_14717

Based on the above table, three out of the six feeders identified have recently had reliability work done or are on schedule as part of the Reliability Enhancement Plan for 2015.

See summary below:

- Feeders 14717, 15707 and 15199 were part of the 2014 REP work plan in the District of Columbia. As such Pepco believes the reliability of these feeders should improve during 2015; and
- Feeders 15166, 14132 and 15172 were addressed at the time of the event and their 2013-2014 performances indicate that these were isolated incidents and no further actions are needed at this time.

Joint Failure Analysis

According to OMS, for the period of October 2013 through September 2014, including MEDs, the District of Columbia experienced 31 events due to transformer failures. These events affected 8,792 customers contributing to 9% of the total customers affected due to equipment failure.

Months Ending	Mode of Failuer: Joint					
	Events	Pct.	CI	Pct.	CMI	Pct.
Sep. 2014	31	2.8%	8,792	9.3%	1,692,031	10.7%
Sep. 2013	13	1.4%	1,628	1.9%	238,777	1.5%

Table 2.4-L1 – Joint Failure Rates

Analysis of these events indicated that 61% of customers impacted by joint failures can be attributed to five events on five different feeders. For two of these events affecting 3,568 customers, the responding field crews found it necessary to open the feeders' breakers at the substation prior to initiating any work on the damaged feeder. It is important to note that opening the breaker to make repairs is generally done as a safety precaution and to comply with safety regulations.

Table 2.4-L2 – Event Detail for Joint Failures

Feeder	Substation		Neighborhood(s)	Date	CI	Cause	Device (s)
14722	Harvard13	13	Columbia Heights, Mt Pleasant	12/21/2013	1526	Joint failure at subway switch. Crew opened breaker to make permanent repairs	SSW790398-757866-4_14722
84	Harvard4	13	Columbia Heights	1/3/2014	593	ML joint failure	BRKR792398-397273-8_00084
211	G street	28	Old City 1	1/23/2014	639	ML joint failure	BRKR802381-555514-4_00211
15021	Ft slocum	190	Brightwood, Chillum, Petworth, Shepherd Park	5/8/2014	2042	UG cable to pothead joint failed. Crew opened breaker to isolate fault.	LBSW792410-110580_15021
14146	Van ness	129	Garfield Massachusetts Avenue Heights, Observatory Circle, Rock Creek Park 1, Woodley	6/11/2014	572	ML joint failure	BRKR777403-420913-28_14146

Order No. 16975 states the following at paragraphs 68 and 109:

68. ***Decision:*** *Pepco is directed to report on efforts to reduce equipment failure in the 2013 Consolidated Report and in future Consolidated Reports.*

109. Pepco is ***DIRECTED*** *to report on its efforts to reduce equipment failure consistent with paragraph 68 herein;*

Analysis of effort to reduce equipment failure rates

The analysis of the top three causes of equipment failure outages in the District of Columbia shows the impacts of ongoing efforts to improve Pepco's overall system and the effectiveness of numerous programs currently in progress as part of Pepco's Reliability Enhancement Plan. As shown in the detail above, most of the issues that contributed to the top three equipment failure modes during the evaluation period have been or are scheduled to be addressed in various elements of the REP.

Historical data on SAIFI over the last 3 years shows evidence of improvement, as shown on Figure 2.4-B.

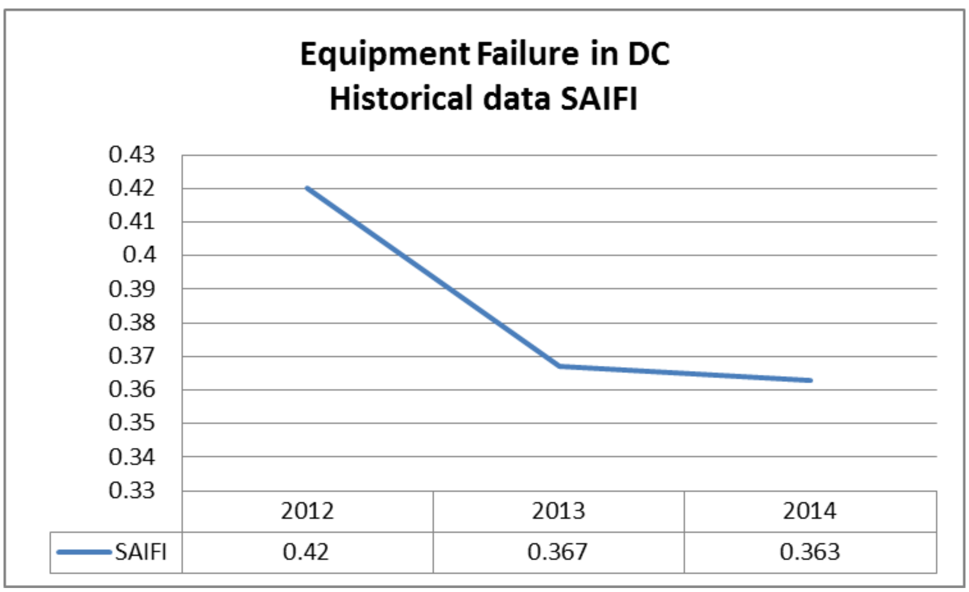


Figure 2.4-B

Improvements in the overall impact of equipment failures bear testament to the effectiveness of the REP in identifying and remediating the most impactful equipment failure modes, ideally those which contribute to the majority of customer outages.

As noted in the above analysis, cable failure remains the largest contributor to customer outages caused by equipment failure. From this analysis it was identified that one-fourth of those failures had a catastrophic effect on underground to overhead terminations or transitions. Also, it was identified that cable failure at the get-away pole on feeder 84 had a cascading that affected feeders 117 and 133.

Furthermore, analysis of connection and joint failure revealed three other events associated with failures at or near termination points from underground to overhead affecting 5,054 customers. As a result, these feeders have been referred to the failure analysis team for further analysis to determine if there is a pattern or trend that could result in potential failures or if these are isolated events.

2.4.5 OUTAGE CAUSES

Interruptions to electric service can be caused by a range of occurrences, such as downed trees or limbs on power lines; high winds and lightning; heavy rain, snow, or ice; animals on equipment or power lines; traffic accidents that damage poles and equipment; underground construction accidents; and equipment failures.

The eight main outage causes in the OMS are:

- Animal – Outage caused by contact between Birds, Squirrels, Snakes and Other small animals and the distribution system;
- Equipment Failure - Includes Equipment Failures Only;
- Equipment Hit - Includes Cable Cuts, Motor Vehicle Hits and Foreign Contact;
- Others - Includes Employee, Fire, Load Shedding, Source Lost, Vandalism, Voltage;
- Overload - Includes Overloading only;
- Tree - Includes Outside ROW- Limb, Outside ROW-Down, Inside ROW-Limb, and Inside ROW-Down;
- Unknown - Includes Unknown Only indicates that the field responder did not know the cause of the outage; and
- Weather - Includes Flood, Ice, Lightning, Wind.

The following table displays the outage cause options from which crews select when entering data into the Advantex Mobile application at the time of restoration. Through the Advantex Mobile NMS (Network Management System) completion window, crews have the ability to enter the event restoration information through drop down menus that are represented in the following table as well as any additional information through a free form text field. The outage cause selections are later classified into the categories above for reporting purposes. The detailed outage causes are maintained to assist in analysis of not only the cause of the outage but also the corrective actions necessary to reduce future outages.

An explanation of the selection categories from the drop-down menus follows Table 2.4-M below.

Select 1	Select 1	Select 1	Select 1	Select up to 3	Select 1	Select 1	Select 1	Select up to 7	Select up to 4
NON PHI	**Weather**	**Class**	**Device**	**Action**	**Cause/Problem**	**Equipment Failure** Select if Equipment Failure Cause selected	**Phase**	**Manhole**	**Follow-Up Area**
APGE	Clear	Dist Primary - OH	ACR	Assisted	Animal/Bird	ACR	A	Cable Burnout Visible	ACE - Cape May
Bad Address	Extreme Cold	Dist Primary - UG	Autotransformer	Braced	Animal/Other	Autotransformer	B	Cable Smoking	ACE - Glassboro
Cust Equip	Extreme Heat	Dist Primary - URD	Bushing	Bypassed	Animal/Snake	Bushing	C	Cover - Double Action	ACE - Operations
FD Disconn- Left Disconn	Ice	Dist Secondary - OH	Cable	Closed	Animal/Squirrel	Cable	ABC	Cover - Rdwy Grate	ACE - Pleasantville
FD Disconn- Reconnected	Fog	Dist Secondary - UG	Capacitor	Cleared/Cut in Clear	Avoided Dispatch	Capacitor	+/-	Cover - Sdwk Grate	ACE - Winslow
N/R (No Response)	Rain	Dist Secondary - URD	Connection (i.e. Loose)	Disconn	Cable Cut - Billable	Connection (i.e. Loose)	AB	Cover - Slotted	Bay - Centreville
N/R Volt Checks OK	Snow	Network	Crossarm	Isolated	Cable Cut - Marked Wrong	Crossarm	AC	Cover Displaced	Bay - Exmore
No Access	Windy	St. Lgt.	Cutout	Jumpered	Cable Cut - Unknown	Cutout	BC	Gas Present	Bay - Harrington
Ok by Phone	Thunder/Lightning	Substation	Distr. Ckt. Breaker	Left MLSO	Employee	Distr. Ckt. Breaker	A, +/-	Joint Smoking	Bay - Millsboro
Ok on Arrival		Sub-Transmission	Elbow/Insert	Made Safe	Equipment Failure	Elbow/Insert	B, +/-	MH Fire	Bay - Operations
Utility - CATV		Traffic Signal	Fuse	Made Tie	Fire	Fuse	C, +/-	MH Smoking	Bay- Salisbury
Utility - Phone		Transmission	Insulator	Notified Customer	Foreign Contact	Insulator	AB, +/-	Structure Damage	Claims
Utility - Other			Joint Failure	Perm Repairs	Load	Joint Failure	AC, +/-	Water Above Cable	Forestry
			Lightning Arrestor	Reconnected	Load Shedding	Lightning Arrestor	BC, +/-	Water Below Cable	NC - Christiana
			Meter	Referred	Motor Vehicle	Meter	ABC, +/-	Other	NC - North East
			Meter - Primary	Removed	Scheduled	Meter - Primary			NC - Operations
			"Mole"	Repaired	Source Lost	"Mole"			Pepco - BSID
			None	Replaced	Tree ROW - Limb	None			Pepco - Conduit
			PAC / Spacer Cable	Temp Repairs	Tree ROW - Down	PAC / Spacer Cable			Pepco - Cust Design DC
			Pole	Voltage Check	Tree Outside ROW - Limb	Pole			Pepco - Cust Design MD
			Regulator		Tree Outside ROW - Down	Regulator			Pepco - Cust Operations
			Relay		Unknown	Relay			Pepco - Distribution Test
			Sectionalizer		Vandalism	Sectionalizer			Pepco - Line Clearance
			Service		Voltage - F/L or H/L	Service			Pepco - Meter
			Splice		Weather / Flood	Splice			Pepco - OH Forestville
			Street Light / Traffic		Weather / Ice	Street Light / Traffic			Pepco - OH Rockville
			Switch		Weather / Lightning	Switch			Pepco - Operations
			Switch - Gang Op		Weather / Salt	Switch - Gang Op			Pepco - UG Benning
			Termination		Weather / Wind	Termination			Pepco - UG Rockville
			Transclosure			Transclosure			Pepco - URD - Rockville
			Transformer			Transformer			Pepco - URD Forestville
			Transformer - Padmount			Transformer - Padmount			
			Transformer - Subsurface			Transformer - Subsurface			
			Wire - Bare			Wire - Bare			
			Wire - Covered			Wire - Covered			

Table 2.4-M

- **Non PHI** - If the event is not caused by Pepco equipment or if it is impossible to complete the request (e.g. bad address) crews must select one item from the Non-PHI list box of the MDS restoration screen indicating the circumstances, such as other utility, customer equipment, APGE (advise party to get electrician). If a selection is made from this list, the crew can complete and close ticket without further information. If no selection is made, then the event is on Pepco equipment and additional information is needed to complete the record.
- **Weather** - Crew must select from the list the observed weather conditions at the time of the outage.
- **Class** - Crew must select one item from the drop-down list describing the construction type.
- **Device** - Crew must select the clearing device.
- **Action** - Crew selects the action taken to restore the event/outage.
- **Cause/problem** - Crew must select the cause of the event. A ticket cannot be closed without a cause selection if the event was on Pepco equipment.
- **Equipment Failure** - Crew must enter information about the failed device related to the event if equipment failure is the cause / problem selected.
- **Phase** - Selection box for the phase(s) impacted by the event/outage.
- **Manhole** - Selection box for items describing the contents of a manhole.
- **Follow-up Area -** For an event that needs additional work but does not require immediate attention, a crew may select a follow-up area. For example, in the case of a URD cable failure where all load is restored through a common tie, the event would have a follow-up selection.

The most common causes of power outages are equipment failures and vegetation-related. High winds, heavy rain or snow and ice can cause trees or branches to topple and tear down power lines. Tree limbs brushing or resting on the lines cause short circuits and blown fuses. Please note, as shown in Table 2.4-M, there are several different equipment types that fall under the “Equipment Failure” category. One such type is fuse-related outages. The job of the fuse is to protect equipment. If a fuse blows, it is not an equipment failure but rather the fuse is performing its designed function. As a result, there are fewer actual “Equipment Failures” than are captured by the OMS.

If a non-Pepco construction crew digs a foot or two in the wrong direction, damage to an underground power line could cause an instant disruption of electric service, or could cause damage that may not result in a power outage until days, weeks or months later.

Vehicles that damage utility poles or equipment can also cause power outages. Small animals, like squirrels, sometimes chew into lines or come into contact with a piece of equipment and an energized line, causing a fault and subsequent interruption of electric service.

An event classified as "Unknown" indicates that the field responder did not know the cause of the outage and this classification is used most frequently where a service interruption results from the operation of a protective device such as a fuse or recloser. These devices protect the electric distribution system from damage by sensing fault current on a particular circuit and activating a break in the flow of current. Typically, if there is no discernable damage to the circuit and the cause of the fault is not evident in the vicinity of the protective device that was activated, the device will be replaced or reset and the circuit re-energized. If the device holds (no fault current is detected), the field responder may report “Equipment Failure” or "Unknown" as a cause and move on to the next trouble call assigned. The operation of these protective devices are not equipment failures because the fuse or recloser is operating correctly when it opens to isolate a fault further down the line. Occasionally, the field responder may find a probable cause some distance from the protective device involved (such as a tree branch on the ground underneath the overhead lines), but, for the most part, crews are focused on restoration of service rather than full investigation of the cause of any interruption (where this is not immediately evident).

Table 2.4-N1/N2 contains District of Columbia outage cause data for calendar year 2014. Note, there were no Major Service Outages in 2014. Table 2.4-N3 presents calendar year 2014 District of Columbia equipment failure statistics exclusive of Major Service Outages.

District of Columbia System Outage Causes (Interruptions) - Through December, 2014 (Includes Major Service Outages)												
Outage Cause	Customer Interruption Statistics									Reliability Indices		
	Event	Pct	Rank	Cust Out	Pct	Rank	CMI	Pct	Rank	SAIFI	CAIDI	SAIDI
Animal	208	10%	3	19,373	11%	4	1,784,279	7%	4	0.07	92	7
Equip Fail (Deterioration)	1,106	52%	1	81,541	45%	1	13,063,484	52%	1	0.31	160	50
Equip Hit (Accident)	100	5%	7	11,528	6%	6	1,386,826	5%	5	0.04	120	5
Others*	149	7%	4	5,857	3%	7	255,840	1%	8	0.02	44	1
Overload	76	4%	8	1,517	1%	8	311,851	1%	7	0.01	206	1
Tree	244	11%	2	25,967	14%	2	3,326,748	13%	3	0.10	128	13
Unknown	114	5%	6	13,710	8%	5	730,121	3%	6	0.05	53	3
Weather	135	6%	5	20,559	11%	3	4,455,549	18%	2	0.08	217	17
Grand Total	**2,132**	**100%**		**180,052**	**100%**		**25,314,698**	**100%**		**0.69**	**141**	**96**

* "Other" is a grouping of known causes too small for individual classicication such as employee, source lost and load shedding, etc.
** No Major Service Outages in 2013.

Table 2.4-N1

Pepco Region - District of Columbia

Primary Equipment Failures

Equipment Type	Nbr of Outages	Pct (%)	Nbr of Cust Out	Pct (%)	Total Cust Min	Pct (%)	Indices SAIFI	CAIDI	SAIDI
ACR	2	0.2%	1,409	1.7%	25,973	0.2%	0.005	18.4	0.10
AUTOTRANSFORMER	1	0.1%	1	0.0%	10	0.0%	0.000	9.7	0.00
BUSHING	12	1.1%	1,027	1.3%	539,086	4.1%	0.004	524.9	2.05
CABLE	128	11.6%	20,346	25.0%	3,527,717	27.0%	0.078	173.4	13.44
CAPACITOR	2	0.2%	2,792	3.4%	24,249	0.2%	0.011	8.7	0.09
CONNECTION(I.E. LOOSE)	37	3.3%	14,272	17.5%	1,379,207	10.6%	0.054	96.6	5.26
CROSSARM	7	0.6%	2,621	3.2%	139,103	1.1%	0.010	53.1	0.53
CUTOUT	28	2.5%	675	0.8%	87,002	0.7%	0.003	128.9	0.33
DISTR. CKT. BREAKER	3	0.3%	2,537	3.1%	373,159	2.9%	0.010	147.1	1.42
ELBOW INSERT	8	0.7%	944	1.2%	371,012	2.8%	0.004	393.0	1.41
FUSE	79	7.1%	1,547	1.9%	230,526	1.8%	0.006	149.0	0.88
INSULATOR	1	0.1%	91	0.1%	9,581	0.1%	0.000	105.3	0.04
JOINT FAILURE	20	1.8%	7,172	8.8%	1,389,222	10.6%	0.027	193.7	5.29
LIGHTNING ARRESTOR	6	0.5%	119	0.1%	11,795	0.1%	0.000	99.1	0.04
METER-PRIMARY	1	0.1%	1	0.0%	431	0.0%	0.000	430.5	0.00
PAC / SPACER CABLE	3	0.3%	1,123	1.4%	114,181	0.9%	0.004	101.7	0.44
POLE	4	0.4%	1,141	1.4%	159,378	1.2%	0.004	139.7	0.61
REGULATOR	1	0.1%	919	1.1%	5,836	0.0%	0.004	6.4	0.02
RELAY	1	0.1%	1	0.0%	53	0.0%	0.0000	52.9	0.00
SECTIONALIZER	1	0.1%	109	0.1%	25,862	0.2%	0.0004	237.3	0.10
SERVICE	2	0.2%	88	0.1%	31,713	0.2%	0.0003	360.4	0.12
SWITCH	15	1.4%	5,761	7.1%	779,461	6.0%	0.0220	135.3	2.97
SWITCH - GANG OP	6	0.5%	1,048	1.3%	218,892	1.7%	0.0040	208.9	0.83
TRANSFORMER	85	7.7%	3,850	4.7%	1,167,133	8.9%	0.0147	303.2	4.45
TRANSFORMER - PADMOUNT	3	0.3%	69	0.1%	22,574	0.2%	0.0003	327.2	0.09
TRANSFORMER - SUBSURFACE	14	1.3%	1,275	1.6%	466,442	3.6%	0.0049	365.8	1.78
WIRE - BARE	11	1.0%	2,809	3.4%	341,458	2.6%	0.0107	121.6	1.30
WIRE - COVERED	11	1.0%	1,377	1.7%	147,402	1.1%	0.0052	107.0	0.56
Total Primaries	**492**	**44.5%**	**75,124**	**92.1%**	**11,588,458**	**88.7%**	**0.2863**	**154.3**	**44.16**

Secondary Equipment Failures

Equipment Type	Nbr of Outages	Pct (%)	Nbr of Cust Out	Pct (%)	Total Cust Min	Pct (%)	Indices SAIFI	CAIDI	SAIDI
MOLE	3	0.3%	34	0.0%	17,757	0.1%	0.0001	522.3	0.07
CABLE	251	22.7%	4,101	5.0%	1,025,104	7.8%	0.0156	250.0	3.91
CONNECTION(I.E. LOOSE)	145	13.1%	1,092	1.3%	168,191	1.3%	0.0042	154.0	0.64
JOINT FAILURE	12	1.1%	507	0.6%	76,377	0.6%	0.0019	150.6	0.29
METER	117	10.6%	223	0.3%	40,153	0.3%	0.0008	180.1	0.15
NONE	1	0.1%	1	0.0%	352	0.0%	0.0000	352.1	0.00
SERVICE	70	6.3%	288	0.4%	97,953	0.7%	0.0011	340.1	0.37
SPLICE	2	0.2%	25	0.0%	6,872	0.1%	0.0001	274.9	0.03
TRANSFORMER	2	0.2%	10	0.0%	2,231	0.0%	0.0000	223.1	0.01
TRANSFORMER - SUBSURFACE	1	0.1%	21	0.0%	21,105	0.2%	0.0001	1,005.0	0.08
WIRE - BARE	4	0.4%	20	0.0%	12,352	0.1%	0.0001	617.6	0.05
WIRE - COVERED	6	0.5%	95	0.1%	6,578	0.1%	0.0004	69.2	0.03
Total Secondaries	**614**	**55.5%**	**6,417**	**7.9%**	**1,475,026**	**11.3%**	**0.0245**	**229.9**	**5.62**

Equipment Failures at Primary and Secondary Levels

Equipment Type	Nbr of Outages	Pct (%)	Nbr of Cust Out	Pct (%)	Total Cust Min	Pct (%)	Indices SAIFI	CAIDI	SAIDI
Total Primary and Secondaries	**1,106**	**100%**	**81,541**	**100%**	**13,063,484**	**100%**	**0.3107**	**160.2**	**49.78**

Table 2.4-N2

2.4.6 VM BUDGET, TREE-RELATED OUTAGES[69] [70]

Table 2.4-O1 shows District of Columbia distribution tree trimming expenses (not including poles, substation mowing, or storm-related tree trimming) and budgets. Provided are actual and budgeted amounts for 2007-2014, the 2015 budget, and the preliminary 2016 and 2017 budgets.

Pepco's VM program includes increased trimming above all three-phase and single-phase lines. For three-phase lines it also includes the removal (with permission) of any limbs identified by Pepco Arborist planners that have a probability of breaking and falling into the conductors.

[69] In Order No. 16623 at paragraphs 37 and 56, the Commission ordered the following:

37. Decision: …We require Pepco to explain why it has decreased its budget for tree trimming over the last seven years, if tree trimming is the most important factor impacting customers suffering from power outages. Pepco should include that explanation in the 2012 Consolidated Report.

56. Pepco is DIRECTED to provide an explanation of its budget for tree trimming consistent with paragraph 37.

[70] Order No. 16975 states the following at paragraphs 43 and 99:

43. Decision: The Commission finds Pepco's explanation of its budget variance for the single year 2011 insufficient to explain budget variances that totaled 26.9% below budget for five of the last six years. Therefore, the Commission requires Pepco to explain the budget variances that have occurred from 2006-2011 in its 2013 Consolidated Report. Additionally, we agree with Staff Recommendation #3 and require Pepco to include an explanation of any budget variance in its vegetation management expenditures and its EIVM expenditures in future years' Consolidated Reports. We are extremely concerned about the explanation provided in the Consolidated Report for why vegetation management expenditures were below budget in five of the last six years. Pepco stated that "while actual expenditures were below budget, work was completed consistent with planning.*" This is an inadequate explanation for a repeated failure to spend budgeted amounts on tree-trimming – arguably, the "most important factor impacting customers suffering from power outages." We therefore require Pepco to expand upon its explanation. If Pepco means that, through efficiencies, all the work intended to be accomplished in the budget was actually accomplished for less, then we direct Pepco to document what was intended to be included in the budget and what efficiencies were achieved so that the budgeted work was accomplished at a lower cost. The Commission also requires Pepco to explain what impact these efficiencies had on the budget process in subsequent years. If Pepco's statement about planning has some other meaning, we direct Pepco to provide it and to show what "planning" was involved, by whom and when. We also expect a precise and detailed explanation of why such planning would result in expenditures consistently, and significantly, below the budgeted amounts for a number of years. Further, we agree with OPC's suggestion that Pepco explain why its program does not include increased trimming above the three phase tap line or the single tap lines. Pepco is directed to provide this information in the 2013 Consolidated Report.*

99. Pepco is DIRECTED to provide an explanation of budget variances for its own vegetation management work as directed in paragraph 43 herein;

Explanation of Variance in Pepco D.C. O&M Tree Trimming Costs

In both 2013 and 2014, annual O&M actual spending for VM was in excess of the annual budgets. Table 2.4-O1 shows that the 2014 actual Pepco D.C. O&M tree trimming costs were approximately $2.16 million, compared to a budgeted amount of approximately $2.11 million. The variance between budgeted and actual costs for Pepco D.C. O&M tree trimming was $51,036 (or approximately 2%).

Pepco District of Columbia O & M Tree Trimming Costs

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
ACTUAL											
TREE TRIMMING - DC	$1,017,779	$931,453	$993,124	$1,022,366	$1,197,382	$1,585,406	$1,981,233	$2,352,567	$2,164,336		
BUDGET/FORECAST											
TREE TRIMMING - DC	$1,577,896	$1,352,987	$1,163,390	$1,264,608	$1,145,246	$1,668,154	$2,218,154	$2,218,342	$2,113,300	$2,324,572	$2,371,063
VARIANCE											
TREE TRIMMING - DC	($560,117)	($421,534)	($170,266)	($242,242)	$52,136	($82,748)	($236,921)	$134,225	$51,036		

Notes:
1. Excludes pole inspections, substation mowing costs

Table 2.4-O1

Yearly Data on Tree Trimming & Tree-Related Outages

In accordance with Order No. 15621,[71] presented in the following tables, is Pepco's "yearly data on vegetation management by feeder and wards (or multiple wards) compared to the Company's tree down and tree limb outage causes listed in its monthly power outage reports." The first set of tables lists the feeders that were worked in 2014, sorted by feeder. These tables include the date that vegetation management was completed on the feeder as well as the wards that the feeder serves. The second set of tables lists the outages coded as tree-related in 2014, also sorted by feeder, allowing for a comparison between the two sets of tables. It is possible that additional outages may have been caused by trees but with causes coded as weather or unknown if fallen trees or limbs were not found at the site.

[71] In Order No. 15621 at paragraph 5, the Commission ordered the following:

> *5. Pepco shall file within the Company's annual Consolidated Reports to the Commission, yearly data on tree trimming by feeder and wards (or multiple wards) compared to the Company's tree down and tree limb outage causes listed in its monthly power outage reports beginning with the Company's 2010 Consolidated Report.*

2014 District of Columbia Tree Trimming Data by Feeder and Ward(s)

2014 District of Columbia Vegetation Management Maintenance Cycle		
Feeder	**Ward(s)**	**Completion Date**
99	7	8/20/2014
117	3	12/30/2014
118	6, 7	8/20/2014
132	2, 3	12/30/2014
133	3	12/9/2014
152	7	4/2/2014
227	6	8/12/2014
228	6	8/12/2014
229	6	8/12/2014
244	7	3/14/2014
308	3	11/21/2014
310	3	12/16/2014
327	7	3/14/2014
328	7	5/21/2014
345	6,8	8/14/2014
347	6,7	1/8/2015
348	6	9/24/2014
349	6	7/21/2014
365	6, 8	9/16/2014
367	7	9/16/2014
368	7	3/14/2014
369	7	8/20/2014
380	7	8/20/2014
383	7	9/16/2014
385	7	9/16/2014
386	7	9/19/2014
387	7	9/16/2014
388	7	8/20/2014
413	3	12/9/2014
414	3	12/9/2014
416	3	12/9/2014
476	3	12/9/2014
479	6,7	9/29/2014
481	4	7/22/2014
482	4	7/22/2014
484	4	7/22/2014
485	4	7/22/2014
488	4	7/22/2014
489	4	7/22/2014
490	4	7/22/2014
491	4	7/22/2014
494	6,7	9/24/2014
495	6, 7, 8	8/28/2014
496	6	8/28/2014

Table 2.4-P1

2014 District of Columbia Vegetation Management Maintenance Cycle		
Feeder	**Ward(s)**	**Completion Date**
499	6	8/28/2014
14031	8	3/11/2014
14032	8	3/19/2014
14033	8	3/19/2014
14035	8	3/14/2014
14102	5	12/2/2014
14158	7	2/4/2014
14263	4	4/8/2014
14271	4	5/30/2014
14715	7	3/14/2014
14890	3	12/17/2014
14891	3	12/9/2014
14894	3	10/29/2014
14896	3	12/9/2014
14900	3, 4	12/1/2014
14945	3	3/20/2014
14979	4	11/29/2014
14987	4	11/29/2014
15001	4	6/30/2014
15006	4	6/2/2014
15007	4	6/30/2014
15008	4	6/30/2014
15009	4	4/11/2014
15010	4	6/10/2014
15011	3, 4	6/30/2014
15012	4	6/30/2014
15013	4, 5	7/31/2014
15014	4, 5	6/10/2014
15015	4	6/27/2014
15016	4, 5	6/17/2014
15021	4	6/14/2014
15082	4	8/13/2014
15085	8	8/13/2014
15086	8	8/13/2014
15090	8	8/13/2014
15094	5	4/4/2014
15100	5	4/4/2014
15130	7	12/4/2014
15131	7	12/4/2014
15132	7	5/8/2014
15165	8	4/3/2014
15166	8	3/21/2014
15167	8	3/21/2014
15168	8	3/21/2014

Table 2.4-P1 (continued)

2014 District of Columbia Vegetation Management Maintenance Cycle		
Feeder	**Ward(s)**	**Completion Date**
15169	8	3/21/2014
15170	6, 7, 8	3/21/2014
15171	8	10/1/2014
15172	8	3/21/2014
15173	8	10/1/2014
15174	8	3/21/2014
15175	8	9/26/2014
15197	4	6/30/2014
15458	5	3/31/2014
15459	5	3/31/2014
15631	8	1/3/2014
15632	8	1/3/2014

Table 2.4-P1 (continued)

Tree-Related Outages in 2014
(Inclusive IEEE 1366 – 2003 Std)

Event_ID	Date of Outage	Begin Time	End Time	Outage Duration	VC_SUBCAUSE	Outage_Cause	Customers Affected	Customer Minutes	Feeder
1748203	1/2/2014	21:46	1:06	200	Dist Primary - OH	Tree ROW - Limb	34	6,800	14015
1748302	1/3/2014	0:43	5:04	261	Dist Primary - OH	Tree Row - Down	181	47,241	494
1748427	1/3/2014	3:27	8:17	290	Dist Primary - OH	Tree Outside ROW - Down	625	181,250	14093
1748427	1/3/2014	3:27	18:41	914	Dist Primary - OH	Tree Outside ROW - Down	263	240,382	14093
1749552	1/3/2014	4:08	21:05	1,017	Dist Primary - OH	Tree Outside ROW - Down	10	10,171	14014
1749553	1/3/2014	4:08	16:20	732	Dist Primary - OH	Tree Outside ROW - Down	14	10,248	14014
1748755	1/3/2014	5:08	5:25	17	Dist Primary - OH	Tree Row - Down	316	5,372	494
1748872	1/3/2014	6:42	11:38	295	Dist Secondary - OH	Tree ROW - Limb	5	1,477	177
1748946	1/3/2014	7:50	18:41	650	Dist Primary - OH	Tree Outside ROW - Down	30	19,509	14093
1749253	1/3/2014	11:18	14:54	216	Dist Secondary - OH	Tree ROW - Limb	8	1,726	499
1749442	1/3/2014	14:19	14:54	35	Dist Secondary - OH	Tree ROW - Limb	25	875	348
1750235	1/5/2014	0:27	1:50	83	Dist Primary - OH	Tree ROW - Limb	52	4,300	15015
1750666	1/6/2014	5:12	6:57	104	Dist Primary - OH	Tree Outside ROW - Down	455	47,350	386
1750691	1/6/2014	6:26	6:37	12	Dist Primary - OH	Tree Row - Down	618	7,292	100368
1751378	1/6/2014	20:43	0:17	214	Dist Secondary - OH	Tree ROW - Limb	1	214	133
1751441	1/6/2014	21:00	6:55	594	Dist Primary - OH	Tree Row - Down	18	10,697	15197
1751403	1/6/2014	21:00	6:55	594	Dist Primary - OH	Tree Outside ROW - Down	24	14,262	15197
1751533	1/6/2014	23:35	2:12	156	Dist Secondary - OH	Tree ROW - Limb	1	156	97
1751804	1/7/2014	7:57	16:00	483	Dist Primary - OH	Tree Row - Down	5	2,413	15197
1751804	1/7/2014	11:50	16:00	250	Dist Primary - OH	Tree Row - Down	10	2,500	15197
1753527	1/9/2014	13:27	14:38	71	Dist Primary - OH	Tree ROW - Limb	33	2,340	15197
1754247	1/11/2014	13:23	14:21	59	Dist Secondary - OH	Tree ROW - Limb	1	59	15010
1759572	1/27/2014	17:21	20:10	168	Dist Secondary - OH	Tree ROW - Limb	1	168	15014
1759959	1/28/2014	21:31	22:04	33	Dist Secondary - OH	Tree Outside ROW - Limb	1	33	14014
1760340	1/30/2014	2:29	3:31	61	Dist Primary - OH	Tree ROW - Limb	20	1,225	14261
1761463	2/2/2014	17:29	19:51	142	Dist Secondary - OH	Tree ROW - Limb	61	8,664	484
1761601	2/3/2014	4:10	4:36	26	Dist Secondary - OH	Tree Outside ROW - Limb	13	335	467
1761625	2/3/2014	6:10	7:20	70	Dist Secondary - OH	Tree ROW - Limb	10	699	15198
1763430	2/7/2014	3:34	6:02	147	Dist Secondary - OH	Tree ROW - Limb	1	147	205
1763435	2/7/2014	5:04	5:55	50	Dist Primary - OH	Tree ROW - Limb	12	604	366
1772449	3/3/2014	14:12	15:50	98	Dist Primary - OH	Tree ROW - Limb	1	98	14007
1775646	3/12/2014	20:29	1:11	281	Dist Primary - OH	Tree ROW - Limb	7	1,968	60
1776629	3/13/2014	4:35	18:20	825	Dist Secondary - OH	Tree Outside ROW - Down	12	9,900	14135
1777008	3/13/2014	9:12	2:22	1,030	Dist Primary - URD	Tree Row - Down	2	2,059	15950
1777607	3/13/2014	22:12	0:00	108	Dist Primary - OH	Tree Outside ROW - Limb	35	3,780	14007
1777827	3/14/2014	12:47	14:11	84	Dist Primary - OH	Tree Row - Down	1	84	15169
1777901	3/14/2014	16:26	17:08	42	Dist Primary - OH	Tree Outside ROW - Limb	17	716	15013
1779843	3/19/2014	15:48	1:21	573	Dist Secondary - OH	Tree Outside ROW - Limb	1	573	366

Table 2.4-P2

Tree-Related Outages in 2014
(Inclusive IEEE 1366 – 2003 Std)

Event_ID	Date of Outage	Begin Time	End Time	Outage Duration	VC_SUBCAUSE	Outage_Cause	Customers Affected	Customer Minutes	Feeder
1779267	3/19/2014	18:18	20:31	133	Dist Secondary - OH	Tree ROW - Limb	1	133	394
1779616	3/20/2014	11:54	12:59	66	Dist Secondary - OH	Tree Outside ROW - Down	1	66	15006
1781429	3/26/2014	9:22	9:29	7	Dist Primary - OH	Tree Outside ROW - Limb	680	4,443	488
1781859	3/27/2014	9:01	11:48	167	Dist Primary - OH	Tree Outside ROW - Down	11	1,839	15009
1781910	3/27/2014	9:01	14:29	329	Dist Secondary - OH	Tree Outside ROW - Down	1	329	15009
1782802	3/30/2014	8:25	10:12	106	Dist Secondary - OH	Tree ROW - Limb	1	106	15012
1782931	3/30/2014	18:43	20:31	107	Dist Secondary - OH	Tree ROW - Limb	22	2,363	15001
1783841	4/1/2014	22:43	23:13	31	Dist Primary - OH	Tree Row - Down	304	9,307	15011
1784470	4/3/2014	16:38	17:38	59	Dist Secondary - OH	Tree Outside ROW - Limb	17	1,011	490
1787889	4/13/2014	17:36	18:16	41	Dist Secondary - OH	Tree ROW - Limb	1	41	15001
1788213	4/14/2014	16:45	22:51	366	Dist Secondary - OH	Tree ROW - Limb	1	366	15945
1788279	4/14/2014	21:56	22:53	57	Dist Secondary - OH	Tree ROW - Limb	1	57	15945
1788353	4/15/2014	8:49	11:51	181	Dist Primary - OH	Tree ROW - Limb	1	181	15867
1788682	4/15/2014	16:05	18:41	156	Dist Primary - OH	Tree Outside ROW - Down	23	3,580	15010
1789180	4/16/2014	9:10	11:48	157	Dist Secondary - OH	Tree Outside ROW - Down	1	157	15950
1790117	4/18/2014	11:25	13:09	104	Dist Secondary - OH	Tree ROW - Limb	1	104	15016
1792345	4/25/2014	13:40	15:14	95	Dist Primary - OH	Tree Outside ROW - Limb	4	378	15867
1792428	4/25/2014	18:21	22:00	218	Dist Primary - OH	Tree Outside ROW - Down	14	3,057	15199
1792617	4/26/2014	18:00	18:35	36	Dist Secondary - OH	Tree ROW - Limb	1	36	65
1792643	4/26/2014	19:42	20:48	66	Dist Primary - OH	Tree Outside ROW - Limb	571	37,619	92102
1793488	4/29/2014	23:10	1:23	132	Dist Primary - OH	Tree ROW - Limb	12	1,586	14135
1794054	4/30/2014	23:01	18:17	1,155	Dist Primary - OH	Tree Outside ROW - Down	1	1,155	14133
1794088	5/1/2014	0:20	2:10	110	Dist Primary - OH	Tree Outside ROW - Down	10	1,104	14261
1796141	5/6/2014	6:57	16:41	584	Dist Primary - OH	Tree Row - Down	3	1,752	14767
1800328	5/16/2014	1:43	4:24	161	Dist Primary - OH	Tree Outside ROW - Limb	12	1,927	133
1800576	5/16/2014	8:10	9:24	74	Dist Primary - OH	Tree Row - Down	173	12,802	15014
1800576	5/16/2014	8:10	8:58	48	Dist Primary - OH	Tree Row - Down	1050	50,400	15014
1800642	5/16/2014	8:58	11:54	176	Dist Primary - OH	Tree Outside ROW - Down	912	160,512	15014
1800650	5/16/2014	9:10	9:31	21	Dist Primary - OH	Tree Outside ROW - Down	115	2,411	15014
1800924	5/16/2014	12:35	17:11	276	Dist Secondary - OH	Tree Outside ROW - Limb	1	276	14023
1803085	5/22/2014	5:52	8:08	136	Dist Primary - OH	Tree Row - Down	5	680	132
1803174	5/22/2014	5:52	14:08	496	Dist Primary - OH	Tree Outside ROW - Limb	7	3,472	132
1803461	5/22/2014	5:52	20:29	877	Dist Primary - OH	Tree Outside ROW - Limb	4	3,508	132
1803561	5/22/2014	18:45	19:06	21	Dist Secondary - OH	Tree ROW - Limb	13	267	368
1806513	5/27/2014	19:22	21:27	124	Dist Secondary - OH	Tree ROW - Limb	13	1,617	387
1809128	5/29/2014	22:22	2:44	262	Dist Secondary - OH	Tree ROW - Limb	1	262	75
1809176	5/30/2014	7:24	12:02	278	Dist Secondary - OH	Tree ROW - Limb	1	278	14146
1809186	5/30/2014	7:58	11:00	181	Dist Secondary - OH	Tree ROW - Limb	1	181	133
1809531	5/30/2014	18:32	21:42	189	Dist Secondary - OH	Tree Outside ROW - Limb	1	189	327
1811866	6/5/2014	7:47	11:28	221	Dist Primary - OH	Tree Outside ROW - Limb	13	2,873	14767
1811866	6/5/2014	9:48	11:28	100	Dist Primary - OH	Tree Outside ROW - Limb	4	400	14767

Table 2.4-P2 (continued)

Tree-Related Outages in 2014
(Inclusive IEEE 1366 – 2003 Std)

Event_ID	Date of Outage	Begin Time	End Time	Outage Duration	VC_SUBCAUSE	Outage_Cause	Customers Affected	Customer Minutes	Feeder
1812364	6/6/2014	6:10	10:01	231	Dist Secondary - OH	Tree Outside ROW - Limb	1	231	15016
1815593	6/11/2014	19:44	22:11	147	Dist Primary - OH	Tree Outside ROW - Down	1	147	15949
1815593	6/11/2014	19:44	20:31	47	Dist Primary - OH	Tree Outside ROW - Down	381	17,907	15949
1815627	6/11/2014	20:13	22:11	118	Dist Primary - OH	Tree Outside ROW - Down	94	11,092	15949
1815627	6/11/2014	20:13	20:31	18	Dist Primary - OH	Tree Outside ROW - Down	663	11,934	15949
1816099	6/12/2014	10:46	12:40	114	Dist Primary - OH	Tree Outside ROW - Down	47	5,366	14133
1816173	6/12/2014	12:30	17:13	282	Dist Secondary - OH	Tree Outside ROW - Limb	7	1,976	15801
1817651	6/16/2014	14:26	17:09	163	Dist Primary - OH	Tree ROW - Limb	24	3,912	14717
1817701	6/16/2014	15:44	16:43	59	Dist Secondary - OH	Tree Outside ROW - Limb	1	59	14135
1819612	6/19/2014	0:32	10:54	622	Dist Primary - OH	Tree Outside ROW - Limb	10	6,217	183
1819664	6/19/2014	0:40	9:49	548	Dist Primary - OH	Tree ROW - Limb	308	168,892	15085
1824850	6/25/2014	22:58	1:13	136	Dist Secondary - OH	Tree Outside ROW - Down	1	136	102
1824765	6/25/2014	23:23	12:50	807	Dist Secondary - OH	Tree Outside ROW - Limb	1	807	372
1825069	6/26/2014	9:34	14:47	313	Dist Secondary - OH	Tree Outside ROW - Down	1	313	102
1825391	6/26/2014	18:00	20:58	177	Dist Secondary - OH	Tree ROW - Limb	1	177	15085
1826791	6/30/2014	13:10	14:18	68	Dist Primary - OH	Tree ROW - Limb	24	1,622	14133
1826791	6/30/2014	13:15	14:18	63	Dist Primary - OH	Tree ROW - Limb	23	1,449	14133
1826791	6/30/2014	13:17	14:18	61	Dist Primary - OH	Tree ROW - Limb	10	611	14133
1826791	6/30/2014	13:44	14:18	34	Dist Primary - OH	Tree ROW - Limb	2	67	14133
1828834	7/3/2014	12:40	14:05	84	Dist Primary - OH	Tree ROW - Limb	29	2,442	416
1828953	7/3/2014	16:26	16:49	1,462	Dist Primary - OH	Tree ROW - Limb	11	16,084	144
1829063	7/3/2014	16:29	13:49	1,279	Dist Primary - OH	Tree Outside ROW - Limb	1	1,279	14767
1828990	7/3/2014	16:31	6:57	866	Dist Primary - OH	Tree Outside ROW - Limb	36	31,176	14767
1829265	7/3/2014	16:35	19:54	1,638	Dist Primary - OH	Tree Outside ROW - Limb	1	1,638	64
1829489	7/3/2014	16:43	5:49	786	Dist Primary - OH	Tree ROW - Limb	9	7,074	14017
1829649	7/3/2014	16:43	21:30	287	Dist Primary - OH	Tree Outside ROW - Limb	44	12,613	14015
1829639	7/3/2014	16:46	17:39	1,493	Dist Primary - OH	Tree ROW - Limb	8	11,944	15021
1829784	7/3/2014	16:49	11:17	1,108	Dist Secondary - OH	Tree ROW - Limb	1	1,108	14900
1829777	7/3/2014	16:49	4:08	678	Dist Secondary - OH	Tree ROW - Limb	1	678	15199
1830256	7/3/2014	17:04	19:43	158	Dist Primary - OH	Tree Outside ROW - Down	1096	173,332	14702
1831075	7/3/2014	17:11	9:36	985	Dist Primary - OH	Tree ROW - Limb	103	101,455	480
1830526	7/3/2014	17:20	11:00	1,059	Dist Secondary - OH	Tree Outside ROW - Limb	1	1,059	118
1830563	7/3/2014	17:21	22:47	325	Dist Primary - OH	Tree ROW - Limb	40	13,010	15710
1830606	7/3/2014	17:24	8:37	913	Dist Secondary - OH	Tree ROW - Limb	19	17,347	15709
1830744	7/3/2014	17:38	8:15	876	Dist Secondary - OH	Tree Outside ROW - Limb	20	17,526	494
1830749	7/3/2014	17:43	9:36	952	Dist Primary - OH	Tree Outside ROW - Down	1	952	480
1830769	7/3/2014	17:45	20:37	171	Dist Primary - OH	Tree Outside ROW - Limb	2044	350,001	14758
1829777	7/3/2014	19:24	4:08	524	Dist Secondary - OH	Tree ROW - Limb	1	524	15199
1831922	7/3/2014	20:23	14:48	1,104	Dist Primary - OH	Tree Outside ROW - Down	1	1,104	14767
1831923	7/3/2014	20:28	17:35	1,267	Dist Primary - OH	Tree Outside ROW - Down	1	1,267	14767
1831803	7/3/2014	21:34	9:36	722	Dist Primary - OH	Tree Outside ROW - Down	1	722	480

Table 2.4-P2 (continued)

Tree-Related Outages in 2014
(Inclusive IEEE 1366 – 2003 Std)

Event_ID	Date of Outage	Begin Time	End Time	Outage Duration	VC_SUBCAUSE	Outage_Cause	Customers Affected	Customer Minutes	Feeder
1831908	7/3/2014	21:49	5:21	452	Dist Secondary - OH	Tree Outside ROW - Limb	1	452	14702
1831995	7/3/2014	22:02	1:00	178	Dist Secondary - OH	Tree Row - Down	1	178	485
1832150	7/3/2014	23:01	2:00	179	Dist Secondary - OH	Tree ROW - Limb	1	179	15710
1832184	7/3/2014	23:18	11:44	746	Dist Primary - OH	Tree Outside ROW - Down	10	7,460	14261
1832346	7/4/2014	1:24	9:32	488	Dist Secondary - OH	Tree Outside ROW - Limb	1	488	347
1832421	7/4/2014	1:59	5:41	222	Dist Primary - OH	Tree Outside ROW - Down	1	222	14261
1832566	7/4/2014	4:11	11:00	409	Dist Secondary - OH	Tree ROW - Limb	1	409	15709
1832583	7/4/2014	4:27	9:33	306	Dist Secondary - OH	Tree Outside ROW - Limb	1	306	347
1832766	7/4/2014	7:17	10:39	201	Dist Primary - OH	Tree ROW - Limb	1	201	15707
1832839	7/4/2014	8:12	12:19	246	Dist Primary - OH	Tree ROW - Limb	1	246	14145
1832855	7/4/2014	8:18	13:46	328	Dist Primary - OH	Tree Outside ROW - Limb	6	1,968	14767
1832913	7/4/2014	9:22	13:15	232	Dist Primary - OH	Tree Row - Down	1	232	14261
1832993	7/4/2014	9:37	12:49	191	Dist Primary - OH	Tree Row - Down	1	191	14145
1833011	7/4/2014	9:52	12:49	176	Dist Primary - OH	Tree Outside ROW - Down	5	881	14145
1833061	7/4/2014	10:23	16:59	396	Dist Primary - OH	Tree Outside ROW - Limb	32	12,672	15709
1833146	7/4/2014	11:15	12:49	94	Dist Primary - OH	Tree Outside ROW - Down	1	94	14145
1833201	7/4/2014	12:08	16:00	231	Dist Primary - OH	Tree ROW - Limb	14	3,239	15198
1833205	7/4/2014	12:14	20:15	481	Dist Secondary - OH	Tree Outside ROW - Down	25	12,025	15710
1833482	7/4/2014	15:14	16:55	101	Dist Secondary - OH	Tree Outside ROW - Down	15	1,515	132
1833545	7/4/2014	16:41	16:57	15	Dist Secondary - OH	Tree Outside ROW - Limb	55	826	15709
1833628	7/4/2014	18:55	21:20	144	Dist Secondary - OH	Tree Outside ROW - Limb	16	2,307	349
1833904	7/5/2014	10:19	12:12	112	Dist Secondary - OH	Tree Outside ROW - Limb	1	112	15710
1833983	7/5/2014	13:58	18:13	255	Dist Secondary - OH	Tree Outside ROW - Limb	1	255	15085
1834043	7/5/2014	18:05	6:07	722	Dist Primary - OH	Tree Outside ROW - Down	49	35,374	14900
1835355	7/8/2014	17:28	19:20	111	Dist Primary - OH	Tree Outside ROW - Limb	109	12,115	14016
1835355	7/8/2014	17:28	21:59	271	Dist Primary - OH	Tree Outside ROW - Limb	1	271	14016
1835312	7/8/2014	17:56	3:03	547	Dist Primary - OH	Tree Outside ROW - Limb	18	9,841	15016
1836050	7/8/2014	19:04	8:32	808	Dist Primary - OH	Tree Outside ROW - Down	111	89,657	15199
1836031	7/8/2014	19:05	16:25	1,280	Dist Primary - OH	Tree ROW - Limb	6	7,678	132
1836345	7/8/2014	19:12	0:39	326	Dist Primary - OH	Tree Outside ROW - Limb	73	23,833	14016
1836378	7/8/2014	19:14	15:45	1,231	Dist Secondary - OH	Tree Outside ROW - Limb	1	1,231	133
1836586	7/8/2014	19:20	13:06	1,065	Dist Secondary - OH	Tree Outside ROW - Limb	1	1,065	15705
1836490	7/8/2014	19:21	20:53	92	Dist Secondary - OH	Tree ROW - Limb	1	92	15197
1836745	7/8/2014	19:37	6:15	637	Dist Primary - OH	Tree ROW - Limb	21	13,382	333
1837136	7/8/2014	20:09	17:11	1,262	Dist Secondary - OH	Tree Outside ROW - Down	1	1,262	15199
1837474	7/8/2014	22:29	12:07	818	Dist Primary - OH	Tree ROW - Limb	15	12,270	15198
1839960	7/9/2014	18:00	18:08	8	Dist Primary - OH	Tree ROW - Limb	16	128	14146
1840328	7/10/2014	11:51	16:57	306	Dist Secondary - OH	Tree ROW - Limb	1	306	394
1840776	7/10/2014	18:36	0:28	352	Dist Primary - OH	Tree Outside ROW - Limb	29	10,208	102
1840822	7/10/2014	21:49	22:12	24	Dist Primary - OH	Tree Outside ROW - Limb	261	6,138	145064
1840895	7/11/2014	0:27	3:46	198	Dist Secondary - OH	Tree Outside ROW - Limb	1	198	234

Table 2.4-P2 (continued)

Tree-Related Outages in 2014
(Inclusive IEEE 1366 – 2003 Std)

Event_ID	Date of Outage	Begin Time	End Time	Outage Duration	VC_SUBCAUSE	Outage_Cause	Customers Affected	Customer Minutes	Feeder
1841351	7/11/2014	17:58	19:23	85	Dist Secondary - URD	Tree ROW - Limb	4	341	14766
1842221	7/13/2014	22:35	7:00	504	Dist Primary - OH	Tree Outside ROW - Down	93	46,888	14765
1842223	7/13/2014	22:40	7:00	500	Dist Primary - OH	Tree Outside ROW - Down	1	500	14765
1842226	7/13/2014	22:44	7:00	496	Dist Primary - OH	Tree Outside ROW - Down	1	496	14765
1842379	7/14/2014	3:04	5:41	157	Dist Secondary - OH	Tree ROW - Limb	10	1,569	15016
1842900	7/14/2014	16:50	0:25	455	Dist Primary - OH	Tree Row - Down	7	3,185	64
1842891	7/14/2014	16:50	18:12	81	Dist Primary - OH	Tree ROW - Limb	579	47,015	92102
1842902	7/14/2014	16:54	19:40	166	Dist Secondary - OH	Tree Outside ROW - Limb	1	166	234
1842943	7/14/2014	16:58	20:59	240	Dist Primary - OH	Tree ROW - Limb	73	17,539	14016
1843384	7/14/2014	17:11	22:40	329	Dist Secondary - OH	Tree Outside ROW - Limb	10	3,290	14005
1843005	7/14/2014	17:11	22:40	329	Dist Secondary - OH	Tree Row - Down	16	5,262	14005
1843253	7/14/2014	18:53	3:44	532	Dist Secondary - OH	Tree Outside ROW - Down	27	14,360	15006
1843404	7/14/2014	20:47	21:44	56	Dist Secondary - OH	Tree ROW - Limb	1	56	15706
1844542	7/15/2014	14:42	20:49	367	Dist Primary - OH	Tree ROW - Limb	2	734	14767
1845527	7/15/2014	20:51	10:09	798	Dist Primary - OH	Tree ROW - Limb	15	11,969	15001
1845534	7/15/2014	20:53	1:30	277	Dist Primary - OH	Tree ROW - Limb	392	108,453	167
1845899	7/15/2014	20:55	3:08	374	Dist Primary - OH	Tree Row - Down	61	22,808	15001
1845882	7/15/2014	23:59	1:56	116	Dist Primary - OH	Tree Row - Down	252	29,308	490
1845830	7/15/2014	23:59	0:53	54	Dist Primary - OH	Tree Row - Down	372	20,069	490
1846593	7/17/2014	5:07	7:15	128	Dist Primary - OH	Tree ROW - Limb	6	768	451
1848586	7/21/2014	15:08	16:11	63	Dist Primary - OH	Tree ROW - Limb	15	945	102
1848585	7/21/2014	15:08	16:11	63	Dist Primary - OH	Tree Outside ROW - Limb	14	882	102
1851308	7/26/2014	11:24	11:40	16	Dist Secondary - OH	Tree Outside ROW - Limb	1	16	14135
1851478	7/27/2014	5:07	7:48	160	Dist Primary - OH	Tree ROW - Limb	15	2,401	15001
1851599	7/27/2014	21:57	0:16	139	Dist Secondary - OH	Tree Outside ROW - Limb	1	139	205
1851846	7/28/2014	12:48	18:06	318	Dist Primary - OH	Tree Outside ROW - Limb	5	1,590	368
1851888	7/28/2014	13:30	14:50	79	Dist Primary - OH	Tree ROW - Limb	58	4,595	14006
1852920	7/30/2014	9:57	13:30	213	Dist Primary - OH	Tree Outside ROW - Limb	44	9,372	14767
1852984	7/30/2014	10:07	19:04	537	Dist Secondary - OH	Tree ROW - Limb	1	537	414
1854355	8/2/2014	2:02	9:32	450	Dist Secondary - OH	Tree Outside ROW - Limb	15	6,750	15945
1854379	8/2/2014	9:24	13:45	261	Dist Secondary - OH	Tree Outside ROW - Limb	1	261	15171
1854633	8/3/2014	1:52	2:03	11	Dist Primary - OH	Tree ROW - Limb	37	407	75
1857188	8/7/2014	10:49	11:26	37	Dist Primary - OH	Tree Outside ROW - Limb	1977	73,149	15705
1857517	8/7/2014	19:24	19:59	35	Dist Secondary - OH	Tree ROW - Limb	1	35	15130
1858642	8/10/2014	12:20	13:29	70	Dist Secondary - OH	Tree Outside ROW - Limb	29	2,018	15010
1859229	8/12/2014	10:53	13:02	128	Dist Secondary - OH	Tree ROW - Limb	1	128	15006
1862014	8/17/2014	20:10	21:23	74	Dist Primary - OH	Tree Outside ROW - Down	1	74	15169
1864505	8/24/2014	2:30	4:22	112	Dist Primary - OH	Tree Row - Down	201	22,495	133
1864505	8/24/2014	2:30	5:18	167	Dist Primary - OH	Tree Row - Down	137	22,918	133

Table 2.4-P2 (continued)

Tree-Related Outages in 2014
(Inclusive IEEE 1366 – 2003 Std)

Event_ID	Date of Outage	Begin Time	End Time	Outage Duration	VC_SUBCAUSE	Outage_Cause	Customers Affected	Customer Minutes	Feeder
1864500	8/24/2014	2:30	4:22	111	Dist Primary - OH	Tree Row - Down	136	15,135	133
1864745	8/25/2014	11:07	13:07	119	Dist Secondary - OH	Tree Outside ROW - Limb	1	119	15943
1866248	8/28/2014	16:26	19:10	163	Dist Secondary - OH	Tree Outside ROW - Down	1	163	14007
1866762	8/30/2014	16:34	17:26	52	Dist Primary - OH	Tree ROW - Limb	2	105	14006
1866763	8/30/2014	16:47	17:26	39	Dist Primary - OH	Tree Outside ROW - Limb	7	273	14006
1866924	8/31/2014	13:49	15:14	85	Dist Secondary - OH	Tree Outside ROW - Limb	1	85	14700
1867226	8/31/2014	18:41	21:33	171	Dist Secondary - OH	Tree Outside ROW - Down	1	171	15001
1867701	9/1/2014	3:07	3:13	5	Dist Primary - OH	Tree ROW - Limb	2068	11,133	14758
1869779	9/2/2014	21:43	0:17	154	Dist Primary - OH	Tree Outside ROW - Limb	525	80,780	65
1870495	9/3/2014	11:28	18:03	395	Dist Primary - OH	Tree ROW - Limb	5	1,975	14031
1870709	9/3/2014	19:16	19:59	43	Dist Secondary - OH	Tree ROW - Limb	1	43	15945
1872932	9/7/2014	21:13	0:05	172	Dist Secondary - OH	Tree Outside ROW - Limb	1	172	15012
1875303	9/13/2014	13:59	14:23	24	Dist Primary - OH	Tree Outside ROW - Limb	723	17,509	14200
1875318	9/13/2014	14:17	14:23	6	Dist Primary - OH	Tree Outside ROW - Limb	213	1,250	14200
1875611	9/13/2014	19:43	20:00	17	Dist Primary - OH	Tree Outside ROW - Limb	41	697	118
1878887	9/22/2014	1:58	8:27	389	Dist Primary - OH	Tree ROW - Limb	20	7,778	205
1880334	9/24/2014	23:43	1:48	125	Dist Secondary - OH	Tree Outside ROW - Down	1	125	14261
1880964	9/26/2014	11:46	13:53	127	Dist Primary - OH	Tree ROW - Limb	53	6,731	15001
1880964	9/26/2014	13:15	13:53	38	Dist Primary - OH	Tree ROW - Limb	154	5,852	15001
1881189	9/27/2014	8:45	10:07	82	Dist Secondary - OH	Tree Outside ROW - Limb	1	82	372
1882711	10/1/2014	12:25	14:46	141	Dist Secondary - OH	Tree ROW - Limb	1	141	15014
1882853	10/1/2014	19:22	21:00	98	Dist Primary - OH	Tree ROW - Limb	84	8,219	15130
1883925	10/3/2014	20:46	22:09	84	Dist Secondary - OH	Tree ROW - Limb	1	84	308
1884229	10/4/2014	13:50	16:15	145	Dist Secondary - OH	Tree ROW - Limb	1	145	15943
1884442	10/5/2014	3:26	3:33	7	Dist Primary - OH	Tree Outside ROW - Limb	349	2,443	146476
1884853	10/6/2014	12:47	15:20	152	Dist Secondary - OH	Tree ROW - Limb	1	152	394
1885009	10/6/2014	18:22	19:21	59	Dist Secondary - OH	Tree ROW - Limb	29	1,711	15010
1885065	10/7/2014	7:23	9:48	144	Dist Secondary - OH	Tree ROW - Limb	1	144	14261
1885698	10/8/2014	11:59	15:10	190	Dist Secondary - OH	Tree Outside ROW - Limb	1	190	14752
1887021	10/11/2014	8:04	8:55	51	Dist Primary - OH	Tree Outside ROW - Limb	6	303	15801
1887103	10/11/2014	16:48	16:55	6	Dist Primary - OH	Tree Outside ROW - Limb	298	1,922	92082
1887106	10/11/2014	16:48	17:34	45	Dist Primary - OH	Tree ROW - Limb	52	2,363	82
1887229	10/12/2014	8:55	13:12	257	Dist Secondary - OH	Tree ROW - Limb	1	257	15012
1887726	10/13/2014	21:36	22:58	83	Dist Secondary - OH	Tree Outside ROW - Limb	1	83	14035
1891820	10/21/2014	19:00	20:33	93	Dist Secondary - OH	Tree ROW - Limb	19	1,769	15198
1891928	10/22/2014	4:45	10:42	357	Dist Primary - OH	Tree ROW - Limb	2	714	15011
1892753	10/23/2014	12:45	14:41	116	Dist Primary - OH	Tree ROW - Limb	64	7,424	145064
1892762	10/23/2014	12:54	14:41	107	Dist Primary - OH	Tree ROW - Limb	4	428	64
1893716	10/26/2014	19:33	21:10	97	Dist Secondary - OH	Tree Outside ROW - Limb	1	97	490
1894468	10/28/2014	10:51	12:27	96	Dist Primary - OH	Tree Outside ROW - Limb	21	2,016	15197

Table 2.4-P2 (continued)

Tree-Related Outages in 2014
(Inclusive IEEE 1366 – 2003 Std)

Event_ID	Date of Outage	Begin Time	End Time	Outage Duration	VC_SUBCAUSE	Outage_Cause	Customers Affected	Customer Minutes	Feeder
1896506	11/2/2014	14:11	15:14	63	Dist Secondary - OH	Tree Outside ROW - Limb	23	1,449	15016
1896561	11/2/2014	17:21	23:10	348	Dist Primary - OH	Tree Outside ROW - Down	12	4,177	14135
1896671	11/3/2014	6:59	10:23	204	Dist Primary - OH	Tree ROW - Limb	1	204	14007
1897952	11/6/2014	5:27	7:43	136	Dist Primary - OH	Tree ROW - Limb	34	4,624	467
1898262	11/6/2014	7:23	10:54	211	Dist Primary - OH	Tree Outside ROW - Limb	6	1,266	394
1898892	11/7/2014	12:40	14:13	93	Dist Secondary - OH	Tree Row - Down	20	1,863	309
1902624	11/15/2014	10:14	15:53	339	Dist Primary - OH	Tree Row - Down	20	6,780	117
1902712	11/15/2014	15:42	15:53	11	Dist Primary - OH	Tree Row - Down	57	627	117
1903852	11/18/2014	17:01	18:35	94	Dist Primary - OH	Tree Outside ROW - Down	257	24,158	15130
1905608	11/24/2014	2:18	5:25	187	Dist Primary - OH	Tree ROW - Limb	1	187	14006
1909254	12/5/2014	10:35	12:10	95	Dist Primary - OH	Tree Outside ROW - Limb	9	855	386
1910358	12/9/2014	20:24	22:18	114	Dist Primary - OH	Tree Row - Down	252	28,728	111097
1912462	12/17/2014	11:06	12:25	79	Dist Primary - OH	Tree ROW - Limb	10	787	15174
1913283	12/20/2014	12:31	16:37	245	Dist Primary - OH	Tree Outside ROW - Limb	1	245	118
1914139	12/24/2014	7:43	10:19	156	Dist Primary - OH	Tree Outside ROW - Down	7	1,092	14007
1914543	12/27/2014	7:49	9:33	104	Dist Primary - OH	Tree ROW - Limb	28	2,912	14132
1915507	12/31/2014	13:23	16:34	191	Dist Primary - OH	Tree Row - Down	1370	261,670	15707
1915507	12/31/2014	13:23	14:41	78	Dist Primary - OH	Tree Row - Down	920	71,760	15707
1915507	12/31/2014	16:04	16:34	30	Dist Primary - OH	Tree Row - Down	661	19,830	15707

Table 2.4-P2 (continued)

2.4.7 ELECTRICITY QUALITY OF SERVICE STANDARDS (EQSS)

The Commission introduced the EQSS to establish standards and requirements for ensuring that electric utilities operating in the District of Columbia meet an adequate level of quality and reliability in the electric service provided to District residents. On February 29, 2008, the Commission issued a Notice of Final Rulemaking (NOFR) on the EQSS. The EQSS are now adopted as Chapter 36, Electricity Quality of Service Standards in Title 15 of the District of Columbia Municipal Regulations. Subsequently on July 25, 2008, the Commission issued a NOFR on Compliance Reporting. Pepco and all electricity suppliers within the District of Columbia were directed to collect EQSS data on a monthly basis and retain the reporting data for seven (7) years. Further, quarterly submissions, containing monthly data, are to be filed with the Commission on April 30, July 30, October 30 and January 30 for the prior three (3) months respectively. Specific Consolidated Report requirements from the EQSS portion of the D.C.M.R. are listed below.

3602.6 Progress on current corrective action plans [on customer calls answered] shall be included in the utility's annual Consolidated Report.

3602.7 The utility shall report the actual call center performance during the reporting period in the annual Consolidated Report of the following year.

3602.12 Progress on any current corrective action plans [on call abandonment rates] will be included in the utility's annual Consolidated Report.

3602.13 The utility shall report the actual performance obtained during the reporting period in the annual Consolidated Report of the following year.

3602.14 The utility shall complete installation of new residential service requests within ten (10) business days of the start date for the new installation.

3602.21 Progress on any current corrective action plans [on new residential service installation requests] will be included in the utility's annual Consolidated Report.

3602.22 The utility shall report the actual performance obtained during the reporting period in the annual Consolidated Report of the following year.

3603.5 The utility shall report on the progress of the corrective action plan [on repeat least performing feeders] in the Annual Consolidated Report submitted to the Commission.

3603.8 The utility shall report on the number and percentage of non-major service outages that extend beyond the twenty-four (24) hour standard and the reasons each such outage extended beyond the twenty-four (24) hour standard.

3603.9 The report drafted pursuant to Section 3603.8 shall be included in the annual Consolidated Report on reliability data.

3603.16 The utility shall report on the progress of the corrective action plan [on SAIFI, SAIDI and CAIDI benchmarks] in the annual Consolidated Report submitted to the Commission.

3603.17 The utility shall also, per the orders of the Commission, continue current requirements of reporting annual reliability indices of SAIFI, SAIDI and CAIDI (with and without major events) in the annual Consolidated Report of the following year.

Electricity Quality of Service Standards Results

January – December 2014 Aggregate Totals

3601	Reporting Requirements for Service Outages, Incidents and Power Quality Complaints						
Standards			2014 Aggregate Totals				
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3601.2/ 3601.6	Report major and non-major service outages by telephone and e-mail within one (1) hour after the utility has determined that a major service outage occurred or after the utility becomes aware of the incident.	Report by telephone and e-mail **within one (1) hour.**	378	99%	See FC Nos. 982 & 1002, Pepco's Quarterly EQSS filings dated April 29, 2014; July 30, 2014; October 30, 2014; and January 30, 2015.		
3601.3/ 3601.8	Each telephone and e-mail report on major and non-major outages should contain a) the location, b) Wards affected, c) # of customers out of service, d) cause of the outage, e) the estimated repair time, and, for major outages, f) notification of progress to major outage status.	Each 3601.3 report must contain **(a) - (f)**, each 3601.8 report must contain **(a) - (e)**.	378	99% (Except for ward data)	See FC Nos. 982 & 1002, Pepco's Quarterly EQSS filings dated April 29, 2014; July 30, 2014; October 30, 2014; and January 30, 2015.		
3601.4	Report periodically (frequency to be determined by the Commission's Office of Engineering) regarding the status of the major service outage.	**TBD**	NA	NA			

3601	Reporting Requirements for Service Outages, Incidents and Power Quality Complaints						
Standards			2014 Aggregate Totals				
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3601.5	Specific restoration information, including restoration times, shall be provided to District customers by customer service representatives and the automated voice response unit.	**TBD**	NA	NA			
3601.9/ 3601.11	Report by telephone all manhole incidents (smoking manholes, manhole fires, manhole explosions) and all incidents that result in the loss of human life and/or personal injury requiring hospitalization within thirty (30) minutes upon receiving notice of the incident.	Report **within 30 minutes** of receiving notice of incident.	77	96%	See FC Nos. 982 & 1002, Pepco's Quarterly EQSS filings dated April 29, 2014; July 30, 2014; October 30, 2014; and January 30, 2015.		
3601.10/ 3601.12	Telephone and e-mail reporting of incidents to include: a/b) location/description of the incident, b/c) Ward, c/d) customers and/or persons affected, d/e) cause of incident, e) estimated repair and/or restoration time (for manhole incidents), and f) steps utility will take to provide assistance (for personal injury incidents).	**Each 3601.10 report must contain (a) - (e)**, each 3601.12 report must contain **(a) - (f)**.	77	96% (Except for ward data)	See FC Nos. 982 & 1002, Pepco's Quarterly EQSS filings dated April 29, 2014; July 30, 2014; October 30, 2014; and January 30, 2015.		

3601	Reporting Requirements for Service Outages, Incidents and Power Quality Complaints						
Standards			2014 Aggregate Totals				
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3601.13/ 3601.15	Written reports concerning non-major service outages and/or manhole incidents shall be submitted to OE and OPC within five (5) days from the date of the event occurrence. Written reports on the loss of human life/personal injury shall be submitted within five (5) days of receiving notice of the incident.	Submit 3601.13 report **within 5 days of event,** and 3601.15 report **within 5 days of receiving notice.**	455	100%			
3601.14/ 3601.16	At a minimum: each written report on non-major service outages and/or manhole incidents shall state, a) description, b) location, c) Wards, d) time of the outage, e) repair and restoration times, f) duration of outage(s) in hrs/min., g) total # of customers, h) total # of manholes, i) classification of the manhole incident(s); each written report on loss of human life and/or personal injury shall state, a) description, b) location, c) Ward, d) exact time, e) total # of customers, f) assistance steps, g) time it took assistance to arrive, h) steps to prevent reoccurrence.	Each 3601.14 report must contain **(a) - (i)**, each 3601.16 report must contain **(a) - (h)**.	455	100%			
3601.17	Provide a detailed report on non-major service outages, manhole incidents, and/or incidents that result in the loss of human life or personal injury to the Productivity Improvement Working Group (PIWG) every quarter.	Submit all applicable reports to the PIWG **every quarter**.	4	100%			

3601	Reporting Requirements for Service Outages, Incidents and Power Quality Complaints						
Standards			2014 Aggregate Totals				
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3601.18	File a written report concerning major service outages within 3 weeks following the end of the outage.	File the required written report **to each office within three (3) weeks** of the end of a major service outage.	0	NA			
3601.19	Specifies minimum requirements for the contents of the written report for major service outages. ***Please refer to the EQSS for (a)-(o) as they are very detailed and are not listed here.***	Each written report must **contain** information **from (a) - (o).**	NA	NA			
3601.2	Submit a written report on the Outage Management System's (OMS) actual performance during the major service outage within 30 days after restoration efforts are completed.	Submit written report **within 30 days** after restoration.	NA	NA			
3601.21/ 3601.23	Record and report the number of power quality complaints received, types of complaints received, results of subsequent investigations, corrective actions taken, and the time it took to resolve the customer's problem.	Submit the report **45** days after each **six (6) month** reporting period.	2 See reports filed May 15, 2014 and Nov. 15 2014 in FC Nos. 982 & 1002	NA			

3602	Customer Service Standards							
Standards			2014 Aggregate Totals					
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3602.1	Maintain a customer service (walk-in) office located in the District of Columbia.	Notify location of **one (1)** office.	701 9th St NW, Washington, DC 20068	100%			
3602.2	Answer at least seventy (70) percent of all customers' phone calls received within thirty (30) seconds and maintain records delineating customer phone calls answered by a utility representative or an automated operator system. Utility shall measure and report on the average customer wait time for a customer transferred from an automated operator system to a utility representative.	70% of received calls answered within **30** seconds	1,054,030 (Total calls) Call answering rate = 75%	100%			
3602.4/ 3602.6/ 3602.7	Develop a corrective action plan if 3602.2 standard is not met. Report on the progress of current corrective action plans and actual call center performance in the annual Consolidated Report.	Written corrective action plan in CR	NA	NA			
3602.8	Call abandonment rate must be maintained below ten (10) percent.	Call abandonment rate **below 10%**	50,462 (Calls abandoned) Call abandonment rate = 5%	100%			
3602.10/ 3602.12/ 3602.13	Develop a corrective action plan if 3602.8 standard is not met. Report on the progress of current corrective action plans and actual call center performance in the annual Consolidated Report.	Written corrective action plan in CR	NA	NA			

3602	Customer Service Standards (cont'd.)						
Standards			2014 Aggregate Totals				
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3602.14	Complete installation of new residential service requests within ten (10) business days of the start date for the new installation.	Service requests installed within **10** days of start.	307	99%			
3602.16	Submit a written report on its performance in 3602.14 every six (6) months.	One report every six **(6)** months.	2 See reports filed May 15, 2014 and Nov. 15 2014 in FC Nos. 982 & 1002	100%			
3602.19/ 3602.21/ 3602.22	Develop a corrective action plan if 3602.14 standard is not met. Report on the progress of current corrective action plans and actual performance in the annual Consolidated Report.	Written corrective action plan in CR	1	100%	See report filed May 15, 2014 in FC Nos. 982 & 1002		

3603	Reliability Standards							
Standards			**2014 Aggregate Totals**					
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3603.1	Implement a plan to improve the performance of the two (2) percent least performing feeders.	Written plan identifying the 2% LP feeders targeted.	See Consolidated Report Filed 2/15/2014	100%			
3603.3/ 3603.5	If the utility fails to comply with 3603.1, a corrective action plan is required. Report on the progress of the corrective action in the Consolidated Report.	Written corrective action plan in CR	See Consolidated Report Filed 2/15/2014	100%			
3603.7/ 3603.8	Complete service restoration within 24 hours following a non-major service outage. Report on the number and percentages of outages that extend beyond the 24 hour standard and the causes for the extended outages.	Restoration within **24** hrs. Written report on 24 hr exceedance in CR	378	97%	See FC Nos. 982 & 1002, Pepco's Quarterly EQSS filings dated April 29, 2014; July 30, 2014; October 30, 2014; and January 30, 2015.		
3603.10/ 3603.11/ 3603.12/ 3603.13	Utility shall not exceed the benchmark levels established for the System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), and the Customer Average Interruption Duration Index (CAIDI).	Refer to Order No. 16700.	NA (Refer to Order No. 16700)	NA			
3603.14/ 3603.16/ 3603.17	Develop a corrective action plan if 3603.10 standard is not met. Report on the progress of current corrective action plans and actual performance in the annual Consolidated Report.	Document Corrective action plan in CR	NA	NA			

3604	Billing Error Notification						
Standards			**2014 Aggregate Totals**				
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3604.1	Inform Commission and OPC of a billing error when it affects 100 or more customers or the number of affected customers is equal to or more than two (2) percent of the utility's or service provider's customer base (whichever is less). If the customer base is less than 100, report errors when two (2) or more customers are affected.	Notices when 100, or 2%, or 2 or more customers are affected.	3	100%			
3604.2/ 3604.3	Submit an initial billing error notification (by e-mail) within one (1) business day of discovering or being notified of the error, submit a written report within 14 calendar days and a final written report within 60 calendar days.	Initial notification within one **(1)** b/day, 1st written report within **14** c/days, final written report within 60 c/days.	1	100%			
3604.4	Initial billing error notification shall contain: a) type of billing error, b) when discovered, c) how discovered, and d) # of customers affected.	Notification must contain **(a) - (d)**.	1	100%			
3604.5	Follow-up written report shall contain: a) type of billing error, b) when it occurred, c) # of customers affected, d) the cause of the error and correction status, and, e) timeline for completing correction plan.	Report must contain **(a) - (e)**, and show closeout of **(d) within 60 days.**	1	100%			

3604	Billing Error Notification (cont'd.)						
Standards			**2014 Aggregate Totals**				
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3604.6/ 3604.7	Final written report shall contain: a) type of billing error, b) when it occurred, c) # of customers affected, d) duration of the billing error(s), e) corrective and preventive measures taken, and, f) lessons learned, if any. Commission shall determine whether further investigation is necessary.	Report must contain **(a) - (f).**	3	100%			

2014 EQSS Report Errata

During the production of the 2015 CR, several inadvertent errors in Pepco's the first three quarters of 2014 EQSS reports were discovered. The following table identifies and corrects those errors:

2014 EQSS Report Errata				
	Section	Filed	Correction	Explanation
1st Quarter				
February	3603.7/3603.8	32	34	Entered number of events compliant not Total number of Events.
March	3603.7/3603.8	31	32	Entered number of events compliant not Total number of Events.
1st Qtr. Aggregate	3603.7/3603.8	98	101	Entered number of events compliant not Total number of Events.
2nd Quarter				
April	3601.9/3601.11	8	7	Incorrect number of Manhole Events Only seven events in April.
	3601.10/3601.12	8	7	Incorrect number of Manhole Events Only seven events in April.
	3601.13/3601.15	37	36	Total number of Events reduced by 1 due to above.
	3601.14/3601.16	37	36	Total number of Events reduced by 1 due to above.
2nd Qtr. Aggregate				
	3601.9/3601.11	13	12	Total number of Events reduced by 1 due to above.
	3601.10/3601.12	13	12	Total number of Events reduced by 1 due to above.
	3601.13/3601.15	118	117	Total number of Events reduced by 1 due to above.
	3601.14/3601.16	118	117	Total number of Events reduced by 1 due to above.
3rd Quarter				
August	3601.9/3601.11	5	4	Incorrect number of Manhole Events Only four events in August No change in Percent compliant 100%.
	3601.10/3601.12	5	4	Incorrect number of Manhole Events Only four events in August No change in Percent compliant 100%.
	3601.13/3601.15	24	23	Total number of Events reduced by 1 due to above.
	3601.14/3601.16	24	23	Total number of Events reduced by 1 due to above.
September	3601.9/3601.11	6	5	Incorrect number of Manhole Events Only five events in September. Percent compliant changed from 67% to 60%. 3 Events were compliant.
	3601.10/3601.12	6	5	Incorrect number of Manhole Events Only five events in September.
	3601.13/3601.15	28	27	Total number of Events reduced by 1 due to above.
	3601.14/3601.16	28	27	Total number of Events reduced by 1 due to above.
3rd Qtr. Aggregate				
	3601.9/3601.11	19	17	Total number of Events reduced by 2 due to above. Percent compliant changed from 85% to 82%
	3601.10/3601.12	19	17	Total number of Events reduced by 1 due to above. Percent compliant changed from 85% to 82%
	3601.13/3601.15	146	144	Total number of Events reduced by 2 due to above.
	3601.14/3601.16	146	144	Total number of Events reduced by 2 due to above.

New Residential Service Installation Requests

In 2014, Pepco completed 99% (306 of 307) of the new residential service installation requests received for the District of Columbia in accordance with Section 3602.14 of the EQSS as stated below.

> *The utility shall complete installation of new residential service requests within ten (10) business days of the start date for the new installation.*

As a result of not achieving 100% for this standard for 2014, in accordance with Section 3602.21 in the EQSS, Pepco is required to report on the progress of any current correction action plans in the Company's annual Consolidated Report. As reported in Pepco's May 15, 2014 filing in FC Nos. 982 and 1002, corrective action includes addressing data entry issues with the responsible employee(s).

Quarters	Percentage of New Residential Service Connections Made in Accordance with Section 3602.14 of EQSS	
	CY 2013	CY 2014
1st	100%	99%
2nd	98%	100%
3rd	96%	100%
4th	100%	100%

Table 2.4-Q

Non-Major Outages, Restoration Completion Within 24 Hours

In accordance with Section 3603.8 in the EQSS, Pepco is to include in the Consolidated Report the number and percentage of non-major customer outages that extend beyond the 24 hour standard and the causes for these extended service outages. A Major Service Outage in the District of Columbia, as defined in Section 3699.1, Definitions, of the EQSS states, "*customer interruption occurrences and durations during time periods when 10,000 or more of the electric utility's District of Columbia customers are without service and the restoration effort due to this major service outage takes more than 24 hours.*" Tables 2.4-R and 2.4-S provide the required information.

For 2014, there were 11 (out of 378) non-major outages (3%) that extended beyond 24 hours.

Percentage of Non-Major Outages that Extended Beyond 24 Hours

Total number of Non-Major Outages extending beyond 24 hours	11
Total number of Non-Major Outages: January 1 - December 31, 2014	378
Percentage of Non-Major Outages extending beyond 24 hours	3%

Table 2.4-R

2014 Non-Major Outage Reporting to the Public Service Commission of the District of Columbia - Outages Exceeding 24 Hours

Report Sequence Number	Outage Sequence Number	Manhole Sequence Number*	Month	Day of Outage	OH or UG	Outage Cause/ Incident Description	Location	Quadrant	Ward	Time of Outage/ Incident	Actual Restoration Time	Duration of Outage Hours	Duration of Outage / min	Max No. of Cust. Affected	Reason for Outage Exceeding 24 Hours to Restore	Feeder No.
21	52		February	13	UG	Equipment failure/Secondary service cable failure/ Replaced service cable	1300 Michigan Avenu	NE	5	1559	2114 (2/14)	29	15	1	The extended outage on feeder 14007 was due to the cold temperatures', snow and ice from 2/12/14 through 2/14/14. At 15:59 on 2/13/14 a customer reported no lights. At 17:05 on 2/13/14 the lead line mechanic reported a dead leg inside the meter and the service is fed underground. The underground crews replaced the service cable and all load was restored at 21:14 on 2/14/14.	14007
21	53		February	13	UG	Equipment failure/Customer had partial service/ Crew found neutral off in manhole/Permanent repairs made	300 block of 17th Stre	SE	6	1740	2300 (2/14)	29	20	1	The extended outage on feeder 208 was due to the cold temperatures', snow and ice from 2/12/14 through 2/14/14. At 17:40 on 2/13/14 a customer reported partial service. The UG Crew found a neutral off in the manhole. Permanent repairs were made by splicing the neutral. The customer's load was restored at 23:00 on 2/14/14.	208
44	94		March	21	UG	Equipment failure/Secondary cable fault/Feeder tripped/On 3-22-14 at 0015 hrs. Underground completed temporary repairs/At 0305 hrs. received reports of partial current/Second fault located/Replaced cable/All load restored	16th Street and Newton Street, NW	NW	1	1847	0549 (3/23)	35	2	337	The extended outage on feeder 86 was due to multiple faults on the feeder. At 18:47 on March 21, 2014 feeder 86 tripped. At 20:32 on March 21 the UG Crew Located a fault in the cable joint and start preparations for the repair. On March 22, 2014 at 00:15 the crew completed temporary repairs to feeder 86 and restored load. At 0305 reports of partial current were received. CR& T located the second fault at 13:05. The UG Crew started repairs of second fault at 15:00 on March 22, 2014. Two sections of cable were removed . There were problems removing second section of cable. On March 23, 2014 the second section of cable was installed and splicing completed at 05:00. All load was restored at 05:49 on March 23, 2014.	86
57	118		April	22	UG	Dig in/Cable and conduit damaged/Blown fuse/Temporary repairs made/Referred to Conduit Department to repair duct/Load restored	4th and College Streets, NW	NW	1	1525	2029 (23)	29	4	3	4-22-14 A report of a cable cut due to contractors working E/O 4th and College Streets, NW. The Pepco crew responded at 18:00 hrs. The crew isolated the cable cut and made temporary repairs, the crew assumed they restored all load. Their were no reports of partial service. The parties involved were not aware of a 150 E fuse was blown until 4-23-14 at 08:30 hrs While inspecting job for permanent repairs. The Crew re[placed the fuse and all load was restored at 15:02 hrs.	14004
61	130		April	30	UG	Equipment failure/Partial service/Secondary service failed/Replaced secondary service/All load restored(Note: could not get access to neighbor's yard to locate problem)	2600 block of Sherman Avenue, NW	NW	1	1156	2100 (5/1)	33	4	1	This was a complaint dispatched to the trouble truck on 4/30. The crew found a pipe bus with no access, the house was under renovation with no occupants this was referred to Service crew in the morning on 5/1. The Burns box (connection point) was blocked by construction debris. Once access was established, the service duct was found broken down and conduit was needed to repair the duct line, the General shops was also needed to cut wooded planks installed as a porch. This was all very time consuming.	4729

Table 2.4-S: 2014 Non-Major Outages Extending Beyond 24 Hours

2014 Non-Major Outage Reporting to the Public Service Commission of the District of Columbia - Outages Exceeding 24 Hours

Report Sequence Number	Outage Sequence Number	Manhole Sequence Number*	Month	Day of Outage	OH or UG	Outage Cause/ Incident Description	Location	Quadrant	Ward	Time of Outage/ Incident	Actual Restoration Time	Duration of Outage Hours / min		Max No. of Cust. Affected	Reason for Outage Exceeding 24 Hours to Restore	Feeder No.
63	135		May	1		Equipment failure/transformer failed/Replaced transformer	600 block of Monroe Street, NE	NE	5	905	1943 (5/2)	34	38	1	On 5/1/14 a Pepco employee was sent to investigate a partial current @ 625 Monroe St. N.E. There are 4 subsurface transformers @ that location feeding 4 different switchboards. The transformer in question 800399-673864 a 750 kva subsurface transformer on feeder 14200 had blown 2 fuses in the previous couple of days. The Underground Department decided to have CR&T meager the service. They identified 1 set of 500 service cable that would not meager. We hooked the remaining 6 sets up and re-energized and blew the fuse again. Removed the secondaries and fuse blew again. We replaced the 750 kva transformer restoring, all load. This transformer was installed last year this also, happened after the last major rain storm.	14200
97	225		July	3	OH	Vegetation/Tree limb/Wire down/Fuse blown/Reinstalled wire/Replaced fuse	3500 Block of Overlook lane, NW	NW	3	1635	1954 (7/4)	27	19	7	Due to the outages cause by the storm on July 3, 2014, Pepco was not able to assign a crew to this location until the following day. The OH crew found an 85a line fuse blown because of the primary wire down between poles due to a tree limb. The crew reinstalled the wire and replaced the fuse restoring the load at 19:54 hours on July 4, 2014.	64
97	227		July	3	OH	Vegetation/Tree limb/Wire down/Reinstalled wire	4200 block of 52nd Street, NW	NW	3	1626	1649 (7/4)	24	23	11	Due to the outages cause by the storm on July 3, 2014, Pepco was not able to assign a crew to this location until the following day. The OH crew found several spans of primary wire down between poles due to a tree limbs. The crew reinstalled the wire, restoring the load at 16:49 hours on July 4, 2014.	144
97	236		July	3	OH	Vegetation/Tree limb/Wire down/Permanent repairs made	16th Street and Tuckerman Street, NW	NW	4	1646	1739 (7/4)	24	53	8	Due to the outages cause by the storm on July 3, 2014, Pepco was not able to assign a crew to this location until the following day. The OH crew found the secondary bus and the primary wire down between poles due to a tree limb. The crew made permanent repairs restoring the load at 17:39 hours on July 4, 2014.	15021
98	246		July	4	UG	Equipment failure/Trans closure failure/Cable failure/Fuse blown/Isolated trans closure and cable fault/Closed tie/Replaced fuse/All load restored	Wisconsin Avenue and Rodman Street, NW	NW	3	2035	0303 (7/6)	30	28	196	The extended outage on feeder 14136 was due to a cable faults on the feeder. The crew arrived at 12:15 am on July 15,2014 isolated the fault and closed the tie restoring load. The UG crew reported that the porcelain insulator in trransclouser fell apart while replacing fuse. The transcoluser was replaced at 12:59 on July 5, 2014. The fuse was replaced and closed blowing the fuse due to another cable fault. The fault was isolated the fuse replaced, restoring the load at 03:03 on July 6, 2014.	14136
	329	DC14-68	Septembe	22	UG	Equipment failure/A fuse box and two oil switches damaged when concrete collapsed into the vault /Feeders tripped/Permanent repairs made/load restored	1700 block of East C	NE	6	1922	0301 (9/24)	31	39	5	On September 22, 2014 at 19:22 Feeder 14804 and14154 tripped. At 19:32 the DCFD reported an explosion in the 1700 block of East Capitol Street, NE. At 20:22 MO arrived on location and reported that the manhole had caved in. Upon arrival the UG crew reported that two oil switches were blown off the wall with slabs of concrete and exposed cable in the manhole. Permanent repairs were made and at 01:39 on September 24, 2014 the VLF testing was performed on the feeder. At 03:01 on September 24, 2014 the feeder passed the VLF testing. At this time the feeder was closed, restoring all load.	14145, 14804

Table 2.4-S (con't): 2014 Non-Major Outages Extending Beyond 24 Hours

PART 3: 2014 MANHOLE EVENT REPORT

PART 3: 2014 MANHOLE EVENT REPORT[72]

Part 3 of the Consolidated Report includes manhole event information, underground failure analysis results, detail tracking trends in reportable events based on manhole cover type, and Pepco's cable splice records for 2014. The appendices provide detail regarding manhole events, Pepco's manhole inspection program, and Pepco's Network Accuracy Procedure implementation.

[72] In Order No. 16091 issued on December 10, 2010, the Commission stated at paragraphs 56, 59, 65, and 66 the following:

56. Decision. Pepco has agreed to make the recommended changes in the 2011 Consolidated Report with the exception of data on failure rates. We require that the members of the PIWG discuss the need for and feasibility of providing data on failure rates in future Consolidated Reports and include in the 2011 Consolidated Report the PIWG conclusions and recommendations, if any.

59. Decision. We adopt the Staff's recommendation and require Pepco to: (1) combine the Manhole Events portion of the failure analysis report with Part 3 of the Consolidated Report; (2) include data in the 2011 Consolidated Report that separates 4 kV primary failures from 13 kV primary failures; (3) include data in the 2011 Consolidated Report that separates 4 kV from 13 kV manhole events; (4) include trend analyses for "Use of Slotted Manhole Covers;" and (5) include in the Cable Splice or Joint Database section of the Consolidated Report, cable type, age, type of splice and other pertinent information, except that cable type and age can be excluded if unavailable. If data on failure rates for all variables is available for manhole events, Pepco shall include such information in its 2011 Consolidated Report. If such data is unavailable, we require the members of PIWG to discuss the need for and the availability of such data include in the 2011 Consolidated Report the PIWG conclusions and recommendations, if any.

65. Pepco IS DIRECTED to include a discussion of failure data rates in the agenda for the Productivity Improvement Working Group, consistent with Paragraphs 56 and 59 of this Order; and

66. Pepco IS DIRECTED to include additional Manhole Event data in the 2011 Consolidated Report, consistent with Paragraph 59 of this Order.

In Order No. 15152 paragraphs 76 and 66, the Commission ordered the following:

76. PEPCO is DIRECTED to include as part of the 2009 Consolidated Report a proposed plan for significantly reducing manhole events consistent with paragraph 66 of this Order…

SECTION 3.1 – 2014 MANHOLE EVENT INTRODUCTION

Pepco herein submits its annual Manhole Event Report for 2014 in accordance with Order Nos. 11716, 13812, 15620 and 16091.

Summary of 2014 Manhole Events

During 2014, there were a total of 77 reportable manhole events in the District of Columbia. Of these 77 manhole events, 59 were classified as Smoking Manholes (S), 13 were classified as Manhole Explosions (E), and 5 were classified as Manhole Fires (F). Sixty-six of the 77 events occurred on the 13 kV system. Of these, 49 were classified as Smoking Manholes (S), 12 were classified as Manhole Explosions (E) and 5 were classified as Fires (F). Of the ten events occurring on the 4 kV system, ten were classified as Smoking Manholes (S) and one was classified as a Manhole Explosion (E). Appendix 3A is a list of the 2014 manhole events, categorized and described as directed in Order Nos. 11716, 15620 and 16091.

SECTION 3.2 – UNDERGROUND FAILURE ANALYSIS

Order No. 17074 Requirement

Order No. 17074 states the following at paragraphs 38 and 40:

38. *The Order further noted OPC's statement that according to Pepco, its replacement program would screen all feeders by collecting the number of underground faults experienced by each feeder in the last ten years and feeders with five or more faults ("5-in1-10") would be further analyzed for replacement. [Footnote: See F.C. 766-ACR-12, Order No. 16975, paragraph 75.] …Thus, we direct Pepco to report on the results of its screening program along with Pepco's recommendations for further analysis and replacement in the ACR starting with 2013.*

40. *… Some progress should have been made in the development of a tracking mechanism for PILC actual replacement and Pepco should be able to report on the actualization of its strategy with data that will help the Commission to better understand Pepco's future plans for PILC replacement and examine the results of its PILC Replacement Strategy. Thus, the Company is required to report on the actualization of its PILC Replacement Strategy in the ACR and to include in the report the information identified in Recommendations 8(c), (d) and (e). If the requested information is not available, Pepco shall provide a reasonable substitute that will allow the Commission to assess the progress that Pepco has made and intends to make in the implementation of its PILC Replacement Strategy for the ten-year period from 2012 to 2021.*

Pepco Response – Corrective Actions

Pepco is currently in the process of analyzing available data of the underground electric system faults in the District of Columbia over the ten-year period from December 2004 through December 2014. Feeders with at least five faults within 10 years were identified for further analysis. From that list of feeders, those that are already being addressed as part of Pepco's Reliability Enhancement Plan and/or other strategies—or programs that would address these issues on the feeders—were removed to avoid duplication of efforts.

In 2014, five feeders were selected through this process as potential candidates for targeted replacement. Preliminary evaluations of these five feeders yielded approximately 13,200 feet of PILC for possible replacement. Further field investigation revealed that approximately 5,000 feet of PILC have already been replaced with solid dielectric cable EPR or flat strap. See Table 1 for details.

Table 1: PILC replacement Status.

Year	Feeder ID	Location		Cable Length		Status	Est. Completion date	Comments
		Ward	Streets	Planned (ft)	Actual (ft)			
13	14150	3	Rodman St, Wisc Ave	4,204	5,375	In Construction	6/1/2015	DSO will not allow outage until weather conditions improve
13	14712	5	N/A	10,800	-	Closed	-	Cost of conduit exceeds replacement benefits.
13	15197	4	N/A	7,000	-	Closed	-	Recently replaced PL cable with EPR.
13	15206	1,6		700	1,700	In Construction	3/20/2015	75% completed.
13	14411	6	N/A	6,050	3,550	Closed	-	Cost of conduit exceeds replacement benefits.
13	14537	6	N/A	5,900	5,700	Closed	-	Cost of conduit exceeds replacement benefits.
13	14582	2	Massachusetts Ave.	2,300	2,997	In Construction	6/1/2015	DSO will not allow outage until weather conditions improve
13	14710	6	N/A	4,300	-	Closed	-	Cost of conduit exceeds replacement benefits.
13	15615	2	Independence Ave	1,600		Engineering	6/15/2015	Delayed due to clearance issues with Secret Service. Currently in design.
13	15631	8	Alabama Ave, 15th Pl, Stanton Rd	700	3,400	In Construction	4/30/2015	DSO will not allow outage until weather conditions improve
13	15632	8	Alabama Ave, 15th Pl, Stanton Rd	3,800	4,800	In Construction	4/30/2015	DSO will not allow outage until weather conditions improve
14	14407	6	Buzzard Point	1,700	1,850	Engineering	6/30/2015	Replace 1850' of PL with 500 flat strap
14	14536	6	Benning Rd	2,000	2,026	Engineering	6/30/2015	Replace 2000' of PL Cable with 600 EPR and 500 flat strap
14	15338	1	13th St, btwW & Clifton Sts	4,000	3,823	Engineering	6/30/2015	Design completed. Pending final approval.
14	15341	1	13th St, btw V & W Sts	500	346	Completed	3/1/2015	Job completed 2/20/2015
14	15755	6	3rd and I Sts	1600-5000	-	Closed	-	Entire Feeder is EPR cable.

In Pepco's 2001 "Alternative Design Proposal to Pepco's 15kV Paper Insulated Lead Covered Power Cables (PILC)" study, Pepco estimated there were 1,109 miles of primary lead cables on the Pepco system in the District of Columbia. Given the current configuration of the

District of Columbia underground system, which includes varied duct and manhole sizes, it is not possible know how many of those miles are non-replaceable. Reconfiguring the manholes and ducts would allow most of Pepco's PILC cable to be replaceable, albeit at significant cost and time. As stated in Pepco's PILC Replacement Strategy, in line with most other electric utilities and with industry best practice, Pepco has not committed to replacing a fixed number of miles of PILC each year and has not identified a year by which full replacement of primary PILC would be expected. Instead, Pepco is seeking opportunistic replacement based on conditions, which it expects to be a more cost-effective replacement strategy.

Consequently, although Pepco cannot provide an estimate of the number of miles of PILC that will be replaced by EPR for the 10 year period from 2012 through 2021, Pepco can show progress in the actualization of its PILC replacement strategy, as demonstrated in the following table.

Years	***PILC Replaced Footage***	***PILC Replaced Mileage***
2001	0	0
2002	0	0
2003	0	0
2004	7,733	1
2005	27,981	5
2006	14,322	3
2007	26,341	5
2008	26,217	5
2009	28,217	5
2010	25,593	5
2011	17,824	3
2012	35,571	7
2013	17,037	3
2014	25,882	5
Total	***252,718***	***47***

Underground (UG)Failure Analysis

The results of Pepco's annual UG failure analyses are presented below, in compliance with Order No. 12735 paragraph 138. [73]

In analyzing the performance of the Pepco UG system, it is necessary to distinguish three different measures of system performance:

- Equipment Failures
- Outages
- Reportable Events (RE)

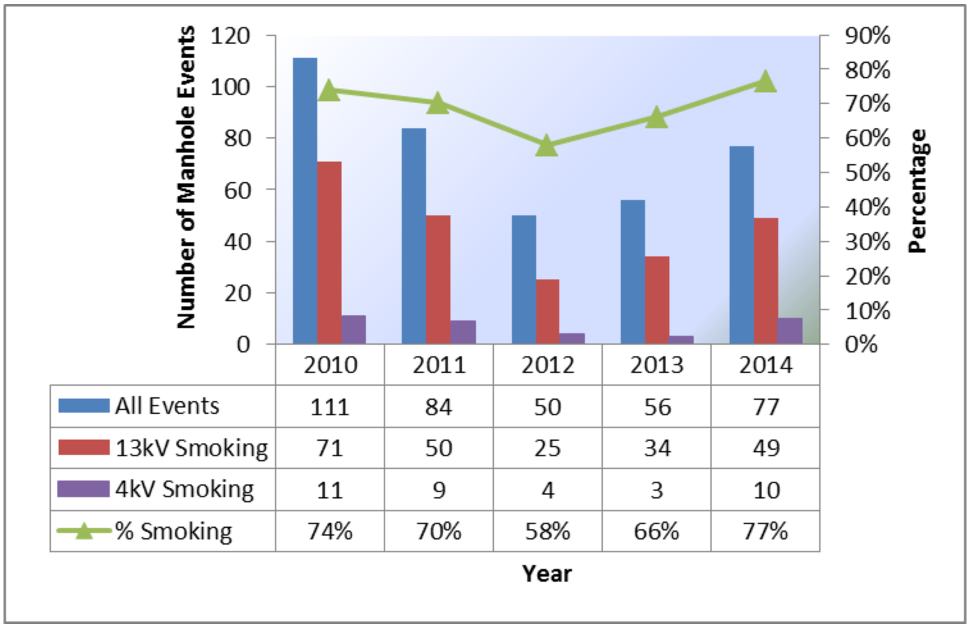
An RE is a reported explosion, fire, or smoke in a manhole. Some Pepco equipment failures may result in customer outages, REs or both. However, not all Pepco equipment failures result in an outage and/or an RE. This is due to the redundancy of some components of the system, especially on secondary networks. In fact, for the underground secondary networks, most equipment failures do not result in customer outages because each network is fed by multiple primary feeders, and each customer can be fed from multiple transformers and secondary mains, making them less susceptible to outages. Further, some underground outages or events are not initiated by equipment failures, but are in fact caused by accidents, such as dig-ins by excavation contractors, failures of non-Pepco equipment, such as District of Columbia owned streetlight cables or gas company equipment.

There are three types of manhole reportable events:

- Explosions
- Fires
- Smoking

Of these three types, from 2010– 2014 smoking manhole events account for 58% - 77% of all manhole events experienced in the District. See Figure 3.1.

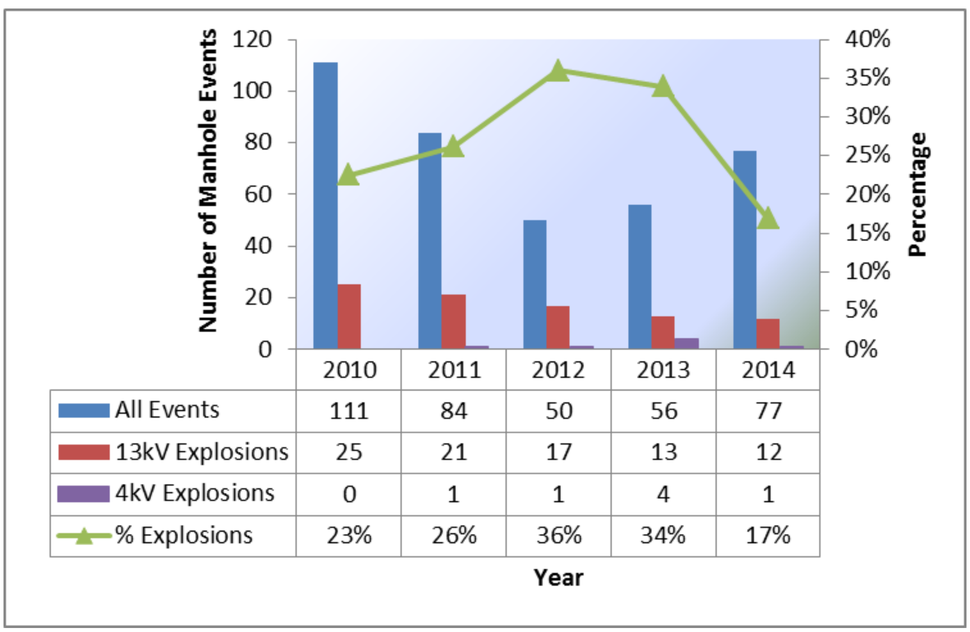
[73] In Order No. 12735, paragraph 138, the Commission ordered the following:
138.Pepco shall file a report that summarizes the results of the failure analyses conducted for the calendar year 2002, 30 days from the issuance date of this Report and Order, and subsequently, to file an annual report on the results of the failure analysis group to the PIWG;



	2010	2011	2012	2013	2014
All Events	111	84	50	56	77
13kV Smoking	71	50	25	34	49
4kV Smoking	11	9	4	3	10
% Smoking	74%	70%	58%	66%	77%

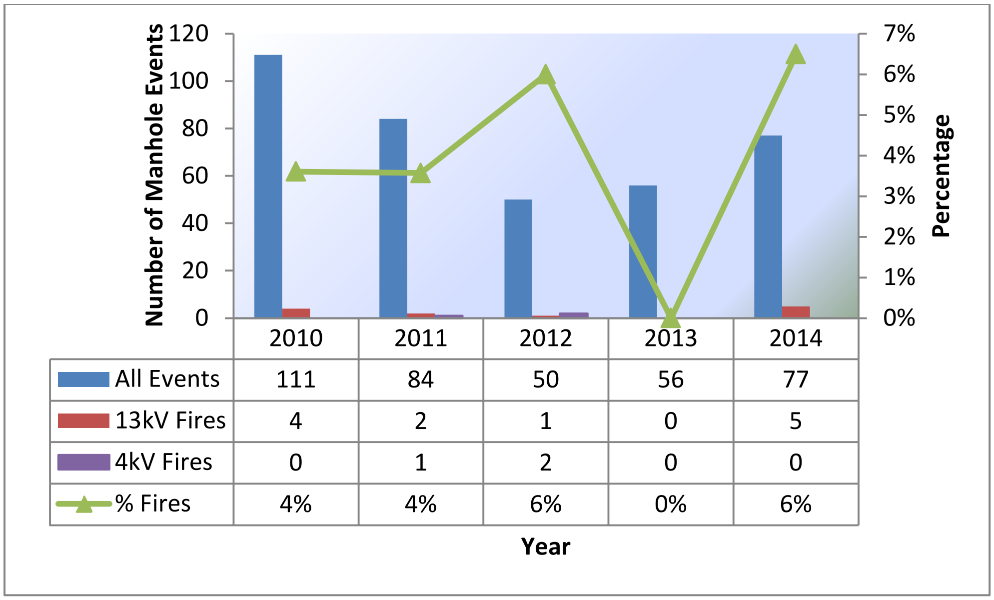
Figure 3.1: Manhole Events - Smoking (2010-2014)

For the same time period, manhole explosions account for 17% - 36% and manhole fires account for 4% - 6% respectively. See Figures 3.2 and 3.3.



	2010	2011	2012	2013	2014
All Events	111	84	50	56	77
13kV Explosions	25	21	17	13	12
4kV Explosions	0	1	1	4	1
% Explosions	23%	26%	36%	34%	17%

Figure 3.2: Manhole Events - Explosions (2010-2014)



	2010	2011	2012	2013	2014
All Events	111	84	50	56	77
13kV Fires	4	2	1	0	5
4kV Fires	0	1	2	0	0
% Fires	4%	4%	6%	0%	6%

Figure 3.3: Manhole Events - Fires (2010-2014)

Since 2008, the majority of the manhole events experienced in the District have occurred on Pepco's secondary equipment. See Figure 3.4.[74]

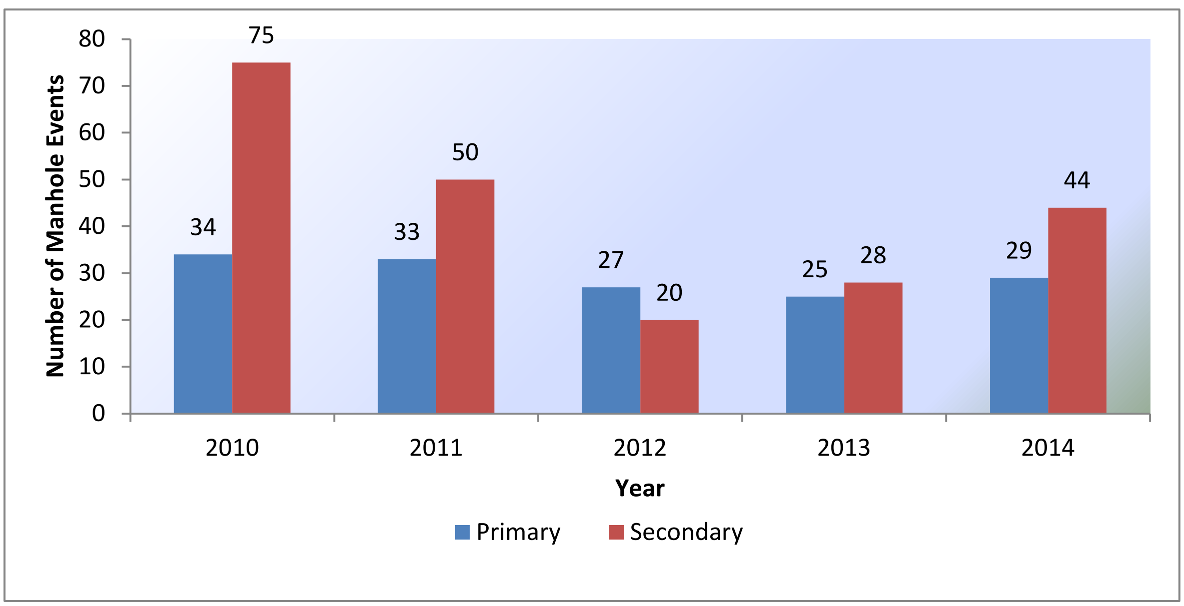


Figure 3.4: Manhole Events by Type of Equipment (2010-2014)

[74] Note: Non-Pepco equipment failures are not included in the following annual totals, and 2010 data has been corrected (Miscellaneous events in 2010 were mislabeled as primary).

As in previous years, most of the smoking manholes occurred on the secondary system, while most manhole explosions occurred on primary equipment. See Figure 3.5.

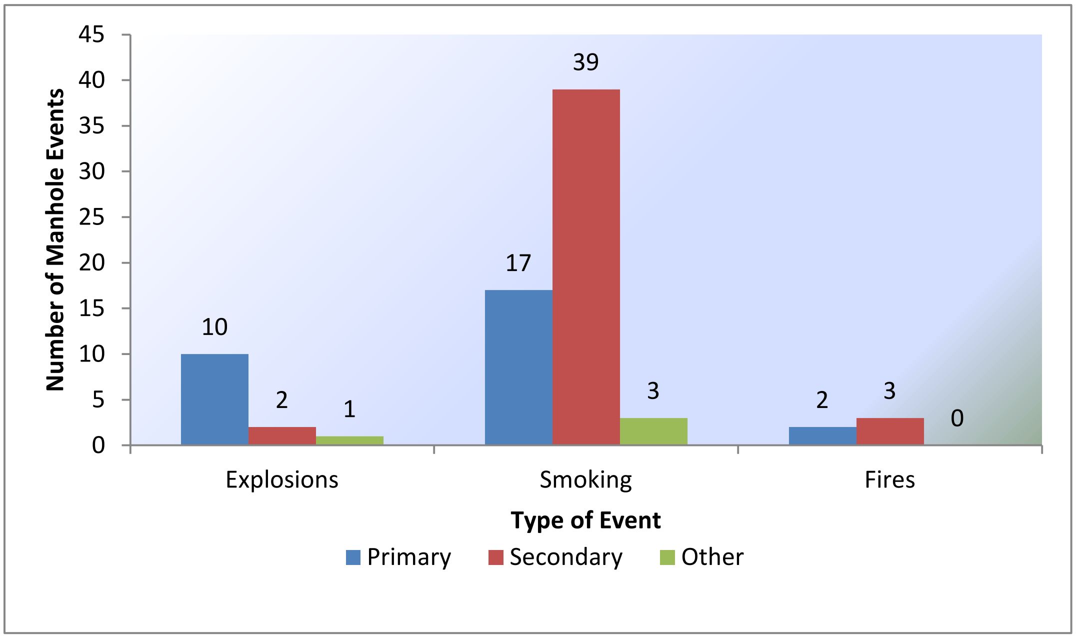
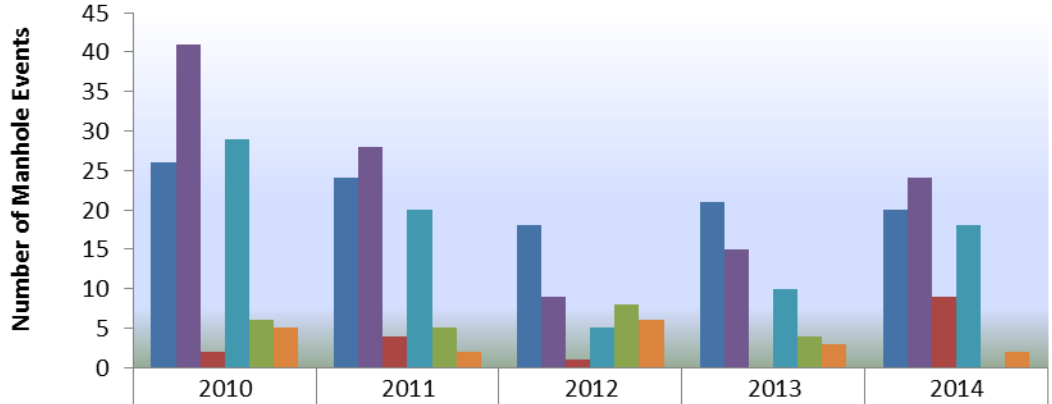


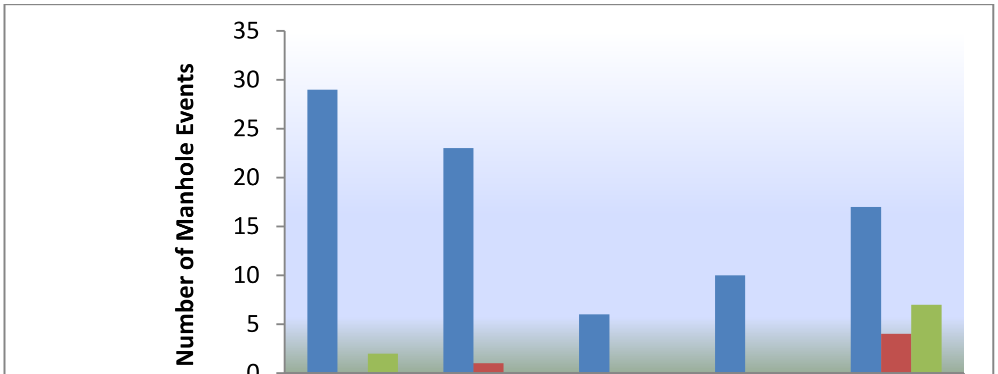
Figure 3.5: Manhole Events by Type and Equipment (2014)

Slotted manhole covers are designed to minimize the frequency and impact of manhole events by allowing gas and smoke to vent from manholes in the event of an underground failure. This provides an early warning and prevents build-up of gases to potentially explosive proportions; thereby allowing energy to disperse more easily should an event occur. The tradeoff when installing slotted covers is that they allow more water and street run-off contaminants to enter into the manhole than solid covers. From 2010 through 2014, most of the reportable events occurring in manholes equipped with a slotted cover involved secondary equipment and were manhole smoking events. See Figure 3-6 and Figure 3-7.



	2010	2011	2012	2013	2014
Solid Primary	26	24	18	21	20
Solid Secondary	41	28	9	15	24
Slotted Primary	2	4	1	0	9
Slotted Secondary	29	20	5	10	18
Grated Primary	6	5	8	4	0
Grated Secondary	5	2	6	3	2

Figure 3.6: Manhole Events by Type, Equipment, and Manhole Cover (2010-2014)



	2010	2011	2012	2013	2014
Slotted Smoking	29	23	6	10	17
Slotted Fire	0	1	0	0	4
Slotted Explosions	2	0	0	0	7

Figure 3.7: Slotted Manhole Events by Type (2010-2014)

By design, primary cable is more insulated than secondary cable. Whereas primary cable and its accessories are designed to their voltage rating and are shielded, secondary cable and its accessories are not shielded. As a result of less physical protection, secondary cable and its accessories are more likely to fail due to a breach in the insulation. Since 2010, the leading cause of manhole reportable events in the District is insulation-related, such as insulation deterioration. See Figures 3.8 through 3.12.

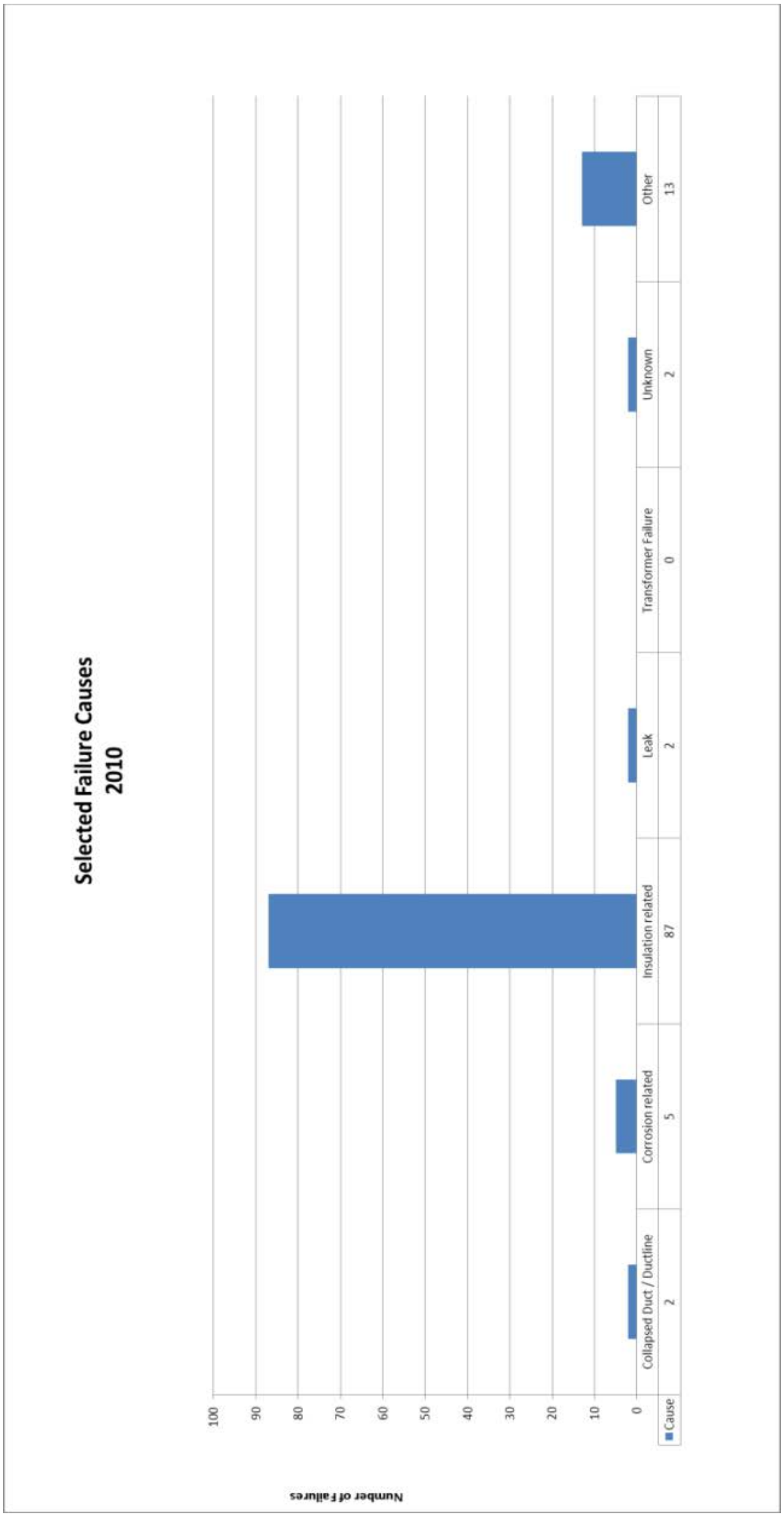


Figure 3.8 Selected Failure Causes (2010)

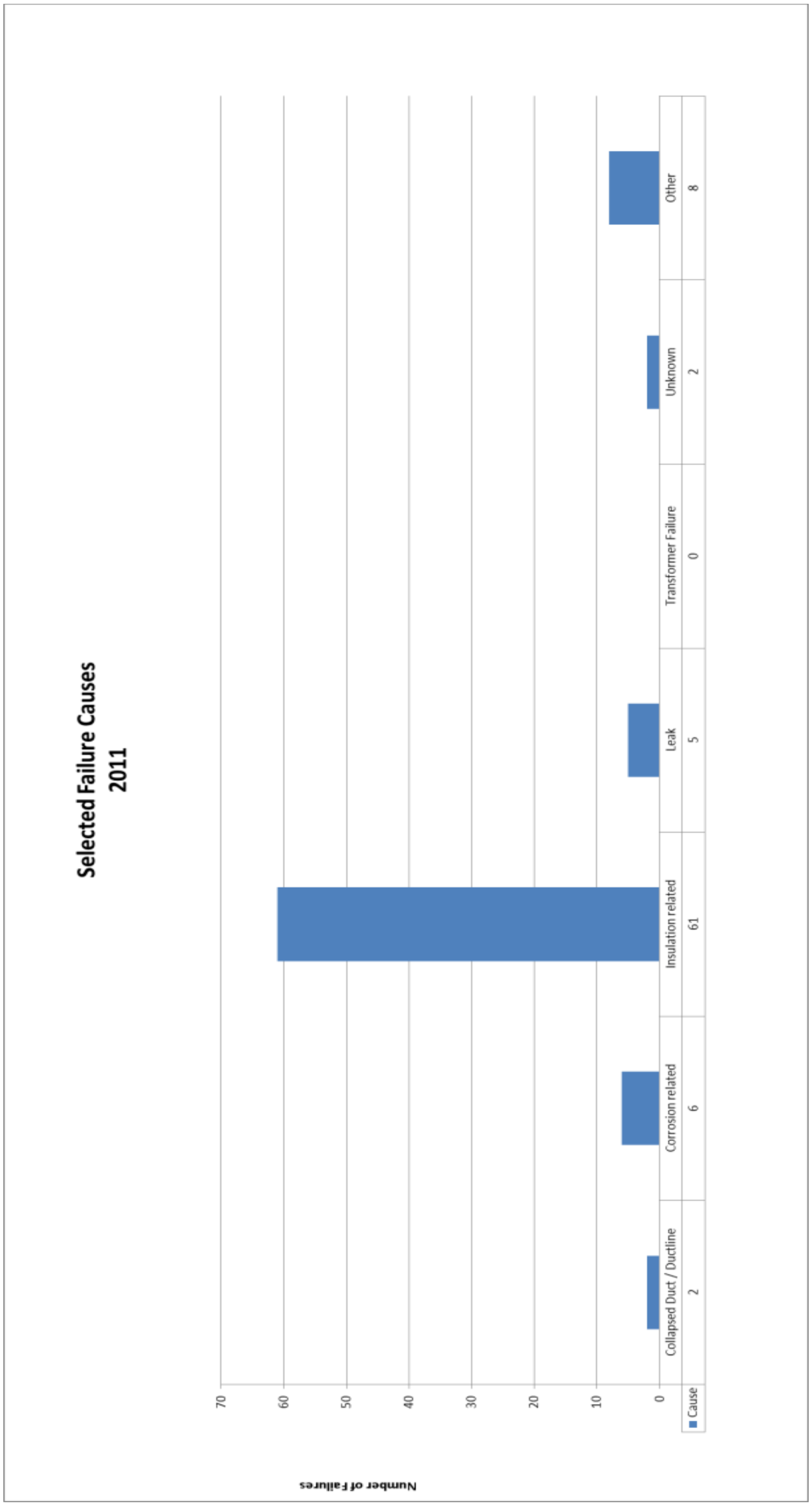


Figure 3.9: Selected Failure Causes (2011)

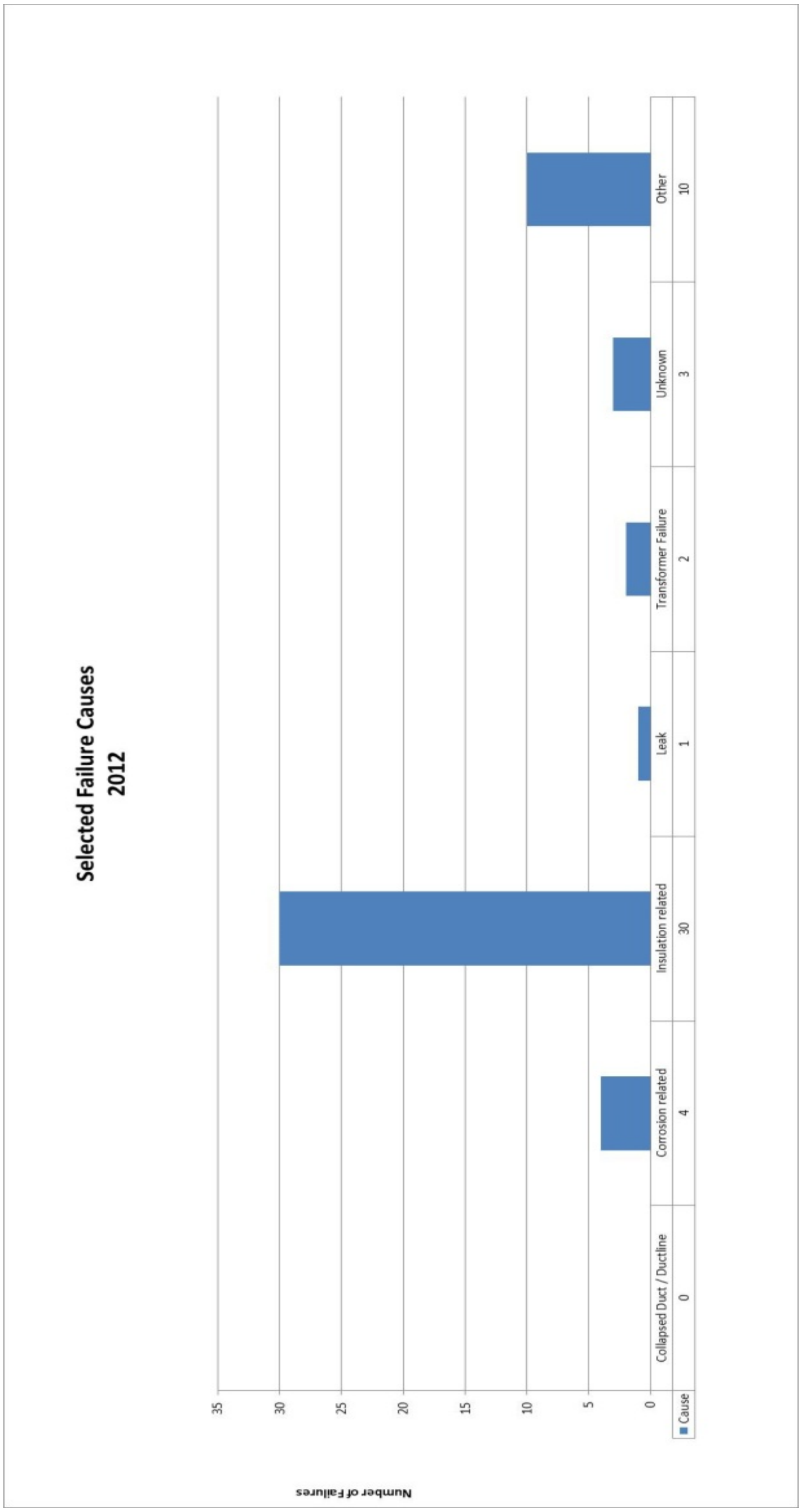


Figure 3.10: Selected Failure Causes (2012)

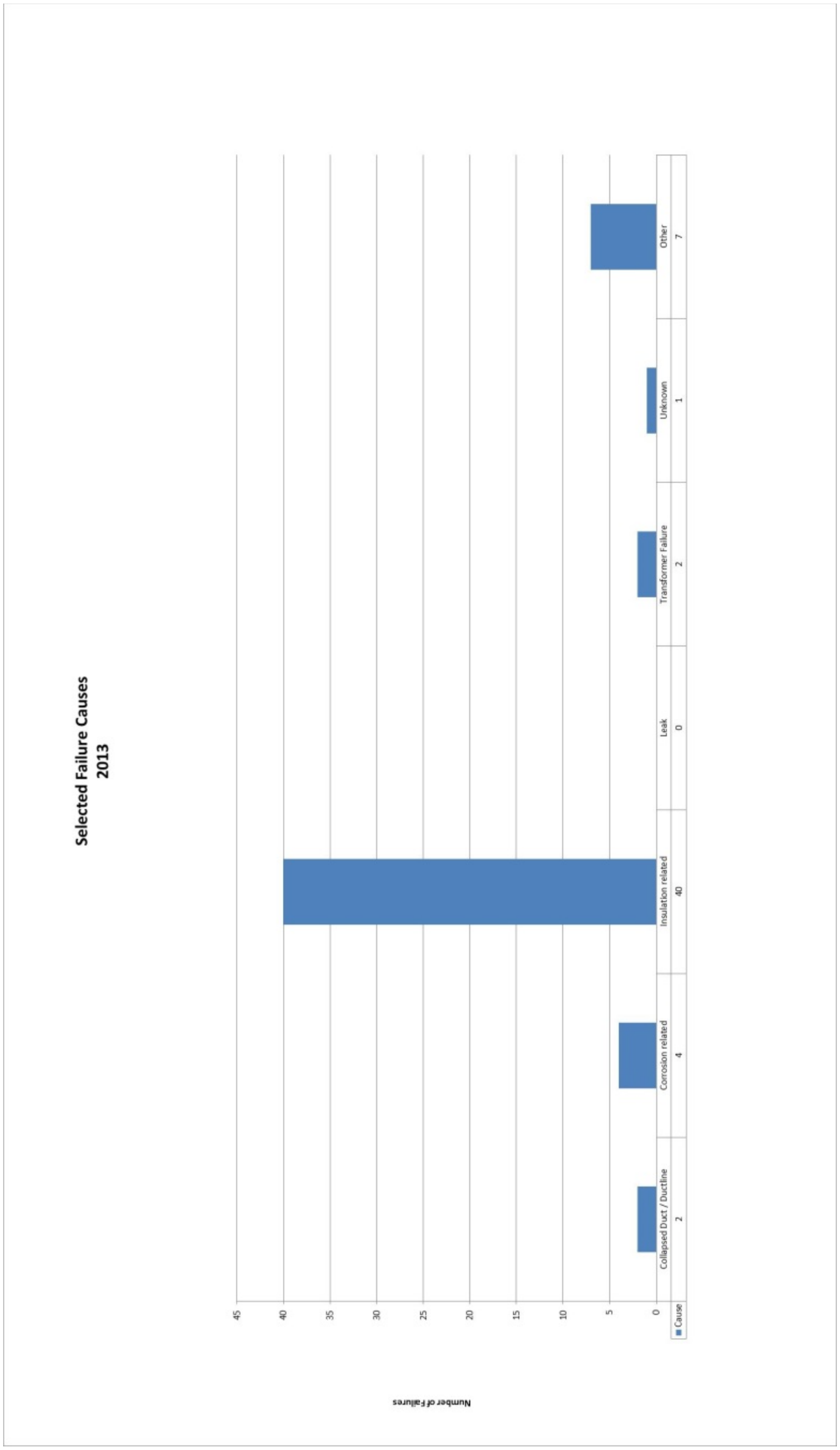


Figure 3.11: Selected Failure Causes (2013)

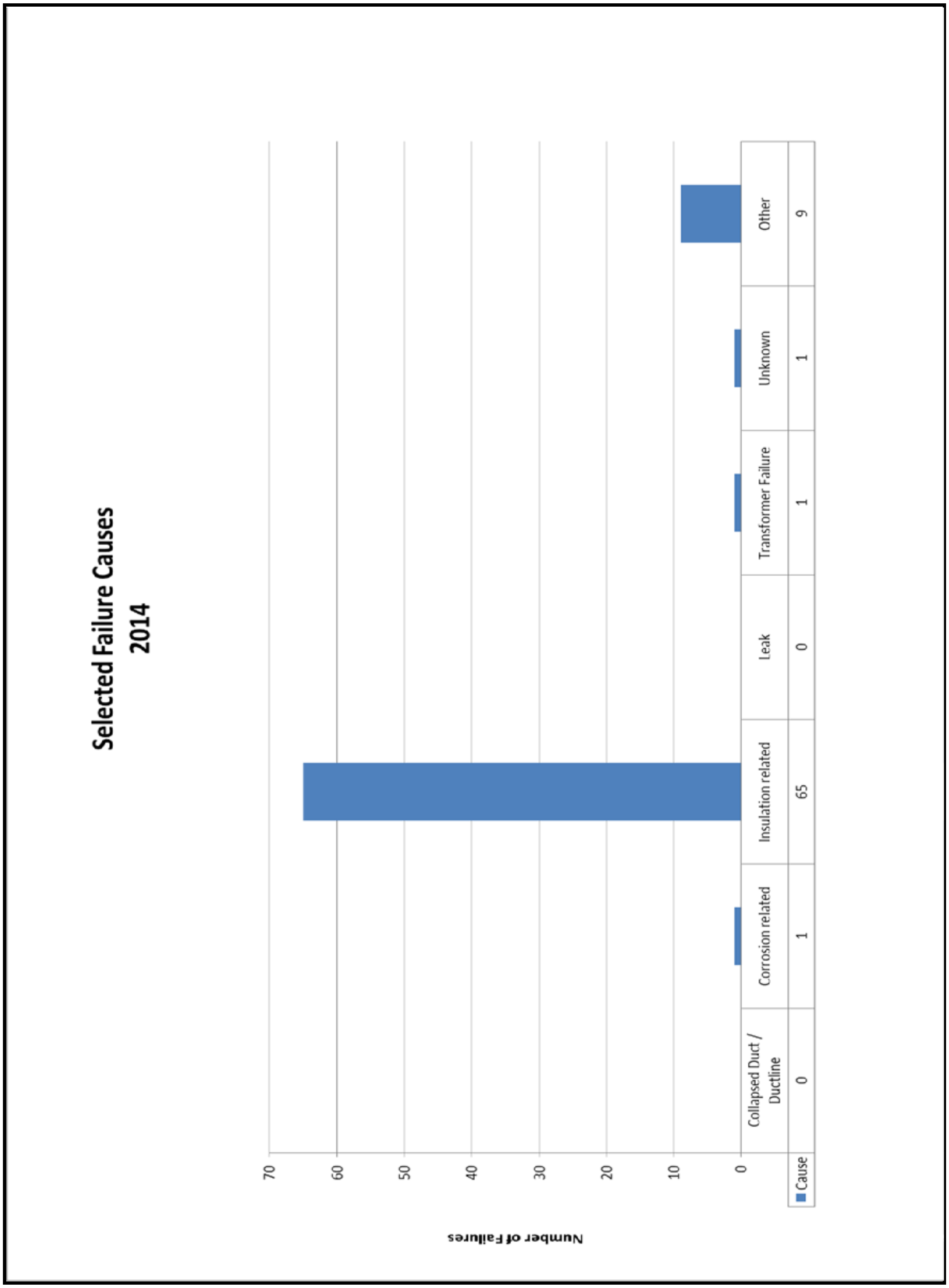
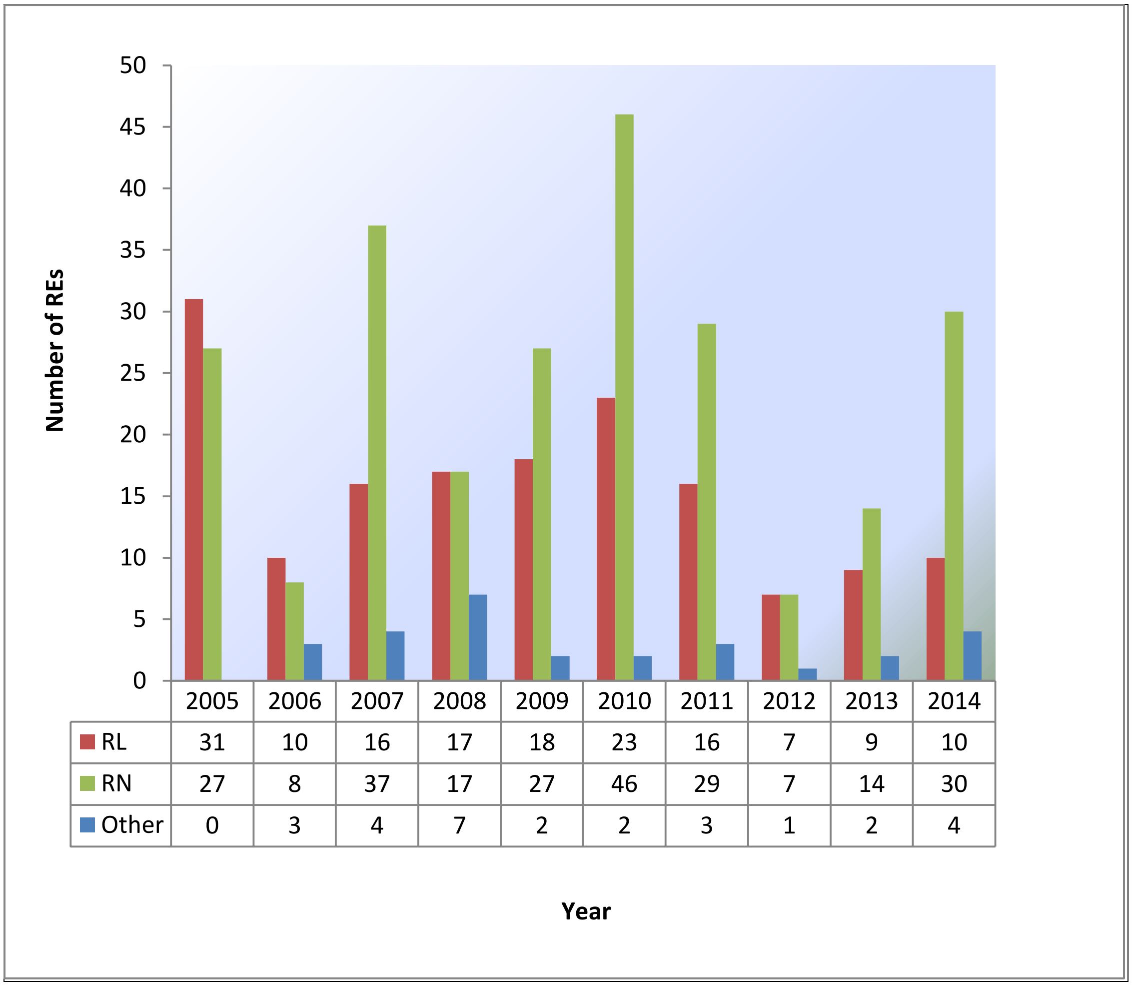


Figure 3.12: Selected Failure Causes (2014)

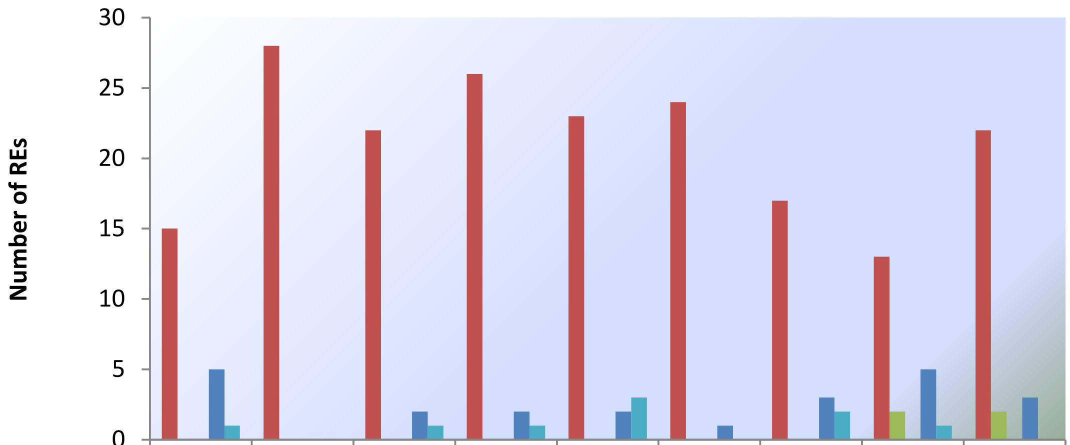
The type of insulation related to cable and joint failures resulting in a reportable event for secondary equipment does not provide a discernible trend in reportable events caused by Rubber Lead (RL), Rubber Neoprene (RN), or other insulation types (Figure 3.13). RL secondary cable is an outdated technology and has not been installed on the system for more than twenty years. It is not possible to trend future reportable events associated with this cable type.



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
RL	31	10	16	17	18	23	16	7	9	10
RN	27	8	37	17	27	46	29	7	14	30
Other	0	3	4	7	2	2	3	1	2	4

Figure 3.13: Insulation Type of Secondary REs (2005-2014)

PILC is the predominant primary cable on the Pepco underground system. Consequently, most primary cable reportable events involve PILC cable (Figure 3.14).

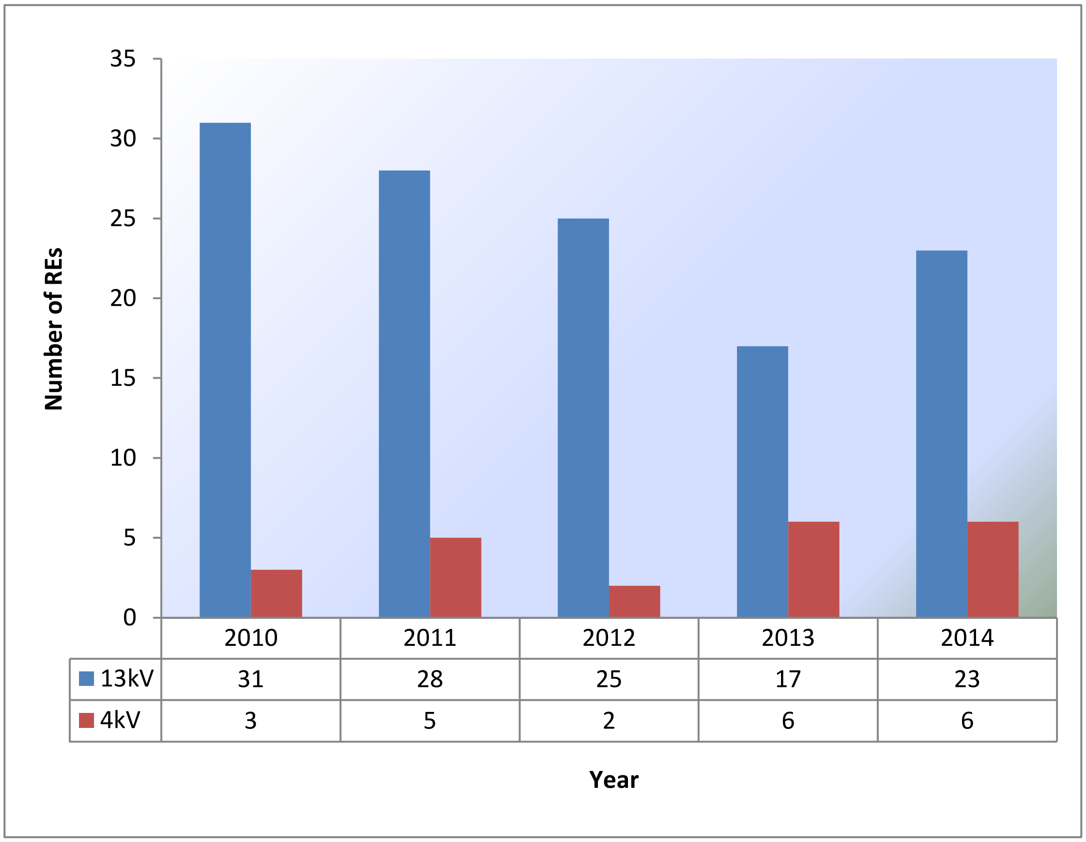


	2006	2007	2008	2009	2010	2011	2012	2013	2014
PILC	15	28	22	26	23	24	17	13	22
RL	0	0	0	0	0	0	0	2	2
RN	0	0	0	0	0	0	0	0	0
EPR	5	0	2	2	2	1	3	5	3
Other	1	0	1	1	3	0	2	1	0

Year

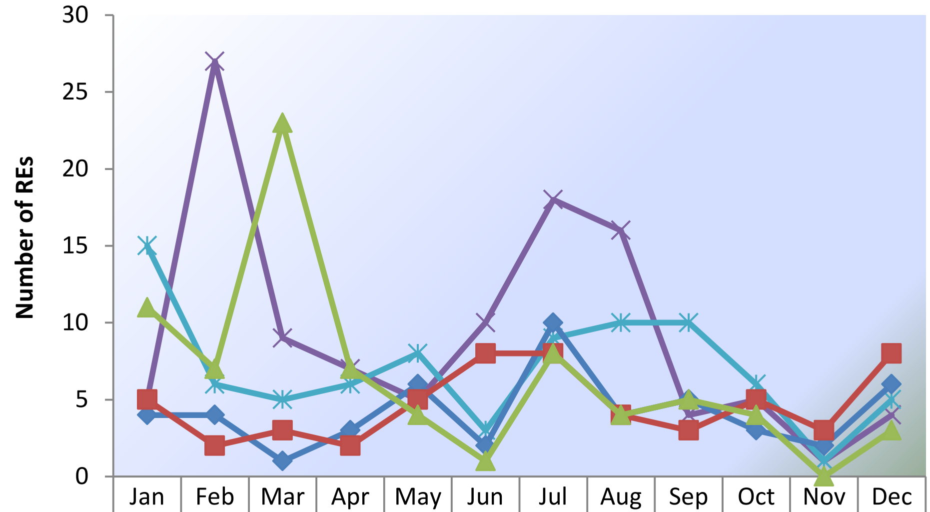
Figure 3.14: Insulation Type of Primary REs (2005-2014)

The majority of reportable events involving primary equipment occur on 13 kV feeders (Figure 3.15). 4 kV is a vintage technology and the majority of Pepco's underground system is 13 kV.



<u>Figure 3.15: Voltage Class of Primary REs (2010-2014)</u>

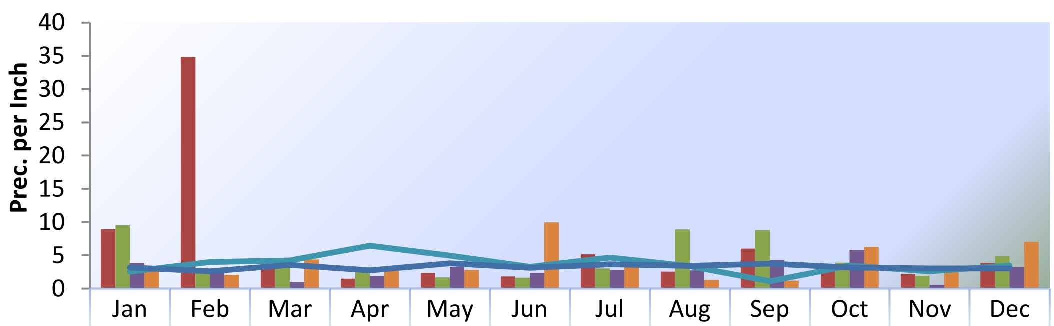
In addition, moisture plays a major role in the deterioration of both primary and secondary cable insulation. When a significant amount of precipitation is received in the District, moisture and contaminants from the street, such as motor oil, lawn chemicals, etc., enter into the manholes and affect cable insulation. Additionally, snow/ice melt chemicals ingress after a storm can also penetrate cable insulation and lead to failure. While moisture affects all cable insulation, since secondary cable is not as robust or of the same design as primary cable, secondary cable is inherently more likely to fail under adverse weather conditions. A comparison of Figures 3.16 and 3.17 suggests that total moisture accumulation affects the number of reportable events.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2010	5	27	9	7	5	10	18	16	4	5	1	4
2011	15	6	5	6	8	3	9	10	10	6	1	5
2012	4	4	1	3	6	2	10	4	5	3	2	6
2013	5	2	3	2	5	8	8	4	3	5	3	8
2014	11	7	23	7	4	1	8	4	5	4	0	3

Year

Figure 3.16: Reportable Events by Month (2010-2014)



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2010	8.96	34.82	3.55	1.5	2.4	1.87	5.17	2.59	6.01	3.4	2.22	3.88
2011	9.55	2.62	4.6	3.2	1.7	1.68	3.03	8.92	8.84	3.91	1.94	4.9
2012	3.89	2.44	1.02	1.92	3.28	2.38	2.81	2.78	4.29	5.82	0.6	3.23
2013	3.43	2.07	4.4	2.76	2.82	9.97	4.43	1.34	1.22	6.25	2.92	7.03
2014	2.58	4.02	4.26	6.47	4.96	3.31	4.68	3.39	1.11	3.49	2.64	3.5
Normal	3.21	2.63	3.6	2.77	3.82	3.13	3.66	3.44	3.79	3.22	3.03	3.05

Month

Figure 3.17: Total Precipitation in Inches by Month (2010-2014)

The number of reportable events for the month of February decreased from 27 in 2010 to 6, 4, and 2 in 20011, 2012, and 2013, respectively. However, in 2014 the RE was slightly increased to 7. This suggests a correlation can be attributed to the more than 34" of snow received in February 2010 and the below-average snowfall in 2011, 2012 and 2013. In 2014 the total precipitation was almost double the amount in each of 2011, 2012 or 2013. There was a significant increase in the number of reportable events in March of 2014, which is likely attributable to 13.63" of precipitation received during the preceding three month.

Year	Reportable Events (REs)	Total Failures
2008	69	284
2009	82	271
2010	111	275
2011	84	268
2012	50	210
2013	56	196
2014	77	196

Table 3.1: Reportable Events and Underground Failures

The Failure Analysis Section will continue to perform failure analysis for all manhole incidents in the District in order to determine trends and remediation activities.

Underground Failures in the District of Columbia

Reportable manhole events reported for 2014 increased by 38% (56 to 77) as compared with 2013. Reportable events may be considered a subset of underground (UG) equipment failures, and are comprised of equipment failures for which there is a significant visual result (smoke, flames, cover displaced). Among UG equipment failures, the most frequent involve cable. As shown in Table 3-2, in 2014 primary joint and miscellaneous equipment failures decreased by a significant amount compared to 2012 and 2013.

An analysis of underground failures for the months of January through December for the years 2010 through 2014 respectively for the 4 kV and 13 kV primary and secondary systems was conducted. The results are presented in Table 3-2 and Figure 3-18. The failures were grouped into six types – primary cable failures in the manhole, primary cable failures in duct, primary splice failures, secondary single phase and secondary three phase cable and splice failures, and underground equipment failures. Pepco continues to seek ways to improve and minimize reportable events.

Year	Primary							Secondary		Total
	13kV Cable in Manhole	13kV Cable in Duct	13kV Splice	4kV Cable in Manhole	4kV Cable in Duct	4kV Splice	Misc. Equipment	Secondary Single Φ	Secondary Three Φ	
2010	32	1	43	3	1	6	53	62	74	275
2011	36	9	38	5	0	3	37	59	81	268
2012	24	2	31	7	0	6	44	40	56	210
2013	26	2	22	4	1	8	31	48	54	196
2014	20	9	30	6	2	2	20	55	52	196

Table 3.2: Underground (UG) Cable Failures in the District

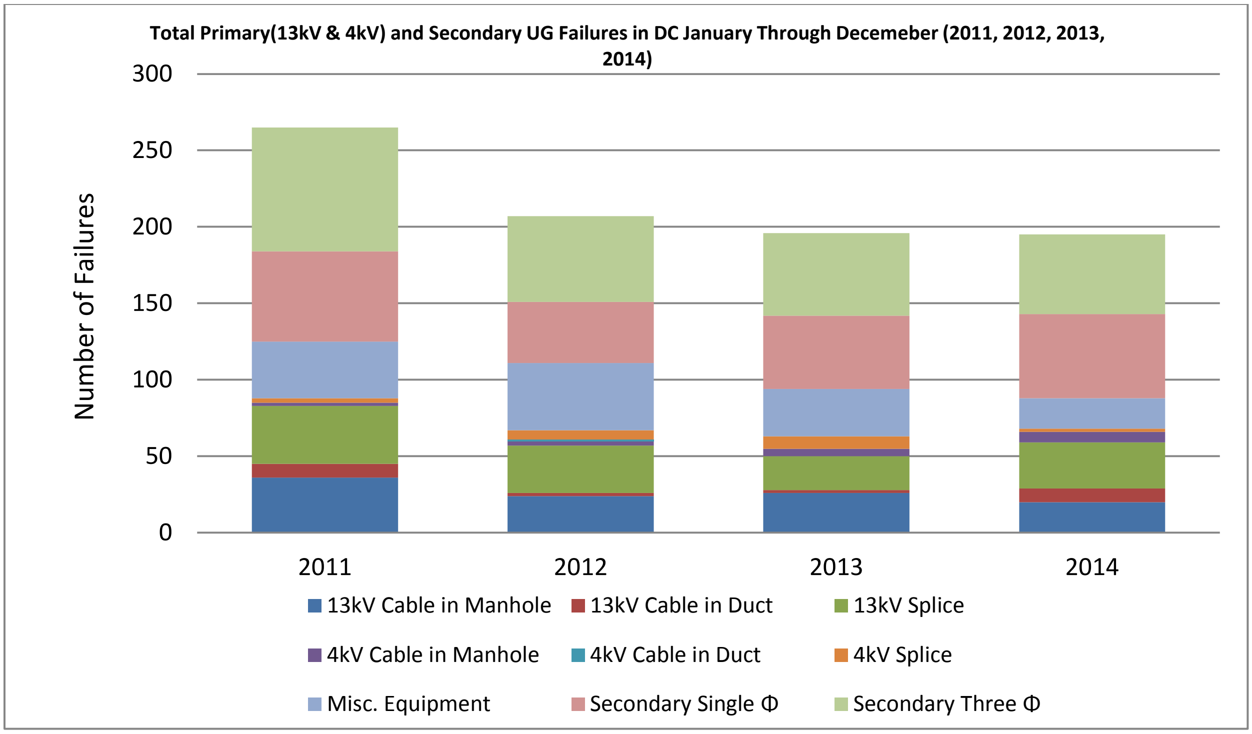
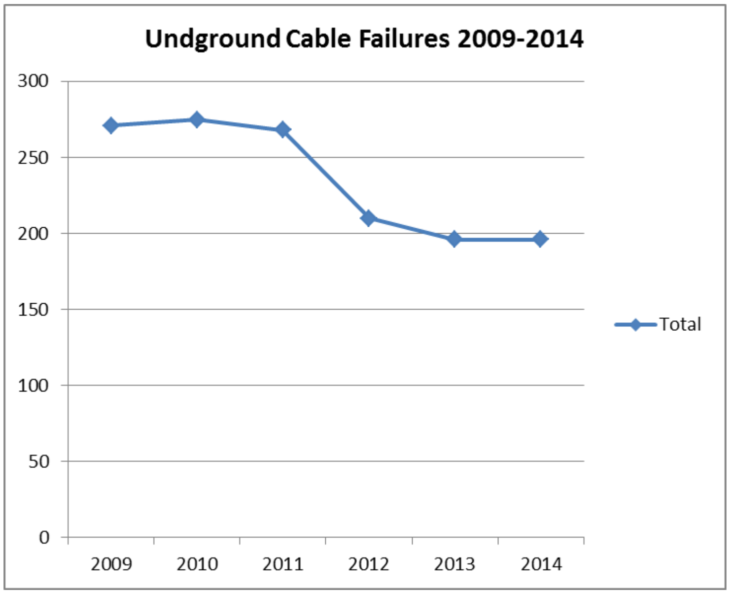


Figure 3.18: UG Failures in the District

Analysis of Underground Cable Failures in 2014[75]

Underground cable failures are identified according to six different types: primary cable failures in the manhole, primary cable failures in duct, primary splice failures, secondary single phase and secondary three phase cable and splice failures, and underground equipment failures. As reflected in Table 3.2, Figure 3.18, and the following table, Pepco's system has experienced fewer manhole events annually 2009-2013, and the number of 2014 events remained equal to 2013.



Description of AMI Equipment Failures[76]

There are two categories of "AMI Equipment" that make up Pepco's AMI network: the AMI meters themselves, and AMI communication equipment. Pepco is not a communications company, and therefore uses meter manufacturing companies to maintain its AMI equipment. This equipment is covered by contractual relationships to minimize Pepco's risk in the event of defective products.

Pepco AMI meters were purchased from the meter manufacturers General Electric and Landis+Gyr. Pepco AMI meters come with a five year warranty from the date of delivery. All

[75] This section responds to the Commission's direction for Pepco to "include in its 2015 Annual Consolidated Report an analysis of its underground cable failures occurring in the District during 2014." *In The Matter of the Annual Consolidated Report of the Potomac Electric Power Company*, Formal Case No. PEPACR-2014-01, Order No. 17816 at P 327 (February 27, 2015).

[76] This section responds to the Commission's direction for Pepco to "include in its 2015 Annual Consolidated Report information describing the number of AMI equipment failures occurring in 2013 and 2014, and how any such failures are being addressed." *In The Matter of the Annual Consolidated Report of the Potomac Electric Power Company*, Formal Case No. PEPACR-2014-01, Order No. 17816 at P 327 (February 27, 2015).

meters removed from the field are evaluated in the Pepco meter shop and suspect meters are returned to the meter manufacturer for warranty repair and/or replacement. Pepco is in the post deployment phase of evaluating and shipping suspect meters back to the meter manufacturers for repair. Pepco has returned or is in the process of returning approximately 3,700 meters to the meter manufacturers for root cause analysis. The overall return rate to the meter manufacturers is approximately 0.44% (less than 1%) of the in-service meter population.

There were less than nine AMI equipment failures in 2014. AMI communication equipment consists of only three equipment types. These equipment types are radios (Access Points and Repeaters) and Battery Backup units. Each installation or assembly consists of one radio and one battery backup unit with associated cables and hardware. The assemblies are replaced as a unit when a failure is suspected. The removed equipment is returned to the manufacturer for repair or replacement as all AMI equipment comes with a five year warranty. AMI communication equipment replacement was considered part of the pilot project in 2013 and was not tracked separately.

Slotted Manhole Covers [77]

New Slotted Manhole Cover Program Locations

In its 2013 Consolidated Report, Pepco discussed its criteria for selecting areas for installation of slotted manhole covers. This included areas with high load growth and potential business development. The list below provides the locations of slotted manhole covers that were installed in 2014.

Slotted Manhole Cover Installations for 2014

Date	Address	Quantity	Ward
11/28/2014	U Street (Shaw)	1	1
8/16/2014	Columbia Heights	1	1
7/21/2014	Petworth	1	1
5/9/2014	Columbia Heights	2	1
5/22/2014	Logan Circle	1	2
8/6/2014	Petworth	1	4
10/9/2014	U Street (Shaw)	1	1
7/2/2014	Shaw	1	6

Figure 3.19: Slotted Manhole Cover Installation Locations[78]

[77] Order No. 16975 states the following at paragraphs 74 and 111:

85. *Decision: …We agree with the Staff that a manhole replacement program that concluded in 2004 may no longer be appropriate, given business development in new areas of the District. We therefore require Pepco to reexamine the criteria used to select locations for the installation of slotted manhole covers and to report on this reexamination in the 2013 Consolidated Report.*

114. *Pepco is DIRECTED to revisit criteria used to select locations for installing slotted manhole covers consistent with paragraph 74 herein;*

[78] This table has been modified to include District of Columbia ward and neighborhood data in response to the Commission's directive to:

> [I]nclude in its 2015 Annual Consolidated Report information on the Table describing current slotted manhole cover installations (shown as Figure 3.19 in the 2014 Annual Consolidated Report) that identifies the Ward and District neighborhood where each newly reported slotted manhole cover was installed.

In The Matter of the Annual Consolidated Report of the Potomac Electric Power Company, Formal Case No. PEPACR-2014-01, Order No. 17816 at P 364 (February 27, 2015).

Historical Slotted Manhole Cover Program[79]

Pepco installed grated manhole covers over single and three-phase transformer installations, and network transformer installations in roadways and sidewalks. Their purpose is to assist in the dissipation of heat from the transformers. To explore the potential of an expanded application of vented manhole covers to non-transformer locations, Pepco contracted the Electric Power Research Institute (EPRI) to simulate manhole explosions. The simulations were specifically designed to test the effectiveness of solid, slotted and grated manhole covers in minimizing displacement of covers under fault conditions. The test data showed that the installation of slotted covers minimizes the frequency and impact of manhole events in three main ways:

- Energy released may escape through the slotted cover without lifting or displacing it;
- Smoke can provide an early warning of cable faults, thus preventing more serious events from occurring; or
- Explosions or fires may be avoided by the dissipation of combustible gases.

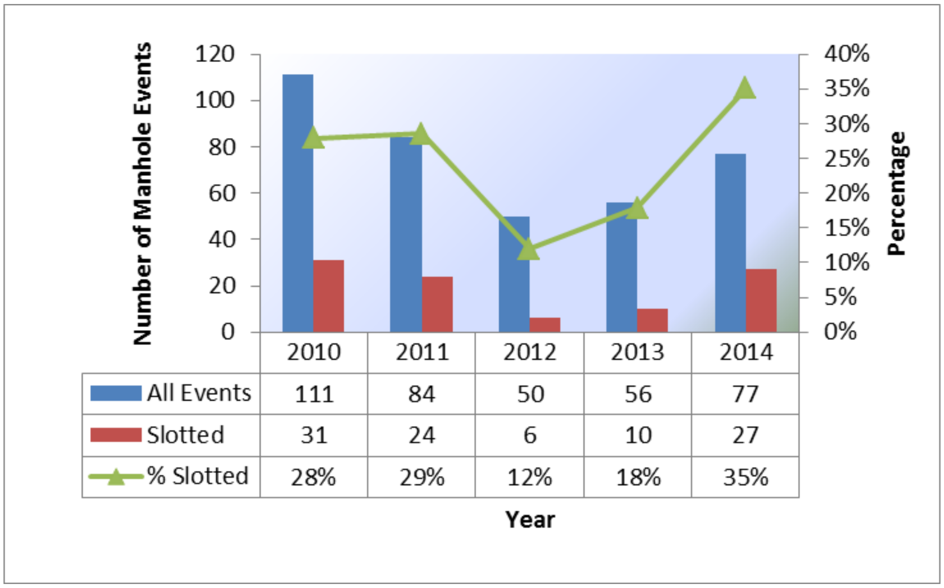
Based on these findings, Pepco installed custom-designed, slotted manhole covers in high volume pedestrian traffic areas of the District of Columbia where the low voltage alternating current network exists. The installation of slotted manhole covers has enhanced public safety while minimizing potential damage to underground electric facilities. The installation program was concluded in 2004 with an overall total of 7,880 slotted manhole covers having been installed.

In Order No. 14093, the Commission approved Pepco's proposal to suspend further slotted manhole installations provided the Company submit an analysis of manhole events and failure rates associated with slotted covers, including recommended actions for 2008 by October 27, 2007, and continue to monitor debris accumulation in manholes with slotted covers. Pepco filed its analysis on August 21, 2007. Pepco realizes that the openings in the covers, while allowing gases to vent, also allow rain, snow, dirt, debris and chemicals into manholes. As a result, Pepco continues to monitor debris accumulation in manholes with slotted covers. Of the 77 reportable manhole events that occurred in the District of Columbia in 2014, 27 involved

[79] In Order No. 16091 issued on December 10, 2010, the Commission stated among other things, at paragraph 59, the following:

59. …(4) include trend analyses for "Use of Slotted Manhole Covers;"

manholes fitted with slotted covers.[80] Twenty of these involved smoke being detected coming from the manhole slots, allowing them to be quickly identified and remedied, and seven involved explosions. Over the five-year period from 2010 through 2014, there were 378 reportable manhole events. Of these, 98 (26%) occurred in manholes with slotted covers. See Figure 3.20.



	2010	2011	2012	2013	2014
All Events	111	84	50	56	77
Slotted	31	24	6	10	27
% Slotted	28%	29%	12%	18%	35%

Figure 3.20: Manhole Events Involving Slotted Covers

[80] One additional event did not involve Pepco facilities.

Cable Splice or Joint Records[81]

Quality of workmanship is also being monitored as part of Pepco's program to reduce underground failures. Pepco repair crews complete a "Splice Manifest" report which records, among other things, the location, date, type of splice, the splicer's name and the foreman's name. Table 3.3 contains information from the "Splice Manifest" report for 2014 maintenance work performed. The splicer and foreman names have been redacted from the table.

[81] In Order No. 16091, the Commission stated among other things, at paragraph 59, the following:
59. *…(5) include in the Cable Splice or Joint Database section of the Consolidated Report, cable type, age, type of splice and other pertinent information, except that cable type and age can be excluded if unavailable.*

Date	Location	Juris-diction	Type of Splice
01/05/14	1309 Columbia Rd., NW	DC	Single Branch Joint 4/0 3/c and below
01/05/14	1309 Columbia Rd., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
01/05/14	13th & Columbia Rd., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
01/05/14	1309 Columbia Rd., NW	DC	Straight Joint 4/0 3/c and below
01/06/14	John McCormack & Michigan Ave, NE	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
01/06/14	John McCormack & Michigan Ave, NE	DC	Single Branch Joint 4/0 3/c and below
01/09/14	1301 New Jersey	DC	Test Cap 350 3/c and below
01/10/14	1301 New Jersey	DC	Test Cap 350 3/c and below
01/11/14	1301 New Jersey	DC	Test Cap 350 3/c and below
01/12/14	1720 M St., NW	DC	Double Branch Joint 4/0 3/c and below
01/12/14	1720 M St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
01/12/14	1720 M St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
01/12/14	1720 M St., NW	DC	Single Branch Joint 4/0 3/c and below
01/15/14	4800 Ft. Totten Dr., NE	DC	3-1/c 500 or 600 Straight Heat Shrink Splices
01/15/14	4800 Ft. Totten Dr., NE	DC	3-1/c 500 or 600 Straight Heat Shrink Splices
01/15/14	4800 Ft. Totten Dr., NE	DC	3-1/c 500 or 600 Straight Heat Shrink Splices
01/21/14	2300 Good Hope Rd., SE	DC	1/c #2 Trans. Splice (Tape)
01/21/14	2300 Good Hope Rd., SE	DC	3-1/c Cold Shrink Potheads #2 to 4/0
01/23/14	13th & G St., SE	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
01/23/14	13th & G St., SE	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
01/26/14	SEC 21st & K St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
01/26/14	SWC 21st & K St., NW	DC	200 AMP Elbows
01/27/14	3400 Benning Road	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
01/27/14	3400 Benning Road	DC	3-1/c 500 or 600 Straight Heat Shrink Splices
02/09/14	555 New Jersey Ave., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
02/09/14	555 New Jersey Ave., NW	DC	200 AMP Elbows
02/10/14	Wisconsin & O St., NW	DC	Straight Joint 350 3/c to 600 3/c
02/10/14	Wisconsin & N St., NW	DC	Straight Joint 750 3/c
02/19/14	SWC 11th & Nevada St., NW	DC	200 AMP Elbows
02/19/14	SWC 11th & Nevada St., NW	DC	Transition Joint
03/01/14	650 Anacostia Ave., NE	DC	3-1/c Cold Shrink Potheads #2 to 4/0
03/01/14	650 Anacostia Ave., NE	DC	200 AMP Elbows
03/08/14	6th & E St., SE	DC	3-1/c URD Slip on Splices
03/08/14	7th & E St., SE	DC	3-1/c URD Slip on Splices
03/15/14	23rd & H St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
03/15/14	23rd & H St., NW	DC	200 AMP Elbows
03/16/14	7th & F St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
03/16/14	7th & F St., NW	DC	200 AMP Elbows
03/31/14	Half & Eye St., SW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
03/31/14	3rd & R St., NE	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
03/31/14	3rd & R St., NE	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
03/31/14	Half & Eye St., SW	DC	3 Tape Joints, EPR to RL #2
03/31/14	3rd & R St., NE	DC	500 Trif 3 1/0 to 3c
03/31/14	3rd & R St., NE	DC	Separable 3 Way Cable Y Splice
04/10/14	13th & W St., NW (Substation)	DC	3-1/c Cold Shrink Potheads 350 to 600
04/10/14	13th & W St., NW	DC	3-1/c Cold Shrink Potheads 350 to 600
04/10/14	13th & W St., NW	DC	3-1/c 500 or 600 Straight Heat Shrink Splices
04/11/14	13th & W St., NW	DC	3-1/c Cold Shrink Potheads 350 to 600
04/11/14	13th & W St., NW	DC	3-1/c Cold Shrink Potheads 350 to 600
04/11/14	13th & W St., NW	DC	3-1/c 500 or 600 Straight Heat Shrink Splices
04/12/14	13th & W St., NW	DC	3-1/c Cold Shrink Potheads 350 to 600
04/12/14	13th & W St., NW	DC	3-1/c 500 or 600 Straight Heat Shrink Splices

Table 3.3: 2014 Splice Data (District of Columbia)

Date	Location	Juris-diction	Type of Splice
04/14/14	13th & W St., NW	DC	3-1/c Cold Shrink Potheads 350 to 600
04/14/14	13th & W St., NW	DC	3-1/c Cold Shrink Potheads 350 to 600
04/14/14	13th & W St., NW	DC	3-1/c Cold Shrink Potheads 350 to 600
04/14/14	13th & W St., NW	DC	3-1/c 500 or 600 Straight Heat Shrink Splices
04/14/14	13th & W St., NW	DC	3-1/c 500 or 600 Straight Heat Shrink Splices
04/15/14	13th & W St., NW	DC	3-1/c Cold Shrink Potheads 350 to 600
04/15/14	13th & W St., NW	DC	3-1/c Cold Shrink Potheads 350 to 600
04/15/14	13th & W St., NW	DC	3-1/c 500 or 600 Straight Heat Shrink Splices
04/19/14	13th & W St., NW	DC	3-1/c Cold Shrink Potheads 350 to 600
04/19/14	13th & W St., NW	DC	2 Sets Cold Shrinks
04/19/14	13th & W St., NW	DC	3-1/c 500 or 600 Straight Heat Shrink Splices
04/25/14	Michigan Ave. at First St., NW	DC	Straight Joint 350 3/c to 600 3/c
04/27/14	Michigan Ave. at Wash. Hosp. Ctr.	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
04/27/14	Michigan Ave. W/O First St.	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
04/28/14	Michigan Ave., F/O Childrens Hosp.	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
04/28/14	Michigan Ave., F/O Childrens Hosp.	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
04/28/14	Michigan Ave., W/O N.Capitol, NW	DC	Test Cap 500 3/c up to 750 3/c
04/28/14	3514 International Ct., NW	DC	3-1/c URD Slip on Splices
04/28/14	3514 International Ct., NW	DC	3-1/c URD Slip on Splices
04/28/14	Michigan Ave., at Childrens Hosp.	DC	Single Branch Joint 350 3/c to 600 3/c
04/28/14	Michigan Ave. at First St., NW	DC	Single Branch Joint 350 3/c to 600 3/c
04/29/14	Rdway W/O First & Michigan Ave.,	DC	3-1/c 500 or 600 Straight Heat Shrink Splices
04/29/14	Rdway W/O First & Michigan Ave.,	DC	3/C PL to 3-1/C EPR or XLP Trif. Jt. 350 to 500
04/30/14	Michigan Ave., at Childrens Hosp.	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
04/30/14	Michigan Ave., at Childrens Hosp.	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
04/30/14	Michigan Ave. at First St., NW	DC	Test Cap 500 Flat Strap
05/02/14	So. Capitol St., SE	DC	3-1/c Test Cap 4/0 Flat Strap
05/03/14	So. Capitol St., SE	DC	3-1/c Test Cap 4/0 Flat Strap
05/12/14	NEC Wisconsin Ave. & Quebec	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
05/12/14	3825 Wisconsin Ave., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
05/22/14	12th & Clifton St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
05/22/14	Garfield Terrace	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
05/22/14	1300 Blk. Independence Ave., SW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
05/22/14	13th & Independence Ave., SW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
05/23/14	2106 Vermont Ave., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
05/23/14	2106 Vermont Ave., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
05/29/14	International Place, NW	DC	3-1/c URD Slip on Splices
05/30/14	International Dr., NW S/O VanNess (Jordanian Embassy)	DC	3-1/c URD Slip on Splices
05/30/14	International Dr., NW S/O VanNess (Kuwaiti Embassy)	DC	3-1/c URD Slip on Splices
06/06/14	SWC Rday Florida Ave. & R St., NW	DC	3-1/c URD Slip on Splices
06/06/14	NEC 3rd & R St., NW	DC	3-1/c URD Slip on Splices
06/11/14	Dalecarlia Water Treatment Plant, NW	DC	3-1/c Cold Shrink Potheads 350 to 600
06/11/14	Dalecarlia Water Treatment Plant, NW	DC	3-1/c 500 or 600 Straight Heat Shrink Splices
06/11/14	3400 Benning Road	DC	3 1/c #2 Tape Joints
06/13/14	4801 Massachusetts Ave., NW	DC	#2 URD Pot head
06/13/14	3220 Connecticut Ave., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
06/13/14	3220 Connecticut Ave., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
06/13/14	4801 Massachusetts Ave., NW	DC	200 AMP Elbows

Table 3.3 (continued): 2014 Splice Data (District of Columbia)

Date	Location	Juris-diction	Type of Splice
06/14/14	F/O 2950 VanNess St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
06/14/14	F/O 2950 VanNess St., NW	DC	3 Single Tran. Tape Joint
06/23/14	5210 Wisconsin Ave., NW	DC	350 Potheads/3-1/c Single Jt. Taped
06/25/14	Dalecarlia Pumping Station	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
06/25/14	Dalecarlia Pumping Station	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
06/25/14	Dalecarlia Pumping Station	DC	3-1/c Cold Shrink Potheads 350 to 600
06/26/14	6th & Bryant St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
06/26/14	6th & Bryant St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
06/26/14	6th & Bryant St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
06/26/14	Dalecarlia Pumping Station	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
06/26/14	Dalecarlia Pumping Station	DC	3-1/c Cold Shrink Potheads 350 to 600
06/28/14	Rdway. SEC 12th & K St., NE	DC	3/c PL to 3-1 EPR or XLP Trif. Jt. 500
06/28/14	Rdway. SEC 11th & K, NE	DC	3/c PL to 3-1 EPR or XLP Trif. Jt. 500
07/01/14	Dalecarlia Pumping Station	DC	3-1/c Cold Shrink Potheads 350 to 600
07/01/14	Dalecarlia Pumping Station	DC	3/c PL to 3-1 EPR or XLP Trif. Jt. 500
07/03/14	4268 Wisonsin Ave., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
07/03/14	17th & Q St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
07/03/14	4268 Wisonsin Ave., NW	DC	3-1/c, #2 Loadbreak Elbows
07/07/14	34th & Benning Rd., NE	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
07/07/14	34th & Benning Rd., NE	DC	3-1/c Cold Shrink Potheads #2 to 4/0
07/09/14	6th & MD, SW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
07/09/14	6th & MD, SW	DC	Straight Joint 4/0 3/c and below
07/14/14	3870 Rodman St., NW	DC	Network Transformer H.V. wiped terminal 13kV comp.
07/14/14	15th & K St., NW	DC	3/c PL to 3 1/c Flat Strap
07/14/14	3870 Rodman St., NW	DC	Straight Joint 4/0 3/c and below
07/15/14	NWC 3rd & F St., NW	DC	Straight Joint 4/0 3/c and below
07/15/14	SWC 3rd & F St., NW	DC	Single Branch Joint 4/0 3/c and below
07/16/14	18th & G St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
07/16/14	18th & G St., NW	DC	3-1/c, #2 Loadbreak Elbows
07/19/14	Stanton Rd. & Elvans Rd., SE	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
07/19/14	Stanton Rd. & Pomeroy Rd., SE	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
07/19/14	18th & I St., NW	DC	500 Trif. Joint
07/19/14	18th & I St., NW	DC	500 Trif. Joint
07/20/14	34th & M St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
07/20/14	34th & M St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
07/31/14	SEC Warden & Lamont	DC	URD Slip On
07/31/14	Opposite 3310 Warden	DC	URD Slip On
08/04/14	1800 E St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
08/04/14	S/S 19th & E St., NW	DC	Single Branch Joint 4/0 3/c and below
08/08/14	23rd Ave. & East West Hwy.	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
08/08/14	23rd Ave. & East West Hwy.	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
08/08/14	23rd Ave. & East West Hwy.	DC	3-1/c 500 or 600 Straight Heat Shrink Splices
08/08/14	23rd Ave. & East West Hwy.	DC	3-1/c 500 or 600 Straight Heat Shrink Splices
08/09/14	11th & NY Ave., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
08/09/14	11th & NY Ave., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
09/04/14	2150 Pennsylvania Ave., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
09/04/14	2150 Pennsylvania Ave., NW	DC	200 AMP Elbows
09/06/14	Montana Ave. & Edwin St., NE	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
09/06/14	Montana Ave. & Edwin St., NE	DC	3-1/c Cold Shrink Potheads 350 to 600
09/07/14	16th & L St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0

Table 3.3 (continued): 2014 Splice Data (District of Columbia)

Date	Location	Juris-diction	Type of Splice
09/07/14	16th & L St., NW	DC	200 AMP Elbows
09/08/14	1312 Massachusetts Ave., NW	DC	#2 Lead to #2 URD Tape Joints
09/08/14	461 H St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
09/08/14	1312 Massachusetts Ave., NW	DC	200 AMP Elbows
09/08/14	461 H St., NW	DC	200 AMP Elbows
09/13/14	13th & Columbia Rd., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
09/13/14	13th & Columbia Rd., NW	DC	Straight Joint 4/0 3/c and below
09/17/14	12th & I St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
09/17/14	12th & I St., NW	DC	200 AMP Elbows
09/22/14	1631 1st St., NW	DC	200 AMP Elbows
09/22/14	213 Q St., NW	DC	200 AMP Elbows/Slip Ons
09/22/14	213 Q St., NW	DC	200 AMP Elbows/Slip Ons
09/23/14	17th & A St., NE	DC	200 AMP Elbows
09/23/14	17th & A St., NE	DC	200 AMP Elbows
10/07/14	1715 Pennsylvania Ave., NW	DC	200 AMP Elbows
10/12/14	McKinley St. & Connecticut Ave., NW	DC	URD To Lead Tape Joint
10/12/14	McKinley St. & Connecticut Ave., NW	DC	URD To Lead Tape Joint
10/21/14	Key Bridge	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
10/21/14	Key Bridge	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
10/30/14	Foxhall & Res. Road, NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
10/30/14	Foxhall & Res. Road, NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/08/14	2401 Calvert St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/08/14	2401 Calvert St., NW	DC	200 AMP Elbows
11/09/14	2401 Calvert St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/11/14	4917 Rockwood Pkwy, NW	DC	1 Transition Straight Jt. #2 URD to #6RL
11/16/14	2500 Calvert St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/16/14	1348 Okie St., NE	DC	3 ea #2 URD Terminations
11/16/14	1348 Okie St., NE	DC	3 ea #2 URD Terminations
11/16/14	2500 Calvert St., NW	DC	Net. Trans. HV 200 AMP Deadbreak Terminal 13kV Comp
11/18/14	18th & K St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/18/14	18th & K St., NW	DC	200 AMP Elbows
11/19/14	Connecticut & N St., NW	DC	3-1/c URL Slip On Splices
11/20/14	Connecticut & N St., NW	DC	Slip Ons
11/23/14	R Street, South Side	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/23/14	3005 Massachusetts Ave., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/23/14	1348 Florida Ave., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/23/14	3005 Massachusetts Ave., NW	DC	200 AMP Elbows
11/23/14	1348 Florida Ave., NW	DC	3-1/c URL Slip On Splices
11/24/14	2nd & T St., NE	DC	3-1/c URD Slip on Splices
11/24/14	2nd & T St., NE	DC	3-1/c URD Slip on Splices
11/25/14	13th & East Capitol St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/25/14	13th & East Capitol St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/25/14	1st & V St., NW	DC	3-1/c URD Slip on Splices
11/25/14	13th & East Capitol St., NW	DC	410 3-1/c Straight Joints
11/26/14	1731 New Hampshire Ave., NW	DC	200 AMP Elbows
11/26/14	1631 New Hampshire Ave., NW	DC	Heat Shrink #2
11/28/14	3333 14th St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/28/14	14th & Park Rd., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
12/01/14	525 12th St., NW	DC	3-1/c Cold Shrink Potheads 350 to 600
12/01/14	525 12th St., NW	DC	3/c PL to 3-11c EPR Jt. 500 to 750

Table 3.3 (continued): 2014 Splice Data (District of Columbia)

Date	Location	Juris-diction	Type of Splice
12/02/14	22nd & G St., NW	DC	Double Branch Joint 750 3/c
12/02/14	22nd & G St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
12/03/14	Warder & Lamont St., NW	DC	3-1/c Cold Shrink Potheads 350 to 600
12/03/14	Warder & Kenyon St., NW	DC	3-1/c URD Slip on Splices
12/03/14	Warder & Kenyon St., NW	DC	3-1/c URD Slip on Splices
12/07/14	3222 N St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
12/07/14	1220 12th St., NW	DC	3-1/c 500 or 600 Straight Heat Shrink Splices
12/07/14	1220 12th St., NW	DC	200 AMP Elbows
12/07/14	3222 N St., NW	DC	200 or 600 AMP Deadbreaks
12/12/14	3401 38th St., NW	DC	3-1/c 500 or 600 Straight Heat Shrink Splices
12/12/14	3401 38th St., NW	DC	200 AMP Elbows
12/12/14	3401 38th St., NW	DC	3-1/c URD Slip on Splices
12/13/14	3401 38th St., NW	DC	200 & 600 AMP Deadbreaks on Outgoing
12/13/14	3401 38th St., NW	DC	200 AMP & 600 AMP Deadbreaks
12/13/14	3401 38th St., NW	DC	200 AMP Elbows
12/14/14	4th & Madison Dr., NW	DC	3/c PL to 3-1/c EPR or XLP Trif. Jt 500 to 600
12/14/14	4th & Pennsylvania Ave., NW	DC	3/c PL to 3-1/c EPR or XLP Trif. Jt 500 to 600
12/14/14	9th & D St., SW	DC	Single Branch Joint 4/0 3/c and below
12/14/14	9th & D St., SW	DC	Single Branch Joint 4/0 3/c and below
12/14/14	9th & D St., SW	DC	Single Branch Joint 4/0 3/c and below
12/14/14	9th & D St., SW	DC	Single Branch Joint 350 3/c to 600 3/c
12/16/14	2513 14th St., NE	DC	3-1/c Cold Shrink Potheads #2 to 4/0
12/16/14	2513 14th St., NE	DC	200 AMP Elbows
12/17/14	7th & 395, SW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
12/17/14	7th & 395, SW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
12/21/14	1625 Massachusetts Ave., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
12/21/14	1625 Massachusetts Ave., NW	DC	3-1/c URD Slip on Splices
12/24/14	17th & I St., NW	DC	Straight Joint 4/0 3/c and below
12/24/14	17th & I St., NW	DC	Straight Joint 4/0 3/c and below
12/24/14	17th & Connecticut Ave., NW	DC	Straight Joint 4/0 3/c and below
12/24/14	17th & I St., NW	DC	Single Branch Joint 4/0 3/c and below
12/30/14	Connecticut & 17th St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
12/30/14	Connecticut & 17th St., NW	DC	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0

Table 3.3 (continued): 2014 Splice Data (District of Columbia)

Appendix 3A: 2014 Manhole Events[82] [83]

82 In Order No. 11716 ordering paragraph 3, the Commission ordered the following:

3. PEPCO shall file an annual report on the previous calendar year's manhole incidents;

83 Order No. 16975 states the following at paragraphs 72 and 110:

72. Decision: We accept the Staff's recommendation and require Pepco to include grid numbers and Siemens' inspection dates on manhole event reports. Each year over 200 manholes are selected through stratified sampling criteria and inspected by Siemens. Including grid numbers and inspection dates will help to identify manhole events traced to the manholes recently inspected, manholes located along Pepco's Priority Feeders, and manholes with and adjacent to recent manhole events. This will enhance independent/third party validation and quality assurance of the manhole inspection program.

110. Pepco is DIRECTED to provide grid numbers consistent with paragraph 72 herein;

As required by Order 16975, the grid numbers and Siemens' inspection dates have been included in the Manhole Event data reported below.

New Manhole Event Information

At the December 13, 2011 and February 16, 2012 PIWG meetings, it was decided that the following types of additional information related to manhole events would be included in future Consolidated Reports. The following categories of information have been included in this year's Consolidated Report.

- Incident Date
- Work Order/Request #
- Address
- Grid Number
- Feeder Number
- Manhole cover type (solid, slotted, roadway, round, sidewalk)
- Manhole Condition (clean, water below cable, water above cable, debris above cable)
- Voltage class (600V, 4kV, 13kV, 34kV, 69kV)
- Type of equipment (transformer, protector, cable, switch, straight joint, branch joint, trifurcating joint, transition joint, other)
- Equipment description: details specifics of the equipment such as size, insulation, phases, type of joint
- Repair description: details repair work
- A description of the failure mode (not previously recorded)
- A determination if the failure is a repeating event at this location (not previously recorded)

Pepco undertook a substantial database conversion during 2012 to make these additions to enhance summary reporting and analysis. The duration of the repair effort, which was outstanding in the database conversion effort as of the 2013 Consolidated Report, is now included within the database.

The listing of 2014 Manhole Events is provided in the following table.

2014 MANHOLE EVENT REPORT - DISTRICT OF COLUMBIA

As of : 3/27/15

EVENT No.	DATE	LOCATION	Quad	EVENT TYPE	EQUIPMENT INVOLVED	Prim/Sec	Cable	Insulation	MANHOLE COVER	Cover	MH Size	FDR	DESCRIPTION/CAUSE	ACTION
DC14-01	1/3/14	1309 Columbia Road, NW.	NW.	S	Primary Joint	Primary	4/0 3/C PILC 4kV	PILC	Solid	Solid	6'x10'	84	Primary joint: Insulation deterioration	Remade joint
DC14-02	1/5/14	3rd and Varnum Streets, NW.	NW.	S	Secondary Cable	Secondary	250KCM 1/C RL 600V	RL	Solid	Solid	3'x3'	15012	Secondary cable: Insulation deterioration	Replaced cable
DC14-03	1/6/14	517 C Street, NE.	NE.	S	Secondary Cable	Secondary	250KCM 3/C RN 600V	RN	Solid	Solid	6'x12'	15702	Secondary cable: Insulation deterioration	Repaired cable
DC14-04	1/10/14	9th and H Streets, NW.	NW.	S	Secondary Cable	Secondary	250KCM 1/C RL 600V	RL	Solid	Solid	6'x10'	15330	Secondary cable: Insulation deterioration	Replaced cable
DC14-05	1/11/14	322 G Street, SW.	SW.	S	Secondary Cable	Secondary	250KCM 3/C RN 600V	RN	Slotted	Slotted	3'x3'	14404	Secondary cable: Insulation deterioration	Replaced cable
DC14-06	1/11/14	4000 13th Street, NW.	NW.	S	Secondary Cable	Secondary	#2 1/C RN 600V	RN	Solid	Solid	4'x6'	14722	Secondary cable: Insulation deterioration	Abandoned
DC14-07	1/11/14	1403 Morse Street, NE.	NE.	S	Secondary Cable	Secondary	#2 1/C RN 600V	RN	Solid	Solid	28"x28"	15702	Secondary cable: Cable cut by Gas Co.	Repaired cable and duct
DC14-08	1/14/14	1250 Taylor Street, NW.	NW.	S	Secondary Cable	Secondary	250KCM 3/C RN 600V	RN	Solid	Solid	6'x14'	15015	Secondary cable: Insulation deterioration	Replaced cable
DC14-09	1/15/14	240 M Street, SW.	SW.	S	Misc. Equipment	Secondary	N/A	N/A	Grate	Other	6'x18'	14403	Network protector: Corrosion	Replaced transformer and protector
DC14-10	1/22/14	1150 K Street, NW.	NW.	S	Secondary Cable	Secondary	250KCM 3/C RN 600V	RN	Slotted	Slotted	28"x28"	14517	Secondary cable: Insulation deterioration	Repaired cable
DC14-11	1/22/14	536 11th Street, SE.	SE.	S	Secondary Cable	Secondary	3/0 1/C RL 600V	RL	Solid	Solid	28"x28"	228	Secondary cable: Insulation deterioration	Repaired cable
DC14-12	2/3/14	555 12th Street, NW.	NW.	S	Misc. Equipment	Secondary	N/A	N/A	Solid	Solid	6'x14'	14562	Misc. Equipment: sump pump failure	Removed sump pump
DC14-13	2/3/14	1624 Florida Avenue, NW.	NW.	S	Secondary Cable	Secondary	#2 1/C RN 600V	RN	Slotted	Slotted	3'x3'	14731	Secondary cable: Insulation deterioration	Replaced cable
DC14-14	2/3/14	325 7th Street, NW.	NW.	S	Secondary Joint	Secondary	250KCM 3/C RN 600V	RN	Solid	Solid	3'x3'	14575	Secondary joint: Insulation deterioration	Remade joint
DC14-15	2/8/14	2104 Eye Street, NE.	NE.	S	Primary Cable	Primary	# 2 2/C 15kV EPR	EPR	Solid	Solid	3'x3'	15702	Primary cable: Insulation deterioration	Replaced cable
DC14-16	2/15/14	26th & L Streets, NW.	NW.	S	Secondary Cable	Secondary	250KCM 3/C RN 600V	RN	Solid	Solid	28"x28"	15401	Secondary cable: Insulation deterioration	Replaced cable
DC14-17	2/18/14	1649 C Street, NE.	NE.	S	Non-Pepco	Other	N/A	N/A	Solid	Other	28"x28"	14713	Non-Pepco streetlight cable: Insulation deteriorat	Repaired cable
DC14-18	2/26/14	1900 K Street, NW.	NW.	S	Secondary Cable	Secondary	500KCM 1/C RN 600V	RN	Grate	Other	5.5'x17'	15424	Secondary cable: Insulation deterioration	Retaped cable
DC14-19	3/3/14	900 Brentwood Road, NE.	NE.	E	Primary Cable	Primary	#2 1/C PILC 15kV	PILC	Slotted	Slotted	3'x3'	15458	Primary cable: Insulation deterioration	Repaired cable
DC14-20	3/3/14	3014 Dent Place, NW.	NW.	S	Secondary Cable	Secondary	250KCM 3/C RN 600V	RN	Slotted	Slotted	3'x3'	74	Secondary cable: Insulation deterioration	Repaired cable
DC14-21	3/4/14	2922 Sherman Avenue, NW.	NW.	S	Secondary Cable	Secondary	250KCM 3/C RN 600V	RN	Solid	Solid	3'x3'	14729	Secondary cable: Insulation deterioration	Repaired cable
DC14-22	3/4/14	Connecticut and Florida Avenue, NW.	NW.	S	Secondary Cable	Secondary	250KCM 3/C RN 600V	RN	Solid	Solid	4'x6'	14583	Secondary cable: Insulation deterioration	Repaired cable
DC14-23	3/9/14	1415 11th Street, NW.	NW.	S	Secondary Cable	Secondary	#2 1/C RN 600V	RN	Slotted	Slotted	4'x4'	15027R	Secondary cable: Insulation deterioration	Repaired cable
DC14-24	3/10/14	625 E Street, NW.	NW.	S	Primary Joint	Primary	4/0 3/C EPR Flat Strap 15kV	EPR	Solid	Solid	5'x12'	15326	Primary joint: Insulation deterioration	Remade joint
DC14-25	3/11/14	300 P Street, NW.	NW.	S	Secondary Cable	Secondary	250KCM 1/C RL 600V	RN	Slotted	Slotted	3'x3'	15240	Damaged by DC Water Replacing Hydrant	Remade cable
DC14-26	3/19/14	3115 14th Street, NW.	NW.	S	Primary Joint	Primary	4/0 3/C PILC 4kV	PILC	Solid	Solid	6'x14'	76	Burnt-up temporary repairs	Remade joint
DC14-27	3/19/14	1801 P Street, NW.	NW.	S	Secondary Cable	Secondary	250KCM 3/C RN 600V	RN	Solid	Solid	3'x3'	14372	Secondary cable: Insulation deterioration	Repaired cable
DC14-28	3/19/14	481 C Street NW.	NW.	S	Non-Pepco	Other	N/A	N/A	Solid	Solid	28"x28"	15308	Non-Pepco streetlight cable: Insulation deteriorat	Repaired cable
DC14-29	3/19/14	1721 Riggs Place, NW.	NW.	E	Secondary Cable	Secondary	#2 1/C RN 600V	RN	Slotted	Slotted	2'x2.5'	15764	Secondary cable: Insulation deterioration	Repaired cable
DC14-30	3/19/14	1721 Bay Street, SE.	SE.	S	Secondary Cable	Secondary	#2 1/C RN 600V	RN	Solid	Solid	28"x28"	229	Secondary cable: Insulation deterioration	Repaired cable
DC14-31	3/19/14	1315 K Street, SE.	SE.	S	Secondary Cable	Secondary	250KCM 1/C RL 600V	RL	Solid	Solid	28"x28"	212	Secondary cable: Insulation deterioration	Repaired cable
DC14-32	3/24/14	192 19th Street, SE.	SE.	S	Secondary Joint	Secondary	250KCM 1/C RL 600V	RL	Solid	Solid	2'x2.5'	14810	Secondary joint: Insulation deterioration (Displac	Remade joint
DC14-33	3/24/14	Nebraska and Albermarle Street, NW.	NW.	S	Primary Joint	Primary	600KCM 3/C PILC 15kV	PILC	Solid	Solid	6'x12'	14148w	Primary joint: Insulation deterioration (displaced	Remade joint
DC14-34	3/27/14	2312 Wyoming Avenue, NW.	NW.	S	Secondary Cable	Secondary	250KCM 3/C RL 600V	RL	Solid	Solid	2'x2.5'	14733	Secondary cable: Insulation deterioration	Remade joint
DC14-35	3/28/14	3rd and R Street, NE.	NE.	E	Primary Cable	Primary	4/0 3/C PILC 15kV	PLIC	Solid	Solid	6'x12'	15459	Primary cable: Insulation deterioration	Remade joint
DC14-36	3/29/14	1409 Orren Street, NE.	NE.	S	Secondary Cable	Secondary	#2 Duplex 2/C RL 600V	RL	Solid	Solid	28"x28"	14712	Secondary cable: Insulation deterioration	Remade joint
DC14-37	3/29/14	3336 Prospect Street, NW.	NW.	F	Secondary Joint	Secondary	250KCM 3/C RN 600V	RN	Slotted	Slotted		15411	Secondary joint: Insulation deterioration	Remade joint
DC14-38	3/29/14	1043 Quebec Place, NW.	NW.	S	Secondary Cable	Secondary	250KCM 3/C RN 600V	RN	Solid	Solid		14054	Secondary cable: Insulation deterioration	Repaired cable
DC14-39	3/30/14	2714 Quarry Road, NW.	NW.	F	Secondary Cable	Secondary	250KCM 1/C RN 600V	RN	Slotted	Slotted	6'x14'	15762	Secondary cable: Insulation deterioration	Repaired cable
DC14-40	3/30/14	1613 Irving Street, NW.	NW.	S	Secondary Cable	Secondary	250KCM 3/C RN 600V	RN	Solid	Solid	5'x10'	15762	Secondary cable: Insulation deterioration	Repaired cable
DC14-41	3/30/14	2120 L Streets, NW.	NW.	S	Misc. Equipment	Secondary	N/A	N/A	Slotted	Slotted	6'x12'	14583	T-body termination: Moisture ingress	Replaced terminator
DC14-42	4/2/2014	15th St. & Tennessee Ave NE.	NE.	E	Primary Joint	Primary	#2 3/C PILC 15kV	PLIC	Solid	Solid	4' x 8'	14536	Primary joint: Insulation deterioration	Repaired Joint
DC14-43	4/7/2014	4011 13th St. NW.	NW.	E	Secondary Cable	Secondary	250 RL 4/0	RL	Solid	Solid	28"x28"	14722	Secondary cable: Insulation deterioration	Repaired Cable
DC14-44	4/7/2014	800 22nd St. NW.	NW.	S	Secondary Cable	Secondary	250KCM 1/C RN 600V	RN	Slotted	Slotted		15382	Secondary cable: Insulation deterioration (Concr	Repaired Cable
DC14-45	4/10/2014	Wisconsin Ave. & Van Ness St. NW.	NW.	S	Primary Joint	Primary	500 PILC	PILC	Solid	Solid	7' x 16'	14133	Primary joint: Insulation deterioration	Repaired Joint
DC14-46	4/11/2014	2nd St. & Constitution Ave. NW.	NW.	E	Primary Cable	Primary	500KCM 3/C PILC 600V	PILC	Slotted	Slotted	6' x 10'	14665	Primary cable: Insulation deterioration	Repaired Cable
DC14-47	4/13/2014	15th & A St., SE.	SE.	S	Secondary Cable	Secondary	250KCM 1/C RN 600V	RN	Solid	Solid	5' x 8'	15703	Secondary cable: Insulation deterioration	Repaired Cable
DC14-48	4/30/2014	5301 Georgia Avenue NW.	NW.	S	Secondary Cable	Secondary	#2 1/C RN 600V	RN	Slotted	Slotted	2' x 2'	15015	Secondary cable: Insulation deterioration	Repaired Cable
DC14-49	5/16/2014	1602 Potomac Ave. SE.	SE.	E	Primary Joint	Primary	#2 1/C RL 4kV	RL	Slotted	Slotted	2' x 2'	227	Primary joint: Insulation deterioration	Remade branch joint
DC14-50	5/18/2014	2nd St. & D Street SE.	SE.	F	Misc. Equipment	Secondary	N/A	N/A	Slotted	Solid	28"x28"	15757	Secondary Mains Burnt, Street Light Cable	Two manholes, one slotted, one solid
DC14-51	5/23/2014	2106 Vermont Avenue NW.	NW.	F	Primary Cable	Primary	4/0 3/C PILC 15kV	PLIC	Slotted	Slotted	2' x 2'	15344	Fiber Optic Cable	Repaired Joint
DC14-52	5/31/2014	4801 Indian Lane NW.	NW.	S	Primary Joint	Primary	#2 URD 4/0 RL	RL	Solid	Solid	28"x28"	292	Primary joint: Insulation deterioration	Remade joint
DC14-53	6/11/2014	3220 Connecticut Ave NW.	NW.	S	Primary Joint	Primary	500 3/C PILC	PILC	Solid	Solid	2' x 2'	14146	Primary joint: Insulation deterioration	Remade joint
DC14-54	7/2/2014	4404 Kansas Ave NW.	NW.	S	Non-Pepco	Other	N/A	N/A	Other	Other	3' x 3'	15197	Non-Pepco streetlight cable: Insulation deterioration	
DC14-55	7/7/2014	3400 Benning Rd NE.	NE.	S	Primary Joint	Primary	600 1/C PILC	PILC	Solid	Solid	6' x 12'	14538	Primary joint: Insulation deterioration	Remade joint
DC14-56	7/11/2014	2004 11th St. NW.	NW.	S	Primary Joint	Primary	#2 3/C PILC 15kV	PILC	Slotted	Slotted	6' x 12'	15344	Primary joint: Insulation deterioration	Remade joint
DC14-57	7/15/2014	9th & G St. NW.	NW.	E	Primary Joint	Primary	#2 3/C PILC 15kV	PILC	Slotted	Slotted	6' x 12'	15327	Primary joint: Insulation deterioration	Remade joint
DC14-58	7/18/2014	3000 Stanton Rd. SE.	SE.	E	Primary Joint	Primary	600MCM 3/C PILC	PILC	Solid	Solid	6' x 12'	15632	Primary joint: Insulation deterioration	Remade joint
DC14-59	7/20/2014	1555 L St. NW.	NW.	E	Misc. Equipment	Primary		N/A	Slotted	Slotted		14506	Network Trans. Primary cabinet door blown off	
DC14-60	7/23/2014	S. Capitol St. & Malcolm X Ave. SE.	SE.	S	Primary Joint	Primary	500KCM 3/C PILC	PILC	Solid	Solid	6' x 12'	15629	Primary joint: Insulation deterioration	Remade joint
DC14-61	7/24/2014	20th St. & Biltmore St. NW.	NW.	E	Misc. Equipment	Primary	N/A	N/A	Slotted	Slotted	5' x 16'	14731	MH Collapsed due to water leak.	Removed debris off of secondary cable
DC14-62	8/7/2014	10th St. & D St. SE.	SE.	S	Secondary Cable	Secondary	250KCM 1/C RN 600V	RN	Solid	Solid	6' x 10'	209	Secondary cable: Insulation deterioration	Repaired cable
DC14-63	8/8/2014	11 St. & New York Ave. NW.	NW.	S	Primary Joint	Primary	600 3/C PILC	PILC	Slotted	Slotted	6' x 10'	15202W	Primary joint: Insulation deterioration	Repaired joint
DC14-64	8/12/2014	1990 K St. NW.	NW.	S	Secondary Cable	Secondary	250KCM 1/C RN 600V	RN	Slotted	Slotted	3' x 3'	15423	Secondary cable: Insulation deterioration	Repaired cable
DC14-65	8/18/2014	11th St. & U St. NW.	NW.	S	Secondary Cable	Secondary	250KCM 1/C RN 600V	RN	Slotted	Slotted	3' x 3'	15769	Secondary cable: Insulation deterioration	Repaired cable
DC14-66	9/1/2014	13th St. & Columbia Rd. NW.	NW.	S	Primary Cable	Primary	4/0 3/C PILC 4kV	PILC	Solid	Solid	5' x 8'	76	Primary cable: Insulation deterioration	Repaired cable
DC14-67	9/21/2014	350 G St. SW.	SW.	S	Primary Joint	Primary	#2 PILC 13kV	PILC	Solid	Solid	5' x 8'	14402	Primary joint: Insulation deterioration	Repaired joint
DC14-68	9/22/2014	1700 East Capitol St NE.	NE.	E	Misc. Equipment	Other	N/A	N/A	Solid	Solid		14804	MH Collapsed hitting 2 oil switches	Repaired manhole replaced all equipment
DC14-69	9/25/2014	5910 Georgia Ave, NW.	NW.	S	Secondary Cable	Secondary	250 RN 4/0	RN	Solid	Solid	5' x 8'	15010	Secondary cable: Insulation deterioration	Replaced Cable
DC14-70	9/28/2014	20 F St. NW.	NW.	S	Primary Joint	Primary	1/0 URD 3/C PILC	PILC	Slotted	Slotted	28"x28"	14419	Primary joint: Insulation deterioration	Remade joint
DC14-71	10/12/2014	308 15th Street, SE.	SE.	S	Primary Joint	Primary	#2 PILC 13kV	PILC	Solid	Solid	4' x 4'	208	Secondary joint: Leaded joint failure	Remade joint
DC14-72	10/16/2014	32 S St. NW.	NW.	S	Secondary Cable	Secondary	250 RL 4/0	RL	Slotted	Slotted	5' x 8'	14419	Secondary cable: Insulation deterioration	Repaired cable
DC14-73	10/22/2014	1235 Good Hope Road SE.	SE.	S	Secondary Cable	Secondary	251 RL 4/0	RL	Slotted	Slotted		348	Secondary cable: Insulation deterioration	Repaired cable
DC14-74	10/27/2014	916 G St. NW.	NW.	F	Misc. Equipment	Primary	Blown Test Cap	PILC	Solid	Solid	6' x 12'	15327	Blown Test Cap	Remade Temp Test Cap
DC14-75	12/2/2014	22nd & G St. NW.	NW.	S	Primary Joint	Primary	4/0 3/C PILC 13kV	PILC	Solid	Solid	5' x 9'	15385	Primary joint: Insulation deterioration	Repaired Cable
DC14-76	12/16/2014	6th & H St. NE.	NE.	S	Secondary Cable	Secondary	250KCM 1/C RN 600V	RN	Slotted	Slotted	3 ' x 3'	14538	Secondary cable: Insulation deterioration	Made Repairs
DC14-77	12/28/2014	730 12th St NW.	NW.	E	Primary Joint	Primary	#2 3-1/C EPR 13kV	EPR	Solid	Solid	5' x 8'	14521	Primary joint: Insulation deterioration	Repaired Joint

Table 3A

2014 MANHOLE EVENT REPORT - DISTRICT OF COLUMBIA

As of : 3/27/15

EVENT No.	DATE	Work Order	LOCATION	FAILURE MODE	REPEAT EVENT	4kV / 13kV	Manhole Condition	NO. OF CUST.	Outage (hr/min)	Repair Duration	DATE INSPECTED BY	LAST INSPECTION	Grid No.	Personal injury or property damage
DC14-01	1/3/14	3440910	1309 Columbia Road, NW.	Insulation Related	No	4kV	Water below cable	618	1h41m	1h41m		5/18/11	791398-065470	No
DC14-02	1/5/14	3440915	3rd and Varnum Streets, NW.	Insulation Related	No	13kV	Clean	20	4h02m	4h02m		12/10/12	795404-535295	No
DC14-03	1/6/14	Corr. Main.	517 C Street, NE.	Insulation Related	No	13kV	Water below cable	0	0	1h30m		3/30/09	800385-287869	No
DC14-04	1/10/14	3441349	9th and H Streets, NW.	Insulation Related	No	13kV	Water below cable	1	16h27m	16h27m		2/26/10	792388-637360	No
DC14-05	1/11/14	Corr. Main.	322 G Street, SW.	Insulation Related	No	13kV	Water below cable	0	0	4h0m		11/3/10	795381-442570	No
DC14-06	1/11/14	Corr. Main.	4000 13th Street, NW.	Insulation Related	No	13kV	Water below cable	0	0	1h0m		2/17/09	791402-452864	No
DC14-07	1/11/14	Corr. Main.	1403 Morse Street, NE.	Third Party Damage	No	13kV	Clean	0	0	3h0m		8/1/11	804388-355925	No
DC14-08	1/14/14	3441576	1250 Taylor Street, NW.	Insulation Related	No	13kV	Water below cable	0	0	2h30m		1/8/09	791403-728253	No
DC14-09	1/15/14	3442170	240 M Street, SW.	Corrosion	No	13kV	Water below cable	0	0	2h0m		11/24/10	795379-520517	No
DC14-10	1/22/14	Corr. Main.	1150 K Street, NW.	Insulation Related	No	13kV	Water above cable	0	0	1h30m		3/18/14	791389-995305	No
DC14-11	1/22/14	Corr. Main.	536 11th Street, SE.	Insulation Related	No	4kV	Water above cable	0	0	1h0m		10/1/04	802381-348685	No
DC14-12	2/3/14	Corr. Main.	555 12th Street, NW.	Other	No	13kV	Water below cable	0	0	1h0m		10/20/10	791387-948262	No
DC14-13	2/3/14	Corr. Main.	1624 Florida Avenue, NW.	Insulation Related	No	13kV	Water below cable	0	0	2h0m		2/22/13	789395-212232	No
DC14-14	2/3/14	Corr. Main.	325 7th Street, NW.	Insulation Related	No	13kV	Water below cable	0	0	1h30m		10/15/03	793386-783503	No
DC14-15	2/8/14	3443999	2104 Eye Street, NE.	Insulation Related	No	13kV	Water below cable	0	0	1h15m		11/29/12	807389-292479	No
DC14-16	2/15/14	Corr. Main.	26th & L Streets, NW.	Insulation Related	No	13kV	Water above cable	0	0	2h0m		3/31/11	784389-312802	No
DC14-17	2/18/14	Corr. Main.	1649 C Street, NE.	Insulation Related	No	13kV	Water above cable	0	0	1h0m		8/19/11	805385-248933	No
DC14-18	2/26/14	Corr. Main.	1900 K Street, NW.	Insulation Related	No	13kV	Water above cable	0	0	2h30m		12/18/13	787389-502127	No
DC14-19	3/3/14	Corr. Main.	900 Brentwood Road, NE.	Insulation Related	No	13kV	Water below cable	0	0	1h5m		10/31/13	801394-239139	No
DC14-20	3/3/14	Corr. Main.	3014 Dent Place, NW.	Insulation Related	No	13kV	Water below cable	0	0	1h30m		7/17/14	782392-883742	No
DC14-21	3/4/14	Corr. Main.	2922 Sherman Avenue, NW.	Insulation Related	No	13kV	Water below cable	0	0	7h0m		10/31/13	792398-493435	No
DC14-22	3/4/14	Corr. Main.	Connecticut and Florida Avenue, NW.	Insulation Related	No	13kV	Water below cable	0	0	2h30m	6/12/2012	04/08/14	786393-723545	No
DC14-23	3/9/14	Corr. Main.	1415 11th Street, NW.	Insulation Related	No	13kV	Water below cable	113	1h02m	1h02m		03/29/10	792391-258715	No
DC14-24	3/10/14	3447125	625 E Street, NW.	Insulation Related	No	13kV	Water below cable	0	0	2h30m		10/06/10	793387-853010	No
DC14-25	3/11/14	Corr. Main.	300 P Street, NW.	Insulation Related	No	13kV	Clean	0	0	2h0m		01/01/05	795391-493945	No
DC14-26	3/19/14	3438501	3115 14th Street, NW.	Insulation Related	No	4kV	Clean	0	0	2h30m		03/10/14	790399-627313	No
DC14-27	3/19/14	Corr. Main.	1801 P Street, NW.	Insulation Related	No	13kV	Water above cable	0	0	1h30m		01/07/15	787391-804938	No
DC14-28	3/19/14	Corr. Main.	481 C Street NW.	Insulation Related	No	13kV	Water above cable	0	0	1h30m		08/30/12	794386-5850052	No
DC14-29	3/19/14	Corr. Main.	1721 Riggs Place, NW.	Insulation Related	No	13kV	Water below cable	0	0	1h15m		11/08/13	788393-310295	No
DC14-30	3/19/14	3448290	1721 Bay Street, SE.	Insulation Related	No	4kV	Water below cable	0	0	3h30m		09/14/12	805383-652524	No
DC14-31	3/19/14	Corr. Main.	1315 K Street, SE.	Insulation Related	No	4kV	Water below cable	0	0	3h30m		11/27/12	803380-440518	No
DC14-32	3/24/14	Corr. Main.	192 19th Street, SE.	Insulation Related	No	13kV	Water below cable	0	0	1h30m		01/08/15	806383-398234	No
DC14-33	3/24/14	3448628	Nebraska and Albermarie Street, NW.	Insulation Related	No	13kV	Water below cable	0		1h30m		04/09/12	777405-995923	No
DC14-34	3/27/14	Corr. Main.	2312 Wyoming Avenue, NW.	Insulation Related	No	13kV	Water below cable	0		6h30m		08/25/10	785394-375600	No
DC14-35	3/28/14	3449012	3rd and R Street, NE.	Insulation Related	No	13kV	Water below cable	0		16h		08/25/10	799393-339019	No
DC14-36	3/29/14	Corr. Main.	1409 Orren Street, NE.	Insulation Related	No	13kV	Water below cable			1h30m		08/17/12	804389-342976	No
DC14-37	3/29/14	Corr. Main.	3336 Prospect Street, NW.	Insulation Related	No	13kV	Water below cable			1h15m		05/15/14	780390-728560	No
DC14-38	3/29/14	Corr. Main.	1043 Quebec Place, NW.	Insulation Related	No	13kV	Water below cable			1h15m		Unknown	791401-751864	No
DC14-39	3/30/14	Corr. Main.	2714 Quarry Road, NW.	Insulation Related	No	13kV	Water below cable			1h30m		09/28/11	788397-734829	No
DC14-40	3/30/14	Corr. Main.	1613 Irving Street, NW.	Insulation Related	No	13kV	Water below cable			2h0m		04/08/11	789398-145910	No
DC14-41	3/30/14	Corr. Main.	2120 L Streets, NW.	Other	No	13kV	Water below cable	0		3h		03/23/10	786389-416735	No
DC14-42	4/2/2014	Corr. Main.	15th St. & Tennessee Ave NE.	Insulation Related	No	13kV	Water below cable	0		1h30m		07/21/11	804387-587631	No
DC14-43	4/7/2014	Corr. Main.	4011 13th St. NW.	Insulation Related	No	13kV	Water below cable	0		4h		12/12/14	791403-490020	No
DC14-44	4/7/2014	Corr. Main.	800 22nd St. NW.	Insulation Related	No	13kV	Water below cable	0		2h		12/29/14	785388-982621	No
DC14-45	4/10/2014	Corr. Main.	Wisconsin Ave. & Van Ness St. NW.	Insulation Related	Yes	13kV	Water below cable	245	1h51min	1h51m	9/23/14 - 10/17/14	09/06/12	778404-076135	No
DC14-46	4/11/2014	Corr. Main.	2nd St. & Constitution Ave. NW.	Insulation Related	No	13kV	Water below cable	0		8h		10/01/12	796385-063576	No
DC14-47	4/13/2014	Corr. Main.	15th & A St., SE.	Insulation Related	No	13kV	Water below cable	0		1h30m		06/22/09	804384-539318	No
DC14-48	4/30/2014	Corr. Main.	5301 Georgia Avenue NW.	Insulation Related	No	13kV	Water below cable	0		1h30m		01/22/13	792408-050242	No
DC14-49	5/16/2014	Corr. Main.	1602 Potomac Ave. SE.	Insulation Related	No	4kV	Water below cable	0	0	10h30m		10/19/13	805381-013780	No
DC14-50	5/18/2014	Corr. Main.	2nd St. & D Street SE.	Other	No	13kV	Water below cable	0	0	8h		11/29/10	798382-939656	No
DC14-51	5/23/2014	Corr. Main.	2106 Vermont Avenue NW.	Insulation Related	No	13kV	Water below cable	0	0	6h30m		01/30/15	792395-884045	No
DC14-52	5/31/2014	Corr. Main.	4801 Indian Lane NW.	Insulation Related	No	4kV	Water below cable	0	0	3h30m		12/12/14	773400-099589	No
DC14-53	6/11/2014	Corr. Main.	3220 Connecticut Ave NW.	Insulation Related	Yes	13kV	Water below cable	0	0	16h	9/23/2014 - 10/17/2014	06/10/08	783400-628536	No
DC14-54	7/2/2014	Corr. Main.	4404 Kansas Ave NW.	Other	No	13kV		0	0			01/23/09	792404-854563	No
DC14-55	7/7/2014	3457949	3400 Benning Rd NE.	Insulation Related	No	13kV	Water below cable	0	0	1h30m		02/15/12	811381-865208	No
DC14-56	7/11/2014	3458380	2004 11th St. NW.	Insulation Related	No	13kV	Water below cable	0	0	6h0m		09/17/09	792394-201820	No
DC14-57	7/15/2014	3458615	9th & G St. NW.	Insulation Related	No	13kV	Water below cable	0	0	1h30m	12/8/2009	10/01/10	793387-126869	No
DC14-58	7/18/2014	3458867	3000 Stanton Rd. SE.	Insulation Related	No	13kV	Water below cable	0	0	1h30m		03/08/12	803371-980790	No
DC14-59	7/20/2014	Corr. Main.	1555 L St. NW.		No	13kV		0	0			03/07/08	789389-684818	No
DC14-60	7/23/2014	3459359	S. Capitol St. & Malcolm X Ave. SE.	Insulation Related	No	13kV	Water below cable	0	0	24h		01/08/15	797368-930420	No
DC14-61	7/24/2014	Corr. Main.	20th St. & Biltmore St. NW.	Contractor Digging	No	13kV		0	0	16h		10/02/07	786396-557267	No
DC14-62	8/7/2014	Corr. Main.	10th St. & D St. SE.	Insulation Related	No	4kV	Water below cable	0	0	1h30m		11/02/12	802382-050362	No
DC14-63	8/8/2014	Corr. Main.	11 St. & New York Ave. NW.	Blown Straight Joint	No	13kV	Water below cable	0	0	12h		09/16/00	792388-228845	No
DC14-64	8/12/2014	Corr. Main.	1990 K St. NW.	Insulation Related	No	13kV	Water below cable	0	0	6h		11/20/13	787389-167221	No
DC14-65	8/18/2014	Corr. Main.	11th St. & U St. NW.	Insulation Related	No	13kV	Water below cable	0	0	6h		10/17/07	792394-197507	No
DC14-66	9/1/2014	Corr. Main.	13th St. & Columbia Rd. NW.	Insulation Related	No	4kV	Water below cable	0	0	10h		05/19/11	791398-262478	No
DC14-67	9/21/2014	Corr. Main.	350 G St. SW.	Insulation Related	No	13kV	Clean	0	0	2h30m		11/04/10	795381-266603	No
DC14-68	9/22/2014	Corr. Main.	1700 East Capitol St NE.	Other	No	13kV			0	12h	4/24/0212	03/07/12	805384-430930	No
DC14-69	9/25/2014	Corr. Main.	5910 Georgia Ave, NW.	Insulation Related	No	13kV	Water below cable	0	0	11h		08/20/12	791410-918829	No
DC14-70	9/28/2014	Corr. Main.	20 F St. NW.	Blown Trif Joint	No	13kV	Water below cable	0	0	2h30m		01/21/15	797387-113428	No
DC14-71	10/12/2014	Corr. Main.	308 15th Street, SE.	Blown Joint	No	4kV	Water below cable	300	5h	5h		01/13/06	804382-580960	No
DC14-72	10/16/2014	Corr. Main.	32 S St. NW.	Insulation Related	No	13kV	Water below cable	2	7h	7h		01/31/13	781393-660731	No
DC14-73	10/22/2014	Corr. Main.	1235 Good Hope Road SE.	Insulation Related	No	4kV	Water below cable	0				04/30/12	803376-492442	No
DC14-74	10/27/2014	Corr. Main.	916 G St. NW.		No	13kV		0	0	29m		03/31/04	792387-889786	No
DC14-75	12/2/2014	Corr. Main.	22nd & G St. NW.	Blown Joint	No	13kV	Water below cable	0	0	16h		02/13/09	786387-039837	No
DC14-76	12/16/2014	Corr. Main.	6th & H St. NE.	Other	No	13kV	Clean	0	0	8h		Unknown	800388-483518	No
DC14-77	12/28/2014	Corr. Main.	730 12th St NW.	Blown Joint	No	13kV	Clean	0	0	16h		05/28/09	791388-890196	No

Table 3A (continued)

Notes:
77 events : 29 primary (17 S, 2 F, 10 E), 44 secondary (39 S, 3 F, 2 E), 4 Other (3 S, 0 F, 1 E)
27 events involved slotted manhole covers (17 S, 4 F, 6 E),
2 events involved grated covers (2 S, 0 F, 0 E),
48 events involved solid manhole covers (40 S, 1 F, 7 E)

Event category breakdown:

Smoking manholes	59		
Manhole fires	5		
Manhole explosions	13		
Total:	77		
Northwest	51	Georgetown:	2
Northeast	11		
Southwest	3		
Southeast	12		
Total:	77		

Events Summary 13kV
66 events : 23 primary (12 S, 2 F, 9 E), 39 secondary (34 S, 3 F,2 E), 4 Other (3 S, 0 F, 1 E)

Event category breakdown:

Smoking manholes	49		
Manhole fires	5		
Manhole explosions	12		
Total:	66		
		Georgetown:	2

Events Summary 4kV
11 events : 6 primary (5 S, 0 F, 1 E), 5 secondary (5 S, 0 F, 0 E),

Event category breakdown:

Smoking manholes	10		
Manhole fires	0		
Manhole explosions	1		
Total:	11		
		Georgetown:	0

First Quarter 2014 - Summary

Insulation Deterioration by Cable Type:	
Paper Insulated Lead Cable (PILC)	5
Rubber Lead (RL)	7
Rubber Neoprene (RN)	22
Ethylene Propylene Rubber (EPR)	2
Cross Link Polyethylene (XLP)	0
Other (Braided)	0
Other	0
Non-Pepco	2
Non-Cable related	3 a/
TOTAL	41

Third Quarter 2014 - Summary

Insulation Deterioration by Cable Type:	
Paper Insulated Lead Cable (PILC)	9
Rubber Lead (RL)	0
Rubber Neoprene (RN)	4
Ethylene Propylene Rubber (EPR)	0
Cross Link Polyethylene (XLP)	0
Other (Braided)	0
Other	0
Non-Pepco	1
Non-Cable related	3 b/
TOTAL	17

Second Quarter 2014 - Summary

Insulation Deterioration by Cable Type:	
Paper Insulated Lead Cable (PILC)	5
Rubber Lead (RL)	3
Rubber Neoprene (RN)	3
Ethylene Propylene Rubber (EPR)	0
Cross Link Polyethylene (XLP)	0
Other (Braided)	0
Other	0
Non-Pepco	1
Non-Cable related	0
TOTAL	12

Fourth Quarter 2014 - Summary

Insulation Deterioration by Cable Type:	
Paper Insulated Lead Cable (PILC)	3
Rubber Lead (RL)	2
Rubber Neoprene (RN)	1
Ethylene Propylene Rubber (EPR)	1
Cross Link Polyethylene (XLP)	0
Other (Braided)	0
Other	0
Non-Pepco	0
Non-Cable related	0
TOTAL	7

* NOTE: There were two manhole events where the inspection date is listed as "Unknown". These two locations are scheduled to be inspected in 2015.

a/ 1 t-body Termination, 1 sump pump, 1 Network protector
b/ 1 Primary cabinet, 2 Manholes collapsed

Table 3A (continued)

Appendix 3B: 2014 Manhole Inspection Program[84]

[84] In Order No. 11716, the Commission stated the following:

PEPCO is hereby directed to include the following information in its [manhole inspection] reports beginning in July 2000:

1. *The general location of the manholes inspected, including the street or streets where the manholes are located and the blocks bounding the street, e.g., M Street, NW, between 23rd and 28th streets;*
2. *The number of manholes inspected in the month, broken down as to the number of manholes containing primary cables only, both primary and secondary cables, and secondary cables only;*
3. *The number of primary cable problems found;*
4. *The number of secondary cable problems found;*
5. *The type of cable problems found in each manhole, categorized as to the physical degradation or damage of the cable, overheating, overloading, damaged splice and deteriorated cable or splice due to age;*
6. *The number of manholes with problems;*
7. *The corrective actions taken for each cable and manhole problem found; and*
8. *Other general condition of the manhole such as whether it contained water, oil, grease, debris, and whether the manhole cover and the manhole are in good mechanical condition.*

APPENDIX 3B - MANHOLE INSPECTION PROGRAM (MIP)

Pepco began development of its manhole inspection program in 1999. By the end of 2006, Pepco had performed a total of approximately 79,295 inspections, completing Phase I. Phase II of the Company's Manhole Inspection Program began in 2007 and was completed in the first quarter of 2013 with a total of approximately 69,670 inspections. Phase III of the manhole inspection program is currently underway. 11,554 manholes were inspected in 2013, approximately 9,054 of which constitute Phase III inspections. In 2014, 11,533 manholes were inspected as part of the Phase III.

In contrast to the reported inspection totals in previous reports, Pepco now reports a Phase II inspection total of 69,670 manholes. A recent investigation of unique manhole inspections undertaken by the Public Service Commission's technical audit revealed that the querying method Pepco historically used to identify unique inspections in the tracking database contained an error. Pepco historically used an estimated population of approximately 60,000 manholes in the District of Columbia in reporting, although the number of manholes containing distribution facilities, and therefore included in the manhole inspection program, is slightly lower. For technical reasons, transmission manholes are inspected through a different program. However, the Company believes the total number of manholes in the District was presented as the population to be inspected as part of the manhole inspection program. Since duplicate inspections are inherent in the design of the program, the possibility of this error was not evident. The Company has since corrected the database querying issue.

Manhole inspections represent a significant undertaking that involve the visual assessment of the underground manholes and vaults and the equipment contained in them, taking load readings of low voltage cables and reviewing the integrity of cable splices. Supervisory personnel review records and corrective actions are identified and tracked. Data obtained during the inspections can be used to ascertain whether the secondary cables are overloaded, or are likely to be overloaded under peak load conditions using appropriate de-rating factors and factors to simulate peak conditions. Inspections are also designed to identify load variations between phases which could indicate possible imbalanced conditions. By identifying such instances and taking appropriate actions, Pepco hopes to further improve the reliability of its system.

Pepco's Manhole Inspection Program (MIP) inspection priority scheme consists of four remediation time frames ranging from immediately to within five days, to 18 months as shown below. The four-priority remediation scheme, in place since October 2001, was renumbered at the beginning of 2004 from 0-3 to 1-4 to coincide with other Company maintenance activities.

Inspection Priority Definitions

- **Priority 1 (Urgent):** Corrective action required immediately, or within 5 days: Perform repairs immediately or within 5 days where the identified deficiencies have caused outages, or present imminent risk of causing outages, or serious safety or environmental risk.
  - Cable smoking
  - Joint smoking
  - Insulation damage – Bare Conductor
  - Burnout visible
  - Loading greater than 140% of rating
  - Heating greater than 200° F
  - Elevated Gas Readings Reported to Gas Company

- **Priority 2:** Corrective action required within 6 months of inspection
  - Insulation damage
  - Loading between 120% and 140% of rating
  - Heating between 175° F and 200° F
  - Open limiters

  Assess cable leak, joint swelling, joint leaking, deformed joint, and neutral corroded condition information to determine Priority 2 or 3.

- **Priority 3:** Corrective action required within 12 months of inspection
  - Braided cable
  - Loading between 100% and 120% of rating
  - Heating between 150° F and 175° F

  Assess upright support condition information to determine Priority 3 or 4.

- **Priority 4:** Corrective action required within 18 months of inspection
  - Re-racking primary cables and secondary cables
  - Cables not secured
  - Structural repairs
  - Retag feeders and buses

- **Non-Reportable Referrals:**
  - Water
  - Debris
  - Cracked wall
  - Other

Current Program Status

During 2014, the MIP has identified the following remediation Priorities:

	Priorities Count	Percentage of CY 2014 Priorities
Priority Code 1	215	11.8%
Priority Code 2	146	8%
Priority Code 3	53	2.9%
Priority Code 4	1406	77.2%

Inspectors are conducting more comprehensive and thorough inspections which have resulted in a substantial increase in Priorities found. In 2014, approximately 15% of the manholes inspected revealed potential areas of concern that have been, or are in the process of being addressed. Figure 3.2-B1 provides a graphical representation of the number of manholes and the percentage of overall inspections with priority conditions during Phase III.

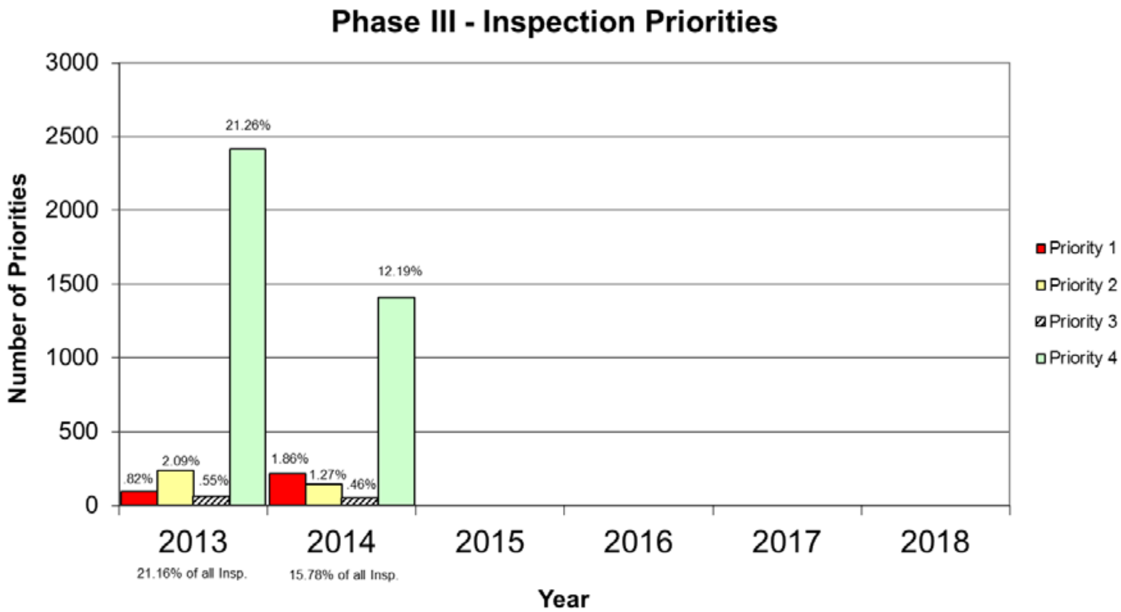


Figure 3.2-B1: Manhole Inspection Priorities – Phase III

With the implementation of the Manhole Inspection Quality Control (QC) Program, inspection Priorities have increased from 155 in 2006 to 1,301 in 2007 to 2,719 in 2008 to 2,450 in 2009, 1,515 in 2010, 1,271 in 2011, 2,856 in 2012 and 2809 in 2013. In 2014, there were 1,820 Priorities. The decrease in 2014 compared to 2013 prior was primarily due to the decrease in Priority 4 conditions detected. Priority 4 conditions which include re-racking cables, securing cables, needing structural repairs and retagging feeders and buses, account for over 82% (3,822 of 4,629) of all Priority conditions found during Phase III. A Priority 4 condition which is required to be remediated with 18 months of the inspection is not considered an imminent risk but has been recommended for remediation by the Commission Staff's consultant (Siemens) in FC No. 991.

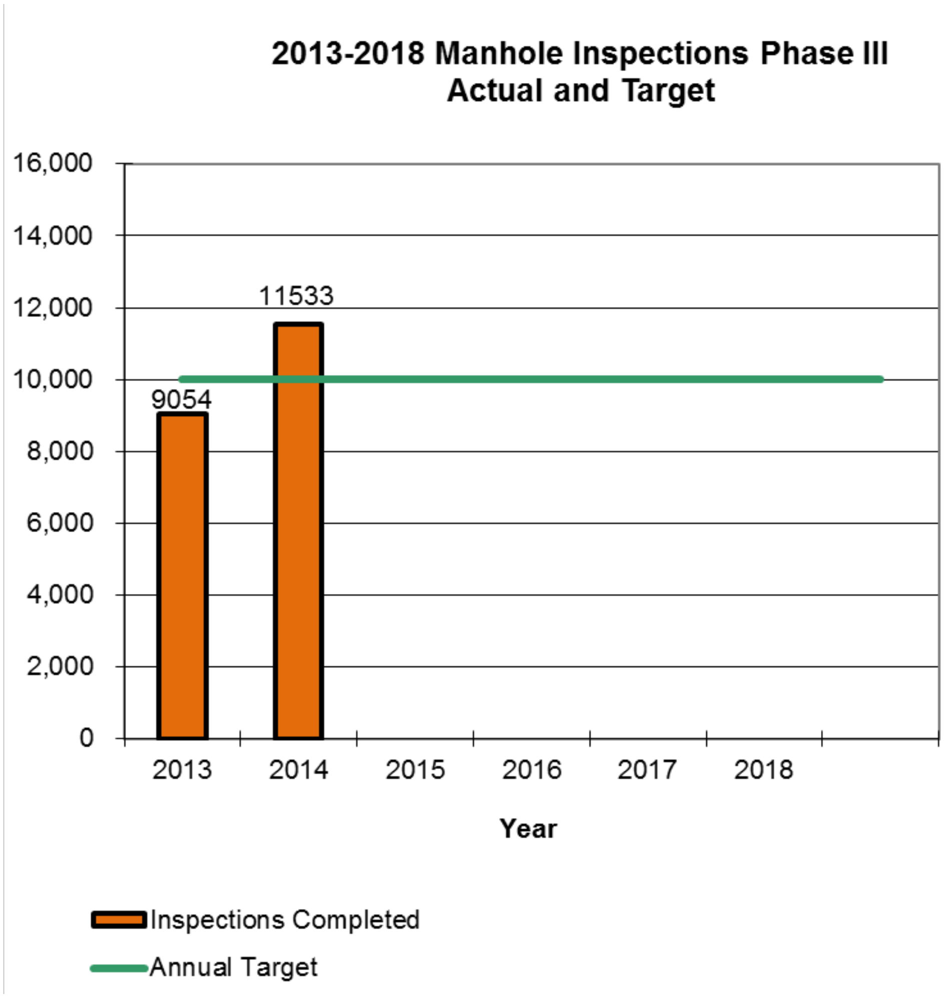


Figure 3.2-B2-A: Manhole Inspections Completed – Phase III

Inspection Plan - Phase III

Implementation of Phase III includes:

- Manholes will be inspected using Pepco's underground department's geographical-based work plan, which designates that all manholes within a specific sub-boundary of the city be inspected during specified timeframes.
- 2013 Inspections: Central Business District's Western Quadrant, 2013 Priority Feeders, Adams Morgan and Shaw Community. Total Phase III inspections planned for 2013; 10,000. 9,054 Phase III inspections completed. Including Phase II inspections, 11,554 inspections were completed in 2013.

- 2014 Inspections: Farragut Square area, North Center Quadrant of Business District, 2014 Priority Feeders, and sections of the Mt. Pleasant area and other dense population areas. Total inspections planned for 2014: 10,000. Total inspections completed in 2014: 11,533.
- Planned 2015 Inspections: Mt. Pleasant area, 2015 Priority Feeders, Columbia Heights area, areas within the Central Business District and other dense population areas. Total inspections planned for 2015: 10,000.
- Planned 2016 Inspections: Vicinity of Substation 2 Tenth and Eleventh Streets, O and P Streets, NW, Feeders 15204 and 15206; (2) 2016 Priority Feeders; (3) Central Business District; and (4) Vicinity of Architect of the Capitol Service Area Substations 18 and 161 SE/NE.
- Planned 2017 Inspections: (1) Georgetown (2) 2011 priority Feeders (3) Vicinity of H Street NE corridor and 14th St, NW corridor (4) Southern 12th St, NW corridor.
- Planned 2018 Inspections: (1) Ward 7, East of Anacostia River between Eastern Ave and Southern Ave, North East to South East; (2) Ward 3, Mass Ave & Western Ave East to Nebraska Ave, North East to Fessenden St.; (3) Ward 4, 14th & Peabody East along Missouri Ave to Eastern Ave.
- Manhole inspections will be performed in the same manner as in Phase I with the exclusion of inventorying the duct banks, as the initial duct bank inventory occurred during Phase I of the Program. Validation of recorded inventory will continue to occur. Thus, the time savings associated with not having to re-inventory the duct bank is estimated to be minimal and does not translate readily into dollar savings as the time saved does not allow for another inspection to be performed.
- A monthly count of manhole inspections will be generated via an appropriate electronic database.

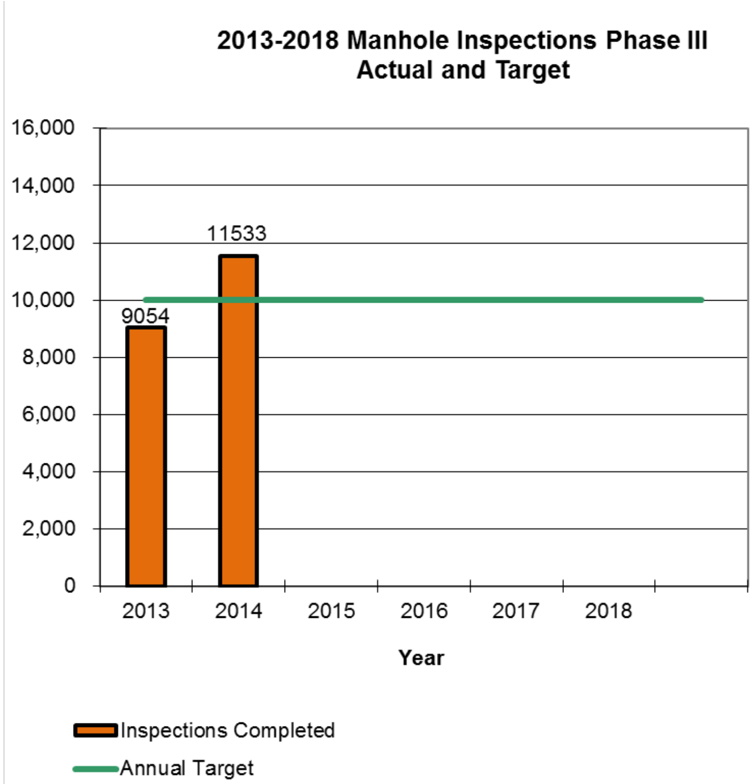


Figure 3.2-B2-B: Manhole Inspections Completed – Phase III

Quality Control Program

The Commission's technical consultant, Siemens, conducted 215 manhole inspections between July and September 2007. The results of Siemens' inspections as compared to Pepco's inspections raised concerns regarding the quality assurance and reliability of Pepco's inspection program. As a result of Siemens' findings, the Company initiated a Quality Control (QC) Program. Effective August 27, 2007, Pepco instituted a QC Program for its Manhole Inspection Program to minimize internal data inconsistencies. The QC Program uses a statistically valid sampling plan based upon Military Standard 105E. Since on average Pepco inspects 2,500 manholes per quarter, the lot size parameter used is "1201 to 3200" with an Acceptable Quality Level ("AQL")[85] equal to 2.5%.

[85] It is common to use an AQL of 1% for major defects, and 2.5% for minor defects. Values of AQL that are 10% or less are suitable for percent nonconforming or nonconformities per 100 items. Values of AQL over 10% are only suitable for nonconformities per 100 items. Source: www.sqconline.com

Utilizing the "Double" sampling procedure, Pepco will re-inspect 80 manholes per quarter. If the number of non-conforming items is three (3) or less, the lot is accepted. However, if the number of non-conforming items is seven (7) or more, the entire lot will be rejected and all manholes for the quarter will be reinspected.

If the number of non-conforming items is between four (4) and six (6) inclusive, 80 additional manholes will be reinspected. If the total number of non-conforming items (sum of nonconforming items in both samples) is eight (8) or less, the lot is accepted. However, if the total number of non-conforming items is nine (9) or more, the entire lot will be rejected and all manholes for the quarter will be reinspected. See Figure 3.2B-3.

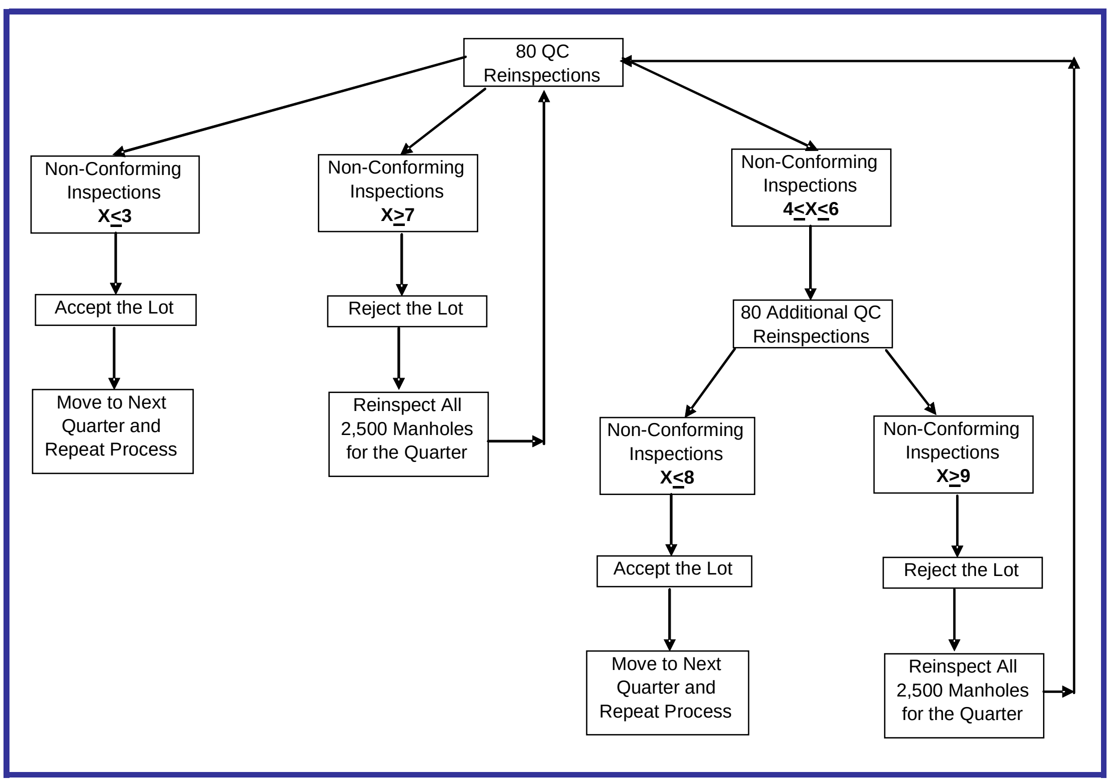


Figure 3.2-B3: QC Program Process Diagram

The QC Program became effective beginning with the third quarter 2007 manhole inspection results. Based on statistical sampling, Military Standard 105E with an Acceptable Quality Level

("AQL") equal to 2.5%, Pepco's quarterly QC inspections have been accepted since the third quarter of 2007. Specifics for the 2014 QC Program results are as follows:

2014 QC Program Results

	Result
1st Qtr. 2014	Accepted: No Failures
2nd Qtr. 2014	Accepted: (1) Cover Type
3rd Qtr. 2014	Accepted: No Failures
4th Qtr. 2014	Accepted: (1) Cover Type

The following criteria must be satisfied in order for the manhole inspection to be considered acceptable.

- The reportable conditions recorded must be consistent with those found during re-inspection. If a reportable condition has been remedied prior to the re-inspection, the QC inspection will consist of verifying the repair.

- The inspection record must contain (1) grid number location and (2) cover type. Both of these fields must be accurate.

Other items that should be accurate and included on the inspection form but are not grounds for rejecting the inspection include the (1) inspector's name, (2) date of inspection, (3) gas percentage reading, (4) cover size, (5) manhole size and (6) manhole type. If one of these items is either inaccurate or missing from the inspection form, the inspector responsible will be notified and discussions on performance improvements will be conducted.

Although Pepco is pleased with the 2014 results, the Company is fully aware that the success of the QC Program can only be measured over sustained periods of time. As such, Pepco is committed to the QC Program to ensure the accuracy, reliability and thoroughness of its manhole inspection program.

The results of the QC Program are presented quarterly during the PIWG meetings along with quarterly manhole inspection data.

Appendix 3C: Network Accuracy Procedure Report[86]

[86] In Order No. 16709 paragraphs 9 and 10, the Commission ordered the following:

9. *The Commission is satisfied that Pepco has developed a reasonable plan to ensure that its underground cables are adequately sized for existing and future loads. However, we do want to monitor Pepco's diligence in performance and the results of implementation of its network modeling, GIS updates, and timely network technology improvements going forward. We, therefore, direct the Company to file periodic reports to keep the Commission and interested parties apprised of the status of several ongoing projects as follows:*
   a. *Pepco is directed to provide a detailed status report on those eight networks that are currently undergoing analysis under the Company's Network Accuracy Procedure including the corrective actions that were identified by December 2011. This report on the eight networks should be added to the Company's 2012 Consolidated Report or filed as a Supplement to the 2012 Consolidated Report if the 2012 Report has already been filed or it is too late to include it for publication in the 2012 Report; and*
   b. *Pepco is directed to file a detailed status report on the results of its modeling and analysis and the implementation of its remedial actions on all of its remaining networks under its Network Accuracy Procedure. This report on the remaining networks should also be added to the 2012 Consolidated Report (or filed as a Supplement to the 2012 report if the 2012 Report has already been filed or it is too late to include it for publication in the 2012 Report) with updates in each subsequent year's report. The status report on those remaining networks shall include corrective actions that have been scheduled and those that have been completed.*

   THEREFORE, IT IS ORDERED THAT:

10. *Pepco shall comply with the directives set forth in paragraph 9 herein.*

Network Accuracy Procedure Report

Order No. 16975 Requirement

Order No. 16975 states the following at paragraphs 56 and 104:

56. ***Decision:*** *In Order No. 16709, the Commission required Pepco to file reports on the status of projects designed to assure that network groups are adequately sized for existing and future loads. The Staff found insufficiencies in the report filed by Pepco on May 11, 2012 and sought additional information and clarification about the models used in the Network Accuracy Procedure. Pepco answered Staff's questions in its August 9, 2012 Response. The Commission accepts the information provided by Pepco as responsive to the questions posed by the Staff. With regard to the additional information requested by OPC, we direct Pepco to provide the following in its 2013 Consolidated Report:*

a. A description of how Automatic Metering Infrastructure data will be used in the Easy Power model;

b. If AMI data is not used in the Easy Power model, an explanation as to why this data is not used;

c. A description of how voltage readings from AMI meters may or may not be used to validate the results of the Easy Power model;

d. A description of how data from network monitors may or may not be used to validate the results of the easy power model; and

e. A report on efforts to validate secondary cable sizes for the network models.

104. Pepco is ***DIRECTED*** *to provide information on its Easypower model and AMI consistent with paragraph 56 herein;*

Pepco Response

Below are Pepco's responses.

a. Starting in Fall 2014 AMI data is used in the Company's Easypower network studies. AMI loads along with previously existing interval meter loads are downloaded, aggregated to the appropriate bus hole locations that serve each customer and imported into the Easypower model. Since most all load data available is interval demand data, the need to convert monthly energy usage into hourly demand is mostly eliminated. Profiled demand based on energy usage data is used in the small number of instances where AMI data is not available for particular customers for the analyzed historical time period. Having interval demand data for most all customers improves the accuracy of the EasyPower model as Pepco has seen smaller discrepancies between summed customer load data and measured loads for many networks analyzed As of 2015, Pepco is converting its process to allow AMI data to be aggregated to bus holes and imported into EasyPower.

b. AMI data is being used.

c. Voltage readings from AMI will be used to validate base case voltages that arise from power flow analysis. AMI metering voltage reading data will also assist Pepco in its investigations of voltage irregularities that are found through power flow analysis or reported by a Pepco customer. Pepco is currently developing a process to download and store voltage information from AMI meters.

d. The Network RMS has the ability to capture transformer loads and voltages, which can be used to validate the same parameters derived in the power flow analysis. Available RMS data has been examined to confirm that the Easypower model is accurate.

e. As part of Pepco's design criteria for adding new load above 25 kW to the LVAC secondary grid, secondary cable sizes in the vicinity of the proposed new load are inspected in the field to confirm the secondary cable sizes and number as indicated in the EasyPower model. In addition, Pepco will be using manhole inspection data to supplement field inspection.

Order No. 16709 Requirement

Commission Order No. 16709 states the following at paragraphs 9 and 10:

9. *The Commission is satisfied that Pepco has developed a reasonable plan to ensure that its underground cables are adequately sized for existing and future loads. However, we do want to monitor Pepco's diligence in performance and the results of improvements going forward. We, therefore, direct the Company to file periodic reports to keep the Commission and interested parties apprised of the status of several ongoing projects as follows:*

   (a) Pepco is directed to provide a detailed status report on those eight networks that are currently undergoing analysis under the Company's Network Accuracy Procedure including the corrective actions that were to be identified by December 2011. This report on the eight networks should be added to the Company's 2012 Consolidated Report or filed as a Supplement to the 2012 Consolidated Report if the 2012 Report has already been filed or if it is too late to include it for publication in the 2012 Report; and

   (b) Pepco is directed to file a detailed status report on the results of its modeling and analysis and the implementation of its remedial actions on all of its remaining networks under its Network Accuracy Procedure. This report on the remaining networks should also be added to the 2012 Consolidated Report (or filed as a Supplement to the 2012 Consolidated Report if the 2012 Report has already been filed or it is too late to include it for publication in the 2012 Report) with updates in each subsequent year's report. The status report on those remaining networks shall include corrective actions that have been scheduled and those that have been completed.

10. *Pepco shall comply with the directives set forth in paragraph 9 herein.*

Pepco Network Accuracy Procedure Implementation Status Report

Commission Order No. 16709 directed Pepco to report on the implementation status of the Network Accuracy Procedure, which was developed in response to the May 31, 2011 Benning Northwest Network outage.

This update addresses application of the Network Accuracy Procedure to the 24 highest-loaded networks in the District of Columbia. It reports the results of the modeling and analysis and the implementation status of the resulting corrective actions. This update also addresses the implementation status of the Network Accuracy Procedure for Pepco's remaining networks.

I. Detailed Status Report on the Analysis of the Highest-Loaded Networks, in Accordance with the Network Accuracy Procedure.

The Network Accuracy Procedure calls for Pepco engineers to complete the fourteen steps described below:[87]

1. Conduct an evaluation of field work orders undertaken in the last two years to ensure that they were accurately modeled, since the last update was conducted two years ago.
2. Create GIS/GWD prints – Highlight in and mark any discrepancies found. Verify feeder designation and cable size.
3. Create legacy Microstation prints for each of the feeders in a particular network. Mark any cable size discrepancies found during the review of the legacy documents on the printed GIS feeder map and the spreadsheet form.
4. Easypower model – Compare GIS with Easypower and note if there are any discrepancies on existing networks, feeder designation, and size of cable on the GIS feeder map and spreadsheet.
5. For points on the feeder where Easypower model shows a larger cable size than GIS and at the critical points along the feeder where a lateral is tapped that serves multiple transformers, obtain the latest manhole inspection report from eFinity, Maximo, or hard copy. Document the cable size in each direction out of the manhole. If review of manhole data verifies cable size, update Easypower and GIS records. If cable size cannot be verified, a field inspection may be necessary.
6. Highlight any transformer discrepancies and send to the respective area Engineering Supervisor to determine required transformer size and verify actual transformer size.
7. For missing cable sizes – review Microstation feeder maps, document information on worksheet to update GIS; verify with field inspection where appropriate when actual cable size cannot be determined from office records.
8. Use Easypower records to update GIS when Easypower shows smaller size cables.
9. Before sending any discrepancies to the field crews Engineering will develop a documented plan for manhole verification to be performed.
10. Pepco Engineering or manhole inspection crews to perform field investigation at critical junctions and manholes designated through office record inspection process.

[87] The Network Accuracy Procedure was filed as Attachment 1 to the Company's Final Report: Analysis of Benning Northwest Network Shutdown, filed in Formal Case No. 1062 on August 29, 2011.

11. Findings from field investigation and office record investigation provided to the GIS and Drafting Services Group for GIS system update.
12. Engineering to perform network modeling (i.e., re-run Easypower Model) upon any new information captured to evaluate the impact of the changes on network system performance.
13. Perform all necessary corrective action within the timeframe for making corrective actions. Determine if the design team and construction team need to be involved to make the corrections.
14. Complete report by documenting all key steps with necessary back-ups for each particular network investigated and corrective action taken.

In accordance with this procedure, Pepco's highest-loaded networks were analyzed as outlined below.

Eight Highest-Loaded Networks

The analysis work associated with the Network Accuracy Procedure for the eight highest-loaded networks was reported in Pepco's May 11, 2012 filing in response to Order No. 16709.

Eight Second-Highest Loaded Networks

The analysis work associated with the Network Accuracy Procedure for the eight second-highest-loaded networks was reported in Pepco's May 2013 filing in response to Order No. 16709.

Eight Third-Highest-Loaded Networks

The analysis work associated with the Network Accuracy Procedure for the eight third-highest-loaded networks was reported in Pepco's February 2014 filing in response to Order No. 16709.

Eight Fourth-Highest-Loaded Networks

The analysis work associated with the Network Accuracy Procedure for the eight fourth-highest loaded networks followed the same pattern as the analysis work for the 24 highest-loaded networks. In 2014, for the eight fourth-highest loaded networks, Pepco Engineering evaluated the field work orders completed over the last two years and updated GIS/GWD and/or the Easypower model as needed. For each network group, an engineer compared the legacy Microstation feeder map and the current GIS/GWD feeder map and noted any discrepancies on the GIS/GWD feeder map. Where discrepancies were found, the manhole inspection data was checked as another source of verification.

At the same time as office records were being checked, engineers identified key manholes at critical junctions for field investigations. These critical junctions were generally at manholes where the feeder branched off to supply a lateral. Field investigations of these manholes were coordinated and completed by designers and field crews. Any discrepancies found in the office records that were not confirmed through the critical manhole inspections were also investigated through field inspections. All office records (GIS and EasyPower model) were updated with field data as necessary. In cases where the EasyPower model was updated with a smaller conductor size than previously existed in the model, a power flow analysis was performed and the results were analyzed to determine if the smaller conductor size created a potential overload condition in the model. Since no potential overload conditions were identified, no work orders needed to be generated for corrective actions.

Continuing with the lessons learned from the Benning Network failure, the Company's network design standards were revised so that engineers are to heavy-up stretches of smaller-sized cable that are positioned between stretches of larger-sized cable on either end when encountered in the course of performing design work. Pepco management added the directive that responsible engineers are to look for instances of smaller-sized cable positioned between stretches of larger-sized cables in the course of conducting office record investigations as part of the Network Accuracy Procedure implementation. Since no such instances were found, no work orders needed to be issued to heavy-up the smaller cable.

<u>Corrective Action Status</u>

Eight Fourth-Highest-Load Network Groups

As mentioned above, no corrective actions were identified or issued for the eight fourth-highest loaded networks, as no overloads were found in the EasyPower analysis; none were required to heavy-up cables to comply with the new design standard either. The following tables detail that no designs were needed after construction field verification; only GIS and EasyPower changes were needed. Once changes were made in EasyPower, no overloads were identified.

Network Mapping Verification Process
Status Summary for 4th Eight Highest Loaded Network Groups

Sub Group	Mapping Record Verification Status	Field Verification Status	EZ-Power Update Status	GIS Update Status	Corrective Actions Design Status	Corrective Actions Construction Status
O Street Sub. 2 North LVAC Network Group	Completed	Completed	Completed	In Progress	None Needed	None Needed
Florida Ave Sub. 10 West LVAC Network Group	Completed	Completed	Completed	In Progress	None Needed	None Needed
Georgetown Sub. 12 North LVAC Network Group	Completed	Completed	Conmpleted	In Progress	None Needed	None Needed
Southwest Sub. 18 South LVAC Network Group	Completed	Completed	Completed	Completed	None Needed	None Needed
10th St. Sub. 52 North LVAC Network Group	Completed	Completed	Completed	Completed	None Needed	None Needed
Little Falls Sub. 77 Spot Network Group	Completed	Completed	Completed	Completed	None Needed	None Needed
22nd St. Sub. 124 East LVAC Network Group	Completed	Completed	Completed	Completed	None Needed	None Needed
Sub. 212 Southwest LVAC Network Group	Completed	Completed	Completed	Completed	None Needed	None Needed

Table 3C-1

Network Accuracy Procedure - Field Corrective Actions

Network	Cable Size (Mapping Records)	Cable Size (Easy Power)	Cable Size (Field)	Feeder #	From Grid #	To Grid #	Corrective Actions	Work Order #	Expected Engineering Completion Date	Expected Construction Completion Date	Conduit Required	Reason for Upgrade
O Street Sub. 2 North No designs needed after construction field verification only GIS and Easypower changes needed. Once changes made in Easypower no overloads were identified.												
Florida Ave Sub. 10 West No designs needed after construction field verification only GIS and Easypower changes needed. Once changes made in Easypower no overloads were identified.												
Georgetown Sub. 12 North No designs needed after construction field verification only GIS and Easypower changes needed. Once changes made in Easypower no overloads were identified.												
Southwest Sub. 18 South No designs needed after construction field verification only GIS and Easypower changes needed. Once changes made in Easypower no overloads were identified.												
10th St. Sub. 52 North No designs needed after construction field verification only GIS and Easypower changes needed. Once changes made in Easypower no overloads were identified.												
Little Falls Sub. 77 No designs needed after construction field verification only GIS and Easypower changes needed. Once changes made in Easypower no overloads were identified.												
22nd St. Sub. 124 East No designs needed after construction field verification only GIS and Easypower changes needed. Once changes made in Easypower no overloads were identified.												
Northeast Sub. 212 Southwest No designs needed after construction field verification only GIS and Easypower changes needed. Once changes made in Easypower no overloads were identified.												

Table 3C-2: Field Corrective Actions for 4th Eight Highest Loaded Network Groups

Eight Third-Highest-Load Network Groups

No corrective actions were identified or issued for the eight third-highest loaded networks, as no overloads were found in the EasyPower analysis; none were required to heavy-up cables to comply with the new design standard either. The following tables detail that no designs were needed after construction field verification; only GIS and EasyPower changes were needed. Once changes were made in EasyPower, no overloads were identified.

Network Mapping Verification Process
From the Report Filed February, 2014
Status Summary for 3rd Eight Highest Loaded Network Groups

Sub Group	Mapping Record Verification Status	Field Verification Status	EZ-Power Update Status	GIS Update Status	Corrective Actions Design Status	Corrective Actions Construction Status
O Street Sub. 2 Central LVAC Network Group	Completed	Completed	Completed	Completed	None Needed	None Needed
O Street Sub. 2 South LVAC Network Group	Completed	Completed	Completed	Completed	None Needed	None Needed
Georgetown Sub. 12 South LVAC Network Group	Completed	Completed	Compeleted	Completed	None Needed	None Needed
Ninth Street Sub. 117 West LVAC Network Group	Completed	Completed	Completed	Completed	None Needed	None Needed
Twenty-Second Street Sub. 124 Central LVAC Network Group	Completed	Completed	Completed	Completed	None Needed	None Needed
Twenty-Second Street Sub. 124 West LVAC Network Group	Completed	Completed	Completed	Completed	None Needed	None Needed
Eye Street Sub. 197 West LVAC Network Group	Completed	Completed	Completed	Completed	None Needed	None Needed
Buzzard Point Sta. B East LVAC Network Group	Completed	Completed	Completed	Completed	None Needed	None Needed

Table 3C-3

Network Accuracy Procedure - Field Corrective Actions

Network	Cable Size (Mapping Records)	Cable Size (Easy Power)	Cable Size (Field)	Feeder #	From Grid#	To Grid#	Corrective Actions	Work Order #	Expected Engineering Completion Date	Expected Construction Completion Date	Conduit Required	Reason for Upgrade
O Street Sub. 2 Central												
No designs needed after construction field verificaion, only GIS and Easypower changes needed. Once changes made in Easypower, no overloads were identified.												
O Street Sub. 2 South												
No designs needed after construction field verificaion, only GIS and Easypower changes needed. Once changes made in Easypower, no overloads were identified.												
Georgetown Sub. 12 South												
No designs needed after construction field verificaion, only GIS and Easypower changes needed. Once changes made in Easypower, no overloads were identified.												
Ninth Street Sub. 117 West												
No designs needed after construction field verificaion, only GIS and Easypower changes needed. Once changes made in Easypower, no overloads were identified.												

Table 3C-4: Field Corrective Actions for 3rd Eight Highest Loaded Network Groups

Network Accuracy Procedure - Field Corrective Actions

Network	Cable Size (Mapping Records)	Cable Size (Easy Power)	Cable Size (Field)	Feeder #	From Grid #	To Grid #	Corrective Actions	Work Order #	Expected Engineering Completion Date	Expected Construction Completion Date	Conduit Required	Reason for Upgrade
Twenty-Second Street Sub. 124 Central												
No designs needed after construction field verificaion, only GIS and Easypower changes needed. Once changes made in Easypower, no overloads were identified.												
Twenty-Second Street Sub. 124 West												
No designs needed after construction field verificaion, only GIS and Easypower changes needed. Once changes made in Easypower, no overloads were identified.												
Eye Street Sub. 197 West												
No designs needed after construction field verificaion, only GIS and Easypower changes needed. Once changes made in Easypower, no overloads were identified.												
Buzzard Point Sta. B East												
No designs needed after construction field verificaion, only GIS and Easypower changes needed. Once changes made in Easypower, no overloads were identified.												

Table 3C-4 (Cont'd)

Eight Second-Highest-Load Network Groups

All five corrective actions for the eight second-highest loaded networks were issued to relieve an overload found in the EasyPower analysis; none were issued to heavy-up cables to comply with the new design standard. The following tables detail these five corrective actions. All recommended work for the eight second-highest loaded networks was completed by the fourth quarter of 2013.

Network Mapping Verification Process
From the Report Filed May, 2013
Status Summary for 2nd Eight Highest Loaded Network Groups

Sub Group	Mapping Record Verification Status	Field Verification Status	EZ-Power Update Status	GIS Update Status	Corrective Actions Design Status	Corrective Actions Construction Status
O Street Sub. 2 West LVAC Network Group	Complete	Complete	Complete	Complete	None Needed	None Needed
Ninth Street Sub. 117 East LVAC Network Group	Complete	Complete	Complete	Complete	Complete	Complete
Benning Sub. 7 Southwest Spot Network Group	Complete	Complete	Complete	Complete	None Needed	None Needed
Tenth Street Sub. 52 East LVAC Network Group	Complete	Complete	Complete	Complete	Complete	Complete
I Street Sub. 197 South LVAC Network Group	Complete	Complete	Complete	Complete	None Needed	None Needed
Florida Avenue Sub. 10 South LVAC Network Group	Complete	Complete	Complete	Complete	None Needed	None Needed
Twenty-Second Street Sub. 124 South LVAC Network Group	Complete	Complete	Complete	Complete	None Needed	None Needed
Buzzard Point Sta. B West LVAC Network Group	Complete	Complete	Complete	Complete	None Needed	None Needed

Table 3C-5

Network Accuracy Procedure - Field Corrective Actions

Network	Cable Size (Mapping Records)	Cable Size (Easy Power)	Cable Size (Field)	Feeder #	From Grid #	To Grid #	Corrective Actions	Work Order #	Expected Engineering Completion Date	Expected Construction Completion Date	Conduit Required	Reason for Upgrade
O Street Sub. 2 West												
No designs needed after construction field verification only GIS and Easypower changes needed. Once changes made in Easypower no overloads were identified.												
Ninth Street Sub. 117 East												
	4/0 3/C	1-3/C-500 MCM	4/0 3/C	14571	793386-725992	793386-940984	Job was already in construction to heavy up cable to 500 MCM	3343306	Completed	Completed		Overload in EZPower model
	4/0 3/C	1-3/C-500 MCM	4/0 3/C	14571	793386-940984	794386-081988	Job was already in construction to heavy up cable to 500 MCM	3343306	Completed	Completed		Overload in EZPower model
	4/0 3/C	1-3/C-500 MCM	4/0 3/C	14571	794386-081988	794386-215987	Job was already in construction to heavy up cable to 500 MCM	3343306	Completed	Completed		Overload in EZPower model
Benning Sub. 7 Southwest												
No designs needed after construction field verification only GIS and Easypower changes needed. Once changes made in Easypower no overloads were identified.												

Network Accuracy Procedure - Field Corrective Actions

Network	Cable Size (Mapping Records)	Cable Size (Easy Power)	Cable Size (Field)	Feeder #	From Grid #	To Grid #	Corrective Actions	Work Order #	Expected Engineering Completion Date	Expected Construction Completion Date	Conduit Required	Reason for Upgrade
Tenth Street Sub. 52 East												
	Null	Null	#2 3/C	15327	792388-535360	792388-386360	Replace #2 3/C with 4/0 3/C	3398251	Completed	Completed	No	Overload in EZPower model
	Null	Null	#2 3/C	15332	793388-058353	792388-508360	Replace #2 3/C with 4/0 3/C	3398251	Completed	Completed	No	Overload in EZPower model

Table 3C-6: Field Corrective Actions for 2nd Eight Highest Loaded Network Groups

Network Accuracy Procedure - Field Corrective Actions

Network	Cable Size (Mapping Records)	Cable Size (Easy Power)	Cable Size (Field)	Feeder #	From Grid #	To Grid #	Corrective Actions	Work Order #	Expected Engineering Completion Date	Expected Construction Completion Date	Conduit Required	Reason for Upgrade
Tenth Street Sub. 52 East												
	Null	Null	#2 3/C	15327	792388-535360	792388-386360	Replace #2 3/C with 4/0 3/C	3398251	Completed	Completed	No	Overload in EZPower model
	Null	Null	#2 3/C	15332	793388-058353	792388-508360	Replace #2 3/C with 4/0 3/C	3398251	Completed	Completed	No	Overload in EZPower model
I Street Sub. 197 South												
No designs needed after construction field verification only GIS and Easypower changes needed. Once changes made in Easypower no overloads were identified.												
Florida Avenue Sub. 10 South												
No designs needed after construction field verification only GIS and Easypower changes needed. Once changes made in Easypower no overloads were identified.												
Twenty-Second Street Sub. 124 South												
No designs needed after construction field verification only GIS and Easypower changes needed. Once changes made in Easypower no overloads were identified.												
Buzzard Point Sta. B West												
No designs needed after construction field verification only GIS and Easypower changes needed. Once changes made in Easypower no overloads were identified.												

Table 3C-6 (cont'd)

Eight Highest-Loaded Network Groups

Below is a status update for the thirteen corrective actions identified in Pepco's report filed May 11, 2012 for the eight highest-loaded network groups. Of the thirteen corrective actions recommended in that report, nine were completed in 2012, two were completed in 2013, and two were completed in the first quarter of 2015.

Network Mapping Verification Process
From the Report Filed May, 2012
Status Summary for Eight Highest Loaded Network Groups

Sub Group	Mapping Record Verification Status	Field Verification Status	EZ-Power Update Status	GIS Update Status	Corrective Actions Design Status	Corrective Actions Construction Status
Benning Sub. 7 Northwest Spot Network Group	Complete	Complete	Complete	Complete	Complete	Complete
O Street Sub. 2 East LVAC Network Group	Complete	Complete	Complete	Complete	Complete	Complete
Southwest Sub. 18 Central LVAC Network Group	Complete	Complete	Complete	Complete	None Needed	None Needed
Tenth Street Sub. 52 West LVAC Network Group	Complete	Complete	Complete	Complete	Complete	Complete
Tenth Street Sub. 52 South LVAC Network Group	Complete	Complete	Complete	Complete	None Needed	None Needed
Van Ness Sub. 129 Wisconsin Avenue North Spot Network Group	Complete	Complete	Complete	Complete	None Needed	None Needed
New Jersey Avenue Sub. 161 South LVAC Network Group	Complete	Complete	Complete	Complete	Complete	Complete
I Street Sub. 197 Central LVAC Network Group	Complete	Complete	Complete	Complete	Complete	Complete

Table 3C-7

Table 3C-8: Field Corrective Actions for Eight Highest Loaded Network Groups

Network Accuracy Procedure - Field Corrective Actions

Network	Cable Size (Mapping Records)	Cable Size (Easy Power)	Cable Size (Field)	Feeder #	From Grid #	To Grid #	Corrective Actions	Work Order #	Expected Engineering Completion Date	Expected Construction Completion Date	Conduit Required	Reason for Upgrade
Tenth Street Sub. 52 South												
No designs needed after construction field verification only GIS and Easypower changes needed. Once changes made in Easypower no overloads were identified.												
Van Ness Sub. 129 Wisconsin Ave. South												
No designs needed after construction field verification only GIS and Easypower changes needed. Once changes made in Easypower no overloads were identified.												
New Jersey Avenue Sub. 161 South												
G Street/Massachusetts Avenue NW to Massachussets Avenue/ North Capitol	#2CU	4/0	#2CU	14414/14415/ 14419	796387-563788	797387-293480	Replace #2 with 4/0	3371371	Complete	Complete	No	Overload in EZP model
E Street between New Jersey Aveneue & North Capitol Street, NW	Null	4/0	#2	14417	796386-457963	797386-043972	Replace #2 with 4/0	3371812	Complete	Complete	No	Overload in EZP model
First Street between E & G Street, NW	4/0	4/0	#2	14419	796387-430789	796386-421958	Replace #2 with 500	3371821	Complete	Complete	No	Overload in EZP model
I Street Sub. 197 Central												
21st Street between F Street & E Street, NW	4/0	4/0	#2	15384	786387-032490	786387-039837	Replace #2 with 4/0	3384247	Complete	Complete	Yes	Overload in EZP model

From the report filed May 11, 2012

Network Accuracy Procedure - Field Corrective Actions

Network	Cable Size (Mapping Records)	Cable Size (Easy Power)	Cable Size (Field)	Feeder #	From Grid#	To Grid#	Corrective Actions	Work Order #	Expected Engineering Completion Date	Expected Construction Completion Date	Conduit Required	Reason for Upgrade
Benning Sub. 7 Northwest												
Feeders were rerouted and heavied-up prior to the Network Accuracy Procedure being implemented. No further issues found during Network Accuracy Procedure analysis												
O Street Sub. 2 East												
13th Street north of M Street, NW	Null	500	#2	14398	791390-496445	791390-498780	Replace #2 with 4/0	3475860	Complete	1st Qtr 2015	No	Construction Standard
13th Street, NW north of M Street, NW	Null	4/0	#2	14400	791390-496445 (N)		Replace #2 with 4/0	3475860	Complete	1st Qtr 2015	No	Construction Standard
Southwest Sub. 18 Central												
No designs needed after construction field verification only GIS and Easypower changes needed. Once changes made in Easypower no overloads were identified.												
Tenth Street Sub. 52 West												
14th Street South of NY Avenue, NW	Null	4/0 3-C	#2 3-C	15314	790388-769150	790388-853160	Replace #2 with 4/0	3382687	Complete	Complete	No	Construction Standard
14th Street South of NY Avenue, NW	Null	350 3-C	4/0 3-C	15314	790388-769150	790387-798428	Replace 4/0 with 500s	3382685	Complete	Complete	No	Construction Standard
G Street between 14th & 13th Street, NW	350 3-C	350 3-C	4/0 3-C	15315	790387-375790	790387-770795	Replace 4/0 with 500s	3382686	Complete	Complete	No	Construction Standard
G Street between 14th & 13th Street, NW	350 3-C	350 3-C	#2 3-C	15316	790387-855794	791387-115792	Replace #2 with 500	3382686	Complete	Complete	No	Construction Standard
G Street between 14th & 13th Street, NW	350 3-C	350 3-C	4/0 3-C	15316	790387-115792	791387-352793	Replace 4/0 with 500	3382686	Complete	Complete	No	Construction Standard
G Street between 15th and 14th Street, NW	NULL	#2	#2	15317	790387-770795(N)	790387-855794	Replace #2 with 4/0	3382685	Complete	Complete	No	Construction Standard
F Street between 14th & 12th Street, NW	350	350	#2	15319	790387-850428	791387-891427	Replace #2 with 350	3382687	Complete	Complete	No	Construction Standard

Table 3C-8 (cont'd)

II. Status Report of the Analysis of the Remaining District of Columbia Networks, in Accordance with the Network Accuracy Procedure.

Pepco has begun the verification process on the next eight highest-loaded networks using office records (Microstation feeder maps, GIS/GWD, and Easypower model) in accordance with the Network Accuracy Procedure. The office record inspections for the next eight highest-loaded networks and updates to GIS/GWD and EasyPower model are to be completed by June 1, 2015. The necessary field inspections will be completed and corrective actions will be identified by November 1, 2015. The time frame for completing the corrective actions for the next eight highest-loaded feeders will be determined once the corrective actions are identified.

The next eight network groups selected for investigation are:

1. Harvard Sub, 13 Spot Network
2. L Street Sub. 21 South Network
3. Harrison Sub. 38 North Network
4. Van Ness Sub. 129 Connecticut Ave. North Network
5. 12th and Irving Sub. 133 East Network
6. ”I” St. Sub. 197 East Network
7. Van Ness Sub. 129 Wisconsin Ave. South
8. Buzzard Point Sta. B Southeast Network

PART 4: REFERENCES

PART 4: REFERENCES

SECTION 4.1 – ABBREVIATIONS AND ACRONYMS

2005 Plan	-	Vegetation Management Plan for Utility Tree Pruning – D.C.
A&G	-	Administrative & General
AC	-	Alternating Current
ACR	-	Automatic Circuit Reclosers
AFP	-	Assist Fire/Police
AMI	-	Advanced Metering Infrastructure
ANSI	-	American National Standards Institute
AQL	-	Acceptable Quality Level
ASR	-	Automatic Sectionalizing and Restoration
CAD	-	Computer Aided Design
CAIDI	-	Customer Average Interruption Duration Index
CBM	-	Condition Based Maintenance
CIC	-	Crisis Information Center
CIS	-	Customer Information System
CMT	-	Crisis Management Team
COG	-	Council of Governments
COOP	-	Continuity of Operations
CPI	-	Composite Performance Index
CRP	-	Comprehensive Reliability Plan (Equivalent to REP)
DA	-	Distribution Automation
D.C.	-	District of Columbia
DDOT	-	District of Columbia Department of Transportation
DGA	-	Dissolved Gas in oil Analysis
DOE	-	Department of Energy
DOT	-	Department of Transportation
DPWT	-	Department of Public Works and Transportation
DRTU	-	Digital Remote Terminal Unit
E	-	Manhole Explosion
ECA	-	Equipment Condition Assessment
EMA	-	Emergency Management Agency
EMF	-	Electromagnetic Field
EMS	-	Energy Management System
EOC	-	Emergency Operations Center
EOP	-	Emergency Operations Plan
EPR	-	Ethylene Propylene Rubber cable
EPRI	-	Electric Power Research Institute
EQSS	-	Electricity Quality of Service Standards
ERIP	-	Emergency Restoration Improvement Project
ETR	-	Estimated Time of Restoration
F	-	Manhole Fire
FAA	-	Federal Aviation Administration
FEMA	-	Federal Emergency Management Agency

FERC	-	Federal Energy Regulatory Commission
FTE	-	Full Time Equivalent
GIS	-	Geographic Information System
GWD	-	Graphical Work Design
GWh	-	Gigawatt-hour
HMPE	-	High Molecular weight Polyethylene
HSEMA	-	Homeland Security and Emergency Management Agency
HVCA	-	High-Volume Call Answering
IEEE	-	Institute of Electrical and Electronics Engineers
ICS	-	Incident Command System
IMT	-	Incident Management Team
ISA	-	International Society of Arboriculture
IST	-	Incident Support Team
kV	-	Kilovolt
LTC	-	Load Tap Changer
LVAC	-	Low Voltage Alternating Current (Network)
MDS	-	Mobile Dispatch System
MDT	-	Mobile Data Terminal
MED	-	Major Event Day
MIP	-	Manhole Inspection Program
MOV	-	Metal Oxide Varistor
MVA	-	Megavolt Ampere
MVAR	-	Megavolt Ampere Reactive
MWh	-	Megawatt-hour
NERC	-	North American Electric Reliability Corporation
NIMS	-	National Incident Management System
NOC	-	Network Operating Center
NOFR	-	Notice of Final Rulemaking
OCB	-	Oil Circuit Breaker
OH	-	Overhead
O&M	-	Operations and Maintenance
OMS	-	Outage Management System
OPC	-	Office of the People's Counsel
OTR	-	Office of Tax and Revenue
P&A	-	Planning & Analysis
PAC	-	Phase Angle Control or Pre-assembled Arial Cable
PCA	-	Palisades Citizens Association
PCB	-	Polychlorinated Biphenyls
PDM	-	Predictive Maintenance
Pepco	-	Potomac Electric Power Company
PHI	-	Pepco Holdings, Inc.
PIP	-	Productivity Improvement Plan
PIWG	-	Productivity Improvement Working Group
PILC	-	Paper Insulated Lead Cable
PJM	-	PJM Interconnection
PLC	-	Power Line Carrier
PNB	-	Prospective New Business report
QC	-	Quality Control

RCM	-	Reliability Centered Maintenance
RE	-	Reportable Event
REP	-	Reliability Enhancement Plan
RFC	-	Reliability First Corporation
RL	-	Rubber Lead
RN	-	Rubber Neoprene
ROW	-	Right of Way
RPTA	-	Real Property Tax Administration
RTO	-	Regional Transmission Organization
RTU	-	Remote Terminal Unit
S	-	Smoking Manhole
SAIDI	-	System Average Interruption Duration Index
SAIFI	-	System Average Interruption Frequency Index
SCADA	-	Supervisory Control and Data Acquisition
SEC	-	Security Exchange Commission
SGIG	-	Smart Grid Investment Grant
SMECO	-	Southern Maryland Electric Cooperative
SOS	-	Standard Offer Service
StormMan	-	Oracle Storm Management module/function
T&D	-	Transmission and Distribution
TGR	-	Tree Growth Regulator
TOA	-	Transformer Oil Analyst
UFA	-	Urban Forestry Administration
UG	-	Underground
URD	-	Underground Residential Distribution
VAR	-	Volt-ampere Reactive
VLF	-	Very Low Frequency
VM	-	Vegetation Management
WMIS	-	Work Management Information System
XLPE	-	Cross Link Polyethylene

SECTION 4.2 – TECHNICAL TERMS AND DIAGRAMS

This section contains definitions, explanations and diagrams used in discussing electric system operations, design characteristics, and performance.

Alternating Current (AC)
A current, which reverses at regularly recurring intervals of time and that has alternately positive and negative values.

Ampere
The "ampere" is the basic unit of current equal to the flow of one coulomb of charge passing a point in one second. It is also the amount of current that is allowed to flow when a difference of potential of one volt is applied to a resistance of one ohm.

Ampere-hour
The flow of current per hour. Ten ampere-hours is equal to the flow of 10 amperes for a period of one hour or the flow of one ampere for ten hours.

Arrester
A device that provides an alternate path for surge currents caused by over-voltage resulting from lightning or switching surges.

Battery
Two or more cells electrically connected for producing electric energy. A device that transforms chemical energy into electric energy.

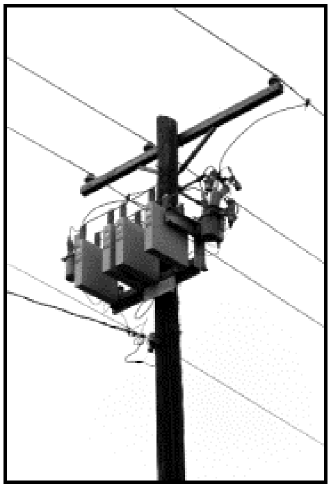
Cable Joint
A connection between two or more separate lengths of cable with the conductors in one length connected individually to conductors in other lengths and with the protecting sheaths so connected as to extend protection over the joint.

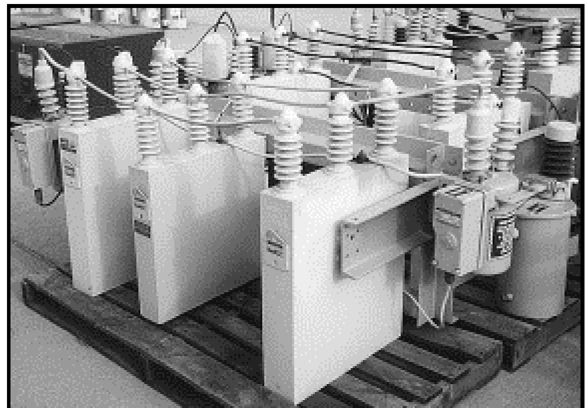
Cable Rack
A device usually secured to the wall of a manhole, cable raceway, or building to provide support for cables.

Cable Splice
See Cable Joint

CAIDI (Customer Average Interruption Duration Index)
Represents the average time required to restore service to the average customer per sustained interruption. Mathematically equal to SAIDI divided by SAIFI.

Capacitor
An electrical device for storing a charge of electricity and returning it to the line. It is used to balance the inductance of a circuit, since its action is opposite in phase to that of inductive apparatus; it throws the current ahead of the electromotive force in phase. It is made of alternate plates of tinfoil and insulating material. The size of plates and the thickness of insulating material determine the capacity for holding electric charge. Capacity is measured, practically, in micro-farads, millionths of a farad.





Capacitors

Circuit
A conductor or system of conductors through which an electric current is intended to flow.

Circuit Breaker
A device designed to open and close a circuit by non-automatic overload of current without damage to itself when properly applied within its rating.

Conductor
A material that allows the flow of electricity; a metal wire, in the center of an electrical cable, through which current flows.

Conduit
A pipe, most often made of polyvinyl chloride, used for the installation of cables underground.

CPI (Composite Performance Index)
A distribution feeder performance measuring index created by combining 4 industry standard reliability indicators. The indicators used in CPI are Number of Interruptions (NI), Number of Customer Hours of Interruption (CHI), System Average Interruption Frequency (SAIF) and System Average Interruption Duration (SAID).

Cycle
One complete set of positive and negative values of an alternating current.

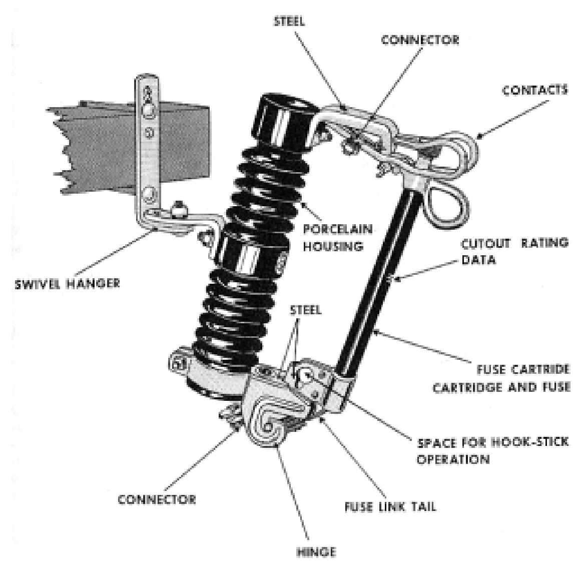
Duct
A single enclosed runway for conductors or cables.

Duct Bank
An arrangement of conduit providing one or more continuous ducts between two points.

Efficiency
The ratio of the useful output to the input of energy, power, quantity of electricity, etc.

Fault Current
A current that flows from one conductor to ground or to another conductor owing to an abnormal connection (including an arc) between the two. Note: A fault current flowing to ground may be called a ground fault current.

Fuse
An electrical safety device consisting of, or including, a wire or strip of fusible metal that melts and interrupts the circuit when the current exceeds a particular amperage.



Fuse Cutout
A device that is used to de-energize and re-energize components. A fuse cutout contains a fuse, which protects the line and components from the effect of overloads and faults.

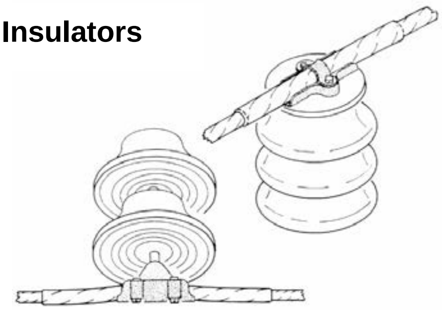
Fuse Element
The part of a fuse that melts and interrupts the circuit when excessive current flow occurs.

Ground
A conducting connection, whether intentional or accidental, by which an electric circuit or equipment is connected to the earth or to some conducting body that serves in place of the earth.

Inductance
The process that produces a voltage due to interaction of a conductor, a magnetic field, and relative motion between them.

Insulator
A material that offers a great deal of resistance to electron flow.

Insulators

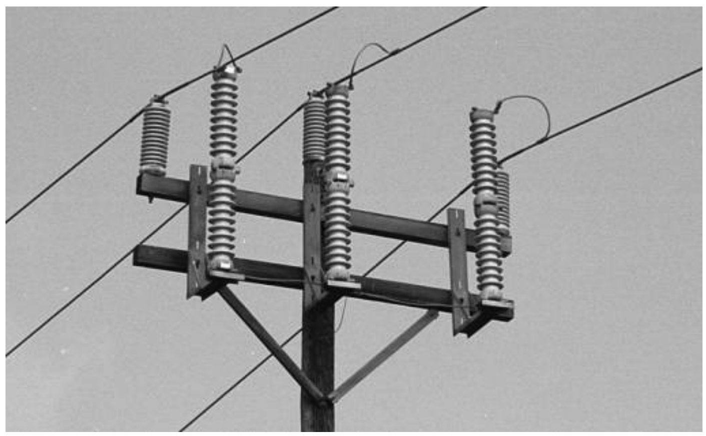


Kilowatt-Ampere (kVA)
The unit of apparent power in alternating current circuits as distinguished from kilowatts which represent true power.

Kilowatt (kW)
A unit of electric power equal to one thousand watts.

Kilowatt-hour (kWh)
The work performed by one kilowatt of electric power during one hour.

Lightning Arrester
A device that has the property of reducing the voltage of a surge applied to its terminals by the surge current to ground. It is capable of interrupting follow current if present and restores itself to original operating conditions.



Load Factor
The ratio of the average load over a designated period of time to the peak load occurring in that period.

Low Voltage (LV)
600 volts and lower.

Manhole
A subsurface chamber, large enough for a man to enter, in the route of one or more conduit runs and affording facilities for placing and maintaining in the runs, conductors, cables, and any associated apparatus.

Megawatt (MW)
One million watts.

Network
An aggregation of interconnected conductors consisting of feeders, mains, and services.

Overload
A load greater than the rated load of an electrical device.

Paper-Insulated Lead Cable (PILC)
A primary cable designed with paper insulation wrapped around a shielded conductor and covered with a flexible lead covering.

Phase
The relative time of change in values of current or electromotive force. Values that change exactly together are in phase. Difference in phases is expressed in degrees, a complete cycle or double reversal being taken as 360 deg. A 180-deg phase difference is complete opposition in phase.

Polychlorinated Biphenyls (PCB)
A toxic environmental contaminant requiring special handling and disposal in accordance with US Environmental Protection Agency Regulations. No longer used in transformers.

Pothead
A device used to protect the connection between a URD and an overhead system. A pothead also provides a termination for the URD cable insulation.

Power
The rate of doing work or the rate of expending energy. The unit of electrical power is the watt. Power is calculated by multiplying current time voltage.

Power Factor (pf)
The ratio of the actual power of an alternating current as measured by a wattmeter, to the apparent power, as indicated by ammeter and voltmeter reading. The power factor of an inductor, capacitor or insulator is an expression of their losses. The ratio of total watts to the total root-mean-square (RMS) volt-amperes. It is a mathematical term whose value is less than or equal to unity, or one. This term is used to show the relationship between volt-amperes (which is the basis for rating transformers, generators, etc.) and watts which is the measure of usable power delivered. A low power factor results in a lower usable power delivery or consumption for a given value of electric current than would result with a high power factor. The result of a low power factor is higher losses through the wires, cables, and other electrical apparatus.

$$pf = \frac{\sum Watts}{\sum RMS\ VoltsxAmperes}$$

Preassembled Aerial Cable (PAC)
Preassembled Aerial Cable (PAC) is an installation of three single underground cables triplexed together and installed on the overhead distribution system in heavily wooded areas. Each of the three conductors is a fully insulated cable grouped together in a package that is supported by a metallic messenger. The installation is more robust than tree wire and has the ability to withstand falling tree limbs.

Primary Circuit
The higher voltage circuit in a URD system that carries power to the transformers.

Protective Relay
A relay whose function is to detect conditions of an abnormal or dangerous nature and to initiate appropriate control circuit action.

Reactive Power
The product of voltage and the out-of-phase component of alternating current, generally measured in kilovars (kVAR). Reactive power decreases the substation's ability to deliver real power and increases system losses.

Reactor
A device, the primary purpose of which is to introduce reactance into a circuit.

230 kV Reactor

Real Power
The rate, generally measured in kilowatts (kW), of generating, transferring, or using energy. The power which serves the customers' end-use electrical devices and the power for which the customer is metered.

Relay
An electric device that is designed to interpret input conditions in a prescribed manner and, after specified conditions are met, to respond to cause contact operation or similar abrupt change in associated electric control circuits.

Remote Terminal Unit (RTU)
A device that controls substation equipment.

SAIDI (System Average Interruption Duration Index)
Average time customers are interrupted. Mathematically equal to the sum of Customer Interruption Hours divided by Total Number of Customers Served.

SAIFI (System Average Interruption Frequency Index)
Average frequency of sustained interruptions per customer. Mathematically equal to the sum of Number of Customer Interruptions divided by Total Number of Customers Served.

SCADA (Supervisory Control and Data Acquisition) System
A system that allows dispatchers to monitor and control substation equipment from a central location; also provides documentation for record keeping.

Secondary
Referring to the energy output side of transformers or the conditions (voltages) usually encountered at this location.

Short-Circuit
An abnormal connection of relatively low resistance, whether made accidentally or intentionally, between two points of different potential in a circuit.

Splice
A joint used for connecting in series, two lengths of conductor or cable.

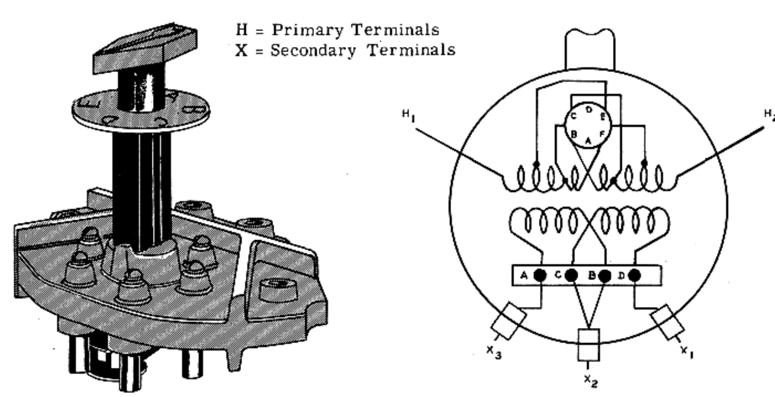
Substation
An assemblage of equipment for purposes other than generation or utilization, through which electric energy in bulk is passed for the purpose of switching or modifying its characteristics. Note: A substation is of such size or complexity that it incorporates one or more buses, a multiplicity of circuit breakers, and usually is either the sole receiving point of commonly more than one supply circuit, or it sectionalizes the transmission circuits passing through it by means of circuit breakers.

Mobile Substation

Switchgear
A general term covering switching and interrupting devices and their combination with associated control, metering, protective, and regulating devices, also assemblies of these devices with associated interconnections, accessories, enclosures, and supporting structures, used primarily in connection with the generating, transmission, distribution and conversion of electric power.

Tap
Connections that allow a transformer's turns ratio to be adjusted by adding turns to or subtracting turns from the transformer's primary or secondary winding. A connection brought out of a winding at some point between its extremities to permit changing the voltage or current ratio (general). An intermediate point in an electric circuit where a connection may be made.

A Tap Changer is Used to Adjust the Turns Ratio of a Transformer



No Load Tap Changer

Typical Internal Wiring of Transformer with Tap Changer

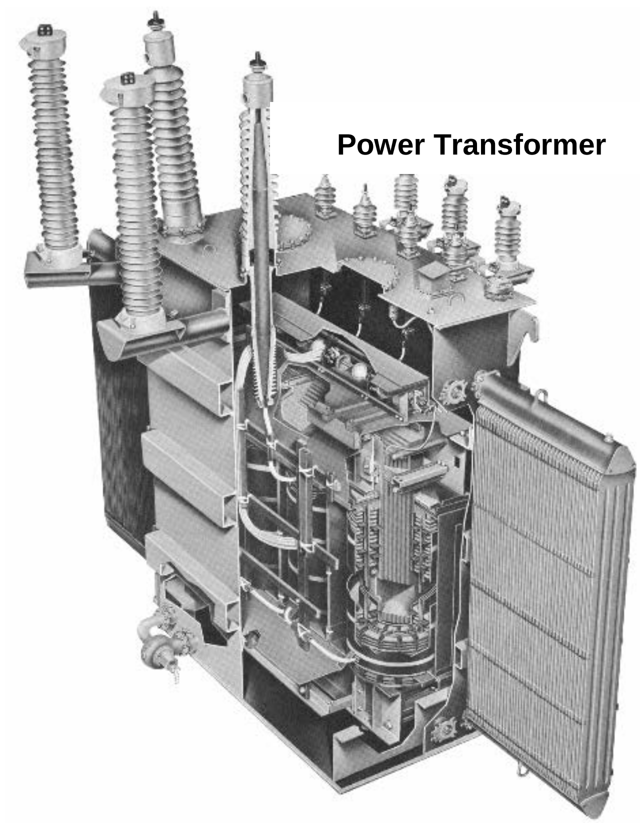
Tap Changer
A device for changing the turns ratio of a transformer.

Telemetering
Transmission of intelligence such as meter readings over a fairly long distance, usually from stations to the dispatcher's office, by direct wire or carrier current.

Three-Phase Circuit
A combination of circuits energized by alternating voltages that differ in phase by one-third, that is, 120 degrees.

Three-Wire System
A system of electric supply comprising three conductors, one of which, known as the neutral wire, is maintained at a potential midway between the potential of the other two, referred to as the outer conductors. There are two distinct voltages of supply, one being twice the other.

Transformer
A component used to change AC voltage to meet specific requirements. A device consisting of a winding with tap or taps, or two or more coupled windings, with or without a magnetic core, for introducing mutual coupling between electric circuits.



Transmission Line
A line used for electric-power transmission.

URD System
A local distribution system designed primarily to be buried in the ground and to serve residential customers.

VAR
Reactive volt-amperes.

Volt
Unit of measure for voltage. One volt is defined as the voltage necessary to drive a current of one ampere through a resistance of one ohm.

Voltage
Electric potential or potential difference expressed in volts.

Watt
Unit of measure for electric power, equal to the amount of power produced when one volt causes one ampere of current to flow.

Watt-hour

Basic unit used to measure electrical energy. Watt-hours are determined by multiplying power by time. One watt-hour is the amount of energy used when one watt of power is delivered to an electrical device for one hour.

SECTION 4.3 – SELECTED COMMISSION ORDERS

COMPREHENSIVE PLAN

System Planning

The initial requirements for the Comprehensive Plan section of the Consolidated Report were delineated in hearings taking place from November 5-7, 2001. The Commission requested that the Company provide a Comprehensive Plan detailing proposed changes to the electric system for the purposes of meeting load growth or maintaining system reliability. On pages 143-144 of the hearing transcript, Pepco's witness Mr. Gausman explained the nature of the Company's existing plans for the distribution and transmission systems:

> *We have plans for each of our substations in D.C., and in each of those plans we address the needs for that location, what the growth forecast is, what type of construction is going to be needed for expansion in the distribution system in each of those locations… Now when you go up to the transmission level or the substation supply level, there you have a plan that is addressing a larger area of the town because you're looking at the whole capacity of the system.*

The Company expanded its responses to the Commission's requests in the first filed Comprehensive Plan. Since that date, the Company's Comprehensive Plans have been expanded based on several Commission directives. The report that follows either expands upon the discussion in the initial hearings requesting the Consolidated Report or responds to subsequent Commission directives as cited below.

The following section of the report addresses system plans based on forecasted load growth.

In Order No. 12804 paragraph 53 B, the Commission stated the following:

> *53. The 2003 PIP is hereby APPROVED, provided that PEPCO:*
>
> *(b) Submit quarterly reports to the PIWG as well as a report in the 2004 and subsequent PIPs on its plans for implementing the recommendations for alleviating the anticipated transmission constraints identified in the RTEP report;*

Load Forecasting

In the initial November 5-7, 2001 hearings requiring the production of the Comprehensive Plan, the following topics were discussed, as cited on pages 141-144 of the hearing transcript:

- *Comprehensive long-term planning on the underground system*
- *Pepco's 10-year construction plans*
- *Distribution load growth forecasts by substation*
- *Transmission/substation supply load growth forecasts*

In order No. 12735 issued on May 16, 2003 the Commission stated at paragraph 139, the following:

139. PEPCO shall file the additional information not included in its expurgated comprehensive plan as outlined below, within three months of the issuance date of this Report and Order:

(a) Customer growth projections by District of Columbia wards (including historical comparisons);

(b) Load growth projections encompassing commercial and residential development by District of Columbia wards (including historical comparisons);

The summary should cover a 10-year planning horizon while historical comparisons should provide at least five years of history.

In Order No. 12804 paragraph 53, the Commission stated the following:

53. The 2003 PIP is hereby APPROVED, provided that PEPCO:

(a) Provide the projected zonal and projected default (i.e., SOS) load data for the District of Columbia to the PIWG on a quarterly basis as well as in the 2004 and subsequent PIPs;…

Power Factors

In Order No. 10133, the Commission directed Pepco to include performance factors relating to the transmission and distribution (T&D) system in future PIPs.

"PEPCO…was directed to…provide in future PIP reports forecasts of plant performance factors which are based on analyses of both the projected performance and the prior year's actual performance"(page 10, Section B).

"…the Commission finds it entirely appropriate to include performance measures for PEPCO's transmission and distribution in the mix of issues examined by the PIWG and reported in the PIP"(page 12, third paragraph).

By way of compliance with the above requirements, in the September 1993 PIWG Meeting, Pepco proposed reporting performance data on its 13 kV distribution substation power factors.

Substation

In the initial November 5-7, 2001 hearings requiring the production of the Comprehensive Plan, Commissioner Meyers stated the following (page 266 of the hearing transcript):

> *But what we were talking about here yesterday was that the comprehensive plan would include… any rebuilt substations you might have; any new substations you might have…*

Distribution

In the initial November 5-7, 2001 hearings requiring the production of the Comprehensive Plan, Commissioner Meyers stated the following (pages 266-267 of the hearing transcript):

> *But what we were talking about here yesterday was that the comprehensive plan would include… anything that you might envision to account for distribution load growth…*

In Order No. 12735 issued on May 16, 2003, the Commission stated the following at paragraphs 74 and 135:

74. During the November 2001 hearings the Commission requested that PEPCO submit a comprehensive plan to include a current assessment of, and future plans for, its underground distribution and network facilities.[179] The Commission requested the plan as a tool to evaluate PEPCO's planning methodology and to assess PEPCO's ability to anticipate and respond to changing conditions in its underground distribution system…

135. PEPCO shall file the additional information not included in its expurgated comprehensive plan as outlined below, within three months of the issuance date of this Report and Order:

> *(c) Listing of underground distribution projects, such as the Adams-Morgan neighborhood project (including budgets, time schedules, and expected benefits) by secondary vs. primary system by District of Columbia wards affected, but not specific locations;*

The summary should cover a 10-year planning horizon while historical comparisons should provide at least five years of history.

Technology

In Order No. 12804 paragraph 53 E, the Commission stated the following:

53. The 2003 PIP is hereby APPROVED, provided that PEPCO:

(e) Provide to the PIWG, quarterly status reports on the new Technology Initiatives being undertaken by Pepco. An annual status report should be included in the 2004 and future PIPs. The status reports should include current accomplishments, plans for the future, and anticipated completion dates.

SCADA

The initial requirements for the Comprehensive Plan section of the Consolidated Report were delineated in hearings taking place from November 5-7, 2001. On page 313 of the hearing transcript, Commissioner Meyers stated the following:

We're going to ask Pepco to please include a section on reporting and monitoring in the comprehensive plan… And just as a quick for instance of this real-time systems control and data acquisition system, SCADA, what could it do? Give me a for instance there.

DA

In Order No. 12804 paragraph 53 E, the Commission stated the following:

53. The 2003 PIP is hereby APPROVED, provided that PEPCO:

(e) Provide to the PIWG, quarterly status reports on the new Technology Initiatives being undertaken by Pepco. An annual status report should be included in the 2004 and future PIPs. The status reports should include current accomplishments, plans for the future, and anticipated completion dates.

OMS

In Order No. 13422 on the 2004 Consolidated Report, paragraph 66, the Commission stated the following:

66. The 2004 Consolidated Report: Productivity Improvement Plan and Comprehensive Plan is hereby APPROVED, provided that PEPCO:

(a) Report in the 2005 Consolidated Report, due February 15, 2005, on the corrective actions taken to fix the OMS;…

CIS

The initial requirements for the Comprehensive Plan section of the Consolidated Report were delineated in hearings taking place from November 5-7, 2001. On page 503 of the hearing transcript, Commissioner Meyers stated the following:

> *You've been a leader in CADS all along, computer assisted data systems. There's some discussion here about various other types of reporting and monitoring systems…*

Power Delivery Information Systems Projects

In Order No. 12735, paragraph 139, the Commission stated the following:

> *PEPCO shall file the additional information not included in its expurgated comprehensive plan as outlined below, within three months of the issuance date of this Report and Order:…*
>
> *(d) Listing of power delivery information system projects with implementation schedules, annual costs, and milestones;*
>
> *(e) Listing of new technology investigations with decisions, annual costs, and implementation schedules;*
>
> *…The summary should cover a 10-year planning horizon while historical comparisons should provide at least five years of history.*

Equipment Standards

The initial requirements for the Comprehensive Plan section of the Consolidated Report were delineated in hearings taking place from November 5-7, 2001. On page 149 of the hearing transcript, Commissioner Meyers stated that the Comprehensive Plan should include:

> *…not only [the 10-year underground construction budget and 4 kV to 13 kV conversion], but… incorporating standards of what you want this to look like…*

Equipment Inspections

In Order No. 16091, paragraphs 46 and 63, the Commission stated the following:

> *46. Decision. … we shall require that Pepco provide a list of the types of equipment for which a "run to failure" method applies and those for which a preventive method applies. (Footnote: If other maintenance methods are used, Pepco shall describe them as well.) The Commission requires that Pepco provide an explanation of why different maintenance methods apply*

to different types of equipment. We also require a description of the "test procedures" that Pepco uses to assess the performance and remaining life of the equipment. (Footnote: See Pepco comments at 7.) Further, Pepco shall provide an estimate of the current book value of equipment maintained under each method used by Pepco. The 2011 Consolidated Report shall include this description of maintenance policies and methods.

63. Pepco IS DIRECTED to provide a description of its maintenance policies and methodologies, consistent with paragraph 46 of this Order;

Storm Readiness / ERIP

In Order No. 15152 at paragraph 71, the Commission ordered the following:

71. PEPCO is DIRECTED to prepare an action plan to reduce service restoration times and improve SAIDI and CAIDI performance, consistent with Order No. 14643 issued November 30, 2007 and herein, to be included in the 2009 Consolidated Report;

Order No. 15568 followed, requiring the following:

32. The Commission directs Pepco to report to each meeting of the PIWG on its Action Plan. That report should include a written description of the steps taken pursuant to the Plan. For example, in connection with the item that includes "Develop a process design and implement training," Pepco should describe the design and the training given to crews, including the number of employees who have availed themselves of the training. In addition, Pepco should be prepared to answer questions about the progress of the Action Plan from other members of the PIWG.

52. Pepco IS DIRECTED to report to each meeting of the PIWG on its Action Plan, consistent with Paragraph 32 of this Order;

Electricity Quality of Service Standards

Specific Consolidated Report requirements from the EQSS portion of the D.C.M.R. are listed below.

3602.6 Progress on current corrective action plans [on customer calls answered] shall be included in the utility's annual Consolidated Report.

3602.7 The utility shall report the actual call center performance during the reporting period in the annual Consolidated Report of the following year.

3602.12 Progress on any current corrective action plans [on call abandonment rates] will be included in the utility's annual Consolidated Report.

3602.13 The utility shall report the actual performance obtained during the reporting period in the annual Consolidated Report of the following year.

3602.14 The utility shall complete installation of new residential service requests within ten (10) business days of the start date for the new installation.

3602.21 Progress on any current corrective action plans [on new residential service installation requests] will be included in the utility's annual Consolidated Report.

3602.22 The utility shall report the actual performance obtained during the reporting period in the annual Consolidated Report of the following year.

3603.5 The utility shall report on the progress of the corrective action plan [on repeat least performing feeders] in the Annual Consolidated Report submitted to the Commission.

3603.8 The utility shall report on the number and percentage of non-major service outages that extend beyond the twenty-four (24) hour standard and the reasons each such outage extended beyond the twenty-four (24) hour standard.

3603.9 The report drafted pursuant to Section 3603.8 shall be included in the annual Consolidated Report on reliability data.

3603.16 The utility shall report on the progress of the corrective action plan [on SAIFI, SAIDI and CAIDI benchmarks] in the annual Consolidated Report submitted to the Commission.

3603.17 The utility shall also, per the orders of the Commission, continue current requirements of reporting annual reliability indices of SAIFI, SAIDI and CAIDI (with and without major events) in the annual Consolidated Report of the following year.

Industry Comparisons

In Order No. 15568 paragraph 57, the Commission ordered the following:

57. Pepco IS DIRECTED to provide a report on the Electric Utilities Best Practices, consistent with Paragraph 50 of this Order. This report shall be included in that 2010 Consolidated Report; and shall include the best practices of the electric utility industry on improving reliability and outage restoration (from the Benchmarking Studies). Pepco shall submit a continuous improvement plan, including resourcing, specific performance targets, and milestone dates to achieve the reliability and outage restoration performance of the best (quartile) performing (comparable) utilities in the Benchmarking Studies.

Implementation of Twenty Best Practices

In Order No. 16091 paragraph 61, the Commission stated the following:

61. Pepco IS DIRECTED to include a "2011 Best Practices Report" in its 2011 Consolidated Report describing its on-going implementation of no fewer than twenty of the best practices identified in the 2009 Polaris Program, consistent with Paragraph 22 of this Order;

22. Decision. First, we conclude that Pepco has complied with the requirements of Paragraphs 32 and 52 of Order No. 15568. Second, as to the Staff's Recommendation that Pepco file a "Best Practices Report" from the PA Consulting's 2009 Polaris Transmission and Distribution Benchmarking Program, we agree that a report may be helpful in assuring that best practices continue to be implemented. Therefore, the

> *Commission shall require that Pepco include in its 2011 Consolidated Report a section entitled "2011 Best Practices Report" in which Pepco shall describe its on-going implementation of no fewer than twenty of the best practices identified in the 2009 Polaris Program included in the 2010 Consolidated Report as Appendix 2D. The twenty best practices selected by Pepco should be those judged to have the most impact on reliability and outage restoration performance. Pepco shall report on all its activities during 2010 to implement these best practices, including data on staffing levels, expenses and results. This requirement is separate from the requirement to produce a "Continuous Improvement Plan," as is described more fully in Section IV.A.1.f.*

PA Consulting Recommendations

In Order No. 15632 issued in these proceedings, the Commission states at paragraph 5 the following:

> *5. Pepco shall file with the Company's annual Consolidated Reports to the Commission data on the Company's measures to continue to address each of the recommendations made by PA Consulting and the effectiveness of the Company's approaches to improve CAIDI and SAIDI to at least the average of PA Consulting benchmarks. This obligation shall begin with the 2010 Consolidated Report.*

In Order No. 15568 issued October 7, 2009 in these proceedings, the Commission states at paragraph 52 the following:

> *52. Pepco IS* ***DIRECTED*** *to report to each meeting of the PIWG on its Action Plan, consistent with Paragraph 32 of this Order;*
>
> *32. The Commission directs Pepco to report to each meeting of the PIWG on its Action Plan. That report should include a written description of steps taken pursuant to the Plan. For example, in connection with the item that includes "Develop a process design and implement training." Pepco should describe the design and the training given to the crews, including the number of employees who have availed themselves of the training. In addition, Pepco should be prepared to answer questions about the progress of the Action Plan from other members of the PIWG.*

In Order No. 16091 issued in these proceedings, the Commission states at paragraph 22 the following:

22. *Decision. First, we conclude that Pepco has complied with the requirements of Paragraphs 32 and 52 of Order No. 15568.*

PRODUCTIVITY IMPROVEMENT PLAN

Productivity Improvement Plan

In Order No. 15152 on the 2008 Consolidated Report, paragraph 68, the Commission ordered the following:

68. The Productivity Improvement Working Group, which includes OPC, provided a reasonable definition of a productivity improvement project in 2006. Specifically, the PIWG states:

> *T&D productivity improvement projects were considered those projects that will increase T&D system efficiency by reducing losses and improve[ing] system reliability, and which may defer more costly additions to the electric system. (Footnote: F.C. No. 766, Decision on Consideration of OPC's T&D Productivity Improvement Working Group in Response to Commission Order No. 13754, filed July 6, 2006 ("2006 PIWG Report"), at 2.)*

The power serving the District's Standard Offer Service customers is now procured through a wholesale procurement process by PEPCO and, as such, productivity improvement is applicable only to transmission and distribution issues. We find the PIWG's definition of a productivity improvement project workable and adopt it here.

69. The PIWG also provided a reasonable definition of comparative cost analysis for reliability projects. The PIWG suggested that the comparative cost analysis used for reliability projects should "consist of a comparison of the cost of alternative reliability improvement solutions as well as any differences in relative reliability improvement." (Footnote: 2006 PIWG Report at 2.) …

Reliability Statistics

Page 190 of the transcript for the November 5-7, 2001 hearings documents Commissioner Cartagena as stating the following:

You testified earlier that you have a 10-year plan for updating the system or addressing whatever changes are required with regards to that. Does that 10-year plan contain reliability goals or other measurable performance objectives? In other words, are there some kinds of standards that we can look at and will give us an idea of whether the company is hitting or missing those standards and objectives with regards to its plan?

This section of the Consolidated Report addresses the Company's performance with respect to reliability standards and Electricity Quality of Service Standards.

Targeted Reliability Indices

In Order No. 12735, paragraph 139, the Commission ordered the following:

PEPCO shall file the additional information not included in its expurgated comprehensive plan as outlined below, within three months of the issuance date of this Report and Order:

(f) Targeted reliability indices (including historical comparisons); and

The summary should cover a 10-year planning horizon while historical comparisons should provide at least five years of history.

Also, in paragraph 142, the Commission directed the Company to file performance indices for the District of Columbia only.

PEPCO is DIRECTED to work with the PIWG to develop target system reliability indices for the District of Columbia, only.

Vegetation Management

In Order No. 15621 at paragraph 5, the Commission ordered the following:

5. *Pepco shall file within the Company's annual Consolidated Reports to the Commission, yearly data on tree trimming by feeder and wards (or multiple wards) compared to the Company's tree down and tree limb outage causes listed in its monthly power outage reports beginning with the Company's 2010 Consolidated Report.*

Priority Feeders & Aggressive Initiatives

The Electricity Quality of Service Standard D.C.M.R. 3603.6 states the following:

3603.6 The utility shall continue the current reporting of the worst performing (lowest two (2) percent) feeders (utility methodology) and corresponding corrective action plans, with the action taken in year 1 and the subsequent performance in year 2 in the annual Consolidated Report.

In Order No. 15152 paragraph 73, the Commission ordered the following:

73. Pepco is DIRECTED to investigate the viability of the "aggressive" initiatives for all least performing feeders, to file a progress report regarding the implementation of these initiatives where viable as part of the 2009 Consolidated Report, and to file quarterly progress reports thereafter, consistent with paragraph 62 of this Order;

In Order No. 15809 paragraph 11, the Commission ordered the following:

11. Pepco IS DIRECTED to include in its 2011 Consolidated Report a plan for development and application of "aggressive initiatives" to its underground distribution feeders;

Repeat Priority Feeders

In Order No. 15152 issued on Pepco's 2008 Consolidated Report, the Commission stated (at paragraph 72),

*72. PEPCO is **DIRECTED**, beginning with the 2009 Consolidated Report, to identify the feeders that are part of the separate annual program of corrective actions for reappearing least reliable feeders, describe the corrective actions planned for each feeder and the projected dates for completion of the corrective actions and explain whether the corrective actions improved the performance of these feeders consistent with paragraph 59 of this Order;*

In Order No. 15941 issued on August 18, 2010, the Commission stated at paragraphs 13 and 16, the following:

13. Beginning with the 2011 Consolidated Report, Pepco shall identify any feeders that have appeared more than once on the Priority Feeder List, by year from the first Priority Feeder List in 2002, so that it shall be apparent how many times each feeder has appeared on the Priority Feeder List…

16. Pepco IS DIRECTED to identify in its 2011 and successive Consolidated Reports, each feeder that has appeared more than once on the Priority Feeder List.

4 to 13 kV Conversions

These projects are a continuation of the 2011 Reliability Projects, as required by Order No. 16091 at paragraph 64 and referenced paragraphs 50 and 53:

*64. Pepco IS **DIRECTED** to provide detailed schedules and budgets for conversion projects, as well as justification for any non-minor deviations from these , consistent with Paragraphs 50 and 53 of this Order;*

50. <u>Decision.</u> We agree with the Staff recommendation and require Pepco to provide justification for any deviations from the plan schedules and annual budgets for 4 kV to 13 kV conversion projects in its Consolidated Reports, excluding minor deviations of less than 5%.

This information may be provided in the discussion of "Reliability Projects."

53. *Decision. …we have not adopted the Staff's "replace or rebuild" recommendation. However, we agree that future Consolidated Reports should contain detailed schedules and budgets for Reliability Projects, as well as justification for deviations from those schedules and budgets. We shall require Pepco to submit such schedules in future Consolidated Reports.*

Manhole Event Report

In Order No. 16091 issued on December 10, 2010, the Commission stated at paragraphs 56, 59, 65, and 66 the following:

56. *Decision. Pepco has agreed to make the recommended changes in the 2011 Consolidated Report with the exception of data on failure rates. We require that the members of the PIWG discuss the need for and feasibility of providing data on failure rates in future Consolidated Reports and include in the 2011 Consolidated Report the PIWG conclusions and recommendations, if any.*

59. *Decision. We adopt the Staff's recommendation and require Pepco to: (1) combine the Manhole Events portion of the failure analysis report with Part 3 of the Consolidated Report; (2) include data in the 2011 Consolidated Report that separates 4 kV primary failures from 13 kV primary failures; (3) include data in the 2011 Consolidated Report that separates 4 kV from 13 kV manhole events; (4) include trend analyses for "Use of Slotted Manhole Covers;" and (5) include in the Cable Splice or Joint Database section of the Consolidated Report, cable type, age, type of splice and other pertinent information, except that cable type and age can be excluded if unavailable. If data on failure rates for all variables is available for manhole events, Pepco shall include such information in its 2011 Consolidated Report. If such data is unavailable, we require the members of PIWG to discuss the need for and the availability of such data include in the 2011 Consolidated Report the PIWG conclusions and recommendations, if any.*

65. *Pepco IS DIRECTED to include a discussion of failure data rates in the agenda for the Productivity Improvement Working Group, consistent with Paragraphs 56 and 59 of this Order; and*

66. *Pepco IS DIRECTED to include additional Manhole Event data in the 2011 Consolidated Report, consistent with Paragraph 59 of this Order.*

In Order No. 15152 paragraphs 76 and 66, the Commission ordered the following:

76. *PEPCO is DIRECTED to include as part of the 2009 Consolidated Report a proposed plan for significantly reducing manhole events consistent with paragraph 66 of this Order…*

In Order No. 12735, paragraph 138, the Commission ordered the following:

Pepco shall file a report that summarizes the results of the failure analyses conducted for the calendar year 2002, 30 days from the issuance date of this Report and Order, and subsequently, to file an annual report on the results of the failure analysis group to the PIWG;

Slotted Manhole Covers

In Order No. 16091 issued on December 10, 2010, the Commission stated among other things, at paragraph 59, the following:

59. …(4) include trend analyses for "Use of Slotted Manhole Covers;"
60.

Cable Splice or Joint Database

In Order No. 16091, the Commission stated among other things, at paragraph 59, the following:

59. *…(5) include in the Cable Splice or Joint Database section of the Consolidated Report, cable type, age, type of splice and other pertinent information, except that cable type and age can be excluded if unavailable.*

Failure Rates

In Order No. 16091, the Commission stated among other things, at paragraph 59, the following:

59. …(5)…If data on failure rates for all variables is available for manhole events, Pepco shall include such information in its 2011 Consolidated Report. If such data is unavailable, we require the members of PIWG to discuss the need for and the availability of such *data include in the 2011 Consolidated Report the PIWG conclusions and recommendations, if any.*

Appendix 3A – 2011 Manhole Events and Summary of Selected Failures

In Order No. 11716 ordering paragraph 3, the Commission ordered the following:

PEPCO shall file an annual report on the previous calendar year's manhole incidents;

Appendix 3B – 2011 Manhole Inspection Program

In Order No. 11716, the Commission stated the following:

PEPCO is hereby directed to include the following information in its [manhole inspection] reports beginning in July 2000:

1. *The general location of the manholes inspected, including the street or streets where the manholes are located and the blocks bounding the street, e.g., M Street, NW, between 23rd and 28th streets;*
2. *The number of manholes inspected in the month, broken down as to the number of manholes containing primary cables only, both primary and secondary cables, and secondary cables only;*
3. *The number of primary cable problems found;*
4. *The number of secondary cable problems found;*
5. *The type of cable problems found in each manhole, categorized as to the physical degradation or damage of the cable, overheating, overloading, damaged splice and deteriorated cable or splice due to age;*
6. *The number of manholes with problems;*
7. *The corrective actions taken for each cable and manhole problem found; and*
8. *Other general condition of the manhole such as whether it contained water, oil, grease, debris, and whether the manhole cover and the manhole are in good mechanical condition.*

SECTION 4.4 – COMPOSITE PERFORMANCE INDEX[88] [89]

The Company has discontinued use of CPI to select feeders for inclusion in its 2% Priority Feeder program; however, in compliance with Order No. 16975, the Company still tracks and performs remediation work on feeders that would have been on the list using CPI selection methodology.

[88] In Order No. 15152 paragraph 74, the Commission ordered the following:

> *74. Pepco is DIRECTED to provide more detail, in the 2009 Consolidated Report, regarding how it applied the Composite Performance Index methodology in identifying the list of 2008 High Priority Feeders consistent with paragraph 65 of this Order;*
>
> *65. Although PEPCO uses the Composite Performance Index as the methodology for identifying high priority feeders, OPC asserts that it is unclear how the methodology was applied in this instance. Essentially, OPC believes that PEPCO should provide more detail on the particular inputs and variables used in the CPI process. OPC also maintains that the comparisons between PEPCO and other utilities (PSE&G Benchmarking Study, SEE study, and the Large City Reliability Survey) would be more useful if the data were "disaggregated" among those parts of the distribution system "served by underground networks, by underground radial and by overhead radial." If that data is not available, OPC believes that it would be helpful to know the percentage of each of the surveyed utilities' distribution system that is served by "these system designs." According to OPC, the disaggregated information would provide the basis for "a more thorough analysis" when comparing PEPCO's reliability performance with other utilities. Staff similarly believes that PEPCO should provide more detail on how it applied the CPI methodology and that the comparative information should be disaggregated. The Commission is of the view that the recommendations have merit and directs PEPCO to submit the additional information in the 2009 Consolidated Report.*

[89] Order No. 16975 states the following at paragraph 60:

> *60. The Commission notes that in recent PIWG meetings, Pepco has indicated its intention to change the methodology which it uses to determine Priority Feeders. A change in methodology would diminish the value of the Priority Feeder List in determining historically poorly performing feeders and would lessen our ability to track and compare the historical data. Therefore, we require Pepco to provide two Priority Feeder Lists, using both the historical (CPI) and any new methodologies in the 2013, 2014 and 2015 Consolidated Reports.*

CPI, which is unique to Pepco, has historically been used to evaluate and rank feeder performance. CPI was developed at Pepco many years ago and more recently underwent refinement by PA Consulting (formerly PHB-Hagler Bailly). The Company used CPI to track feeder performance, incorporating all appropriate variables, and to track results of improvement efforts.

CONCEPTUAL FRAMEWORK

CPI is not only calculated on basic variables (interruptions, duration, customers affected, etc.), but also on averaged or combined indices such as System Average Interruption Frequency (SAIF) and System Average Interruption Duration (SAID). In total, CPI is composed of four measurements that are applied to each feeder:

- Number of Interruptions (NI),
- Number of Customer Hours of Interruption (CHI),
- System Average Interruption Frequency (SAIF), and
- System Average Interruption Duration (SAID).

The basic concept behind CPI and the statistical model is to plot a feeder in 4 dimensions and measure its distance from the point representing the "ideal" feeder. It is a statistical effort to locate any ***outliers*** in these categories or a combination of them. It is a sort of weighted average of the 4 indicators from different angles in a space.

However, because the 4 measures are not independent of each other, it requires a linear transformation (scaling and rotating) of the original data as well as a reduction of dimensions considered relevant. To understand the dependence between indicators/measures and the reduction in dimensions, consider the case of determining the winner of a decathlon. Even though there are 10 original tests (dimensions), the winner should be the athlete that proves best in perhaps 4 underlying characteristics (principal components): velocity, strength, resistance and agility. Several tests are correlated as they address similar abilities to differing degrees:

- Velocity – short races, hurdles, broad jump, high jump, javelin, pole vault
- Strength – broad jump, high jump, javelin, pole vault, shot put, discus
- Resistance – long races, and the set of all tests together
- Agility – hurdles, pole vault, high jump

To avoid redundancy, the method to determine the winner should try to extract the scores on the 4 principal components and calculate the results based on them. In the case of CPI, the method for determining feeder performance starts with 4 variables and creates Principal Components, and mean and standard deviations for 4 variables. It then transforms the raw value of the feeder and the origin to calculate the CPI index over 3 principal components.

Figure 4.4-A illustrates the CPI concept spatially, and Figure 4.4-B explains CPI process in detail.

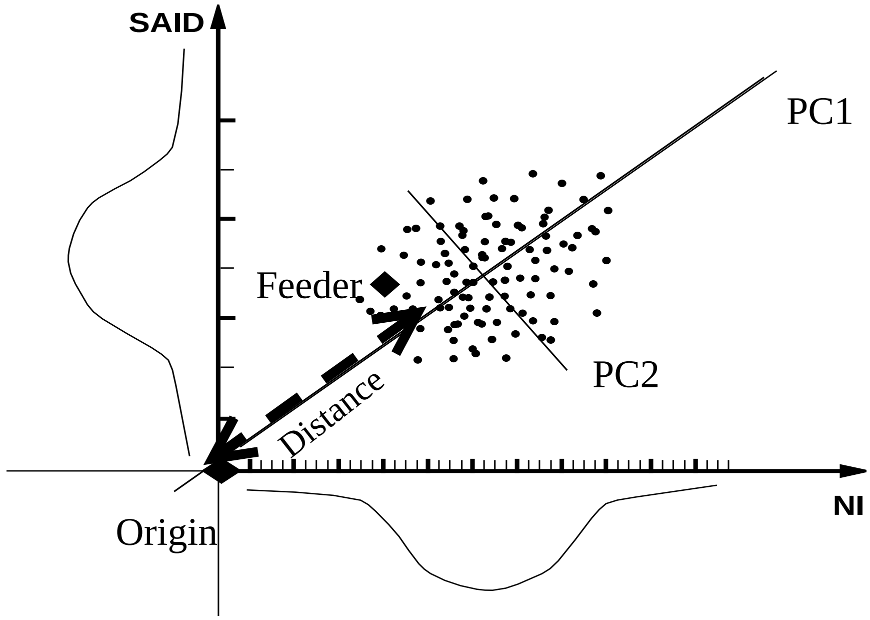
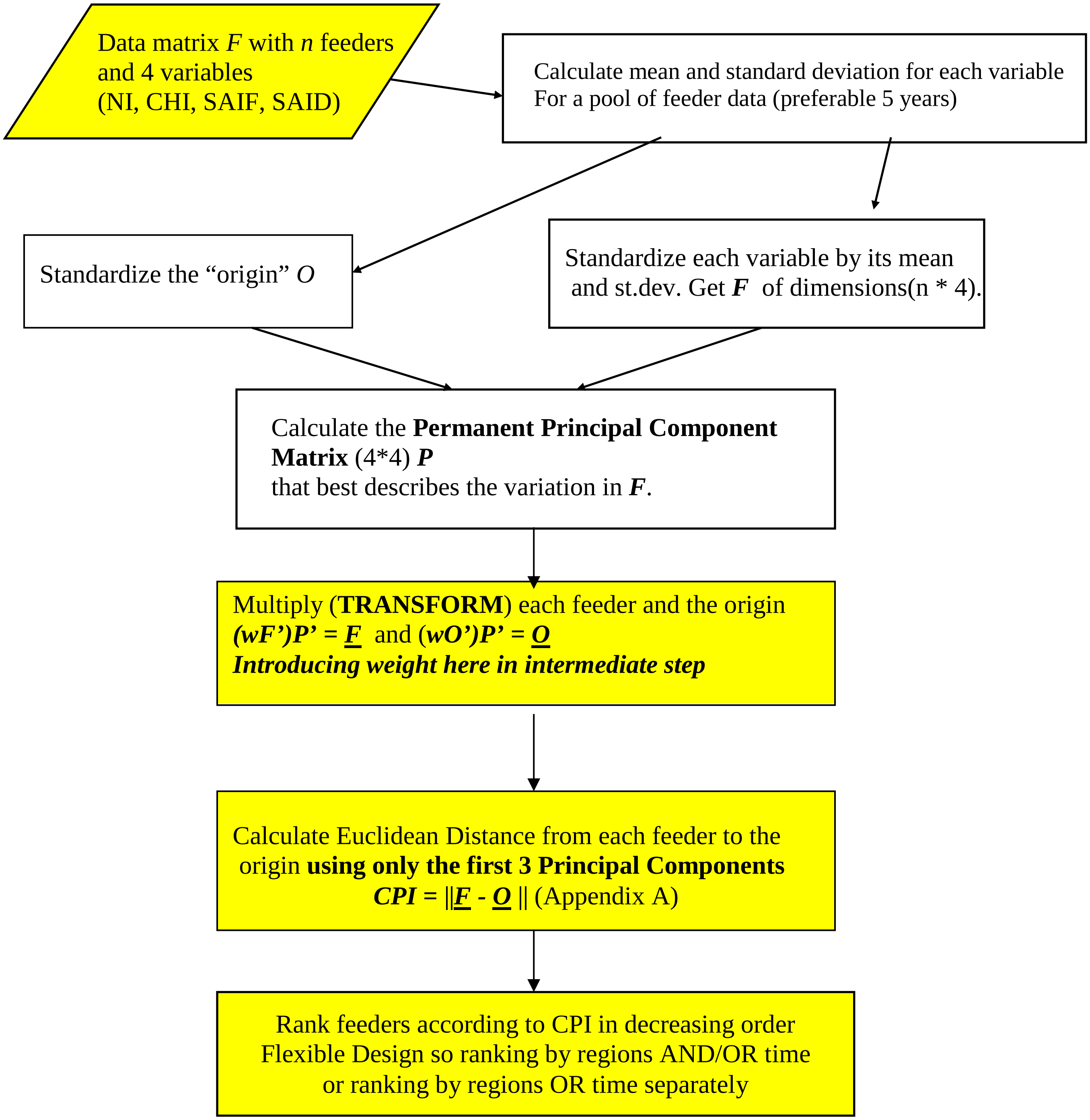


Figure 4.4-A: CPI Spatial Concept

<u>DESCRIPTION OF CALCULATION PROCESS</u>

The following flow chart (Figure 4.4-B) illustrates the process for calculating the Composite Performance Index for a feeder.



<u>Figure 4.4-B -- Illustration of CPI Concept</u>

Description of Euclidean Distance to Derive CPI

Definitions

Principal Component Matrix (each row is Principal Component vector)

$$P = \begin{bmatrix} PC_1 \\ PC_2 \\ PC_3 \\ PC_4 \end{bmatrix} = \begin{bmatrix} pc_{1,NI} & pc_{1,CHI} & pc_{1,SAIF} & pc_{1,SAID} \\ pc_{2,NI} & pc_{2,CHI} & pc_{2,SAIF} & pc_{2,SAID} \\ pc_{3,NI} & pc_{3,CHI} & pc_{3,SAIF} & pc_{3,SAID} \\ pc_{4,NI} & pc_{4,CHI} & pc_{4,SAIF} & pc_{4,SAID} \end{bmatrix}$$

Original Feeder Data

$$originalFeeders = F = \begin{bmatrix} f_{1,NI} & f_{1,CHI} & f_{1,SAIF} & f_{1,SAID} \\ f_{2,NI} & . & . & . \\ . & . & . & . \\ f_{n,NI} & . & . & f_{n,SAID} \end{bmatrix}$$

Weight

$$W = \begin{bmatrix} w_{NI} & 0 & 0 & 0 \\ 0 & w_{CHI} & 0 & 0 \\ 0 & 0 & w_{SAIF} & 0 \\ 0 & 0 & 0 & w_{SAID} \end{bmatrix}$$

Standard Deviation

$$\Sigma = \begin{bmatrix} \sigma_{NI} & 0 & 0 & 0 \\ 0 & \sigma_{CHI} & 0 & 0 \\ 0 & 0 & \sigma_{SAIF} & 0 \\ 0 & 0 & 0 & \sigma_{SAID} \end{bmatrix}$$

Intermediate Calculations

$$M = \Sigma * W = \begin{bmatrix} \frac{w_{NI}}{\sigma_{NI}} & 0 & 0 & 0 \\ 0 & \frac{w_{CHI}}{\sigma_{CHI}} & 0 & 0 \\ 0 & 0 & \frac{w_{SAIF}}{\sigma_{SAIF}} & 0 \\ 0 & 0 & 0 & \frac{w_{SAID}}{\sigma_{SAID}} \end{bmatrix}$$

Transformation

$$\hat{F} = F * M * P'$$

$$\hat{F} = \begin{bmatrix} f_{1a} & f_{1b} & f_{1c} & f_{1d} \\ f_{2a} & . & . & . \\ . & . & . & . \\ f_{na} & . & . & f_{nd} \end{bmatrix}$$

Where

F is the original feeder data matrix (size n*4)

M is the intermediate calculation matrix (size 4*4)

P' is the (transposed) principal component matrix (size 4*4)

Finalization of CPI – Euclidean Distance Method

For each feeder *i* take the values for the 3 first components of row *i* in the last matrix above.

$$CPI_{f_i} = \sqrt{f_{ia}^2 + f_{ib}^2 + f_{ic}^2}$$

REP Work Plan Summary

Project Name	Project Description	Performance Metric	Miles/Feeders
Vegetation Management	Program to address vegetation, designed to maintain appropriate clearance on the system, remediate trouble spots (e.g., Priority Feeders), and remove the vegetation hazards that have the greatest impact on system reliability.	Annual tree related SAIFI/SAIDI performance for all feeders.	Number of miles pruned
Feeder Improvement	Program to address equipment, vegetation, weather, and animal-related interruptions which negatively impact reliability performance. These projects involve installing, removing, and replacing reclosers, switches, conductors, animal guards, lightning arresters and other equipment deemed necessary on the worst performing, top SAIFI contributing, and high customer interruption feeders to maintain safe operation and improve reliability.	Annual cumulative SAIFI/SAIDI performance for all feeders included within the feeder improvement as well as feeders where DA has been installed and feeders are undergrounded.	Number of feeders impacted
URD Cable Replacement and Enhancement	Program to address reliability of the underground residential infrastructure. These projects involve replacing or rejuvenating underground residential distribution (URD) cable in order to minimize URD failures.	Annual number of underground (URD) cable failures.	Number of miles replaced/ injected
Distribution Automation	Program to address system reliability by deploying technology. These projects involve installing advanced control systems across the distribution system in order to automatically identify and isolate faults in real time and restore service to customers in the unaffected parts of the system.	Annual cumulative SAIFI/SAIDI performance for all feeders included within the feeder improvement as well as feeders where DA has been installed and feeders are undergrounded.	Number of ASR schemes
Conversions **Load Growth**	Program to address increasing load demands to maintain reliability and to ensure that future demands can be met under adverse conditions. These projects involve adding or upgrading feeders in order to reliably supply new customers and support increased usage required by existing customers.	Operate substations within design loading criteria.	N/A

Non-REP Work Plan Summary

Project Name	Project Description	Performance Metric	Miles/Feeders
Non-REP	Non-REP reliability infrastructure projects.	N/A	N/A

REP Work Plan Summary

Project Name	Project Description	Performance Metric	Miles/Feeders	2012 Budget	2012 Actual	2013 Budget	2013 Actual	2014 Budget	2014 Actual	2015 Spend (Budget)
Vegetation Management	Program to address vegetation, designed to maintain appropriate clearance on the system, remediate trouble spots (e.g., Priority Feeders), and remove the vegetation hazards that have the greatest impact on system reliability.	Annual tree related SAIFI/SAIDI performance for all feeders.	Number of miles pruned	2,218,154	1,981,233	2,218,342	2,352,567	2,113,300	2,164,335	2,324,572
Feeder Improvement	Program to address equipment, vegetation, weather, and animal-related interruptions which negatively impact reliability performance. These projects involve installing, removing, and replacing reclosers, switches, conductors, animal guards, lightning arresters and other equipment deemed necessary on the worst performing, top SAIFI contributing, and high customer interruption feeders to maintain safe operation and improve reliability.	Annual cumulative SAIFI/SAIDI performance for all feeders included within the feeder improvement as well as feeders where DA has been installed and feeders are undergrounded.	Number of feeders impacted	20,511,872	33,471,048	37,825,244	34,707,170	38,006,054	21,656,931	24,421,050
URD Cable Replacement and Enhancement	Program to address reliability of the underground residential infrastructure. These projects involve replacing or rejuvenating underground residential distribution (URD) cable in order to minimize URD failures.	Annual number of underground (URD) cable failures.	Number of miles replaced/ injected	1,558,237	1,640,848	465,004	541,759	471,203	1,139,768	408,887
Distribution Automation	Program to address system reliability by deploying technology. These projects involve installing advanced control systems across the distribution system in order to automatically identify and isolate faults in real time and restore service to customers in the unaffected parts of the system.	Annual cumulative SAIFI/SAIDI performance for all feeders included within the feeder improvement as well as feeders where DA has been installed and feeders are undergrounded.	Number of ASR schemes	10,515,442	4,476,859	10,382,257	5,989,221	9,689,165	3,889,448	9,552,956
Conversions	Program to address increasing load demands to maintain reliability and to ensure that future demands can be met under adverse conditions. These projects involve adding or upgrading feeders in order to reliably supply new customers and support increased usage required by existing customers.	Operate substations within design loading criteria.	N/A	12,693,531	3,984,125	14,751,658	9,394,129	22,412,777	18,212,888	19,957,789
Load Growth				24,596,308	21,595,461	37,020,814	36,634,850	78,021,448	41,659,244	65,099,111
Total REP				**72,093,544**	**67,149,574**	**102,663,319**	**89,619,696**	**150,713,947**	**88,722,614**	**121,764,365**

Non-REP Work Plan Summary

Project Name	Project Description	Performance Metric	Miles/Feeders	2012 Budget	2012 Actual	2013 Budget	2013 Actual	2014 Budget	2014 Actual	2015 Spend (Budget)
Non-REP	Non-REP reliability infrastructure projects.	N/A	N/A	55,903,803	55,244,262	66,763,676	57,818,812	65,603,861	55,843,298	63,050,178
Total REP and Non-REP				127,997,347	122,393,836	169,426,995	147,438,508	216,317,808	144,565,912	184,814,542

Work Breakdown Structure - 2015 Projects										
REP Section	**WBS Element**	**WBS Element Description**	**WBS Detailed Description**	**2012 Budget**	**2012 Actual**	**2013 Budget**	**2013 Actuals**	**2014 Budget**	**2014 Actuals**	**2015 Budget**
REP Projects										
Vegetation Management	N/A	N/A	N/A	$2,218,154	$1,981,233	$2,218,342	$2,352,567	$2,113,300	$2,164,335	$2,324,572
			Vegetation Management Total	$2,218,154	$1,981,233	$2,218,342	$2,352,567	$2,113,300	$2,164,335	$2,324,572
Feeder Improvement	UDLPRM4BF	PSC Priority Ckt Improvement: Benning	Install, remove, replace reclosers, switches, poles, wires, animal guards, lightning arresters and other equipment deemed necessary on the PSC mandated 2% Priority Feeders in the District, to maintain safe operation and improve reliability.	$9,982,875	$21,601,507	$15,851,801	$19,230,629	$16,003,043	$9,912,324	$14,462,995
	UDLPRM63D	Pepco DC: Feeder Reliability Improvements	Design and construct reliability improvements to additional feeders based on reliability performance. These feeders are in addition to the Priority Feeders. Install, remove, replace reclosers, switches, poles, wires, animal guards, lightning arresters and other equipment deemed necessary to improve performance.	$10,528,997	$11,869,540	$21,973,443	$15,476,541	$22,003,011	$11,744,607	$9,958,055
			Feeder Improvement Total	$20,511,872	$33,471,048	$37,825,244	$34,707,170	$38,006,054	$21,656,931	$24,421,050
URD Cable Replacement and Enhancement	UDLPRM4BC	Benning: Replace Deteriorated URD Cable (UDLPRM4BC)	Reactive replacement of damaged and/ or failed URD cable	$119,442	$0	$119,273	$0	$120,964	$0	$117,808
	UDLPRM4BD	Benning: Planned URD Cable Replacements	Planned URD cable replacement or curing in DC. Planned program to reduce cable failures in URD cable and to prevent future failures from occurring.	$1,438,795	$1,640,848	$345,731	$541,759	$350,239	$1,139,768	$291,079
			URD Cable Replacement & Enhancement Total	$1,558,237	$1,640,848	$465,004	$541,759	$471,203	$1,139,768	$408,887
Distribution Automation	DDLPRDA1D	UF: Distribution Automation Project - Line Equipment - Pepco DC	Design & install automated switches and automatic circuit reclosers on various feeders per System Planning Recommendations under DOE SGIG Distribution Automation (DA) Program.	$122,173	$98,367	$44,747	-$25,563	$0	$0	$0
	DDSPRD8SD	UF : Install Smart Relays & Replace RTU'S - DC	DOE: Install smart relays & replace RTU's in seven (7) substations in DC: Sub. 38 Harrison, Sub. 129 Van Ness, Sub. 77 Little Falls, Sub. 133 12th and Irving, Sub. 97 Green Meadows, Sub. 190 Fort Slocum and Sub. 27 Takoma.	$174,093	$2,158	$0	$10,189	$0	$0	$0
	DDSPRDA1D	UF Pepco DC: Sub Distribution Automation (DOE)	Substation automation to support the control and monitoring of line equipment installed for system restoration.	$76,869	$0	$0	$0	$0	$0	$0
	DOIPRASRD	Pepco DC: Install ASR Computer - DOE	Install Automatic Sectionalizing and Restoration (ASR) computer and complete point to point testing with field devices for the Harrison Van Ness Little Falls ASR Scheme and the 12th & Irving Fort Slocum Green Meadows Takoma ASR Scheme.	$189,528	$46,454	$183,892	$178,109	$0	-$8,238	$0
	DORPOBR1D	UF : Pepco DC Comm Work - Collector to Data Network	Design and construct radio mesh communications network (repeaters, master radios & access points) for DOE Distribution Automation (DA) schemes in DC. For the Benning Tuxedo sub Group, Walker Mill ASR Scheme, Harrison-Van Ness - Little Falls Sub group, and 12th and Irving-Fort Slocum Sub group.	$378,183	$324,546	$246,378	$354,458	$0	$0	$0
	DORPODA1D	DC Comm Work: Install Radios In Line Equip	Complete engineering and installation of Distribution Automation (DA) field device controls, radios and antennas under DOE plan.	$468,152	$916,231	$402,084	$320,654	$0	-$16,363	$0

Work Breakdown Structure - 2015 Projects

REP Section	WBS Element	WBS Element Description	WBS Detailed Description	2012 Budget	2012 Actual	2013 Budget	2013 Actuals	2014 Budget	2014 Actuals	2015 Budget
Distribution Automation (con't)	DORPORBSB	Benning : Install Broadband Wireless Base Stations	Under DOE SGIG program, design and construct base station equipment to transport Distribution Automation (DA) traffic over private, licensed wireless infrastructure to the Power Delivery Data Network (PDDN).	$619,225	$96,892	$238,328	$735,241	$0	-$72,499	$0
	DORPORSSB	Benning : Sub Subscriber - BBW	Under DOE SGIG program, design and construct subscriber (remote) radio units colocated at access points and master radios to transport Advanced Metering Infrastructure (AMI) and Distribution Automation (DA) traffic over private, licensed wireless infrastructure to the Power Delivery Data Network (PDDN).	$954,463	$11,700	$542,501	$66,276	$0	-$36,766	$0
	UDLPRDA1D	Distribution Automation - Pepco DC	Design & install automated switches and automatic circuit reclosers on various feeders per System Planning recommendations under Distribution Automation (DA) Program.	$0	$0	$1,000,183	$0	$701,815	$0	$569,071
	UDLPRM4SN	Network Monitoring and Control Upgrades	Design and install Network Transformers and associated Protectors to support the Network Remote Monitoring System.	$6,839,920	$704,429	$1,870,022	$0	$0	$0	$0
	UDSPRD8SD	Install Smart Relays and Replace RTU's - DC	To design and construct Digital Remote Terminal Unit (DRTU) in Substations for DA and non DA Applications.	$0	$104,902	$564,714	$1,535,169	$1,000,000	$846,729	$1,174,845
	UDSPRD8VD	NERC Physical Security Pepco	Substations included in the ASR schemes are connected through a secure communication infrastructure. In line with industry best practice, the Company is installing additional security equipment.	$117,796	$174,907	$110,519	$55,347	$119,693	$119,537	$110,682
	UOIPRASRD	Pepco DC: Install ASR Computer	Install Automatic Sectionalizing and Restoration (ASR) computer and complete point to point testing with field devices.	$0	$0	$132,641	$0	$500,000	$0	$294,349
	UORPOBR1D	DC Comm Work - Collector to Data Network	Design and construct radio mesh communications network (repeaters, master radios & access points) for Distribution Automation (DA) schemes in DC.	$0	$0	$375,072	$0	$500,000	$270,763	$287,823
	UORPODA1D	DC Comm Work: Install Radios in Line Eq	Complete engineering and installation of Distribution Automation (DA) field device controls, radios and antennas.	$215,059	$154,798	$769,003	$76,295	$710,445	$414,836	$511,374
	UORPORBSB	Base Stations for Communications Infrastructure - Benning	Design and construct base station equipment to transport Distribution Automation (DA) traffic over private, licensed wireless infrastructure to the Power Delivery Data Network (PDDN).	$153,674	$38,321	$161,022	$26,609	$137,660	$302,189	$117,053
	UORPORCPD	Install Cap Controlls - DC	The purpose of this projects is to install controller and remote radios for line capacitors in Pepco DC.	$0	$0	$0	$0	$500,000	$11,643	$956,942
	UORPOR34D	Install Fault Detection System (FDS) in DC	Install smart fault indicators with telecommunications to aid in the location of faults on the distributiion circuits.	$0	$0	$0	$0	$125,182	$0	$133,161
	UORPORNPD	Network Remote Monitoring System Installation	Design and install communication devices for the Network Remote Monitoring System.	$0	$1,776,082	$3,578,826	$2,441,055	$5,250,364	$2,090,268	$5,397,656
	UORPORSSB	Benning: Sub Subscriber - BBW	Design and construct subscriber (remote) radio units colocated at access points and master radios to transport Advanced Metering Infrastructure (AMI) and Distribution Automation (DA) traffic over private, licensed wireless infrastructure to the Power Delivery Data Network (PDDN).	$206,308	$27,072	$162,325	$215,380	$144,006	-$32,651	$0
			Distribution Automation Total	$10,515,442	$4,476,859	$10,382,257	$5,989,221	$9,689,165	$3,889,448	$9,552,956

Work Breakdown Structure - 2015 Projects

REP Section	WBS Element	WBS Element Description	WBS Detailed Description	2012 Budget	2012 Actual	2013 Budget	2013 Actuals	2014 Budget	2014 Actuals	2015 Budget
Conversions	UDLPRM8BC	North Capital Sub 40: Convert 4 to 13kV	This project is being recommended to initiate infrastructure upgrades to the existing 4kV system in the North Capitol Street, Kennedy Street, and New Hampshire Avenue, NW area. The proposed 4 to 13 kV conversions will be accomplished by extending and/or rearranging existing or new 13 kV distribution feeders from Fort Slocum Sub. 190 beginning in 2014. The total amount to be converted is approximately 50,600 feet.	$5,432	$0	$6,215	$637	$2,400,732	$1,851,637	$1,106,935
	UDLPRM8BG	Convert portions of Fdrs 482 & 485 to Fdrs. 15006, 15012, 15015	1/09/13 The North Capitol Sub. 40 - 4kV system is an aging, isolated area on the Pepco distribution system that is not connected to any other 4kV substations or systems. Recent substation inspections have revealed deteriorating circuit breakers that are subject to a few failures that include a relatively high number of arc shute and internal problems. The current Preventive Maintenance Program for these breakers calls for them to be overhauled every 72 months. The aging switchgear necessitates the salvage of spare parts from like equipment. In the event of a catastrophic failure at North Capitol Sub. 40, no external 4kV support is available. 4kV feeders are of mostly older construction and backed up by other North Capitol Sub. 40 feeders or through bus ties. Capacity from nearby Fort Slocum Sub. 190 is readily available for the 4kV to 13kV conversions. Customers served by these feeders experienced a total of about 155,000 customer minutes of interruption in 2010.	$0	$0	$0	$0	$0	-$25,794	$0
	UDLPRM8BQ	Harrison-Van Ness: Convert Fdr 82 to 13kv	1/09/13 Extend and/or rearrange 4kV Feeder 82 (Veazey East Sub. 90-E & Nebraska Sub. 92) and Van Ness Sub. 129 – 13kV Feeder 14135 in the vicinities of Nebraska Avenue & Connecticut Avenue, NW and Connecticut Avenue & Chesapeake Street, NW to convert approximately 0.8 MVA of load from Feeder 82 to Feeder 14135.	$0	$0	$0	$0	$0	$1,428	$0
	UDLPRM8BI	Fort Carroll Sub. 130: Convert 4-13kV Conversion (UDLPRM8BI)	Converting approximately 26,000 circuit feet of overhead; Fort Carroll Sub. 130 approximately 20,000 feet, Congress Heights Sub. 64 approximately 6,000 feet.	$0	$0	$0	$0	$3,000,000	$664,206	$2,264,493
	UDLPRM8BT	Convert 4-13 kV-Georgetown	This is the continuation of Project M34 for the Georgetown infrastructure projects and will convert the remaining 4kV load supplied from this substation. The project will identify all required underground system modifications necessary to maintain and improve distribution facilities by converting to 13kV. Area 2B is the next location identified for conversion and encompasses between P and S Sts. east of Wisconsin Avenue, NW. 50,000 ft conduit, 115,000 ft cable, 8 3-way switches, 3 13/4 kV step-down transformers, replace secondary where needed.	$3,446,593	$624,307	$4,099,951	$3,528,582	$4,804,472	$7,009,228	$5,461,506
	UDLPRM8BU	Convert 4-13 kV-12th St.	The 12th Street Sub. 126 contains oil circuit breakers that will be removed based on review of condition and reliability. Both the 13 kV/4 kV transformers are identified as suspect and in need of eventual replacement. These oil circuit breakers are no longer manufactured and the manufacturer no longer provides spare parts. The existing conduit and cables are very old and upgrades of this system are being proposed to eliminate potential reliability concerns proactively.	$3,804,429	$65,144	$4,626,708	$1,668,848	$4,781,265	$5,592,139	$4,967,804

Work Breakdown Structure - 2015 Projects

REP Section	WBS Element	WBS Element Description	WBS Detailed Description	2012 Budget	2012 Actual	2013 Budget	2013 Actuals	2014 Budget	2014 Actuals	2015 Budget
Conversions (con't)	UDLPRM8BY	Convert 4-13 kV-Harvard	This project is being recommended to continue infrastructure upgrades to the existing 4kV system in the Upper Shaw and Harvard/Columbia Heights areas. Two 13kV Feeders extended from Florida Avenue Sub. 10 in 2011 provide capacity for portion of the conversion and allow load to be transferred to Sub. 10 from Sub. 13. Existing 13kV Feeders from Sub. 13 and new 13kV Feeders from Sub. 25 will be used to convert the remaining 4kV load starting in 2014. Total amount to be converted is approximately 60,200 feet. Customers supplied from the Harvard 4 kV substation experienced a total of 2,831,000 customer minutes of interruption in 2010.	$5,437,077	$3,294,674	$6,018,784	$4,196,062	$7,426,308	$3,120,044	$6,157,051
			Conversions Total	$12,693,531	$3,984,125	$14,751,658	$9,394,129	$22,412,777	$18,212,888	$19,957,789
Load Growth	UDLPL10S1	Sub 52 South to Sub. 52 Central LVAC Cutover	Extend the 10th St Sub. 52 Central Low Voltage AC (LVAC) Group east along H St. from between 13th & 14th Sts. to 13th St., then south along 13th St. to between G St. and H St. using approximately 600' of new conduit and 3300' of new cable to transfer load from the Sub. 52 South LVAC Group.	$0	$0	$498,792	$117,578	$1,977,694	$2,620,810	$48,784
	UDLPL10S2	Sub 52 East to Sub. 52 North LVAC Cutover	Extend the 10th St Sub. 52 North Low Voltage AC Group west along F St from between 9th & 10th Sts to 10th St using approximately 500' of new conduit and 3000' of new cable to transfer load from the Sub. 52 East Group.	$0	$0	$535,985	$179,918	$327,694	$1,741,139	$48,784
	UDLPLALB1	Extend 4-13kv Feeders from Sub 136 to DHS	Extend Feeder # 15192, 15193, 15194, &15195 cables into the St. Elizabeth's Campus from Alabama Ave substation. These feeders will provide feeder capacity to the entire complex and will support future load growth.	$910,617	$618,410	$0	$0	$0	$0	$0
	UDLPLBN1	Benning Sub 7: Extend Two 13kV UG Dist Fdrs	Extend 2 13kV Benning Sub. 7 UG feeders from Sub.7 to the Benning Road and 15th St., NE area including half loops to transfer approximately 8.0 MVA of summer 2014 load from Benning Sub. 7 Feeders 14712, 14713, 15703 & 15708. Build a conduit bank as necessary and install approximately 4,000 feet of 600 MCM cable and 4 underground 3-way switches. Feeder extension required to relieve projected overload and to provide increased feeder capacity in the area.	$9,584	$0	$1,973,043	$386,711	$267,959	$410,100	$143,536
	UDLPLFL1	Florida Ave Sub 10: Ext 69kv to New T4	Install 69kv 1500kcm pipe-type cable circuit for 2.41 miles from New Jersey Avenue Sub 161 to Florida Avenue Sub 10 to supply fourth 69/13kv transformer.	$277,580	$106,334	$4,479,381	$5,353,829	$750,000	$993,714	$0
	UDLPLFL2	Florida Ave Sub 10: New High Voltage Grp xfer from 12th & Irving	Extend a new High Voltage Group (Feeders 15771,15772,15773, 15774,15775,and 15776) from Florida Ave. Sub. 10 approximately 0.1 miles from Barry Place and Georgia Ave. NE. & .09 miles from Bryant St. and Georgia Ave. to First St. and Michigan Ave. NE.,and rearrange with 12th and Irving sub 133 west High Voltage Group Feeders 14025,14026, 14027, 14028, 14029, and 14030. Model with UDLPLFL1 & UDSPLFL1.	$5,996	$0	$2,769,684	$8,654,221	$1,161,361	$1,997,300	$0
	UDLPLIRV1	12th & Irving Sub. 133 - Transfer West H. T. Group Load to Sub. 10	Extend a new H. V. Group from Florida Ave. Sub. 10 approximately 0.1 miles from Barry Place and Georgia Ave. to Bryant St. and Georgia Ave. NE, & 0.9 miles from Bryant St. and Georgia Ave. to 1st St. and Michigan Ave. NE., and rearrange with 12th & Irving Sub. 133 West H. T. Group Feeders 14025, 14026, 14027, 14028, 14029, and 14030. Model with UDLPLFL1 & UDSPLFL1.	$0	$0	$5,396	$41,575	$400,000	$469,672	$144,037

Work Breakdown Structure - 2015 Projects										
REP Section	WBS Element	WBS Element Description	WBS Detailed Description	2012 Budget	2012 Actual	2013 Budget	2013 Actuals	2014 Budget	2014 Actuals	2015 Budget
Load Growth (con't)	UDLPLIST1	I STREET SUB 197 - EXTEND NEW 13KV FEEDER	Extend new feeder out of Sub 197 to improve reliability and to provide load transfer capabilities in the area.	$776,562	$145,369	$0	$0	$1,000,000	$0	$10,131
	UDLPLLF1	Little Falls Sub. 77 - Extend New Dist. Feeder (UDLPLLF1)	The purpose of this project is to extend one outgoing 13.8kV Distribution feeder from Little Falls Sub. 77 along Loughboro Rd., north on Dalecarlia Pkwy, south on Rockwood Pkwy until Tilden St., and north on Tilden St. until Fordham Rd. underground a total distance of about 0.9 miles. Then, extend overhead from Fordham Rd & Tilden St. north on Fordham Rd. a total distance of approximately 0.1 mile. This feeder will be used to relieve Little Falls Sub. 77 Feeder 14766. Model with Term for new Little Falls Sub. 77 feeder project.	$0	$0	$0	$0	$2,106,836	$0	$0
	UDLPLM7W	Dist Feeder Load Relief - DC	1). Balance phase loadings on Twining City Sub. 150 – 4kV Feeder 345. 2). Rearrange 12th & Irving Sub. 133 Feeders 14007, 14014, and 14015. 3). Install two 3-way switches in Harrison Sub. 38 13kV Feeders 14894 & 15930. 4). Balance I St. Sub. 197 Central LVAC group. 5). Install one (1) 300kVAr capacitor bank on Nebraska Sub. 92 – 4kV Feeder 117. 6). Rearrange capacitor banks on various 4 kV feeders to maintain voltages within required limits. 7). Install one (1) normally closed switch in Feeder 292 (Wesley Sub. 61 & MacArthur Blvd. Sub. 152). 8). Remove one (1) set of 3-175 kVA + 5% voltage regulators in Fort Slocum Sub. 190 – 13kV Feeder 15012 located on 4th Street north of Emerson Street, NW and install one (1) set of 3-250 kVA + 5% voltage regulators in Feeder 15012 in the vicinity of 4th & Buchanan Streets, NW.	$2,941,010	$2,176,822	$7,668,357	$3,449,376	$2,678,723	$4,131,073	$9,482
	UDLPLNE1	Northeast Sub: New Supply 3rd Transf	Install 20,500 circuit feet of 69kv 1250kcm EPR cable from Benning Station A to Northeast Sub 212 to supply the 3rd 56 MVA 69/13kv transformer. Install one 9 MVAR bus capacitor.	$4,740,926	$3,069,294	$0	$4,379	$0	$0	$0
	UDLPLNE2	Northeast: Construct Supply for 4th Transf	Install 20,500 circuit feet of 69kv 1250kcm EPR cable from Benning Station A to Northeast Sub 212 to supply the 4th 56 MVA 69/13kv transformer. Expenses are for the start of engineering to support the installation of the fourth supply and transformer.	$633,436	$166,292	$860,435	$4,852,601	$1,708,223	$3,847,619	$358,507
	UDLPLNE3	NE Sub: Extend New LVAC Group to Sub 7	Extend a new 6 Feeder - 13kV LVAC Network Group from NE Sub. 212. Build an 8-way conduit bank from NE Sub. 212 along New York Avenue and N. Capitol St. NE for approximately 3,000 feet and on 3rd St., NE for approximately 1,500 feet. Approximately 18,000 feet of new 600 3/c MCM and 9,000 feet of new 500 3/c cable will be installed. This will allow for transfer of approximately 40.0 MVA of summer 2012 load from Benning Sub. 7 to NE Sub. 212.	$2,250,250	$3,257,149	$0	$241,239	$0	$0	$0
	UDLPLNE4	NE Sub New HV Grp, Transfer HV Load fm Sub. 117 to Sub. 161 to Sub. 212 (UDLPLNE4)	The purpose of this project is to extend the Northeast Sub. 212 Southeast Spot Network Group south along North Capitol St from H St to Mass Ave using approximately 1100' of new conduit and 6600' of new cable to transfer load from the Sub. 161 South Group.	$0	$0	$0	$0	$15,000	$0	$0
	UDLPLNE5	Sub. 52 to Sub. 212 Network Cutover	Extend a new (2nd) six feeder LVAC group from Northeast Sub. 212 west along Harry Thomas Way and Q St, south along North Capitol St and west along N St to 6th St using approximately 7000' of new conduit and 42000' of new cable to transfer all load from the Sub. 52 North LVAC Group.	$7,302	$0	$0	$0	$6,937,906	$0	$4,931,953

Work Breakdown Structure - 2015 Projects

REP Section	WBS Element	WBS Element Description	WBS Detailed Description	2012 Budget	2012 Actual	2013 Budget	2013 Actuals	2014 Budget	2014 Actuals	2015 Budget
Load Growth (con't)	UDLPLNE6	NE Sub: New LVAC Grp Transfer LVAC from NE Sub to SE	Extend a new South Spot Network Group from Northeast Sub. 212 and rearrange with the Northeast Sub. 212 Southeast Spot Network Group and the Northeast Sub. 212 Southwest Low Voltage AC Network Group by extending underground six new feeders from Sub. 212, north on Eckington Pl, west on R St. until North Capitol St., and south on north capitol St. until M St. NE a total distance of approximately 1.1 miles.	$0	$0	$5,753,667	$27,685	$7,029,086	$5,020,248	$2,036,427
	UDLPLNW1	Harrison: Convert 3-4kv Fdrs & Reconf Fdrs	Convert load from portions of North Capitol Sub. 40 – 4kV Feeders 482 and 485 along 4th Street, NW between Buchanan and Hamilton Streets, NW to Fort Slocum Sub. 190 -13kV Feeders 15006, 15012 and 15015. The total amount to be converted from 4kV to 13kV is approximately 15,900 feet.	$0	$705	$5,715,059	$7,373,386	$5,233,789	$6,584,281	$0
	UDLPLNW3	New NW Sub: Extend New Dist Fdrs to 38 (UDLPLNW3)	The purpose of this project isto extend 17 -13.8kV underground feeder supplies a total distance of 1/4 mile, and rearrange with each of the existing Harrison Sub. 38 Distribution feeders. Build 4 -8W duct banks from new Northwest Sub. a total distance of approximately 1/4 mile. Model with new Northwest 138/13kV Sub. Model with UDSPLNW2, UTLPLNW1, UDSPLNW3 AND UDLPLNW1.	$0	$0	$0	$0	$10,000	$10,985	$3,254,809
	UDLPLWF1	SE:Sub136: Extend 7 Fdrs to Retire Anacostia	This project will require the extension of two overhead distribution feeders from Alabama Ave. Sub. 136, which along with existing feeders will be used to transfer all distribution load from Anacostia Sub. 8. Three new 13 kV feeders are to be extended to transfer the supplies of Twining City Sub. 50 from Sub. 8 to Sub. 136. Two new spot network feeders would be extended to transfer the spot network load from Sub. 8 to Sub. 136. The three feeders and the two spot network would be extended underground in new 8-way conduit from Sub. 136 to Sub. 8 to cut over the five Anacostia feeders, a distance of approximately 9500 feet.	$2,088,159	$2,685,701	$487,578	$832	$16,000	$4,495	$5,010,836
	UDLPLWF2	SE: Anacostia: 23rd St - 4 to 13kv Convert	Convert Feeders 331, 332, 335 & 353 to Sub. 8 Fdrs 14700 & 14703 & Sub. 136 Feeder 15173 per System Planning recommendations 05-02-01.1, 02.1 & 05-05-01.1. This will be converting 21,000 circuit feet of overhead 4 kV system.	$1,105,670	$967,218	$0	$236,589	$0	$2,011	$0
	UDLPLWF3	SE: Anacostia Sub : Convert 4 to 13kv & Retire Sub	The proposed 4 to 13kV conversions will be accomplished by extending and/or rearranging existing or new 13kV distribution feeders from Alabama Avenue Sub. 136 and converting all feeders from Anacostia Sub. 8 4kV along with portions of feeders from Congress Heights Sub. 64, Fort Carroll Sub. 130 and Twining city Sub. 150. This will require converting approximately 141,900 circuit feet of overhead. Anacostia Sub. 8 18,900 feet, Congress Heights Sub. 64 18,300 feet, Fort Carroll Sub. 130 60,200 feet, and Twining City Sub. 150 44,500 feet of overhead circuit. Conversion of 4 kV load out of Anacostia substation will allow the retirement of the station, which other wise would have to be rebuilt.	$1,514,793	$2,670,543	$495,259	$286,619	$16,632	$34,188	$0
	UDLPLWF4	SE: Waterfront Sub: Construct New LVAC Groups (UDLPLWF4)	The purpose of this projects is to extend 6 -13kV underground feeder group from the new Waterfront Sub. 223 to cutover Buzzard Pt. Sta. B - East LVAC group. Build approximately 0.4 miles of a new 8 way conduit bank and install approximately 2.4 miles of 600 MCM 3/c cable. Model with UDSPLWF1 138/13kV Waterfront Sub. 223 and UTLPLWF1 Waterfront Sub. 223 -new 138kV supply feeders.	$0	$0	$0	$0	$5,353	$0	$5,529,428

Work Breakdown Structure - 2015 Projects

REP Section	WBS Element	WBS Element Description	WBS Detailed Description	2012 Budget	2012 Actual	2013 Budget	2013 Actuals	2014 Budget	2014 Actuals	2015 Budget
Load Growth (con't)	UDLPRM8BG	North Capitol Sub. 40: Convert portions of Feeders 482 & 485 to Feeders 15006, 15012, and 15015	Convert load from portions of North Capitol Sub. 40 – 4kV Feeders 482 and 485 along 4th Street, NW between Buchanan and Hamilton Streets, NW to Fort Slocum Sub. 190 -13kV Feeders 15006, 15012 and 15015. The total amount to be converted from 4kV to 13kV is approximately 15,900 feet.	$1,223,525	$1,356,257	$880,634	$1,247,269	$0	$0	$0
	UDLPRM8BK	Twining City Sub: Convert Fdr 347 to Anacostia Sub	Convert 0.5 MVA of summer 2006 load from Twining City Sub. 150 4kV Feeder 347 to Anacostia Feeder 14702 and reconnect overhead trs. 808375-800950 on Feeder 347 from A phase to B phase. Reconnect overhead trs. 808375-960750, 809375-220690, and 80.	$59,963	$273,675	$0	$0	$0	$0	$0
	UDLPRM8BN	Anacostia Area: Convert Fdrs 234 & 330	Extend and/or rearrange Fort Carroll Sub. 130 - 4kV Feeders 234 and 330 & N.R.L. Sub. 168 - 13kV Feeders 14752, 14753, 14755, and 14758 to accomplish the following: a) Convert approximately 0.2 MVA summer 2008 load from Feeder 234 to Feeder 14753. b) Convert approximately 0.5 MVA summer 2008 load from Feeder 234 to Feeder 14755. c) Convert approximately 0.1 MVA summer 2008 load from Feeder 234 to Feeder 14758. d) Convert approximately 0.3 MVA summer 2008 load from Feeder 330 to Feeder 14752.	$0	$0	$0	$0	$0	$0	$0
	UDLPRM8BP	Anacostia Area: Convert Fdr 271 to 13kv	Extend and/or rearrange Fort Carroll Sub. 130 - 4kV Feeders 271 and 325 & N.R.L. Sub. 168 - 13kV Feeder 14752 to accomplish the following: a) Convert approximately 0.7 MVA summer 2008 load from Feeder 271 to Feeder 14752. b) Transfer approximately 0.8 MVA summer 2008 load from Feeder 271 to Feeder 325. c) Install one 300kVAr capacitor bank on Feeder 325 on Martin Luther King Jr. Avenue. This work should not be performed until recommendation (b) has been completed.	$119,442	$69,516	$0	$0	$0	$0	$0
	UDLPRM8BQ	Harrison-Van Ness: Convert Fdr 82 to 13kv	Project is needed to improve reliability and operating flexibility by removing and/or replacing aging infrastructure.	$497,118	$3,656	$186,444	$282,633	$0	$0	$0
	UDLPRM9BC	Benning Area: Convert 385 to 13kv	Extend and/or rearrange 4kV Feeder 385 (53rd Street Sub. 48-4 & Texas Avenue Sub. 111) and Benning Sub. 7 – 13kV Feeder 15706 to convert approximately 0.4 MVA of summer 2009 load from Feeder 385 to Feeder 15706.	$255,190	$524,695	$0	$1,101	$0	$0	$0
	(UDLPLWF5	Southwest Sub 18: Rearrange Central LVAC to South LVAC	SW Sub. 18 Central LVAC group will be extended from D St., SW along 6th St., to C St., SW to transfer 5.0 MVA of summer 2017 load from SW Central to SW South LVAC group. This will require approximately 3500 feet of 8way conduit bank and 21000 feet of new 500 3/c cable.	$0	$0	$0	$0	$0	$0	$1,685
	UDLPLIST2	Sub 197 Central to Sub 197 North LVAC Cutover	Extend the I St Sub. 197 North LVAC Group south along 19th St St from I St to G St using approximately 1000' of new conduit and 6000' of new cable to transfer load from the Sub. 161 Central Group.	$0	$0	$0	$0	$0	$0	$1,506,822
	UDLPLM7W10	Install Tie Switch Between 4kV Feeders 144 and 308	Extend and/or rearrange 4kV Feeder 144 (Westmoreland Sub. 93 & Palisades Sub. 145) and 4kV Feeder 308 (Westmoreland Sub. 93 & Oliver Street Sub. 146) to install one (1) Normally Open tie-switch between Feeders 144 and 308 on Brandywine Street east of 49th Street, NW.	$0	$0	$0	$0	$0	$0	$8,899

Work Breakdown Structure - 2015 Projects

REP Section	WBS Element	WBS Element Description	WBS Detailed Description	2012 Budget	2012 Actual	2013 Budget	2013 Actuals	2014 Budget	2014 Actuals	2015 Budget
Load Growth (con't)	UDLPLM7W4	O St. Sub. 2 Feeder 14367 heavy-up	Heavy-up O Street Sub. 2 South LVAC Network Group Feeder 14367 from MH# 790389-349295 to MH# 790388-353765 from #2 3/C P.L. to 4/0 3/C P.L., requiring approximately 432' of cable.	$0	$0	$0	$0	$0	$706	$294,336
	UDLPLM7W8	Tenth St. Sub. 52 Feeder 15329 heavy-up	Heavy-up 10th Street Sub. 52 East LVAC Network Group Feeder 15329 from MH# 793388-058353 to MH# 792388-637360 from #2 3/C P.L. to 4/0 3/C P.L., requiring approximately 416' of cable.	$0	$0	$0	$0	$0	$11,578	$23,008
	UDSPRD9SWD	New Harvard - Purchase Property	Pucahse propety for Harvard Sub 13 expansion, located at 2914 Sherman Ave NW DC 20001. Propety will be used to stage temporary switchgears and transformers while Harvard is being rebuilt.	$0	$0	$0	$0	$0	$4,514,768	$0
	UDLPRM9BF	G St: Convert Fdr 209 to Fdr 15875	Extend and/or rearrange G Street Sub. 28 - 4kV Feeder 209 and SW Sub. 18 - 13kV Feeder 15875 to convert approximately 0.5 MVA of summer 2010 load from Feeder 209 to Feeder 15875. (Extend half-loop from the 8th St. & D St. S.E. intersection to convert lo 15875).	$0	$0	$0	$0	$0	$0	$0
	UDLPRM9BG	Harrison-Van Ness:Convrt Fdr 413 to 13kV	Extend and/or rearrange 4kV Feeder 413 (Harrison Sub. 38-6 & Veazey East Sub. 90-E) and Van Ness Sub. 129 – 13kV Feeder 15945 in the vicinity of Wisconsin Avenue between Fessenden Street and Harrison Street, NW to transfer and convert approximately 0.4 MVA of load from Feeder 413 to Feeder 15945. The total amount of overhead line to be converted from 4kV to 13kV is approximately 1500 feet.	$634,113	$182,912	$46,611	$382,952	$0	$0	$0
	UDLPRM9BH	Harrison: Convert Fdr 416 to Van Ness Fdr 14135	Extend and/or rearrange 4kV Feeder 416 (Harrison Sub. 38-5 & Quesada Sub. 89) and Van Ness Sub. 129 – 13kV Feeder 14135 to convert approximately 0.4 MVA of summer 2010 load from Feeder 416 to Feeder 14135.	$0	$236,385	$0	$0	$0	$0	$0
	UDLPRM9BJ	Twining City Sub: Convert Fdr 494 to Anacostia 14702	Convert approximately 0.5 MVA of load from Twining City Sub. 150 – 4kV Feeder 494 to Anacostia Sub. 8 – 13kV Feeder 14702. (Naylor Street) .	$0	$0	$0	$0	$0	$0	$0
	UDLPRM9BK	Harrison-Van Ness:Convrt Fdr 128 to 13kV	Extend and/or rearrange 4kV Feeder 128 (Veazey East Sub. 90-E & Oliver Street Sub. 146) and Van Ness Sub. 129 – 13kV Feeder 15947 in the vicinity of 41st Street between Chesapeake Street and Davenport Street, NW to convert approximately 0.5 MVA of load from Feeder 128 to Feeder 15947. The total amount of overhead line to be converted from 4kV to 13kV is approximately 950 feet.	$502,743	$1,243	$186,444	$113,195	$0	$0	$0
	UDSPLFL1	Florida Ave: Install 4th 69/13kv, 56 MVA Tr	Purchase 69/13kV 56 MVA Spare Transformer to replace transformer #4 at Florida Ave. Sub. 10. Also, install 9 MVAr at Florida Ave. Sub. 10. Connecting this transformer will assist in supplying load growth in the Downtown DC Area. Now combined with UDLPLFL2 - 12th & Irving Sub. 133 - Transfer HT Group to Sub. 10. Now combined with UDLPLFL1 - Extend 69kV Supply to Sub. 10 - 4th Transformer.	$8,434	$0	$1,589,683	$1,470,144	$929,436	$2,723,770	$0
	UDSPLM78A	Northeast Sub: Install 3rd Transformer & Cap Bank	Install 3rd 56 MVA, 69/13.8 kV Transformer at Northeast Sub 212. Install one 9 MVAR bus capacitor. Terminal costs at Benning Sta A for supply to third transformer.	$1,219,196	$1,301,715	$0	$30,438	$0	$0	$0
	UDSPLM79C	New Jersey Ave Sub (161): New Fdr Terminal	Install one 69kV breaker feeder terminal and associated relays.	$0	$0	$431,950	$243,067	$469,317	$203,875	$0

Work Breakdown Structure - 2015 Projects

REP Section	WBS Element	WBS Element Description	WBS Detailed Description	2012 Budget	2012 Actual	2013 Budget	2013 Actuals	2014 Budget	2014 Actuals	2015 Budget
Load Growth (con't)	UDSPLM7W	Dist Fdr Load Relief: DC Sub Work	Benning Sub. 7: Extend 2 new Dist. Feeders by 2014 Alabama Ave. Sub. 136: Extend 5 new Dist. Feeders by 2014 Champlain Sub. 25: Extend 2 new Dist. Feeder by 2015 Alabama Ave. Sub. 136: Extend Fdrs. 15173, 15175, 15176, & 15177 by 2015 New Northwest Sub.: Extend 5 new Dist. Feeder by 2015 Ft. Slocum Sub. 190: Extend one new Dist. Feeder by 2016.	$371,101	$408,994	$185,169	$338,438	$200,000	$561,297	$299,950
	UDSPLMV2	New Mt Vernon Sq Sub: Purchase Land (UDSPLMV2)	The purpose of this project is to Buy land for New Mt. Vernon Square 138/13.8 kV Substation. Model with UDSPLMV1, UTLPLMV1, UDSPLMV3 AND UDLPLMV1.	$0	$0	$0	$0	$30,517,504	$58,638	$17,618,566
	UDSPLNE2	Northeast Sub : Add 4th Transformer	Install 4th 69/13.8 kV Transformer at Northeast Sub 212. Install one 9 MVAR cap bank on the 13.8 kV bus. Terminal costs at Benning Sta A for 69 kV supply to fourth transformer.	$1,296,678	$0	$710,038	$4,359	$2,608,460	$1,302,169	$971,581
	UDSPLNE3	Benning 69kv Sub: Term for 3rd NE Fdr	Build terminal for new 69kV feeder to supply 3rd 56 MVA, 69/13.8 kV Transformer at Northeast Sub 212. Tap existing 69kV Gas Circuit Breaker 18B at Benning S-41and install new protective relays. After the retirement of the Benning generation scheduled in June 2012, remove 18B breaker and associated isolating disconnect switches in addition to the 69kV bus disconnect switch and add a new 69kV motor operated bus disconnect switch with bus work modifications in the Fall of 2012.	$327,519	$525,676	$0	$0	$0	$0	$0
	UDSPLNE4	Benning 69kv Sub: Term for 4th NE Fdr (UDSPLNE4)	The purpose of this project is ND21 - Benning 69kV Sub Terminal for 4th NE Feeder Install 69kV terminal at Benning to extend 69kV feeder to 4th 69/13.8 kV Transformer at Northeast Sub 212. Model UDSPLNE2, UDLPLNE2, and UDLPLNE5.	$0	$0	$0	$0	$416,615	$34,477	$334,333
	UDSPLNW2	New NW Sub: Construct New Sub	Start of engineering for a new substation named Northwest Substation. This station is neededto replace the existing Harrison Substation due to the condition of the existing switchgear and transformers. In addition this new station will support the continued growth in the upper nothwest portion of the District of Columbia. This work will establish a new 138/13.8 kV substation. Extend seventeen (17) feeders from Northwest Sub. 228, and tie them to the existing feeders coming from Harrison Sub. 38.	$646,781	$298,079	$334,035	$644,419	$9,763,691	$2,439,540	$13,215,151
	UDSPLNW3	Oliver St. Sub 146:Install 34/4kv Transf	This work is necessary to retire Harrison Sub. 38-5 and Harrison Sub. 38-6 in advance of the construction of new Northwest Sub. 228.	$0	$379,823	$703,476	$115,997	$637,792	$460,803	$27,247
	UDSPLWF1	SE: Waterfront: Establish New Substation	Start of engineering for a new substation in the Buzzard Point area of the system. Substation needs to supply increased capacity to the southwest portion of the city and support current and increased load growth in that area.	$172,619	$168,998	$523,694	$554,300	$836,377	$1,479,988	$9,270,819
			Load Growth Total	$24,596,308	$21,595,461	$37,020,814	36,634,850	78,021,448	41,659,244	65,099,111
			REP Total	$72,093,544	$67,149,574	$102,663,319	$89,619,696	$150,713,947	$88,722,614	$121,764,365

Work Breakdown Structure - 2015 Projects

Section	WBS Element	WBS Element Description	WBS Detailed Description	2012 Budget	2012 Actual	2013 Budget	2013 Actuals	2014 Budget	2014 Actuals	2015 Budget
Non-REP Projects										
Non-REP	DDSPRD9SD	Pepco Reg: Install DGA Equipment	Install Dissolved Gas Analysis Montoring Equipment on critical transformers.	$219,671	$263,100	$0	(95,973)	$0	$0	$0
	UDLPOEMGD	Pep-DC Damage Equipment Replacements	Unrecovered equipment and facility replacement. Damage caused by others - Theft/Accident.	$370,800	$682,255	$24,996	266,180	25,000	245,131	$0
	UDLPOSV5D	Pepco DC Reg: Salvage Scrap Wire/Cable	The purpose of this project is to capture the cost of scrap metal/wiring.	$0	$0	$0	(1,552,034)	(25,000)	(1,270,746)	(1,225,000)
	UDLPPBB2	Benning 34kV Feeder for T-15	Extend a 34 kV feeder inside the Benning yard from new 34 kV Transformer # 15. This is part of the Benning generation retirement project.	$0	$76,964	$310,741	858,917	$0	$0	$0
	UDLPRACRD	PEPCO-DC - Accural for Reliability	The purpose of this project is to accrue for costs that occur each month but we don't see the invoice till the following month.	$0	$0	$0	(2,630,152)	1,000	(2,608,352)	(26,980)
	UDLPRM31	Replace Equip - OH &	Replacement of broken poles, primary/secondary wires, damaged OH transformers, switches, capacitor banks, padmount transformers, fuses, ACRs, street light fixtures, etc. in various locations in Maryland.	$0	$0	$0	$0	$0	(13,594)	$0
	UDLPRM31D	Damaged equipment replacement	Install/replace oil switches; split poles; anchors; transformers; deteriorated hardware; fuses; mainline secondary; service wire; regulators; capacitor bank; gang switches; bare wire; and tree wire. Also, remove stub poles.	$433,481	$3,415,938	$190,282	323,355	$0	2,314	$0
	UDLPRM32	Emergency Restoration: Cable Replac in Ducts	This WBS element is used for the replacement of underground cable in duct. The project includes work performed to replace cable during an outage situation. Work of this nature depends upon the number of outages due to underground cable failures.	$0	$0	$0	$0	$0	(49,756)	$0
	UDLPRM32D	Emergency restoration cable in ducts	Install/replace deteriorated mainline secondary cable, primary cable, burnt out URD cable, defective transformers, manhole hardware and failed switches.	$7,023,954	$6,646,856	$7,257,844	6,550,493	7,623,773	6,605,541	7,756,454
	UDLPRM3B1	Emergency restoration for OH and UG especially storm related restoration effort	Install/replace primary cable, transformers, poles, sump pumps, witches, deteriorated poles, transclosures, failed/defective transformers, taphole doors, failed fuse boxes, cable supports, bare copper wire, failed oil switches, damaged door gates and damaged manhole frames and covers. Rebuild collasped manholes and deteriorated concrete.	$4,478,517	$6,477,125	$3,263,723	7,754,682	4,478,499	10,135,891	4,386,936
	UDLPRM3K1	Kennilworth: Rest. - UG Equipment	Emergency replacement of network transformers and protectors due damage by storm or other emergencies.	$2,888,184	$1,718,643	$1,892,112	2,765,497	2,000,425	1,105,930	2,137,044
	UDLPRM42D	Placeholder - Future Pepco DC:	Pepco DC: UG Misc Planned Distribution Blanket	$0	$0	$0	$0	$0	43,403	598,003
	UDLPRM4BA	Benning: Misc Distribution Changes	Replace OH & UG equipment as needed based on equipment conditions.	$387,890	$214,888	$433,616	122,253	420,745	905,018	411,909
	UDLPRM4BE	Reject Pole Replace : Benning	Replace/reinforce wood poles that have not passed periodic inspection.	$163,076	$38,783	$586,612	741,562	646,881	336,503	622,059
	UDLPRM4BG	Misc Dist Impvt - Mainline Heavy-Up: Benning	Increase capacity of underground secondary cables and overhead secondary wires to improve system reliability based on customer reliability inquiries.	$179,395	$116,559	$182,163	352,327	170,067	55,761	152,094
	UDLPRM4BH	Avian Protection Impvts:	Avian protection-install device to protect wildlife.	$15,849	$0	$14,507	$0	15,103	$0	$0

Work Breakdown Structure - 2015 Projects

Section	WBS Element	WBS Element Description	WBS Detailed Description	2012 Budget	2012 Actual	2013 Budget	2013 Actuals	2014 Budget	2014 Actuals	2015 Budget
Non-REP (con't)	UDLPRM4BM	Customer reliability improvements	Install/replace tree wire, #4 copper wire, damaged poles, fuses and transformers.	$2,315,446	$1,340,382	$2,016,583	3,240,625	2,026,544	2,796,515	2,313,932
	UDLPRM4BN	Planned network transformer and protector replacements	Network transformer and protector replacement resulting from inspection indicating deterioration towards failure in DC and MD.	$5,792,205	$9,464,324	$9,975,334	10,501,955	10,159,894	10,886,605	10,226,294
	UDLPRM4BO	Benning: Padmount Transformer Replacements	Replacement of padmount transformers that are associated with URD cable replacement projects in DC.	$0	$0	$0	$0	200,516	82,299	223,461
	UDLPRM4BQ	Benning: Upgrades for Multi Device Operations	Replace equipment on a multiple device operation basis identified through OMS outage report.	$0	$0	$536,862	1,198	500,386	$0	549,973
	UDLPRM4DJ	Pepco DC- Add Recloser Sectionalization	Install reclosers to mitigate impact of down-stream outages and reduce customer impact during sustained feeder outages.	$0	$0	$740,788	$0	750,030	$0	706,586
	UDLPRM4F	Pepco - PSC Priority Feeder Improvements	These projects address reliability issues of high customer interruption feeders and the scope of work involves installing/ replacing reclosers, switches, animal gurads, lightning arresters, transformers, poles, fuses, primary/ secondary wires, etc.	$0	$0	$0	$0	$0	(53,376)	$0
	UDLPRM4G	Dist Improv - Heavy-up Mainline	This project covers expenditures on overhead and underground secondary mains and secondary services including transformer replacements due to overload conditions prompted by customer's inquiries.	$0	$0	$0	$0	$0	(408)	$0
	UDLPRM4M	Pepco Reg: Customer Reliability Improvements	This project is the legacy WBS element that was used for performing corrective actions based on customer complaints. The work involves repairing/upgrading wires, cables, replacing transformers, service wires/cables, poles, etc.	$0	$0	$0	$0	$0	5,389	$0
	UDLPRM4VB	Repl Secondary URD cables: DC	URD secondary cable replacements driven by URD cable failure evaluation in DC.	$264,264	$41,462	$120,577	2,253	120,092	72,219	119,218
	UDLPRM4WU	WH - Install Tree Wire/Spacer Cable	Install tree wire or spacer cable in areas where acceptable tree trim cannot be achieved	$0	$0	$1,115,887	$0	$0	(1,397)	$0
	UDLPRM4WV	Rubber covered Secondary Wire - DC (UDLPRM4WV)	OH Open Wire Secondary replacement	$0	$0	$0	$0	$0	12,686	$0
	UDLPRM5BP	MODs Replacement - Benning	Replace inoperative Motor Operated Disconnect switches.	$0	$0	$327,159	$0	150,235	100,627	446,632
	UDLPRM5ED	34 & 69kV Oil Filled Cable Replmnts - DC	Failed sub transmission cable blanket - replace cable that fails while in service	$0	$0	$513,893	$0	3,095,778	737,323	4,086,659
	UDLPRM5EV	IR: 34 & 69kv Oil Filled Cable Replacements - VA	An indepth cable study was performed in 2013 analyzing the current condition of our high pressure pipe type (HPPT) underground transmission feeders and our self-contained fluid filled (SCFF) underground transmission feeders. As a result of the cable study findings, a priority list of cable replacements reccommended a significant number of 69 kV SCFF feeders should be replaced, reconductored, or retired over the next five years.	$0	$0	$0	$0	$0	6,464	1,195,960

Work Breakdown Structure - 2015 Projects

Section	WBS Element	WBS Element Description	WBS Detailed Description	2012 Budget	2012 Actual	2013 Budget	2013 Actuals	2014 Budget	2014 Actuals	2015 Budget
Non-REP (con't)	UDLPRM5SD	Emergency restoration secondary cable in duct	Install/replace mainline secondary cable, mainline single phase cable, secondary neutral cable, non-lead secondary cable and three phase mainline cable.	$2,688,771	$2,905,978	$2,598,201	2,118,627	2,600,963	2,434,963	2,431,615
	UDLPRM5SG	Repl 69kV Slf-Containd UG Supl-Georgetwn,"F" St, 22nd St Subs	The 69 kV loop project will connect Takoma to Georgetown via 22nd Street Sub and F Street Sub. There will be four 69 kV solid dielectric feeders connecting Takoma Sub to 22nd Street Sub. Three of these solid dielectric feeders will continue on to F Street sub and terminate at Georgetown substation. One of the feeders will leave 22nd Street sub and travel directly to Georgetown substation. The last phase of the project will include a reconductoring of 3 exisiting pipe type feeders from Takoma to Champlain. These feeder will be tapped into before they enter Champlain and will travel to L Street substation.	$0	$0	$0	$0	$0	233,659	$0
	UDLPRM8BB	Blue Plains 69kV Feed NRL - Station C	Extend two 69 kV feeders from Blue Plains Sub. 83 to NRL Sub. 168 in order to serve as backup supply feeders to NRL Sub. 168.	$4,057,865	$165,310	$7,482,546	860,818	7,232,547	2,450,321	$0
	UDLPRM9PD	Pepco DC: Upgrade Pumping Plants	Replace obsolete pumping plants. Vendors supply, remove and dispose of old plant then install new plants and then bring new plant on line and provide training for PEPCO personnel.	$567,214	$0	$608,535	1,251,598	50,000	325,033	270,707
	UDLPRM9SC	Spare 1500KCMil Pipe Type Cable@Benn	Purchase spare 1500 KCMil pipe type cable used in 69 kV and 138 kV substation supply circuits.	$0	$0	$1,622,457	1,306,980	$0	$0	$0
	UDLPRPLIC	PILC REPLACEMENT PLANNED (UDLPRPLIC)	Replace approximately 4-5 miles per year of paper lead insulated cable with EPR. Replacement targets determined by PILC replacement strategy. Detailed scopes for planned improvements will be developed and subsequent scope descriptions added to program description.	$0	$0	$0	$0	$0	131,047	2,292,295
	UDSPCPA1	Potomac Annex: Replace 13/4 kv Xfrm	Project is needed to replace aging infrastructure and reduce risk to reliability for the Potomac Annex campus.	$31,760	$48,600	$412,890	19,990	100,000	$0	$0
	UDSPPBB1	Benning: Add 3rd 230/69kv Xfrm	At Benning 69kV Sub. 41 switchyard, the removal of two (2) 69/115kV transformers #4 & #7, the addition of a new 230/69kV, 224MVA transformer #11 and associated disconnects, CCVT's, surge arresters, H-Frame, and transmission pole. This transformer will be supplied from existing 230kV AIS bay #3 of Sub. 7. In addition, removal of one (1) 69/13kV transformer and one (1) 13/34kV transformer behind the generation plant. These two transformers will be replaced with one 69/34kV, 26.5MVA transformer installed at Sub. 41 and supplied from 69kV ring bus at Sub. 41.	$3,841,090	$6,893,113	$125,278	418,656	$0	$0	$0
	UDSPPBB2	Benning: Install 2-50MVAR 69kv Cap Banks	Install two (2) 50 MVAR, 69kV Capacitor Banks with associated current limiting reactors, disconnect switches, breakers, and relays at Benning 69kV Sub 41.	$1,729,247	$2,139,310	$1,110,910	1,679,089	$0	$0	$0

Work Breakdown Structure - 2015 Projects										
Section	**WBS Element**	**WBS Element Description**	**WBS Detailed Description**	**2012 Budget**	**2012 Actual**	**2013 Budget**	**2013 Actuals**	**2014 Budget**	**2014 Actuals**	**2015 Budget**
Non-REP (con't)	UDSPRD71	Distributon Substation Emerg (UDSPRD71)	This project is to cover the costs of emergencies that may arise due to the failure of Substation Equipment and unforeseen events.	$0	$0	$0	$0	$0	31,528	$0
	UDSPRD71D	Dist Sub Emergency B	This project is to cover the costs of emergencies that may arise due to the failure of Substation Equipment and unforeseen events in DC.	$216,679	$98,282	$461,075	349,600	600,000	313,409	684,233
	UDSPRD8A	Planned Substation Improvements Distribu	Add nitrogen generator at Georgetown Sub 12 for all four transformer, to replace existing nitrogen tanks.	$100,678	$105,585	$5,266	1,566	$0	$0	$0
	UDSPRD8AD	Planned Dist Sub Impvt: Pepco DC	Foundation and building repairs required at Sub 190 Fort Slocum, presumably from earthquake damage in 2011.	$34,283	$30,070	$73,708	68,776	72,852	6,941	131,627
	UDSPRD8C1	Sta A & C Replace 69 kV Breakers (UDSPRD8C1)	Project Scope involves extending 69kV feeds from NRL and BluePlains and the installation of protective relays at both sites.	$0	$0	$0	$0	$0	677,849	116,448
	UDSPRD8C2	Subs 27 & 149 : Install 34.5kv Bkrs (UDSPRD8C2)	Takoma Sub #27 - Replacing 4 Oil Circuit Breakers with vacuum breakers. Project Lanham Sub #149 - There will be no breaker change outs on this job for the substation.	$0	$0	$0	194,504	708,110	137,152	$0
	UDSPRD8D2	Pepco DC: Improve/Add Sub Enclosures	Address areas where transformer fire walls and ventilation systems need repair to protect the equipment.	$102,328	$0	$103,022	29,304	101,463	31,714	168,642
	UDSPRD8ED*	Battery & Charger Dist Subs: Pep DC	The existing batteries and chargers have been determined to be beyond their design life, or have been determined to be in failure mode due to testing and observation results. Battery systems across the Pepco system will be tested and visually inspected for condition and replaced accordingly to ensure reliable DC power systems in all Pepco stations. Chargers will be replaced as well as internal caps that have degraded over time.	$112,882	$271,700	$202,829	290,439	123,851	391,771	505,376
	UDSPRD8FD*	Dist Sub Bushing Repl: Pepco DC	Replace remaining U-Type bushings that are susceptible to an industry known problem for equipment failure. Test values of individual bushings will indicate the need for replacement. Bushings are tested at increased frequencies when power factors degrade and until these identified bushings can be replaced.	$94,323	$489,906	$131,364	70,274	136,191	136,927	149,594
	UDSPRD8FV*	Dist Sub Bushing Replacement: Pepco DC	The purpose of this projects is Replace U-Type bushings that are susceptible to an industry known problem for equipment failure. Test values of individualbushings will indicate the need for replacement. Bushings of this type will be tested across PEPCo's system.	$0	$0	$0	$0	63,955	$0	67,921
	UDSPRD8G1	Purchase Spare 13/4kv Transformer	Purchase and install ten 13/4kV and two 34/4kV transformers at ten locations. Purchase one 34/4kV and one 13/4kV spare transformer to support the replacement project.	$2,959,026	$1,169,919	$42,362	135,878	$0	$0	$0

Work Breakdown Structure - 2015 Projects

Section	WBS Element	WBS Element Description	WBS Detailed Description	2012 Budget	2012 Actual	2013 Budget	2013 Actuals	2014 Budget	2014 Actuals	2015 Budget
Non-REP (con't)	UDSPRD8G4	Sub 136: Spare Xfrm 230/13kv	Purchase three spare transformers. Two 56 MVA, 230/13.8kV transformers for Benning Sub 7 with June 2012 delivery and for Alabama Avenue Sub 136 with June 2014 delivery. One 50 MVA 115/34kV transformer for Lanham Sub 149 with June 2015 delivery.	$792,449	$1,078,578	$10,533	172	$0	$0	$0
	UDSPRD8GD*	Pepco DC Reg: Purchase Spare Transformer	This job includes progress payments and assembly of spare 65/13.8kV, 56MVA power transformer to be stored at Benning Sta. A. The spare transformer will be designed to fit the special conditions at Georgetown Sub. 12.	$1,285,250	$39,817	$847,009	1,041,938	$0	111,758	$0
	UDSPRD8H	4kV Substation Automation	Purchase and install transformer secondary, feeder and DRTU smart relays at identified 4kV substations to improve reliability and level of monitoring and control at 4kV stations.	$86,000	$8,864	$16,674	67,054	829,000	518,612	702,982
	UDSPRD8JD	Animal Guards in Dist Subs: Pepco DC	As a result of documented animal related outage within substations in Pepco in DC, this project will either install animal guards on identified vulnerable insulators and equipment or install the new vanquish animal fencing around the substation to entirely keep animals out. Size and cost are key factors when determining if a fence will be used. Two substations in scope for 2013 are Benning and Van Ness based on the history of animal outages at these two substations.	$0	$0	$153,011	7,740	151,640	271,706	216,831
	UDSPRD8KD	13kV Swgr Impvts and Additions: Pepco DC	This project is for the purchase and installation of replacement 13.8kV switchgear in DC substations. Existing deteriorated switchgear will be replaced based on priority list determined through 2011-2012 Kinectrics study. Proposed plan is to replace all bus sections at one substation per year over next 5 years.	$0	$0	$1,024,776	21,524	5,898,944	172,353	3,297,771
	UDSPRD8KFS	Install 69kV High Speed Ground Switch on T2 at Fort Slocum Sub 190 (UDSPRD8KFS)	Installation of a High Speed Ground Switch (HSGS) on TX2 at Fort Slocum. This is a result of the protection concern for Fort Slocum TX2 secondary faults being detected and cleared by the associated load stations of 69143, when 69053 is tied to 69143 for emergency load relief of the Metzerott subsystem	$0	$0	$0	$0	$0	22,266	$0
	UDSPRD8LD	Pepco DC: Substation Ventilation	To be defined when warm weather in the late spring to early summer 2013 begins.	$43,384	$75,095	$42,976	43,255	42,054	(14,091)	41,217
	UDSPRD8NMD	Pepco: Disturbance Monitoring Installation - DC (UDSPRD8NMD)	Installing Disturbance Monitoring Equipment & Sequential Event Recorders as a replacement of all existing Digital Fault Recorders, DFR Master Stations, Master Station software, GPS Sychronizationand associated communications. This equipment was originally installed in the mid-eighties and is approaching the end of its useful life.	$0	$0	$0	$0	771,483	$0	299,579
	UDSPRD8Q1*	Pepco - SPCC Dist BKR Change	The scope is to replace 4 to 5 69 kV SPCC Oil Circuit Breakers with Gas Circuit Breakers a year.	$1,158,179	$1,856,049	$342,348	994,997	$0	$0	$0
	UDSPRD8QD	SPCC Plan - Install Containmt - Pepco DC	In order to comply with federal environmental regulations, PEPCO must provide containment for all its oil filled equipment. If containment is not provided and a spill occurs, PEPCO will be held responsible for any oil that spills in/on public property. US Environmental Law Applicabilty: 40 Code of Federal Regulations 112 (40 CFR 112)	$212,266	$0	$170,893	$0	205,637	$0	220,694

Work Breakdown Structure - 2015 Projects

Section	WBS Element	WBS Element Description	WBS Detailed Description	2012 Budget	2012 Actual	2013 Budget	2013 Actuals	2014 Budget	2014 Actuals	2015 Budget
Non-REP (con't)	UDSPRD8RC	Kennilworth Sub: Retire Sub	This project is for the demolition of Kenilworth Sub. Environmental assessments and permits are required.	$0	$0	$0	$0	$0	12,383	265,666
	UDSPRD8RM	Sub. 50 Marine D & R All 4kV Electrical	Dismantle and remove the retired 4kV bungalo sub - Marine Substation	$0	$0	$0	$0	$0	33,274	83,601
	UDSPRD8RN	Substation Retirements-DC.	The purpose of this project is to capture the costs associated with retiring a substation.	$0	$0	$0	11,012	200,000	114,436	247,216
	UDSPRD8RO	Trinidad Sub 106 - Retire	This project is for the demolition of Trinidad sub 106. Environmental asessments and permits are also required	$0	$0	$0	$0	$0	22,383	83,601
	UDSPRD8SA	Capacitors in Substations 9,13,38 & 160	The purpose of this project is to remove existing capacitor banks and replace with non PCB equipment. The new capacitor banks will be metal enclosed at locations Sligo Sub 9(four 9.0 MVAR banks), Harvard Sub 13 (four 6.0 MVAR banks),and Harrison Sub 38(two 12.0 MVAR banks). The unenclosed cap bank will be installed at Bureau of Standards Sub 160(12 MVAR Double WYE)	$0	$0	$0	1,541,592	739,365	1,235,577	1,089,671
	UDSPRD8SB	Sta "C" : Replc RTU & Sta Service	The existing RTU and station service equipment are located in the plant. This will require a new RTU located in the switchyard control house and two 69000/480 V transformers located in the plant. Replace twelve overdutied oil filled circuit breakers and disconnect switches. This project also includes the environmental remediation for retiring the generating plant.	$1,710,764	$1,711,310	$5,205,842	6,302,336	782,716	2,710,037	11,300
	UDSPRD8SN	Upgrade Transformer FPS_ Harvard Sub 13 (UDSPRD8SN)	The existing fire protection at Sub 13 is not working. Currently, SMC has assigned a personnel to go and watch the substation every so often, that the cost of doing so is more than $200,000 per year.	$0	$0	$0	$0	$0	71,744	$0
	UDSPRD8SO*	Southwest (18) Sub:Upgrade Trs T2,T3,T4	All three existing AC transformers, 138/13.8kV, 56 MVA, in service from 1975, have significant technical problems on Load Tap Changer (LTC) device. Yearly intrusive inspections and repairs of LTC, produce high costs for O&M. LTC device manufacturers could not supply the same LTC device that is on the AC transformer. Therefore the transformer replacement is imminent. This substation supplies Capitol Hill.	$2,228,219	$1,447,778	$3,342,432	4,006,603	3,882,157	6,433,900	143,497
	UDSPRD8ST	Sub 136 Purchase spare Trans 230/13.8kV (UDSPRD8ST)	Purchase and Install a 230/13kV 56MVA power transformer to replace failed transformer #3. GIS in Bay #3 clean up and installation support work. Also, purchase a spare transformer for the station. The spare transformer will be delivered, offloaded in June 2014 and will be assembled and tested in early 2015.	$0	$0	$0	$0	$0	(892,256)	663,646
	UDSPRD8TD	Pepco DC: Roof Replacements	To replace and repair various substation roofs in order to avoid equipment and further structural damage. Multiple points of failure have been identified in the form of severe leaks which are no longer economically feasible to repair.	$62,111	$157,718	$130,808	41,019	126,085	139,557	172,644
	UDSPRD8UD*	Repl Eng Generators Dist Sub: Pepco DC	Replace engine generators that are beyond their useful design life.	$0	$0	$105,918	73,398	307,097	457,677	81,669

Work Breakdown Structure - 2015 Projects										
Section	**WBS Element**	**WBS Element Description**	**WBS Detailed Description**	**2012 Budget**	**2012 Actual**	**2013 Budget**	**2013 Actuals**	**2014 Budget**	**2014 Actuals**	**2015 Budget**
Non-REP (con't)	UDSPRD8VD	NERC Physical Security Pepco Dist Sub.- DC (UDSPRD8VD)	Additional Physical Security Materials to be acquired is 2013 for the following locations: Central Ave (Sub 185)	$0	$0	$0	$0	$0	119,537	110,682
	UDSPRD8XD	Substation Damage & Insurance Funding	These funds to be applied to damaged equipment in the event of a failure within a substation.	$792,496	$0	$984	$0	$0	$0	$0
	UDSPRD9D5	Pepco DC Add Sub Cond Monitoring Points	This project allows us to add condition monitoring points to equipment as it may become impaired throughout the year. These monitoring points enable for proactive repair/replace decisions to be made. These monitoring points can include transformer DGA monitors, bushing monitors, Load Tap Changer monitors and even breaker or battery monitors. If no condition based needs arise funds may be utilized to add monitoring devices to new equipment.	$0	$0	$91,190	$0	108,120	$0	103,691
	UDSPRD9GD*	Pepco DC Xfrmr Repl - Aging Infrastuct	Condition and age related replacement of Transformers T2 at L Street Sub. 21 and T4 at New Jersey Sub. 161.	$0	$0	$4,819,265	447,997	5,351,119	5,238,305	5,671,529
	UDSPRD9SC	Spare 1500KCMil Pipe Type Cable at Benning	Purchase spare 1500 KCMil pipe type cable used in 69 kV and 138 kV substation supply circuits.	$1,635,417	$1,470,729	$179,951	968,168	$0	279,534	$0
	UDSPRD9SD	Southwest Sub. 18 Upgrade Elevator	To replace the elevator at Southwest Substation No. 18.	$0	$0	$0	$0	$0	399,682	$0
	UDSPRD9SE	Purchase 15kV Mobile Switchgear	This project is for the purchase and assembly of 15kV mobile switchgear. This is a spare, 6-feeder mobile unit to be storedat Benning and used in contingency planning and operations.	$0	$0	$0	$0	$0	680,174	400,120
	UDSPRD9SF*	G Street Sub 28 Replace T-2 & T-3	Purchase and replace 13/4kV T-2 and T-3 transformers at G Steet Sub 28. Both transformers are trending wet and need to be cleaned/re-gasketed, replace due to high maintenance/repair projections.	$1,404,920	$741,309	$746,217	505,649	15,151	540,189	$0
	UDSPRD9SG	12 th St 126 Sub: Replc Tr T-1	12th Street Sub 126, transformer T1 is a 1959 vintage transformer. The oil and paper of this transformer are wet and trending higher. The unit also needs to be re-gasketed. Based on the cost to remove the moisture from the paper and oil, in addition to re-gasketing the unit, this unit will be retired and replaced with a new transformer.	$1,087,282	$697,406	$49,405	700,364	$0	(69,437)	$0
	UDSPRD9SH	CVG 120 DC Village: Replace XFMR T-1	Replace existing 13/4kV 3,000 kVA xfmr at DC Village (CVG 120) with a new 13/4 kV 2000 MVA transformer.	$320,655	$53,230	$950,210	7,102	300,000	50,950	2,635
	UDSPRD9SJ	F ST SUB - Replace T2	F Street Sub transformer T2 has been in service since 1955 and is testing with a high insulation power factor. Since the insulation is degrading, it will eventually fail and would need an entire core rewind to repair and return to service. Based on age and the need to rewind the core, this transformer will be replaced with a new unit.	$2,015,533	$601,038	$8,900	173,922	$0	$0	$0

Work Breakdown Structure - 2015 Projects

Section	WBS Element	WBS Element Description	WBS Detailed Description	2012 Budget	2012 Actual	2013 Budget	2013 Actuals	2014 Budget	2014 Actuals	2015 Budget
Non-REP (con't)	UDSPRD9SK	Buzzard Point Sta. B: Reconnect Feeder 69066	This project will put Feeder 69066 back in service by connecting it to Benning spare Transformer 10. Both 69/13.8kV transformers 6604 and 6605 at Buzzard Point are 1942 vintage and testing wet. Both transformers need to be hot oil cleaned and completely refurbished. Based on age and cost to repair these units into a serviceable condition, these transformers will be retired and replaced with one new transformer to serve the required load. These transformers are only back-ups and the primary load is serviced through another provider.	$0	$0	$1,981,050	336,578	1,743,393	163,037	92,960
	UDSPRD9SM	O Street Sub 002, Replace and Install Transformer T3	Transformer T3 has been in service since 1968 and is showing of signs age and deterioration. There is significant gassing in the main tank that is indicative of core grounds. There are several other cosmetic issues that would need to be addressed. Based on the age of the unit and the cost to repair to prevent a potential future failure, this unit will be replaced.	$0	$490,286	$2,059,162	2,527,155	$0	(422,800)	$0
DC PLUG Initiative	UDLPRM4AD	DC PLUG (Power Line Undergrounding) (UDLPRM4AD)	Underground the primary portions of 60 Distrct 13 kV and 4 kV feeders. Project is to be coordinated with the District Department of Transportation who will build most required new conduit. Pepco will install the cables and take ownership of the conduit upon it's completion.	$0	$0	$0	$0	$0	$0	7,046,623
Sub Reliability Improvements	UDSPLM74B	Alabama Ave Sub 136 - Install 18MVAr of Bus Capacitors with reactors	The installation of these bus capcitors at Alabama Avenue Sub. 136 is required in order to mainatain a unity power factor after transfer of load from Anacostia Sub. 8.	$0	$0	$0	$0	$0	2,507	500,659
			Non-REP Total	$55,903,803	$55,244,262	$66,763,676	$57,818,812	$65,603,861	$55,843,298	$63,050,178

Feeder Improvement - 2015 Projects

Program to address reliability performance of the 2% worst performing feeders, high SAIFI feeders, and high customer interruption feeders. These projects involve detailed field inspections and installing, removing, and replacing reclosers, switches, conductors, animal guards, lightning arresters and other equipment deemed necessary in order to maintain safe operation and improve reliability.

	Location	FEEDER ID	WBS	Location-Subdivision	Jurisdiction	Estimated Completion
District of Columbia 2% Priority Feeders	Columbia Heights and Parkview	76	UDLPRM4BF	Vicinity of 14th St. at Monroe St., 11th St. at Park Rd. and Monroe St., and New Hampshire Ave. at Sherman Ave., N.W.	District of Columbia	3rd Quarter 2015
	Forest Hills, Tenleytown, and Cathedral Heights	82	UDLPRM4BF	Area bounded by Nebraska Ave. from Connecticut Ave. to Windom Pl., N.W., and from 36th St. to 40th St., N.W.	District of Columbia	3rd Quarter 2015
	Friendship Heights and Forest Hills	133	UDLPRM4BF	Area bounded by Nebraska Ave. and 30th Pl. and by Nevada Ave. and Military Rd. and by 30th St. and 27th St. and Utah Ave. and Rock Creek Park, N.W.	District of Columbia	3rd Quarter 2015
	Near Barney Circle	211	UDLPRM4BF	Area bounded by C St. and East Capitol St. and 12th St. and 14th St., S.E.	District of Columbia	3rd Quarter 2015
	Manor Park and Brightwood Park	490	UDLPRM4BF	Vicinity of New Hampshire Avenue at N. Capitol Street, N.W.	District of Columbia	3rd Quarter 2015
	Skyland and Hillcrest	15170	UDLPRM4BF	Vicinity of Alabama Avenue and Good Hope Road, S.E.	District of Columbia	3rd Quarter 2015
	Manor Park	15014	UDLPRM4BF	Vicinity of Blair Rd. at Sligo Mill Rd. and Riggs Rd. between Oglethorpe St. and Kennedy St., N.W.	District of Columbia	3rd Quarter 2015
	Hillcrest, Fort Stanton and Buena Vista	14702	UDLPRM4BF	Vicinity of Fairlawn Ave., from Talbert St. to N St., 18th St. from Fairlawn Ave. to Good Hope Rd. and Naylor Rd. from Minnesota Ave. to Alabama Ave., S.E.	District of Columbia	3rd Quarter 2015
	Michigan Park and Brookland	14017	UDLPRM4BF	Area between Irving St. and Buchannan St. and 12th St. and 6th Pl., N.E. and vicinity.	District of Columbia	3rd Quarter 2015
	Skyland and Garfield Heights	15174	UDLPRM4BF	Vicinity of Savannah Street, 23rd Street, Alabama Avenue, 25th Street and Wagner between Stanton Road and 24th Street, S.E.	District of Columbia	3rd Quarter 2015
	Carver/Langston	14006	UDLPRM4BF	Vicinities of Lawrence St. between 12th and 19th Sts. and Edgewood at Franklin Sts., N.E.	District of Columbia	3rd Quarter 2015
	Tenleytown, American Universtiy Park, and Cathedral Heights	15945	UDLPRM4BF	Van Ness ST NW and Nebraska AVE NW North to Wisconsin AVE NW and Ellicott ST NW, West to 48th ST NW, South to Mass AVE NW and West on Van Ness ST NW ending at Nebraska AVE NW	District of Columbia	3rd Quarter 2015
	Columbia Heights	14722	UDLPRM4BF	Vicinity of 16th St. at Monroe St., Meridian Pl. and Oak St. and 14th St. at Spring Rd., Quincy St. and Randolph Rd., N.W.	District of Columbia	3rd Quarter 2015
	Carver/Langston and Trinidad	15701	UDLPRM4BF	Vicinity of Benning Road between Oklahoma Ave and Bladensburg Road also Mount Olivet Road and West Virginia Ave between Bladensburg Road and 17th St., N.E.	District of Columbia	3rd Quarter 2015
	Edgewood, Michigan Park, and Bloomingdale	14200	UDLPRM4BF	Vicinity of Michigan Ave., Irving St. and N.Capitol Street, N.E.	District of Columbia	3rd Quarter 2015

Feeder Improvement - 2015 Projects

Program to address reliability performance of the 2% worst performing feeders, high SAIFI feeders, and high customer interruption feeders. These projects involve detailed field inspections and installing, removing, and replacing reclosers, switches, conductors, animal guards, lightning arresters and other equipment deemed necessary in order to maintain safe operation and improve reliability.

	Location	FEEDER ID	WBS	Location-Subdivision	Jurisdiction	Estimated Completion
District of Columbia 2% Priority Feeders	Spring Valley and American University Park	14767	UDLPRM4BF	Vicinities of MacArthur Blvd. from Macomb St. to 49th St., W St. from 49th St. to Foxhall Rd. and Foxhall Rd. from W St. to Canal Rd.	District of Columbia	3rd Quarter 2015
	Columbia Heights	53	UDLPRM4BF	Vicinity of Michigan Ave, Columbia Rd, Irving St, Georgia Ave	District of Columbia	1st Quarter 2015
	Fairfax Village	14031	UDLPRM4BF	Vicinity of Suitland Rd, Branch Ave	District of Columbia	1st Quarter 2015
	Hillcrest Heights	15085	UDLPRM4BF	Vicinity of Southern Ave, Southview Dr, 13th St, Woodland Blvd SE	District of Columbia	1st Quarter 2015
	Congress Heights and Washington Highlands	15166	UDLPRM4BF	Vicinity of Wheeler Road at Randle Place and Martin Luther King, Jr. Ave. between Mississippi Ave. and Lebaum St., S. E.	District of Columbia	1st Quarter 2015
	Friendship Heights and Chevy Chase	128	UDLPRM63D	Vicinity of Western Ave, 41st Street, Livingston Street, and Wisconsin Ave.	District of Columbia	1st Quarter 2015
	Anacostia	177	UDLPRM63D	Vicinity of Pleasant Street, Valley Place, Cedar St, 14th Street, V Street, 15th Street, and U Street.	District of Columbia	1st Quarter 2015
	Brightwood	15200	UDLPRM63D	Vicinity of New Hampshire Ave, Eastern Ave, 1st Street, Van Buren Street, Underwood Place, North Capitol Street, Riggs Road, Chillum Road, and 19th Ave.	District of Columbia	1st Quarter 2015

Underground Residential Cable Replacement and Enhancement - 2015 Projects

Program to address reliability of the underground residential infrastructure. These projects involve replacing or rejuvenating underground residential distribution (URD) cable in order to minimize URD failures.

Location	FEEDER ID	WBS	Location-Subdivision	Jurisdiction	Estimated Completion
Bloomingdale	14004	UDLPRM4BD	Bloomingdale	District of Columbia	1st Quarter 2015
Edgewood	14006	UDLPRM4BD	4th & Channing St. NE	District of Columbia	3rd Quarter 2015
Hilcrest	14031	UDLPRM4BD	Fort Davis St SE, WDC	District of Columbia	4th Quarter 2015
Anacostia	14031	UDLPRM4BD	V St SE, WDC	District of Columbia	4th Quarter 2015
Anacostia	14031	UDLPRM4BD	W St SE, WDC	District of Columbia	4th Quarter 2015
Burrville	14717	UDLPRM4BD	Eastern Ave NE (913 Porter Ct), WDC	District of Columbia	4th Quarter 2015
Congress Heights	15085	UDLPRM4BD	Barnaby Terrace SE, WDC	District of Columbia	4th Quarter 2015
Congress Heights	15085	UDLPRM4BD	Wheeler Rd & Bellevue St SE, WDC	District of Columbia	4th Quarter 2015
Shipley Terrace	15171	UDLPRM4BD	14th Pl SE, WDC	District of Columbia	4th Quarter 2015
Shipley Terrace	15171	UDLPRM4BD	Congress St, WDC	District of Columbia	4th Quarter 2015
Shipley Terrace	15171	UDLPRM4BD	Southern Ave SE, WDC	District of Columbia	4th Quarter 2015
Douglass	15173	UDLPRM4BD	Savannah Pl SE, WDC	District of Columbia	4th Quarter 2015

Load Growth/4 kV Conversions - 2015 Projects

Program to address increasing load demands to maintain reliability and to ensure that future demands can be met under adverse conditions. These projects involve adding or upgrading feeders in order to reliably supply new customers and support increased usage required by existing customers.

Location	FEEDER ID	WBS	Location-Subdivision	Jurisdiction	Estimated Completion
Downtown	14516, 14517, 14518, 14519, 14520, 14521	UDLPL10S1	Area along H St. from between 12th & 13th Sts. to 13th St., south along 13th St. to between G St. and H St.	District of Columbia	2nd Quarter 2015
Downtown	15327, 15328, 15329, 15330, 15331, 15332	UDLPL10S2	Area along F St. between 7th & 11th Sts.	District of Columbia	1st Quarter 2015
U Street Corridor	15341	UDLPLM7W7	Area along V St. from 13th St. to Georgia Ave., then along Georgia Ave. from V St. to Florida Ave. N.W.	District of Columbia	2nd Quarter 2015
Eckington	15469, 15470, 15471, 15472, 15473, 15474	UDLPLNE6	Area along T St. from 2nd St to North Capitol St. then along North Capitol St. from T St. to M St.	District of Columbia	2nd Quarter 2015
Brookland	14093, 14007, 14015, 14023	UDLPRLIRV1	Area along 10th St. from Evarts St. to Rhode Island Ave.	District of Columbia	1st Quarter 2015
Kingman Park	14151, 14711, 14712, 14713, 15703, 15713	UDLPLBN1	Area along Benning Rd. and Florida Ave. between Anacostia Ave. and Trinidad Ave.	District of Columbia	2nd Quarter 2015
Kingman Park	15701	UDLPLM7W11	Area along Benning Rd. between 26th St. and Bladensburg Rd.	District of Columbia	4th Quarter 2015
Trinidad	15702	UDLPLM7W6	Vicinity of Benning Rd., Bladensburg Rd., H St., and 15th St.	District of Columbia	1st Quarter 2015
Downtown	15204-R, 15204-W, 15206, 15207-R, 15207-W	UDLPLM7W	Vicinity of P St. between 3rd St. and 9th St. N.W.	District of Columbia	1st Quarter 2015
Wakefield	65	UDLPLM7W	Vicinity of Reno Rd. and Ellicott St. N.W.	District of Columbia	3rd Quarter 2015
Foggy Bottom	14681, 14682, 14686	UDLPLM7W	Vicinity of 24th St. and H St. N.W.	District of Columbia	1st Quarter 2015
Cleveland Park	87	UDLPLM7W	Vicinity of Cathedral Ave., and Idaho Ave., N.W.	District of Columbia	1st Quarter 2015
Downtown	14367	UDLPLM7W4	Area along 15th St. N.W. between K St. and I St.	District of Columbia	3rd Quarter 2015
Brookland	14200	UDLPLM7W5	Area along Monroe St. N.E. between 7th St. and 9th St.	District of Columbia	3rd Quarter 2015
Downtown	15329	UDLPLM7W8	Area along H St. between 9th St. and 10th St.	District of Columbia	3rd Quarter 2015
Chevy Chase	414	UDLPLNW1	Area bounded by Huntington St. and Quesada St. and by 41st St. and 32nd St., N.W. and vicinity.	District of Columbia	3rd Quarter 2015
Chevy Chase	416	UDLPLNW1	Vicinity of 31st Pl., 32nd St., Nebraska Ave., Jennifer St., Chevy Chase Pkwy. and Harrison St. and 41st St., between Harrison St., and Jennifer St., N.W. with focus in the vicinity of Nebraska Ave from Jennifer to 31st St., N.W.	District of Columbia	3rd Quarter 2015
Good Hope	14709, 14702	UDLPLWF1	Vicinity of Naylor Rd. and Good Hope Rd.	District of Columbia	3rd Quarter 2015
Buena Vista	Retire Sub.	UDLPLWF1	Vicinity of MLK Jr Ave. and Howard Rd.	District of Columbia	4th Quarter 2015
Petworth	481, 484	UDLPRM8BC	Area along North Capitol St. from north of Crittenden St. to along Rock Creek Church Rd. then to along Harewood Rd. and Clemont Dr.	District of Columbia	1st Quarter 2015
Petworth	491	UDLPRM8BC	Area along Kennedy St. between 2nd St. N.W. and North Capitol St.	District of Columbia	2nd Quarter 2015
Petworth	15012	UDLPRM8BC	Area along Kansas Ave. from Kennedy St. to Hamilton St. and along 4th St. from Hamilton St. to Webster St.	District of Columbia	4th Quarter 2015
Petworth	15197	UDLPRM8BC	Area along Buchanan St. N.W. between 8th St. and 7th St.	District of Columbia	4th Quarter 2015

Load Growth/4 kV Conversions - 2015 Projects

Program to address increasing load demands to maintain reliability and to ensure that future demands can be met under adverse conditions. These projects involve adding or upgrading feeders in order to reliably supply new customers and support increased usage required by existing customers.

Location	FEEDER ID	WBS	Location-Subdivision	Jurisdiction	Estimated Completion
Congress Heights	343, 480, 122, 234, 325	UDLPRM8BI	Area bounded by Mississippi Ave., 1st St., Malcolm X Ave., and 15th St., N.E.	District of Columbia	2nd Quarter 2015
Georgetown	1, 94	UDLPRM8BT	Area along Wisconsin Ave. between S St. and Reservoir Rd. and along R St. N.W. from Wisconsin Ave. to east of 31st St.	District of Columbia	1st Quarter 2015
The Mall	230, 370	UDLPRM8BU	Vicinity of 7th St. from Virginia Ave. to Madison Dr., S.W.; 4th St. from Jefferson Dr. to Madison Dr., S.W.; E St. from 4th to 6th St., S.W., and intersections of Penn Ave. and 4th St., S.W. and Constitution Ave. and 9th St., S.W.	District of Columbia	2nd Quarter 2015
The Mall	232, 233	UDLPRM8BU	Area along 15th St. and 14th St. N.W. from F St. to Independence Ave.; and along Raoul Wellenburg Pl. from Madison Dr. to Maine Ave. and 12th St.	District of Columbia	4th Quarter 2015
Columbia Heights	16, 27, 30, 84, 90, 92	UDLPRM8BY	Area bounded by Florida Ave., Girard St., 13th St., Fairmont St., 14th St., 11th St., Euclid St., Clifton St., Belmont St., and 12th Pl., N.W.	District of Columbia	2nd Quarter 2015
Columbia Heights	84, 141, 147	UDLPRM8BY	Area bounded by Florida Ave., Girard St., 13th St., Fairmont St., 14th St., 11th St., Euclid St., Clifton St., Belmont St., and 12th Pl., N.W.	District of Columbia	2nd Quarter 2015
Columbia Heights	15991, 15992	UDLPRM8BY	Vicinity from Champlain St. and Old Morgan School Pl. N.W. to Kalorama Rd.; and along 16th St. from Kalorama Rd. to Newton St.	District of Columbia	3rd Quarter 2015
Columbia Heights	14722	UDLPRM8BY	Area along Newton St. N.W. from 14th St. to Brown St.; along Brown St. from Monroe St. to Oak St.; and along Meridian Pl. between Brown St. to 14th St.	District of Columbia	4th Quarter 2015
Columbia Heights	76, 86	UDLPRM8BY	Area along Park Rd. N.W. from 13th St. to 16th St.; along 16th St. from Park Rd. to Newton St.; along Newton St. from 16th St. to 14th St.; and along 14th St. from Park Rd. to Newton St.	District of Columbia	4th Quarter 2015
Columbia Heights	76, 84	UDLPRM8BY	Area along 11th St. N.W. between Otis Pl. and Park Rd.; along 13th S. from Park Rd. to Harvard St.; and along Harvard St. between 11th St. and 14th St.	District of Columbia	4th Quarter 2015

Distribution Automation - 2015 Projects

Program to address system reliability by deploying technology. These projects involve installing advanced control systems across the distribution system in order to automatically identify and isolate faults in real time and restore service to customers in the unaffected parts of the system.

ASR Scheme	Feeder	WBS	Location-Subdivision	Jurisdiction	Scope of Work	Estimated Completion
Benning Scheme	15710	UDLPRDA1D UOIPRASRD UORPODA1D UORPORBSB UORPORSSB UORPOBR1D	Vicinity of Blaine St., N.E., 42nd St., N.E., Hayes St., N.E., and Minnesota Ave., N.E.	District of Columbia	Install & program 2 reclosers with associated controllers	Equipment install Q3 2015. ASR activation Q1 2016.
Harrison-Van Ness-Little Falls Scheme	15945	UDLPRDA1D UOIPRASRD UORPODA1D UORPORBSB UORPORSSB UORPOBR1D	Vicinity of Van Ness St., N.W., 42nd St., N.W., River Rd., N.W., 44th St., N.W., Brandywine St., N.W., and 46th St., N.W.	District of Columbia	Install & program 2 reclosers with associated controllers	Equipment install Q4 2015. ASR activation Q1 2016.
	14132		Vicinity of Nebraska Ave., N.W., New Mexico Ave., N.W., Calvert St., N.W., and Benton St., N.W.	District of Columbia	Install & program 2 reclosers with associated controllers	Equipment install Q4 2015. ASR activation Q1 2016.
12th & Irving - Fort Slocum Scheme	14006	UDLPRDA1D UOIPRASRD UORPODA1D UORPORBSB UORPORSSB UORPOBR1D	Vicinity of 10th St., N.E., 7th St., N.E., Franklin St., N.E., Edgewood St., N.E., and Channing St., N.E.	District of Columbia	Install & program 4 reclosers with associated controllers	Equipment install Q4 2015. ASR activation Q1 2016.
	14200		Vicinity of 9th St., N.E., Monroe St., N.E., Michigan Ave., N.E. and Channing St., N.E.	District of Columbia	Install & program 3 reclosers with associated controllers	Equipment install Q3 2015. ASR activation Q1 2016.

Distribution Automation - 2015 Projects

Program to address system reliability by deploying technology. These projects involve installing advanced control systems across the distribution system in order to automatically identify and isolate faults in real time and restore service to customers in the unaffected parts of the system.

ASR Scheme	Feeder	WBS	Location-Subdivision	Jurisdiction	Scope of Work	Estimated Completion
Anacostia Area Scheme	14753	UDLPRDA1D UOIPRASRD UORPODA1D UORPORBSB UORPORSSB UORPOBR1D	Vicinity of Livingston Rd., S.E., Elmira St., S.W., Martin Luther King Jr. Ave., S.W., and Joliet St. S.W.	District of Columbia	The project has been deferred to account for DC PLUG	N/A
	14758		Vicinity of Chesapeake St. S.W., Martin Luther King Jr. Ave. S.W., Galveston St., S.W., and South Capitol St., S.W.	District of Columbia	The project has been deferred to account for DC PLUG	N/A
	15166		Vicinity of Mississippi Ave., S.E., 6th St., S.E., Martin Luther King Jr. Ave., S.E., and Malcolm X Ave., S.E.	District of Columbia	The project has been deferred to account for DC PLUG	N/A
	15170		Vicinity of Good Hope Rd., S.E., 30th St., S.E., Alabama Ave., S.E., and 15th Pl., S.E.	District of Columbia	The project has been deferred to account for DC PLUG	N/A
	15172		Vicinity of Douglass Rd., S.E., Stanton Rd., S.E., 12th Pl., S.E., and Alabama Ave., S.E.	District of Columbia	The project has been deferred to account for DC PLUG	N/A
	15174		Vicinity of 25th St., S.E., Alabama Ave., S.E., 23rd St. S.E., and Savannah St., S.E.	District of Columbia	The project has been deferred to account for DC PLUG	N/A
	15175		Vicinity of Weeler Rc., S.E., Alabama Ave., S.E., and Martin Luther King Jr. Ave., S.E.	District of Columbia	The project has been deferred to account for DC PLUG	N/A
	15176		Vicinity of Firth Sterling Ave., S.E., Stevens Rd., S.E., Sheridan Rd., S.E., and Shannon Pl., S.E.	District of Columbia	The project has been deferred to account for DC PLUG	N/A
	15177		Vicinity of Howard Rd., S.E., Stanton Rd., Pomerroy Rd., S.E., W St., S.E. and Good Hope Rd., S.E.	District of Columbia	The project has been deferred to account for DC PLUG	N/A

Distribution Automation - 2015 Projects

Program to address system reliability by deploying technology. These projects involve installing advanced control systems across the distribution system in order to automatically identify and isolate faults in real time and restore service to customers in the unaffected parts of the system.

ASR Scheme	Feeder	WBS	Location-Subdivision	Jurisdiction	Scope of Work	Estimated Completion
Buzzard Point Network RMS	14119	DORPODA1D	Genral Area around Buzzard Point, Southeast Area around M St. between First St. and 13th St, and Capitol complex and the Navy Yard, N.E.	District of Columbia		Completed
	14120			District of Columbia		Completed
	15596			District of Columbia		Completed
	15597			District of Columbia		Completed
	15598			District of Columbia		Completed
	15599			District of Columbia		Completed
Sub 212 Northeast Network RMS	15463	UDLPRM4BN UORPORNPD	Vicinity of N. Capitol St. around 1st St. and East Capitol St. and M St. and K St., N.E.	District of Columbia		3rd Quarter 2015
	15464			District of Columbia		3rd Quarter 2015
	15465			District of Columbia		3rd Quarter 2015
	15466			District of Columbia		3rd Quarter 2015
	15467			District of Columbia		3rd Quarter 2015
	15468			District of Columbia		3rd Quarter 2015
Sub 18 Central Network	15307	UDLPRM4BN UORPORNPD	General Area of Independence Ave., Constitution Ave., C St. and 7th St., 9th St., 12th St. and Pennsylvania Avenue.	District of Columbia		2nd Quarter 2015
	15308			District of Columbia		2nd Quarter 2015
	15309			District of Columbia		2nd Quarter 2015
	15310			District of Columbia		2nd Quarter 2015
	15311			District of Columbia		2nd Quarter 2015
	15312			District of Columbia		2nd Quarter 2015
Capacitor Control Project		UORPORCPD	Pepco is installting 2-way communicating controllers on forty-four (44) capacitors on 13kV feeders across District of Columbia.	District of Columbia		4th Quarter 2015
Fault Detection System	To be determined	UORPOR34D	To be determined	District of Columbia		4th Quarter 2015

Certificate of Service

I hereby certify that a copy of Potomac Electric Power Company's Consolidated Report will be served by electronic mail, hand delivery, first class mail, postage prepaid on all parties in Docket PEPACR2015-01 on the 1st day of April 2015.

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POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 4

QUESTION NO. 6

Referencing the testimony presented by Witness Cantler at page 8 regarding resiliency and ability to withstand and recover from deliberate attacks, accidents or naturally occurring events to the system infrastructure.

a. The testimony states that planning used by PECO includes a N-1 criteria for distribution, sub-transmission and transmission facilities. In addition to those criteria, provide all new criteria to be used by Pepco to meet the Company’s definition for resiliency that would influence the justification of a new capital project.

b. Provide a complete list of projects included in the MYP that are required for resiliency and identify the planning criteria which requires the investment for each.

c. Provide the most recent copy of Pepco’s Distribution Standards Guideline 1442.

RESPONSE:

a. The Company does not have any established new criteria. Per usual, all projects must meet the Company’s existing criteria. Please see the Company’s response provided in 4-6(b) for the types of projects that are initiated to support resiliency.

b. There is no established listing available. As discussed in the Direct Testimony of Company Witness Cantler (Question 10), the Company’s capital investment strategy during this MYP period (2023-2026) focuses on supporting a pathway to a climate ready grid through, amongst other things, improving grid resiliency. Improved grid resiliency is achieved by, but not limited to, projects initiated to replace aging and/or obsolete infrastructure and routinely and timely performing corrective maintenance work when and where necessary. As detailed in Exhibit PEPCO (H)-2, the Company provides all of its capital funded distribution construction projects, budgeted by year (including 2023) throughout the MYP, including the project’s scope and justification.

   Additionally, project work such as Advanced Distribution Management System Implementation (ITN: 61976, see pg. 174 of Exhibit Pepco H-2), 69kV Distribution Line Improvements (ITN: 70240, see pg. 192 of Exhibit Pepco H-2), 69kV Feeder Rebuild (ITNs: 70242, 70423, on pg. 192-193 of Exhibit Pepco H-2) Champlain Bypass (ITN: 73368 on pg. 193) have all been identified within the project, solutions, justification slides (PSJ) of Pepco (H)-2 as directly supporting grid resiliency of the Company’s distribution infrastructure.

c. Please refer to the attachment labeled: FC 1176 OPC DR 4-6c

SPONSOR: Jaclyn Cantler

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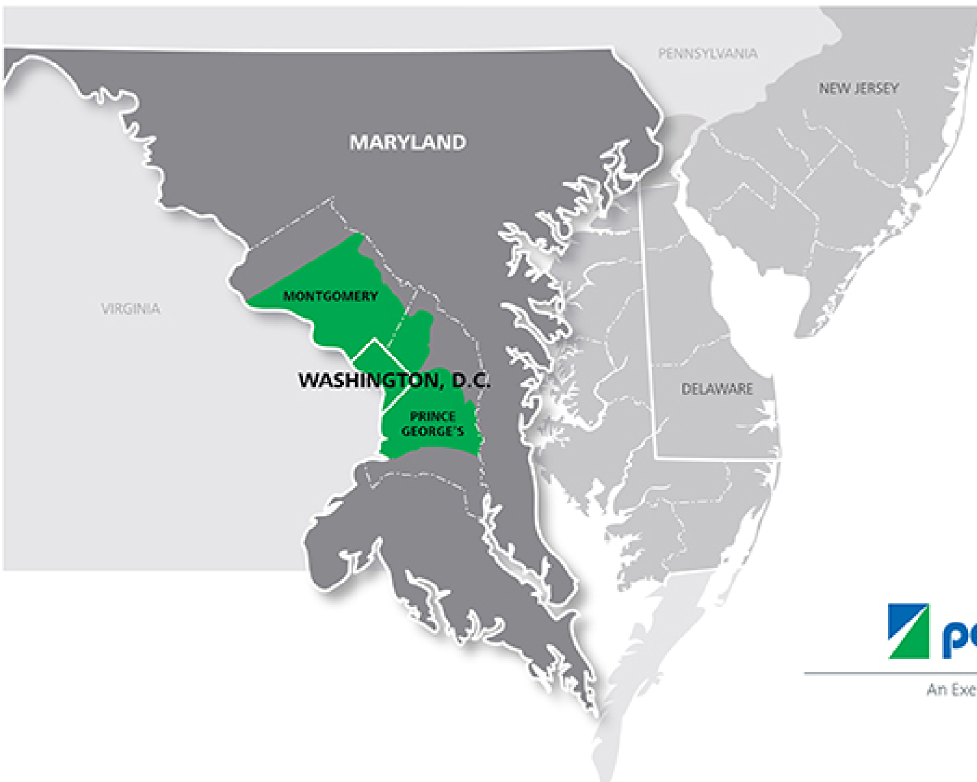

THE DESIGN AND OPERATION OF THE PEPCO FOUR-WIRE DISTRIBUTION SYSTEM

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Distribution Standards Guideline 1442

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1. Overview

This document provides an overall description and philosophy for the Pepco 13 KV distribution system, the design, circuit protection, major equipment, material, and operation. In DC and Maryland, Pepco operates a 4.16 and 13.2 KV 4-wire distribution system. A four-wire system is made up of three energized lines, phases A, B, and C, and a ground referenced neutral line resulting in a wye configuration that allows the system to serve both single phase and 3-phase loads. A four-wire system can maintain relatively balanced voltages on all 3-phases in the presence of minor current imbalances driven by serving both single and 3-phases loads on the same system. The voltages are stabilized by maintaining a robust neutral network that is interconnected between the primary and secondary neutrals with multiple grounding points that parallel the earth return path. Four grounds per mile are required as per Standard OH-6003 (1275) and OH-6002 (C-345).

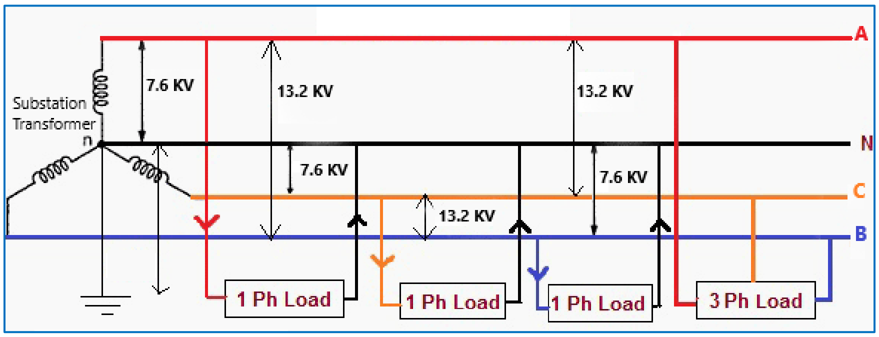

Figure 1: Simple Circuit Diagram of 13.2 KV 3-phase 4-Wire Distribution

1.1. Distribution Design

The overall health and reliability of the distribution system is designed by the Capacity Planning department. Their role is to periodically perform voltage and current analysis studies on the distribution system based on projected peak load forecasts to ensure that the system continues to provide reliable quality electric service to current and future customers. They also perform predictive analysis that includes the loss of a single primary circuit/feeder element in which the subsequent automatic or manual restoration must be accomplished within four load transfers. The goal of Capacity Planning as stated in their design criteria is to expand and upgrade the distribution system in an orderly and economic manner such that:

1. Adequate voltage can be maintained at the customer, typically within +/- 5% of nominal voltage, as directed by state regulations.
2. Applicable ratings of facilities will not be exceeded under normal and more probable contingency conditions.
3. Reasonably reliable system and customer end use service will be provided.
4. Adequate system reactive support is available.
5. As a general rule, a 13KV feeder can supply on average up to 8.5 MVA

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Load forecasting and predictive reliability analysis can generate construction recommendations that continually change the configuration of the distribution system. The local district engineering and operating centers often work in collaboration with Capacity Planning and Central Reliability Engineering to execute distribution system upgrades that are based on these studies. Local district engineering also performs small design changes to the distribution system that are driven by new customers and modifications of existing customer service, as well as, pockets of poor reliability performance.

In order to avoid subjecting customers' electronic equipment to over voltages during fault conditions, line to neutral connected single phase and wye-wye connected 3-phase transformers will only be used on four-wire feeders. For the same reason, line to line connected single phase and delta-wye connected 3-phase transformers will be used exclusively on three wire, commercial, and network feeders. Every reasonable effort is to be made to eliminate conflicts with these guidelines where they are found to exist.

2. Overhead Distribution

2.1. Overhead Design

Pepco uses aluminum conductor steel reinforced (ACSR) as the main primary conductor. 477 ACSR 18/1, 18 strand aluminum 1 strand steel, Pelican[1] is used with a 1/0 ACSR 6/1 Raven neutral for the main 3-phase of the feeder. If the available fault current is between 10 and 20 kA, then 4/0 ACSR Penguin is paired with the 477 ACSR Pelican. This is often the case as Pepco tends to experience high fault currents. In situations where fault current exceeds 20 kA, a 4/0 Cu 7 strand conductor is available for the neutral. 1/0 ACSR 6/1 Raven is used for single and multiple phase lines with lower ampacity requirements, Standard OH-6201 (0880) and Guideline 1500. The primary is constructed on a minimum 45ft class 2 (45/2) wood pole with 8 – 10ft fiberglass crossarms and polymer insulators, Standard OH-1300 (0587). Span lengths are usually less than 180ft. The single-phase primary is constructed on 45 ft class 2 (45/2) wood poles or larger with polymer ridge pin insulators. Span lengths are usually less than 180ft, each mile of line shall have at least 4 arrester and ground locations with a measured resistance less than 25 ohms.

The common overhead secondary main wire that runs from transformer pole to adjacent poles with multiple customers is 4/0 aluminum (AL) cross linked polyethylene (XLPE) triplex and 4/0 AL stacked bus. The overhead secondary service wire, often called service drop, that runs from service pole to customer point of attachment is usually #2, 1/0 or 4/0 AL XLPE triplex depending on loading requirements.

On substation cable getaways, load break gang operated cable equipment must be installed on or preferably within one span of the cable pole for isolating the underground cable portion of the feeder trunk. Load taps are not to be made from the underground

[1] In North American electrical conductors are given code names to aid identifying the different types and sizes of conductors. ACSR birds, AAC flowers and AAAC cities.

trunk between this sectionalizing equipment and the feeder breaker in the substation except through a four-way subway or pad mounted tap switch.

As the distribution feeder extends downstream from the substation to serve more load, the feeder trunk and branches are isolated using load break gang switches, automatic circuit reclosers (ACR), and fused cutouts. The end of each main feeder unfused trunk and branch is terminated at a normally open load break gang switch, SF6 switch or ACR to create a tie point to the neighboring feeder. This provides opportunity for one of the feeders to supply the other should the other experience a fault farther upstream. This segmentation can allow the fault to be isolated to a smaller section of the feeder so that the normally open tie point can be closed to restore the unaffected main trunk feeder segments.

The design goal for the distribution system is to maintain a system of feeders that operate at or below 600 amps building in reserve ampacity for emergency load transfers and reducing system losses. However, the distribution system is a constantly evolving system consisting of newer and legacy construction and design. The cost of a general system rebuild is prohibitive and therefore it is the policy that going forward, the approved Pepco mainline conductors are to be used in all new construction. Capacity Planning Regional Manager will approve any deviations. Furthermore, all design work involving adding additional conductor should be deadended on a structure such as a pole or crossarm, not spliced, to avoid adding points with a higher failure rate to the overhead system.

To avoid major feeder load imbalancing, single and two-phase lateral demand loads must not exceed 45 amperes (360 KVA) per phase. When such a condition cannot be relieved with load transfers, the second or third phase is to be added with the resulting unbalance split between the new phases. If the demand loads on a 3-phase lateral would exceed 100 amperes (800 KVA) on any one phase, a second lateral tap should be extended, or the overloaded tap should be reconductored to 477KCM ACSR and considered part of the main trunk of the feeder. Sectionalizing gang switches or a recloser should be installed in the new trunk branch at or near the branch point and backup should be provided at an open tie point to another feeder if possible.

Extensive use of backup feeder tie points through ACRs and sectionalizing load break gang switches (manually or motor operated) assist in emergency restoration and minimize the exposure of customers to long outages. Switching is performed live, where feeder phase angle differential is within Control Center prescribed boundaries, make before break, to prevent a momentary outage where phase angle difference is calculated to be small. Pepco is installing ACRs in place of select gang operated switches. Motor operated disconnects are being replaced or removed. Typically, reliability projects are being used to accomplish these system improvements.

Substations supplied from different sub-transmission networks experience a substantial difference in phase angle. The phase angle difference between a feeder from one substation and its backup tie feeder from another such substation can cause circulating current large enough to exceed the load break rating and safe close rating of the gang switches. For this reason, feeders supplied from substations supplied from different sub-transmission networks will not normally be tied live. These devices must be labeled as "Does not Phase", "Do not Tie or "Does not Tie" by System Operations and must be clearly marked for field crews.

Similarly, feeders from the same or different substations which employ a legacy unidirectional regulator, if tied, can experience circulating currents in excess of the regulator rating and voltages outside of the mandated voltage ranges. Unidirectional regulators are to be placed in the neutral position and the controls turned off prior to tying such feeders. Bi-directional voltage regulators will be installed for all new installations and replacements of existing aged or failed regulators.

2.2. Overhead Primary Conductor

2.2.1 Feeder Main 3-phase Primary Bare Conductor

The overhead primary conductor links the substation to the customer service transformers throughout the distribution system. These bare stranded conductors regularly operate at 13 KV. In 1982 Mashikian & Associates Consulting Engineers performed a study to determine the optimal 13 KV primary ACSR size conductor for Pepco's main 3-phase bare wire construction. They found that 477 KCMIL 18/1 ACSR Pelican was the most economical bare wire to install due to material availability and ampacity needs. ACSR was chosen over all aluminum conductor (AAC) and all aluminum alloy conductor (AAAC) because of its cost effectiveness, higher strength and ability to traverse longer spans without compromising sag clearance, whereas ACE and DPL mainly use AAC for its lightweight, high conductivity and anti-corrosion properties; especially in coastal areas. Pelican is rated in line with the emergency limit of much of the field equipment on the Pepco system. Table 1 shows the ratings of Pelican and Figure 2 shows an example of its appearance. Standard OH-6201 (0880) provides a listing of the various overhead conductor types.

477 PELICAN	SUMMER	WINTER
NORMAL	735 A	875 A
EMERGENCY	915 A	1035 A

Table 1: Ratings for Pelican 477 KCMIL 18/1 ACSR

Figure 2: Example of 477 Pelican

2.2.2 Primary Lateral Conductor

Pepco uses 1/0 AWG 6/1 Raven ACSR conductor for single phase and multiphase laterals with lower ampacity requirements. Radial 100 ampere laterals of one, two, or 3-phases are tapped from the feeder trunk through fused load break cutouts or a drop out recloser (Trip-Saver II). Some laterals may terminate at a solid blade load break cutout to provide a backup tie point whenever possible. This tie point must be a lateral from the same phase. Tying opposite phases is an unsafe practice and could result in a circuit outage. Therefore, the use of opposite phases at open tie points is strictly prohibited.

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Table 2 and Figure 3: Example of 1/0 ACSR Raven provide the ratings and example for 1/0 AWG ACSR Raven.

1/0 RAVEN	SUMMER	WINTER
NORMAL	265 A	315 A
EMERGENCY	325 A	365 A

Table 2: Ratings for Raven 1/0 AWG ACSR

Figure 3: Example of 1/0 ACSR Raven

2.2.3 Primary Neutral Conductor

4/0 AWG 6/1 Penguin ACSR (1650204) is the standard neutral paired with the 477 Pelican on the Pepco distribution system, due to the relatively high fault currents. This is used for its strength and thermal properties that enable the wire to withstand the maximum available feeder fault current. A 1/0 ACSR is available for areas with less than 10 kA of fault current and 4/0 Cu for areas exceeding 20 kA. The 1/0 ACSR is used as the main neutral for laterals since it may be required to carry full lateral load current. Table 3 provides the ratings for 4/0 AWG Penguin. Construction of 4/0 Penguin is similar to 1/0 Raven only larger. Standard OH-5002 (E-02) lists the ampacity for a wide array of overhead conductors.

4/0 Penguin	SUMMER	WINTER
NORMAL	400 A	480 A
EMERGENCY	485 A	550 A

Table 3: Ratings for Penguin 4/0 AWG 6/1 ACSR

2.2.4 Preassembled Aerial Cable

A 15 KV 500 KCMIL 3-1/C AL EPR preassembled aerial cable (PAC), can be used as the mainline conductor where transit will be made through dense trees, for the third and fourth circuits on a pole line that already contains two bare wire circuits, for high voltage customers who require two or more circuits installed on a common pole line, or overhead express feeders. The aerial cable has an equivalent 4/0 neutral and is fully shielded like underground cable and is not jacketed. PAC is intended for express run applications since adding splices to connect load will reduce the reliability of the cable. PAC should always make a transition to open wire through gang operated load break equipment, see Figure 6 of Standard OH-1603 (1460_G-630). #2 AWG CU PAC cable is also a common cable size used on the Pepco distribution system where ampacity needs are lower.

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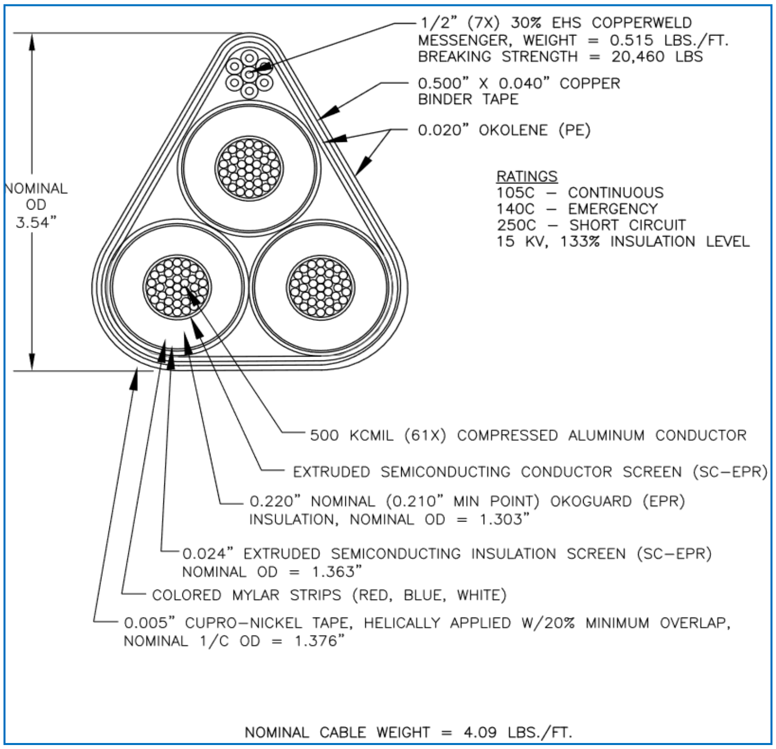


Figure 4: 500 KCMIL AL PAC

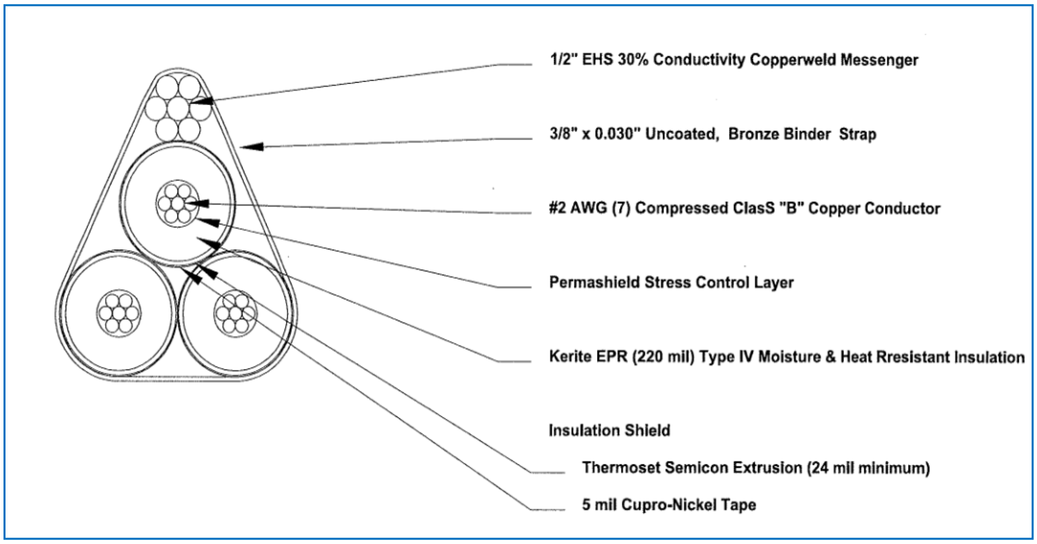
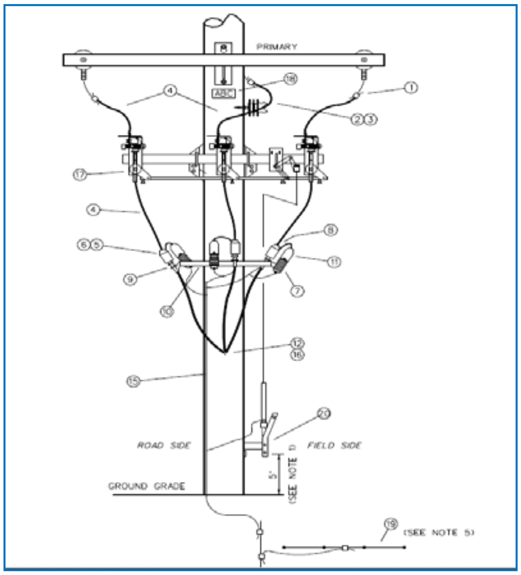


Figure 5: #2 CU PAC



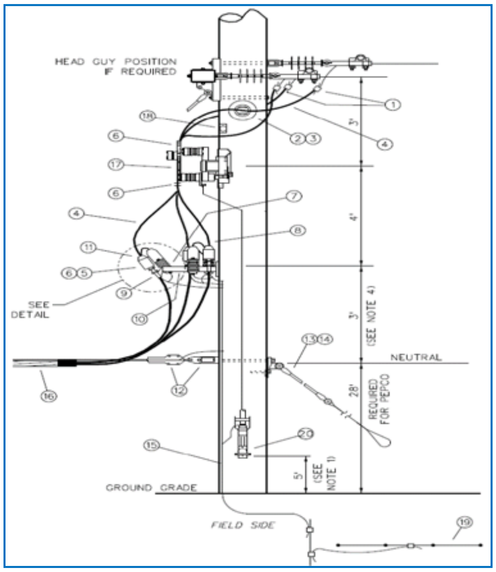


Figure 6: Standard OH-1603 (G630_1460) PAC Cable Transition

500 KCMIL PAC	SUMMER	WINTER
NORMAL	460 A	575 A
EMERGENCY	570 A	665 A

Table 4: Ratings for the 500 KCM PAC

2.2.5 Spacer Cable

Another primary conductor that is available for use on the Pepco distribution system is spacer cable. Spacer cable is intended to be used in similar situations as PAC cable with the added benefit of being able to serve transformers or tap off to laterals with less impact to the cable's performance and reliability. The spacer cable is a 477 KCMIL AAC 15 KV cable with a polyethylene covering. A 46 KV spacer that pairs with the 15 KV cable can be used to match the spacing of armless construction. Cover or coating on spacer cable is not for insulation of the conductor but to protect them from incidental contacts. It is constructed using diamond shaped plastic spacers giving it a low profile. The three energized conductors fit into the bottom and two side positions and the aluminum clad (AWA) messenger fits into the top spot. The AWA messenger provides strength to hold up the conductors and a mechanical shield to falling branches. A complete understanding and adherence to the manufacturer's directions is critical to a successful installation. The manufacturer's best practices will protect the cable insulation which is subject to damage by stray currents over time. Standard OH-1650 (1754) has notes detailing some installation instruction and best practices. The ratings are in Table 5 and Figure 7 shows an example of the installation.

477 Spacer Cable	SUMMER	WINTER
NORMAL	520 A	705 A
EMERGENCY	670 A	825 A

Table 5: Ratings for the 477 KCMIL Spacer Cable

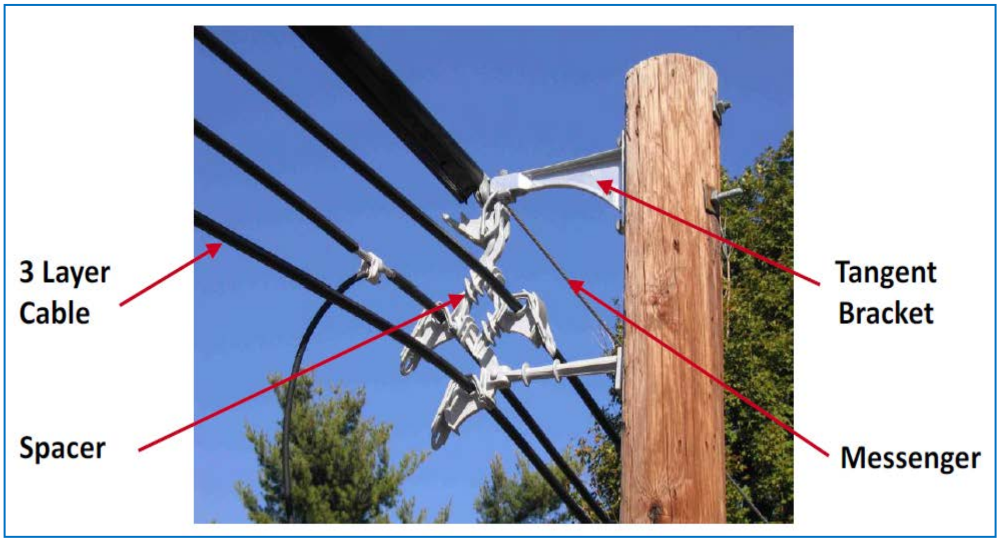


Figure 7: Example of Spacer Cable Installation

2.2.6 Tree Wire

Tree wire is another covered primary conductor option used to improve reliability in heavy tree areas. It is similar to spacer cable except that its construction resembles bare overhead conductor instead of the diamond compact shape of spacer cable. The covering on tree wire is also for mechanical protection and not for conductor insulation. Tree wire is available in 15 KV 1/0 6/1 ACSR, 4/0 6/1 ACSR, and 477 18/1 ACSR, see Standard OH-6201. Tree wire should be grounded a minimum of 6 times per mile, and it is very important that polymer type insulator pin (1652575) and appropriate covered tie wire are used during installation to provide a better dielectric match with the outer covering.

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Figure 8: Example Tree Wire Installation

2.3. Overhead Secondary

The overhead secondary distribution system links the distribution transformers with the customer loads to serve them at their required voltage level commonly ranging from 120 V to 460 V. The secondary conductors run from the transformer to a distribution pole serving several customers and the secondary service wire runs from the pole to the point of attachment at the customer facility.

2.3.1 Secondary Main/Bus Line

The standard distribution secondary wire for single phase customers is 4/0 aluminum (AL) cross linked polyethylene (XLPE) triplex and 4/0 AL 6/1 stacked bus. It is used to transmit power from the distribution transformer to multiple customer loads where higher ampacity is needed, or for longer secondary runs between distribution poles when voltage drop, and flicker are a concern.

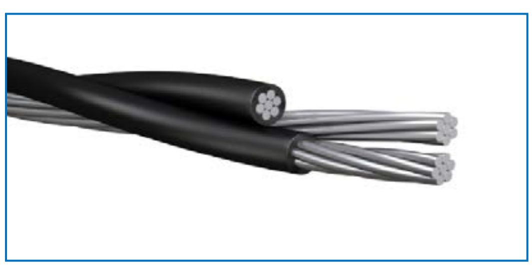

Figure 9: Example of 1/0 AWG Triplex

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2.3.2 Secondary Service

The service wire is an extension of the secondary to the customer facility. It transmits the power from the distribution pole to the customer point of attachment. Depending on customer load, Pepco runs 4/0 AL triplex up to 50 ft, #2 AL triplex and 1/0 AL triplex up to 100 ft. Table 6 shows the rating for some common secondary conductors from Standard OH-5000 (1744_C501).

Conductor	CATID	Rating
#2 Al 2C W/ #4 NEU Triplex	1650142	150 A
1/0 Al 2-1/C W/ 1/0 NEU Triplex	1650139	200 A
4/0 Al 2-1/C W/ 4/0 NEU Triplex	1650138	310 A

Table 6: 1-Phase Secondary Ratings

2.3.3 3-phase Secondary

3-phase customers usually require higher ampacity. The 600 V 4/0 AWG AL 4-1C XLPE quadplex is one of the conductors used to serve these larger 3-phase customers.

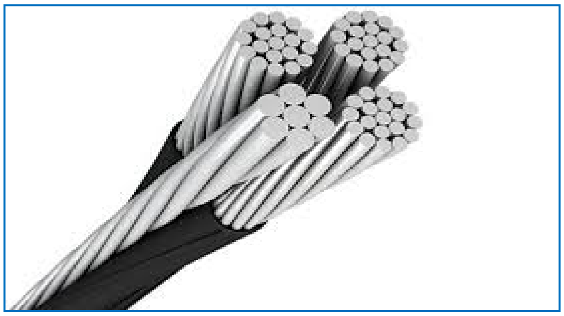

Figure 10: Example of 4/0 Quadplex

Conductor	CATID	Rating
4/0 3-1C W/ 4/0 NEU QUAD	1650140	280 A

Table 7: 4/0 AWG XLPE Quad Rating

2.4. Overhead Transformers

Transformers are used on the distribution system to convert power at primary voltage to secondary voltage for customer use. Pepco uses mineral oil-immersed self-cooled conventional type overhead transformers like the one shown in Figure 11 from Standard 0999. There are several different options that range from 25 to 167 KVA and secondary voltages from 120 to 265 V. One transformer can be installed on a distribution pole to serve single phase load or several can be installed on a cluster mounted bracket to provide 3-phase power in a 3-phase transformer bank. Larger loads are supplied from pad mounted or subsurface transformers of up to 2500 KVA capacity which are covered in the URD section.

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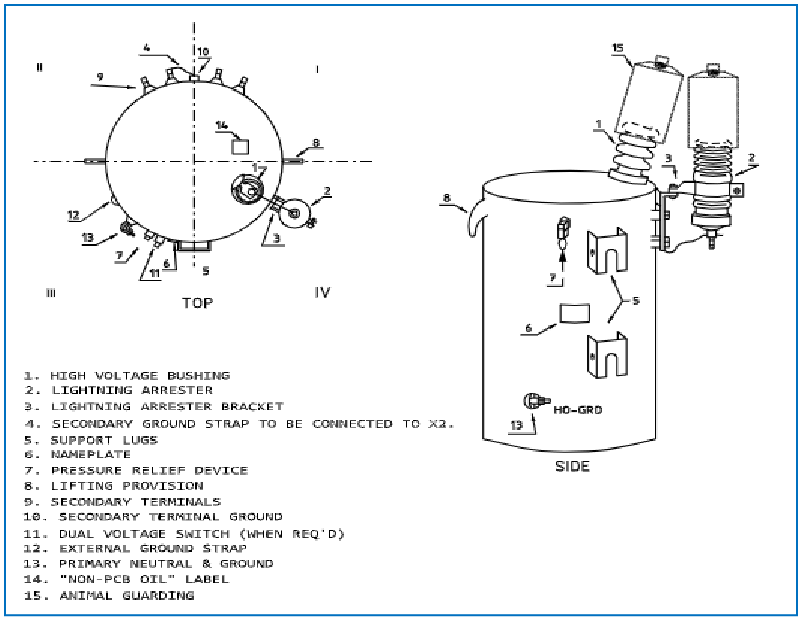

Figure 11: 1 Ph Overhead Transformer Example

2.4.1 1 Ph OH Transformers

Figure 12 from Standard OH-4401 (0598) shows an example of a 1 phase transformer installation and Figure 13 shows the connections from Standard OH-5501 (0584). Pepco uses 25, 50, 100, and 167 KVA overhead transformers to serve single phase and 3-phase loads. A ground strap connects X2 and X3 together and to the neutral creating a zero-reference point resulting in 120 V across X1-X3 and 120 V across X2-X4, 180 degrees out of phase with X1-X3 providing for 240 V across X1-X4. This gives single phase customers 120/240V service with two hot legs and a neutral. All new single-phase transformers are to be 50 KVA or higher and installed on 50 ft poles. 25 KVA transformers can be used for rear lot lines and rural, single customer, connections.

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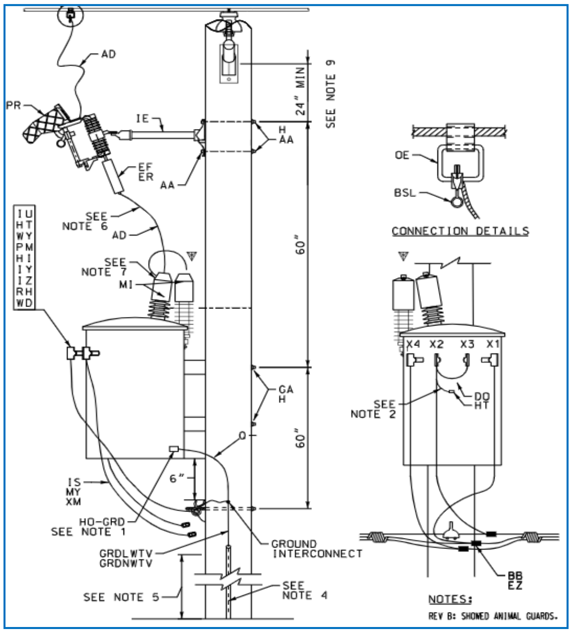

Figure 12: 1 Ph Transformer Installation Example

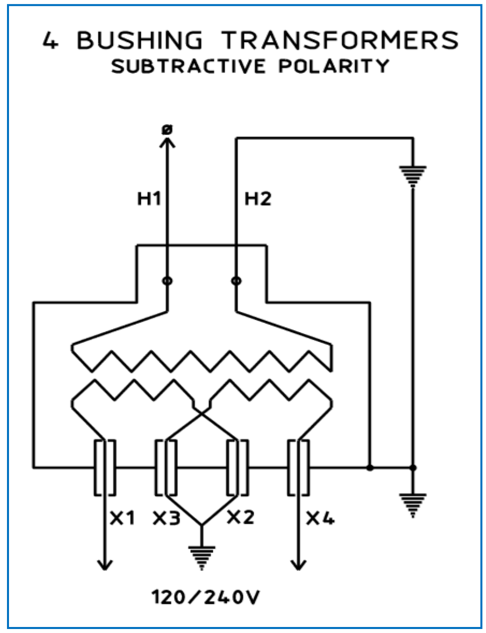

Figure 13: 1 Ph Single Bushing 4 Pole 120/240V Example

2.4.2 3 Ph OH Transformers

3-phase transformer banks range from 75 KVA to 500 KVA and are used to supply power to single and 3-phase loads. They can be configured in serval ways to meet different customer requirements. Some examples are 120/208 V wye-wye, 120/240 V open and closed delta, and 265/460 V wye-wye banks. The below figures show some construction and connection examples. When a customer has a mix of single and 3-phase loads, each transformer will be sized to handle the single-phase load connected to it and 1/3 of the total 3-phase load.

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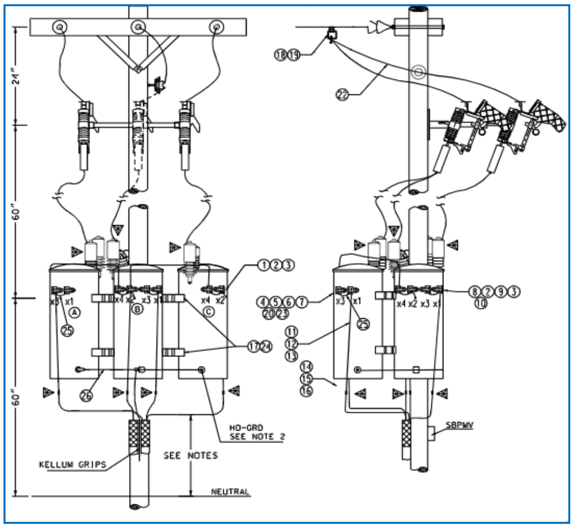

Figure 14: 3 Ph Bank Standard OH-4402 (0616)

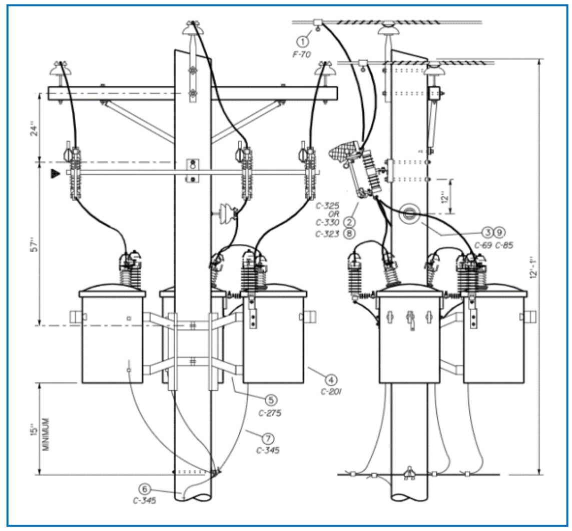

Figure 15: 3 Ph Bank Standard OH-4480 (L-80)

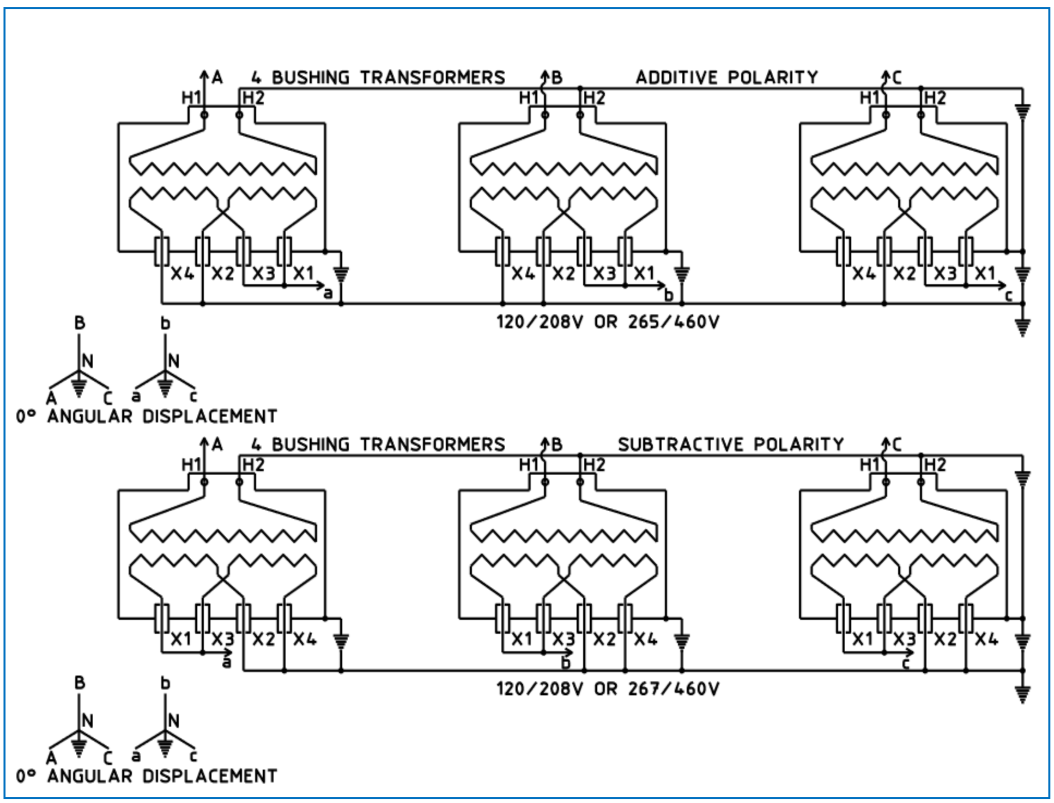

Figure 16: 3 Ph 120/208 V Wye-Wye Bank Example from Standard OH-5501 (0584)

2.4.3 Step Down Transformers

Step down transformers are used to step the primary voltage down to a lower primary voltage. The more common examples are stepping down 13.2 KV to 4.2 KV to serve a large customer or to provide power to an older 4.2 KV circuit or section of circuit that has not been converted to 13.2 KV.

2.5. Overhead Switches

Switches are used on the Pepco distribution system to provide a means to sectionalize and isolate different parts of the feeder. They give operations the flexibility to restore customers out of service by transferring them to another part of the feeder that is still energized or an adjacent feeder. Switches can also be used to transfer customers to reduce their exposure to the more sensitive maintenance mode of the breaker or hot line tag of the recloser should a contact cause a breaker or recloser to lockout.

2.5.1 Underarm Disconnect Switch

Pepco uses a 13 KV 600 A rated under arm disconnect switch on the 4 KV system. They are single unit manually operated switches. Figure 17 and Figure 18 from Standard OH-6905 (0594) show how the switches are installed.

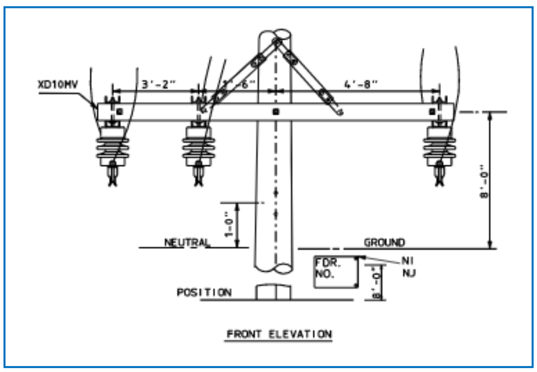

Figure 17: UAD Switch Front View

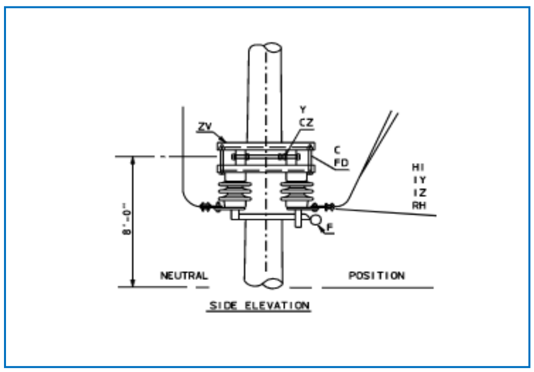

Figure 18: UAD Switch Side View

2.5.2 Gang Operated Switch

Gang operated switches operate all 3-phases simultaneously. This eliminates any current imbalances during switching that is experienced when switching with manually operated underarm disconnect switches. Figure 19 from Standard 0678 shows the installation of a gang operated crossarm mounted switch assembly.

Figure 20 shows an SF6 gang operated switch from Standard OH-4302 (1716_O-45). Refer to Standard OH-6901 (C-301) for a gang operated load break switch and Standard OH-4301 (O-35) for the horizontal (HOG) load break hook stick switch shown in Figure 22

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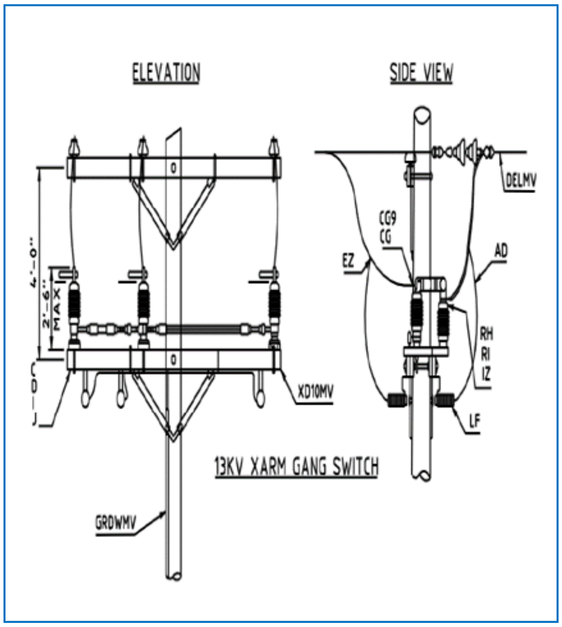

Figure 19: Crossarm Mounted 13 KV Switch

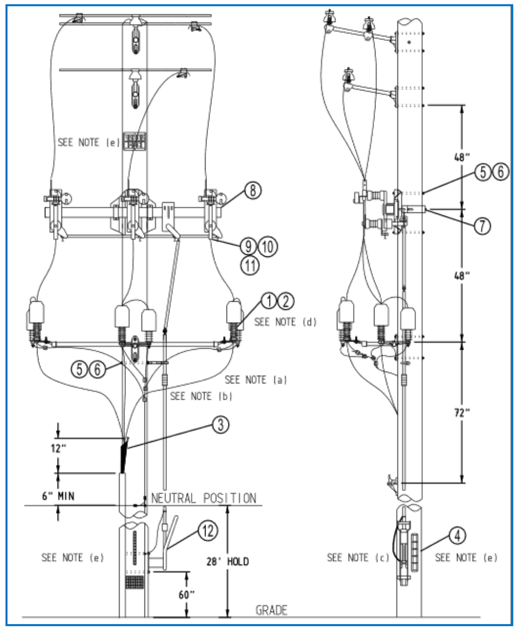

Figure 21: Gang Operates Switch Armless Construction, OH-1455

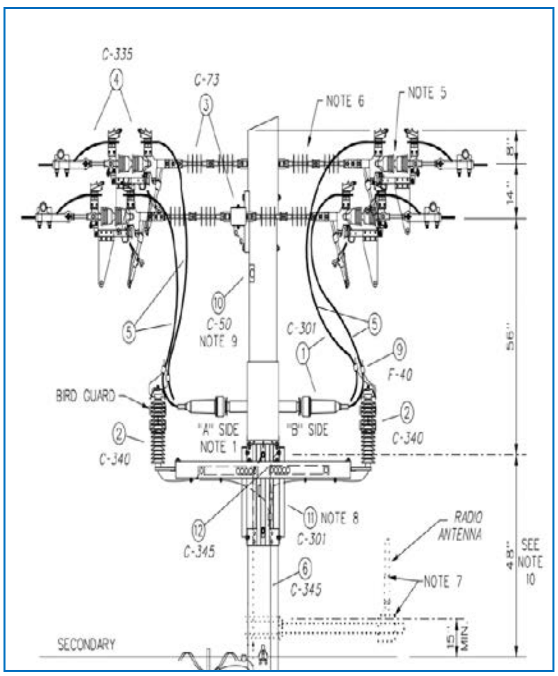

Figure 20: SF6 Gang Operated Switch

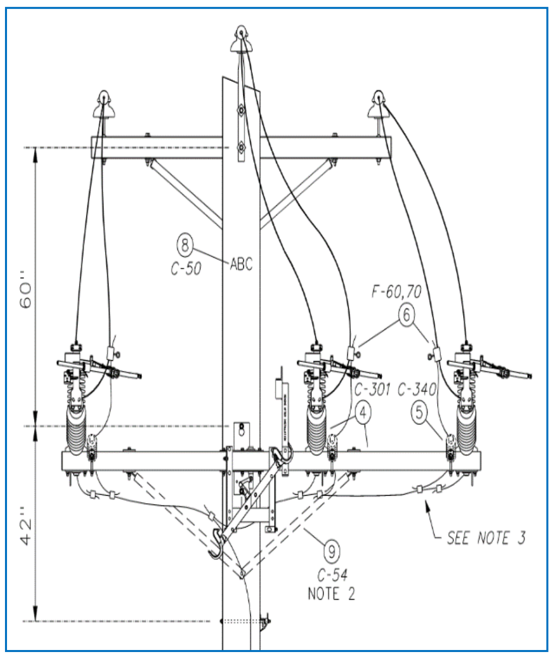

Figure 22: HOG Switch

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2.6. Voltage Management

Distribution loads have an impact to the voltage profile of the circuit. Inductive loads like motors produce inductive reactance causing the current to lag the voltage. Loads far from the source experience lower voltages due to the power losses inherent in the conductor the current needs to traverse. Capacitor banks are used to provide capacitive reactance which counteracts the inductive reactance from the served load and brings the current more in phase with the voltage. They also raise voltage locally helping prop up the voltage in areas farther away from the substation. Voltage regulators can step the voltage up or down allowing the voltage to be controlled more precisely and are mainly used to support voltage where reactive support isn't needed. Surge arresters protect the circuit against voltage swells caused by lightning strikes, manual switching, faults, and other transient phenomena.

2.6.1 Capacitor Banks

Pole type capacitors are used for voltage support and system reactive correction. Figure 23 lists the available capacitor banks and their specifications. Banks are protected with three load break cutouts fused according to Figure 23. Capacitors may be fixed or switchable. Fixed banks are either on or off and need a local technician to physically open and close the bank. Switchable banks have a local controller that can be set to voltage, VAR, temperature, and time modes and will automatically turn the bank on or off as conditions change. A radio can be installed, and the bank can be tied into the SCADA system so that the bank can be operated remotely. See PHI Spec 1600 and the various construction standards available. See Standard OH-4250 for capacitor controls. Figure 24 shows an example of a capacitor bank installation.

CAT ID	ASSEMBLED BANK RATING (KVAR)	VOLTAGE (KV)	BIL (KV)	WEIGTH (lbs.)	a	b	c	NUMBER OF CAPACITORS	INDIVIDUAL CAPACITOR SIZE (KVAR)	REGION
1658930	300	4.16	95	385	39.73"	75.00"	43.78"	3	100	ACE/DPL
1658915	450	4.16	95	430	39.73"	75.00"	43.78"	3	150	ACE/DPL
1651138	300	4.33	95	410	39.73"	73.54"	36.84"	3	100	PEPCO
1658921	900	12.47	150	515	39.73"	75.00"	43.78"	3	300	ACE/DPL
1658922	1200	12.47	150	545	39.73"	75.00"	43.78"	3	400	ACE/DPL
1651090	900	13.80	95	525	39.73"	73.54"	36.84"	3	300	PEPCO
1651125	1200	13.80	95	545	39.73"	73.54"	36.84"	3	400	PEPCO
1658926	900	24.94	150	550	39.73"	75.00"	43.78"	3	300	DPL
1658927	1200	24.94	150	575	39.73"	75.00"	43.78"	3	400	DPL
1658928	1200	34.50	150	600	39.73"	75.00"	43.78"	3	400	DPL
1658931	2400	34.50	150	915	39.73"	75.00"	43.78"	6	400	DPL

Figure 23 Available Capacitor Banks, OH-6103

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ASSEMBLED BANK RATING (KVAR)	VOLTAGE (KV_{L-L})	N-LINK	CLF
300	4.33	60N	65K-MT
600	13.80	60N	65K-MT
900	13.80	60N	65K-MT
1200	13.80	75N	80K-MT

Figure 24: Capacitor Fusing Chart, Standard OH-5604 (M-1)

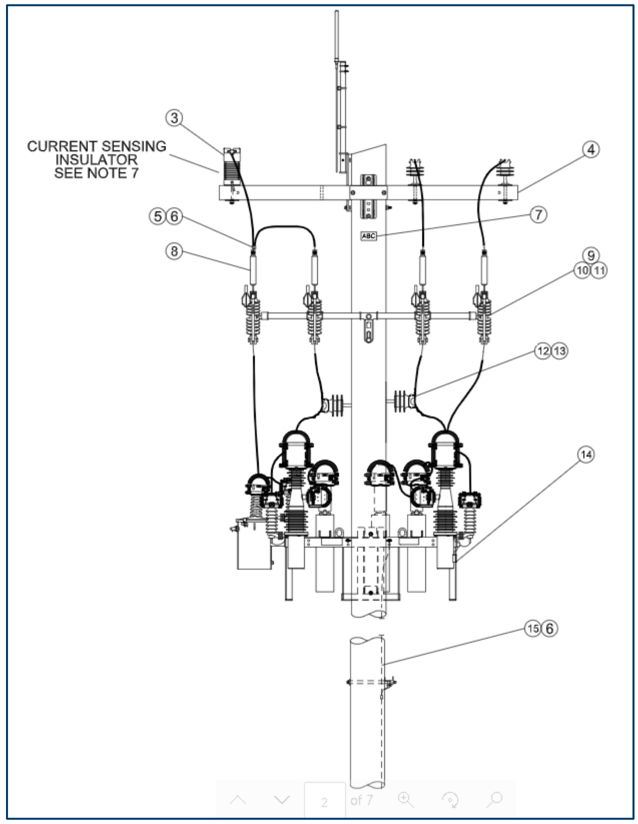

Figure 25: Capacitor Bank Installation, OH-4105

2.6.2 Voltage Regulators

Single phase bi-directional voltage regulators of 50, 167, and 250 KVA are available for voltage correction, Standard OH-6101 (C-225). Bi-directional regulators do not need to be placed in the neutral position prior to switching like uni-directional regulators. The maximum size was increased to 250 KVA to more nearly match the main feeder trunk capacity when set for five percent regulation. Regulator controls are available with or without battery backup. See Tech News 2015-10, PHI Spec 1469, and Standard OH-4151 (0884_L-107). 3 phase loads should be installed either upstream or downstream of a set of regulators but never in between regulators of the same set. This is so that all phase voltages are similar at the customer's service. Where distributed generation is installed on the circuit special control parameters maybe required that could require replacement of existing regulators with more modern devices with the proper control packages. Regulator sizes up to 250 KVA can be installed on their own pole. Larger regulators should be installed on a platform, Standard OH-4152 (L-108). Two regulators up to 167 KVA can be installed on the same pole. Figure 25 from Standard 1363 provides an example of a voltage regulator and Figure 27 and Figure 28 show some methods of construction.

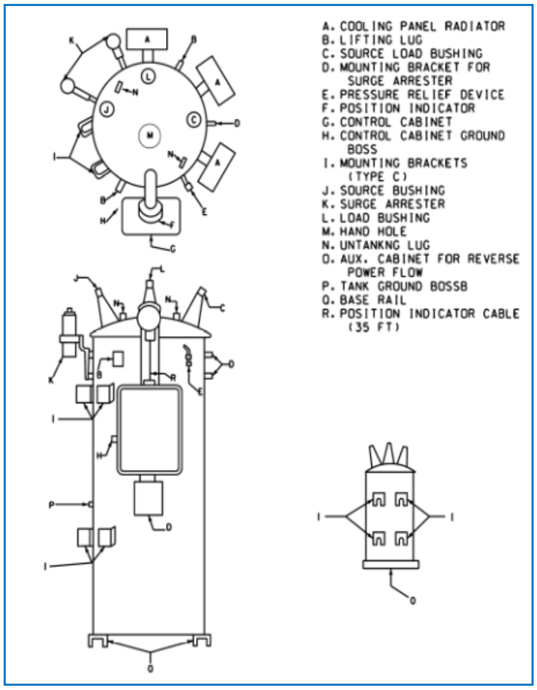

Figure 26: Voltage Regulator Example

Figure 27: Picture of Voltage Regulator

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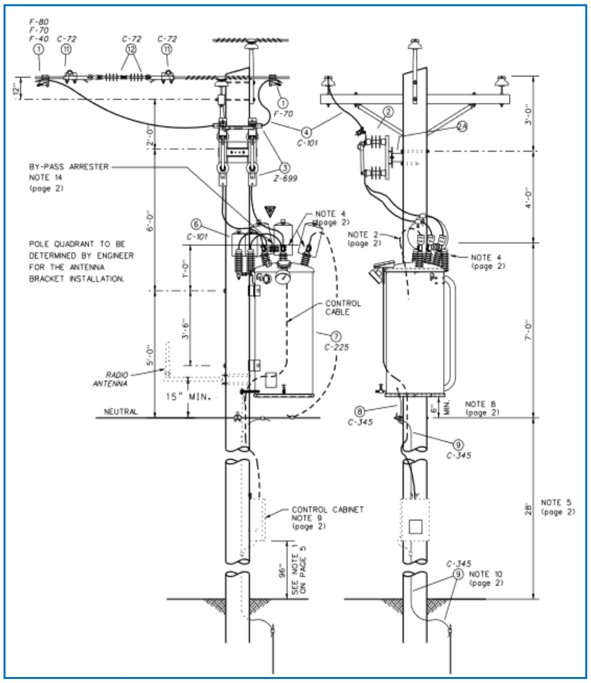

Figure 28: Voltage Regulator Installation Standard OH-4151 (0884_L-107)

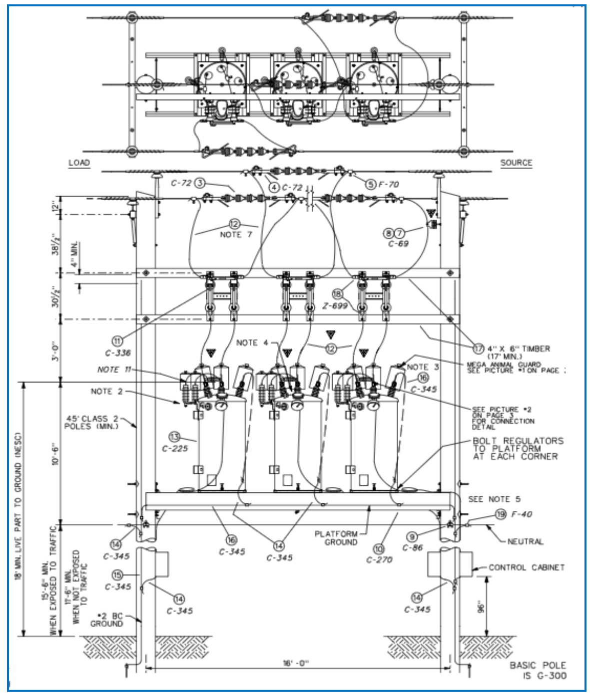

Figure 29: Platform Construction Standard OH-4152 (L-108)

2.6.3 Surge Arresters

Pepco follows industry best practice of installing surge arresters to protect all installed equipment and open points. Example locations are at dead ends, on both sides of switches, capacitor banks, risers, poles adjacent to risers, reclosers, transformers, midpoints, and at open points in pad mounted equipment. Overhead arrester stations must be provided approximately every 600 feet as per Distribution Standards best practice (See Tech News 2004-06). All new overhead arrestors on the 13 KV distribution system are metal oxide varistors (MOV) heady duty class 10 KV MCOV arresters, Standard OH-6002 (C-340). Pole mounted transformers come with arresters pre-installed. For other overhead installations like switches arrestors are provided as an individual stock item (1650861), see Figure 29.

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Figure 30: OH Distribution Class Arrester

2.7. Overhead Protection Equipment

2.7.1 Distribution Circuit Breaker

The Pepco 4-wire distribution system feeders use a feeder circuit breaker located at the substation to protect the substation bus from distribution faults. They use a combination of instantaneous and time current relays that sense feeder phase and ground current and trip at a desired overcurrent value. A high-set instantaneous and time-delayed protection scheme is used at the main feeder breaker for fault protection and programmed to automatically reclose in most cases to restore service to customers should the fault be temporary in nature. Pepco does not use the low set instantaneous setting usually used in a fuse saving philosophy. Instead, the time-delayed setting is used preventing the breaker from tripping for faults downstream fuses and avoiding momentarily interrupting all customers on the feeder. The time-delayed reclosing relay will initiate up to a total of 3 reclose operations. Pepco's fuse blowing philosophy is mainly driven by the fact that the Pepco distribution system has very high fault currents making it difficult to save even the highest size fuses from being damaged or completely melted in the time it takes for the low set instantaneous to operate. The low set instantaneous can be manually enabled by the OCC when needed. It is always enabled during maintenance mode (MM) for worker safety. When in maintenance mode, reclosing will be disabled if tripping occurs. The high set instantaneous protection operates only for very high magnitude faults close to the substation to prevent damaging substation equipment.

2.7.2 Reclosers

Automatic circuit reclosers (ACRs) are pole mounted protective devices that are similar to feeder circuit breakers in that they have the capability to detect faults, trip and reclose a set number of times. Unlike breakers, the newer microprocessor controlled reclosers have more coordination setting options and may trip and lockout single phase. Reclosers provide segmentation of the main feeder trunk like switches with the ability to have protection settings, remote control and reclosing like breakers. Pepco is moving towards a fuse blowing philosophy for recloser protection so downstream fuses will clear faults before the recloser operates. A fuse saving philosophy has one or more trip settings set to operate faster than certain fuse sizes to provide an opportunity to save the fuse in case the fault downstream the fuse is temporary in nature. The downside is increased momentary interruptions for customers downstream the operating recloser.

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The state-of-the art, electronic, 3-phase units may be utilized in complex distribution automation schemes and may be remotely controlled by system operators. A 3-phase 800 continuous amp, 12.5 and 16 KA interruption rated triple single ACR is available for the Pepco distribution system, see Standard OH-6301 (C-310).

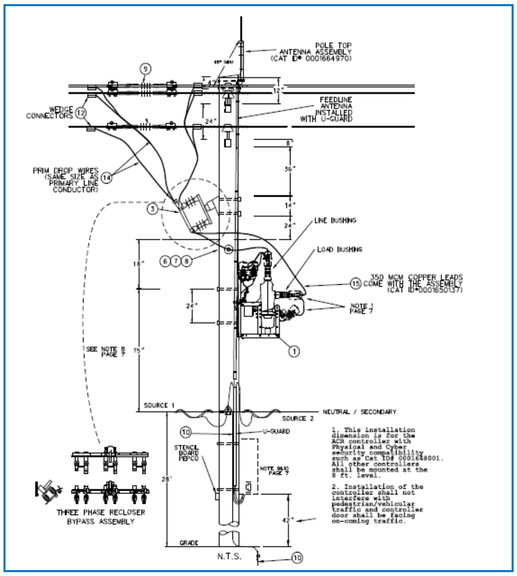

Figure 31: Viper Recloser Standard OH-4004 (1715_O-38)


Figure 32: Viper Recloser

Placement of ACRs should be recommended by Capacity Planning with concurrence by System Protection and Regional Reliability. Fault currents near Pepco substations often exceed ACR ratings and multiple ACRs placed in series can lead to coordination difficulties. Placing them in sectionalizing or switch mode can help solve some of these problems. See PHI Specification 1727 and Standard OH-4004 (1715_O-38) for more information. Additionally, Recloser Guideline 1731 provides more information on reclosers like that shown in Figure 32.

Type of Load	Mode A - Clase 1 Single-Phase Trip, Single-Phase Lockout URD/Underground Circuits	Mode B - Case 2 Single-Phase Trip, Single-Phase Lockout, three phase lockout for multiphase faults (Overhead circuits in close proximity to public roads)	Mode C - Case 3 Single-Phase Trip, Three-Phase Lockout	Mode D - Case 4 Three-Phase Trip, Three-Phase Lockout
Residential	Preferred	Preferred	Not Preferred	Not Preferred
Commerical	Preferred	Preferred	Not Preferred	Not Preferred
Apt of Office Building	Preferred	Preferred	Not Preferred	Not Preferred
Industrial W/delta higth side connections	Not Permitted	Not Permitted	Preferred	Not Preferred
DA Scheme Feeder	Not Permitted	Not Permitted	Preferred	Not Preferred
Major Government Feeders (with 3-Phase delta-wye or spot network service)	Not Permitted	Not Permitted	Not Permitted	Preferred
Deicated Feeder	Not Permitted	Not Permitted	Not Permitted	Preferred
Customer Transformer Delta high side (ACE - Mode A or B by exception)	Not Permitted	Not Permitted	Not Permitted	Preferred
Xfmers Downstream with Unground HS Wdgs	Not Permitted	Not Permitted	Not Permitted	Preferred
Recloser Max. Load > 50% of Upstream GND OC PU (Mostly applies to Pepco)	Not Permitted	Not Permitted	Not Permitted	Preferred
Cogeneration (3-Phase)	Not Permitted	Not Permitted	Not Permitted	Preferred

Figure 33: Mode Selection Guideline for ACR

2.7.3 Single Phase Reclosers

Single unit reclosing devices like the Trip Saver II (Drop Out Recloser) are available to provide similar functionality as the three phase reclosers for single and multi-phase applications. The vacuum interrupting reclosers are mounted into a custom cutout and have a load rating of 100 A with the ability to operate at higher load currents for short durations. They can be programmed with an array of protection settings with the most widely used settings mimicking an N type fuse. They have a display screen capable of displaying a wide range of parameters like the number of times tripped, contact life remaining, and fault and load current. Units are available rated for 12 and 25 KV, see Standard OH-6903 (1069_C-306) for details. When there is a need for high load capacity, an 800 A single phase recloser is available for the 12, 25, and 34 KV distribution systems, see Standard OH-4001 (1746_O-17).

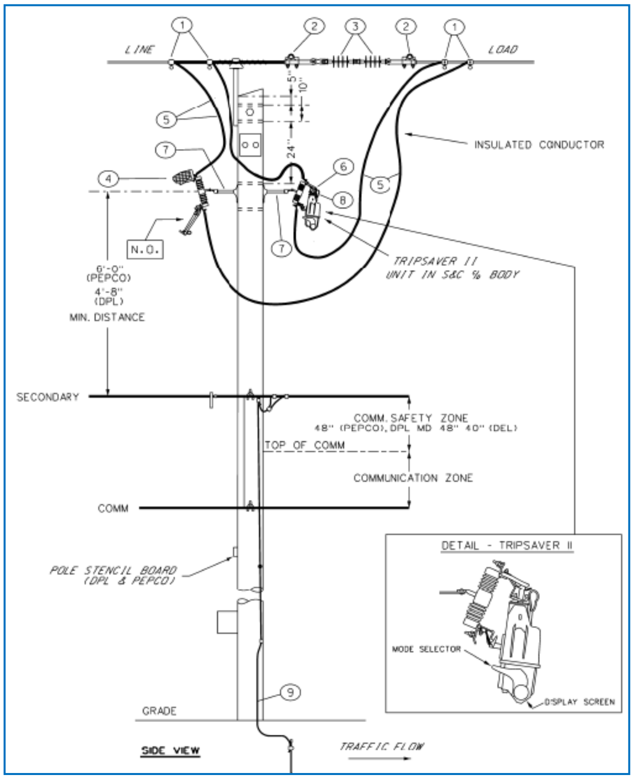

Figure 34: Trip Saver II Installation Standard OH-6906 (1069_C-306)

2.7.4 Line Expulsion Fuses

Fusing is used on the overhead system to improve reliability and customer service by further segmenting the feeder into smaller sections. This allows the outage management system to better predict the location of a fault on the system so first responders are dispatched more closely to the problem area. Pepco uses N type expulsion fuses whereas ACE uses K and DPL uses T type. The K type is fast acting and operates the fastest of the three. The T type is slow acting and therefore the slowest of the three leaving N type in the middle. Pepco lateral taps at or near the main trunk are commonly fused with a 100 amp N type expulsion fuse in a load break cutout to protect the main feeder trunk from faults on laterals. Expulsion fuses are metal alloys designed to start melting at a particular current value and completely clear in a certain amount of time based on the magnitude of the fault current. The gases produced by internal arcing "blow" the arc out This in combination with mechanical forces of the cutout door dropping and opening interrupt the fault current. Subsequent fusing should be two sizes lower than the upstream device, 75N downstream a 100N for example. The fuse coordination chart in Figure 36 shows the maximum fault current one N type fuse will coordinate with another N type and can also be used to more precisely coordinate fuses if the maximum fault current at the location is known.

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Line segment fuses must be rated above the anticipated maximum load current of the segment to avoid fuse operation during normal load conditions and should be sized to clear the minimum anticipated fault current of approximately 25 percent of the calculated minimum bolted line to neutral fault. Fuse sizes are recorded in GIS/GWD, tagged on the pole, and on feeder maps.

Figure 35: Fuse Link Example

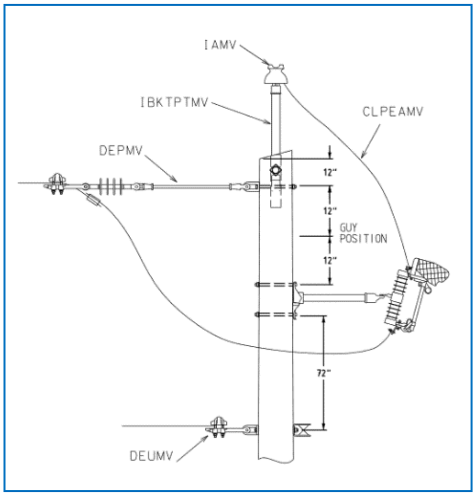

Figure 36: Fuse Cutout Installation Example

Type N fuse links

Protecting fuse link rating - amperes	Protected link rating - amperes													
	8N	10N	14N	20N	25N	30N	40N	50N	60N	75N	85N	100N	150N	200N
	Maximum Fault Current at Which B will Protect A - Amperes													
5N	22	150	280	400	490	640	1250	1450	2000	2650	3500	4950	8900	10000
8N			175	350	490	640	1250	1450	2000	2650	3500	4950	8900	10000
10N				200	370	640	1250	1450	2000	2650	3500	4950	8900	10000
15N					200	450	1250	1450	2000	2650	3500	4950	8900	10000
20N						175	1250	1450	2000	2650	3500	4950	8900	10000
25N							900	1450	2000	2650	3500	4950	8900	10000
30N								1300	2000	2650	3500	4950	8900	10000
40N									1300	2500	3500	4950	8900	10000
50N										1700	3200	4950	8900	10000
60N											2000	4950	8900	10000
75N												3700	8900	10000
85N													8900	10000
100N													6000	10000
150N														3000

This table show maximum values of fault current at which Type N fuse links will coordinate with each other. The table is based on maximum-clearing time curves FL3N for protecting links and 75 percent of minimum-melting time curves FL3N for protected links.

Figure 37: Type N Fuse Coordination Chart

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2.7.5 Current Limiting Fuses

Pepco operates with a closed bus tie configuration at the substation. This operation mode places substation transformers in parallel resulting in more energy available for faults. Therefore, current limiting fuses (CLF) are widely used on the Pepco system. Unlike expulsion fuses that use mechanical and gas forces to interrupt the fault current, current limiting fuses introduce high impedance as the metallic links begin to heat and melt converting the internal sand into glass. This reduces the maximum fault current experienced by the device in series during a fault condition. Pepco uses SMS type K-mate CLFs in all areas for overhead distribution. They are used to protect equipment from being damage catastrophically during a fault event to the point of becoming a major safety hazard. Figure 37 and Figure 38 from Standard OH-6302 (C-324) show an example of a CLF and how it is installed. The CLF is installed on the top of the cutout for sizes >= 65 amps and on the bottom for lower sizes.

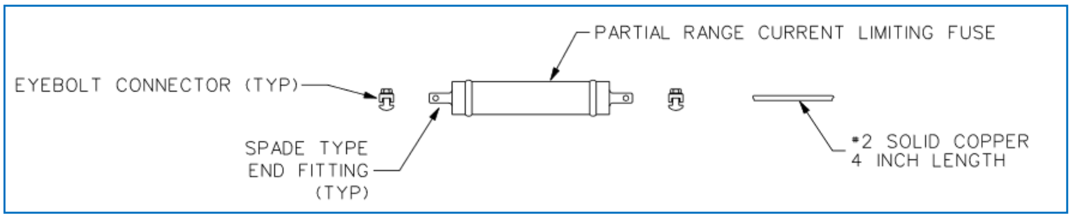

Figure 38: CLF Example

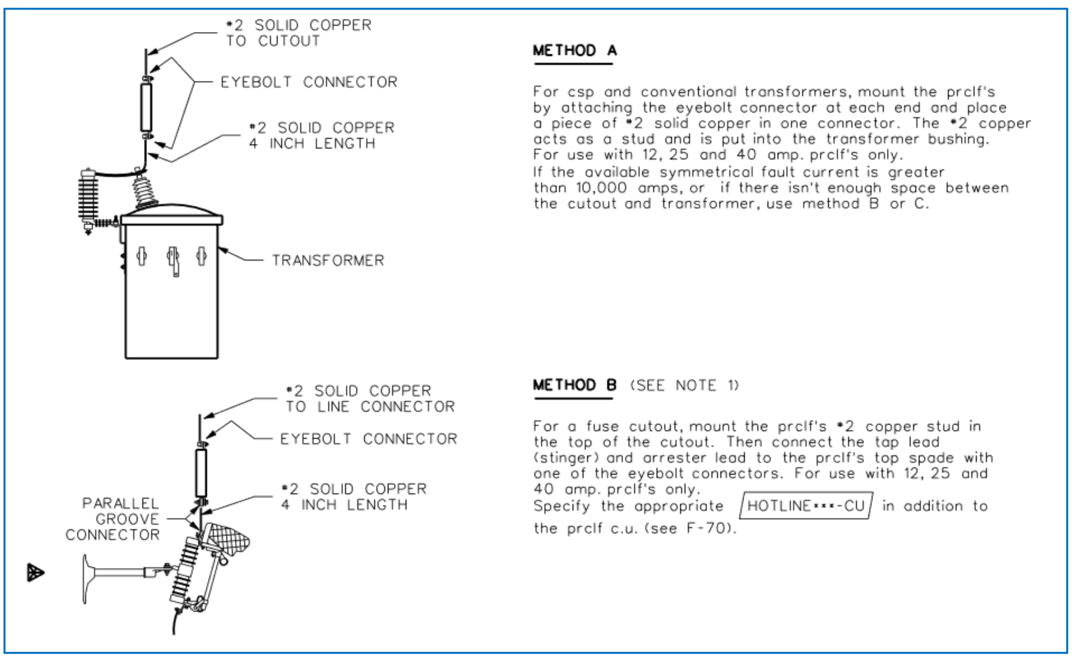

Figure 39: CLF Installation Examples

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2.7.6 Distribution Automation System

The distribution automation (DA) system is a computer-controlled system that ties into the SCADA and EMS interface through the fiber and radio network. It contains a model of the feeders, their breakers and reclosers which are mapped to the devices in the field. When a fault on the main trunk occurs, the upstream recloser or breaker will go through its normal protection sequence. Once it goes to lockout, the DA system will communicate with all devices on the feeder to determine which devices experienced the fault. That information allows the DA system to determine the fault location, then open devices to isolate the faulted segment and close normally open recloser ties to re-energize non-faulted segments. This automated feeder reconfiguration restores customers within a few minutes of the initial device lockout. Below is a simple example of how the system works.

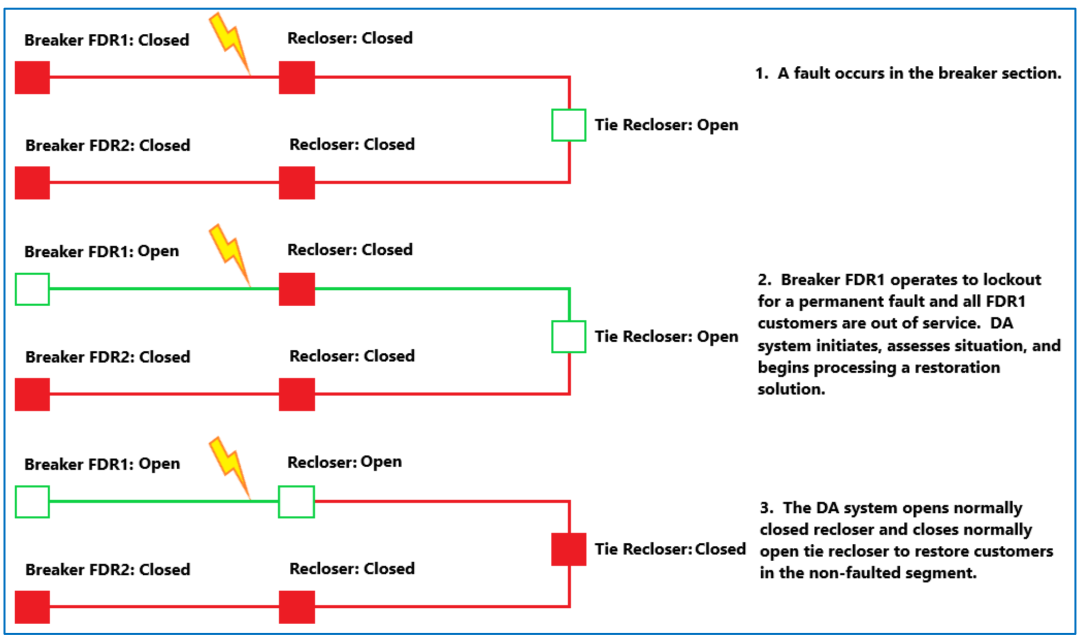

Figure 40: DA Example

2.7.7 Animal Protection

Pepco installs animal guards on all overhead equipment. The most common animal guard is the Shedmount guard in Figure 40. They are used on Viper reclosers, transformer bushings, and lightning arresters. The mini-Shedmount guard in Figure 41 is used for lightning arresters on the Viper reclosers, see technical bulletin TB-20-085. Figure 42 provides an example of both installed on a Viper recloser. Covered conductors are also used to protect against animal contacts. Tap wire comes already covered for new installations and replacement of existing bare tap wire. A conductor covering can be installed on existing bare wire

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Figure 41: Shedmount Animal Guard

Figure 42: Mini-Shedmount Animal Guard

Figure 43: Example Animal Guard Installation

The Shedmount animal guards aim to protect against animals like squirrels, raccoons, and small birds. For larger birds and in avian protection areas, avian specific coverings, excluders, and diverters are used to prevent bird contact with energized equipment and deter building nests, Standards OH-7105 and OH-7110 (C-500). The bird diverter like the one shown in Figure 44 is used to reduce the risk of collision, and should be installed every 15 ft and can be staggered on adjacent conductors to increase the spacing between diverters on any one conductor as shown in the example from technical bulletin TB-20-070.

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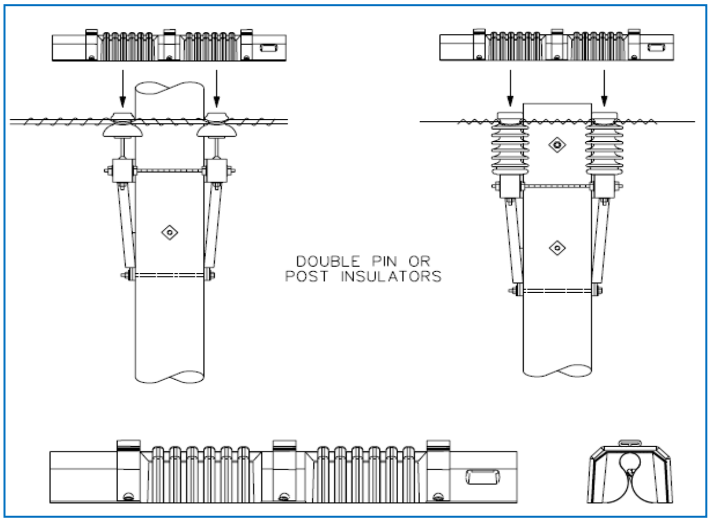

Figure 44: Avian Covering

Figure 45: Bird Diverter

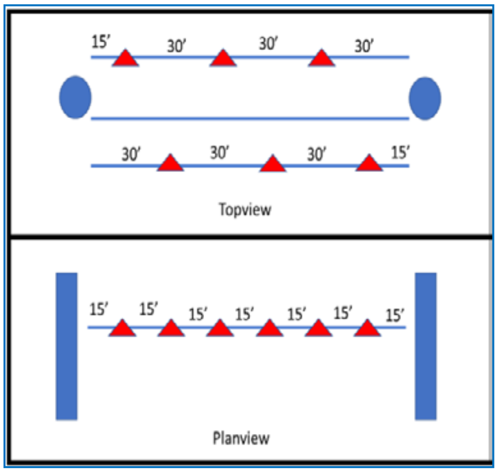

Figure 46: Bird Diverter Spacing

2.7.8 Overhead Fault Circuit Indicators

Pepco uses fault circuit indicators (FCI) on the overhead distribution system to more quickly identify faulted sections of feeders in an effort to reduce outage durations. They are installed on the primary conductor usually near manually operated switches, where the feeder branches, or long express runs. They have a trip current range of 200 A to 2400 A with a max operating voltage of 46 KV. They can withstand current up to 25 KA for 10 cycles and when they are triggered, will flash for up to 8 hours before resetting. They also reset themselves when load reaches 5 A. Figure 46 from Standard OH-6050 shows an example of a fault circuit indicator.

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DIVISION	CU	STOCK #	CAT ID	QUANT	DESCRIPTION
ACE, DPL	FCI100A69	9713-3008	0001651445	1	1PH LED OH CLAMP ON FCI
PEPCO	FCI100A69P	9713-3008	0001651445	1	1PH LED OH CLAMP ON FCI
ALL	N/A	N/A	0001616317	N/A	MAG TEST/RESET TOOL

Figure 47: OH Fault Circuit Indicator

3. Underground Distribution

3.1. Underground Design

The underground four-wire system has evolved into a double loop system with the main radial feeder trunk consisting of loops that have branches through subway or pad mounted four-way, 3-phase, load break, gang switches. Each branch is backed up by a full capacity open tie point from another main trunk feeder. Lateral underground residential distribution (URD) loops tapped from the main feeder are made at 3-phase load break switched tap points and are fused with current limiting, back-up type fuses. The URD supplies the customer load through totally underground radial single, two, and 3-phase circuits without branches, and are backed up by similar one, two or 3-phase radial taps from the same phases of the same or another feeder at a normally open load break tie point, see Figure 47. UG systems involve manhole and vault construction in duct bank and are used for the main feeder 3-phase, express runs, or network applications. URD is typically a mix of conduit and direct buried lines that run to pad mount transformers serving customer load protected by current limiting fuses.

Mainline conduit in public space will be concrete encased 5” or 6” fiberglass reinforced epoxy conduit or, depending on application, encased or direct buried 4” PVC SCH 40 conduit. Conduit on private property installed by the customer, either direct buried or encased, must be SCH 40 PVC. In order to accommodate the larger 13 KV feeder cable, all main trunk conduit is to be 5” fiberglass conduit encased in concrete, including but not limited to tap hole connections and network secondaries. 5” fiberglass conduit should also be used in any application where there is a potential for future unfused mainline trunk primary cables. For further information on conduit, manhole, and cable and splice design, see Conduit Construction and Trenching Practice Guideline 1428 in the underground standards construction section.

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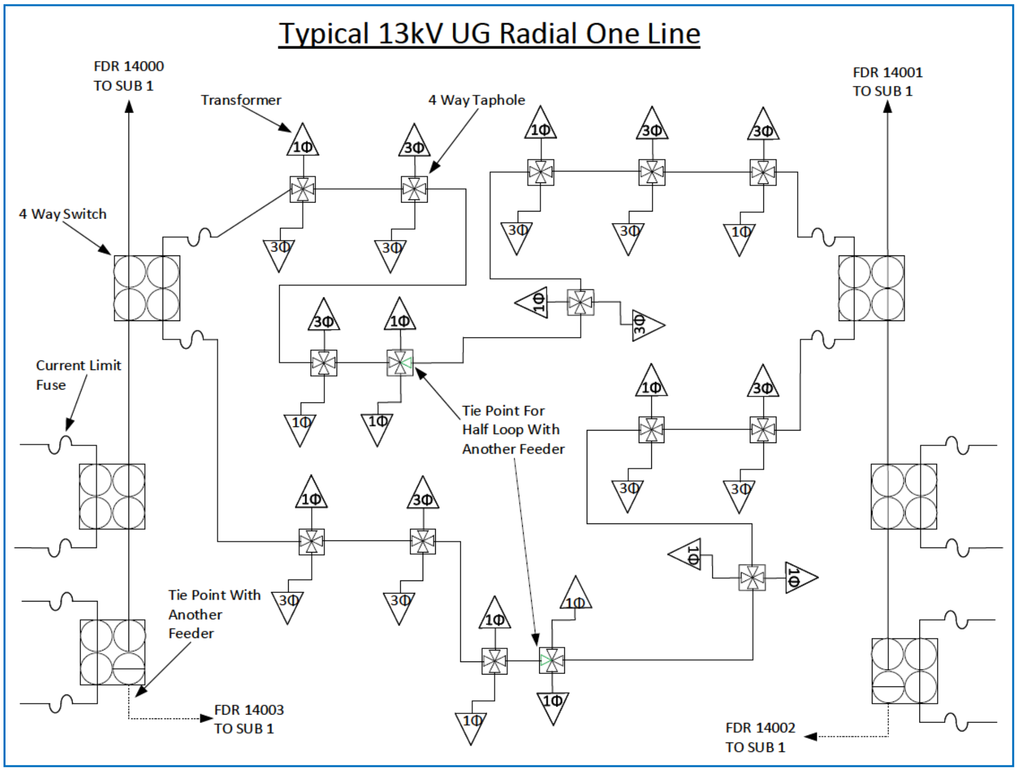


Figure 48: UG Radial 13 KV 4-Wire System Schematic

3.2. Underground Cable

The entirety of the trunk must be a cable sized to carry the full feeder load. All Pepco mainline conductors are to be copper. Currently, Pepco uses 15 KV 600 KCM CU 3-1/C EPR flat strap 133% insulated cable as the standard mainline cable. The cable has an equivalent 4/0 bare copper neutral. A 500 KCM compact flat strap with 100% insulation level is suitable when limited duct size space is a consideration. The 750 KCM flat strap cable (1644096) is also available for special circumstances, but it is not commonly used. Other sizes of flat strap cable are the 4/0 and the 350 KCM. Single legs of 750 KCM copper tape shielded cable are also available for substation getaways if derating is an issue. As in overhead construction, the standard conductor chosen for Pepco's underground distribution system facilitates normal and emergency configurations. Table 8 and Table 9 display the cable ratings for 600 and 500 KCMIL flat strap from Capacity Planning Appendix A Thermal Capacities of Cable and Wire Table III-C.

	SUMMER	WINTER
NORMAL	550 A	570 A
EMERGENCY	685 A	700 A

Table 8: Ratings for the 600 KCM CU flat strap

	SUMMER	WINTER
NORMAL	495 A	510 A
EMERGENCY	615 A	630 A

Table 9: Ratings for the 500 KCM flat strap main line cable

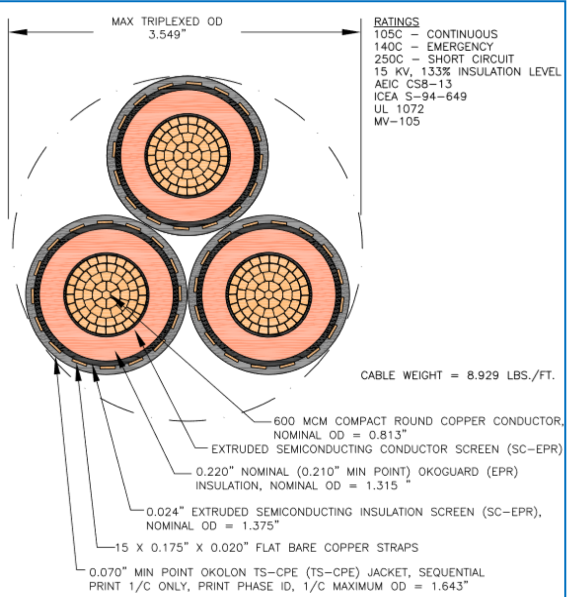
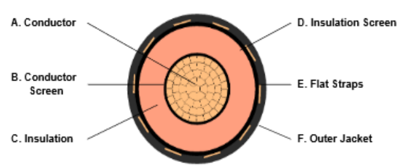


Figure 49: 600 KCM Main Trunk Primary Cable

3/C PLEX, 15kV Rated, 133% Insulation Level, URO-J

A. CONDUCTOR: 600 kcmil Compact Round Class B Strand Copper
B. CONDUCTOR SCREEN: Extruded Semiconducting (SC-EPR)
C. INSULATION: 220 Extruded Ethylene Propylene Rubber OKOGUARD®
D. INSULATION SCREEN: Extruded Semiconducting (SC-EPR)
E. CONC. FLAT STRAPS: 15 X 175 X 020 Bare Copper Flat Straps
F. JACKET: 080 Encapsulated OKOLON TS-CPE® (Thermoset Chlorinated Polyethylene)



Dimensions	Thickness (in.)		Diameter (in.)			Cable Description
	Nominal	Minimum Point	Minimum	Nominal	Maximum	3/C PLEX 600 CLASS B COPPER C-RD -SS- 220 OKOGUARD EPR - 024 SC EPR - TAPE - 15 X 175 X 020 COPPER FLAT STRAPS - DW TAPE - 070 MIN POINT OKOLON TS-CPE - PRINT PHASE ID TRIPLEXED 3 X 1/C - SEQ PRINT 1/C ONLY - 15KV
Conductor	N/A			0.813		
Cond. Screen	0.025	0.020		0.859		
Insulation	0.220	0.210	1.285	1.315	1.335	
Insul. Screen	0.027	0.024		1.375		TEMPERATURE RATINGS 105°C - Continuous, 140°C - Emergency 250°C - Short Circuit
Flat Straps	0.020			1.432		
Outer Jacket	0.080	0.070		1.643		
TRIPLEXED	Triplexed Diameter: Cable Weight (lbs./M'):			3.549 8929		

Figure 50: 600 KCM Primary Cable Specifications

Previous construction using copper shielding neutral required a separate 4/0 compact copper neutral cable. The 4/0 neutral was decided upon as it can withstand 42 KA fault current for 10 cycles without excessive heating. One neutral sufficed for multiple feeders with lead sheaths. Flat strap cables carry their own full rated neutral within the cable jacket and do not need an external neutral under normal use.

3.3. Cable Accessories

Splices play an important role in connecting together cables on the underground system. They come in several different types, each with a variety of configurations.

Separable straight, 2-way, splices are the preferred method for the first manhole outside the substation or before a piece of equipment on the mainline. They are easier to separate compared to other splice types, making it easier to change the number of cables when adding or removing load and when the feeder is reconfigured. They come in cold shrink and premolded receptacle with cold shrink being the preferred style and premolded as a backup or for emergency use, see Standard UG-6504. Separable splices can only be used on solid dielectric cables like EPR. , Figure 50 from Standard UG-6504 (1075), features a replaceable spiking aid to assist when testing for dead

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without destroying the cable. A minimum 6'x12' line hole should be built to accommodate splicing of separable connectors.

Cold shrink splices are the standard for mainline joints when future branch taps will not be needed. Radial feeders, dedicated feeders, and long sections of express cable are a great application of cold shrink splices. They are only used in straight applications and are the preferred method over heat shrink.

Heat shrink splices are another splice type. They are often the backup splicing method to separable and cold shrink providing an alternative means for straight and branch splice applications. They are the only splice type used for transitions between 3/C PILC and 3-1/C EPR.

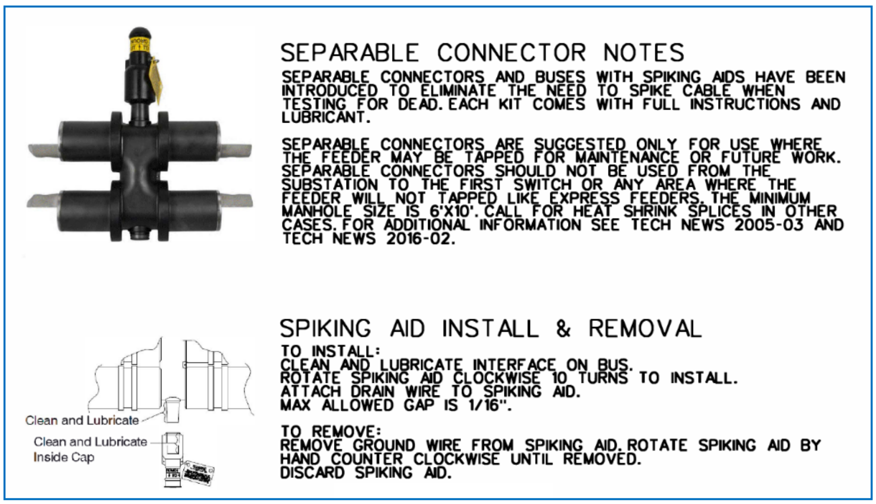

Figure 51: Separable Connector from Standard UG-6504 (1075)

Terminators are another important means of connection on the underground system. They are mainly used for overhead to underground transitions. Figure 51 provides an example of a 3-phase termination. 15 KV terminations are made with range taking cold shrink outdoor rated termination kits and 35 KV use heat shrink outdoor rated.

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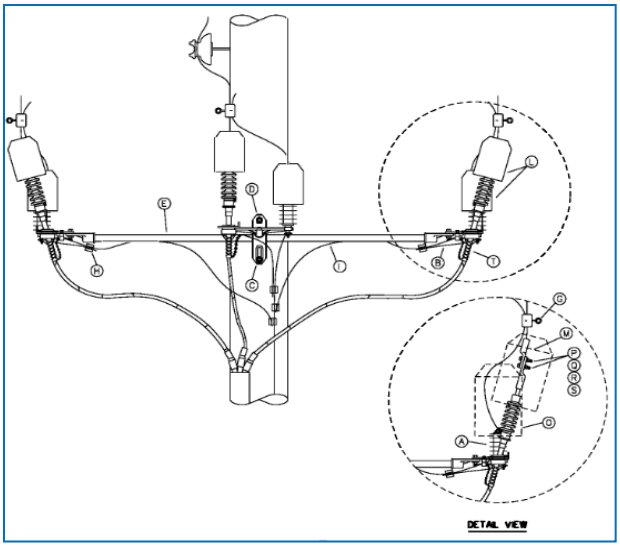

Figure 52: 3-phase Termination Example Standard UG-1100 (Z-420)

For secondary cable, pre-molded secondary busses are available. These copper "S-busses" eliminate problems with hand taped joints and were decided as a best practice in 2012. See Standard UG-6504 (1075) & Technical News 2005-03.

3.3.1 Grounding of Splices and Terminations

The adopted grounding practice dictates that each splice or termination shall have an external ground braid that is bonded to the system ground. When splices are not grounded it can damage a larger footage of cable or lead to touch voltage between the shield and ground.

3.4. Guidelines for Primary & Secondary Cables

- Never bring back fused primary cable into a switch, transformer, or fuse hole. Never run 3-phase into an equipment hole or fused primary through an equipment manhole.
- If radial primary feeder and secondary mains are in the same hole, then they must be racked on different walls. If they absolutely must be on the same wall, rack the secondary above the primary. Arc proof taping should be applied when cables are within 10 inches of each other, see Standard UG-6802 (1398).
- Load calculations must always be performed.

All designers should additionally review G-1441 LVAC Guideline for further best practices and information regarding the derating of cables due to multiple sets of cable in a shared duct bank.

Regional Engineering is responsible for determining whether or not, to facilitate future system expansion and rearrangements, the installation of conduit is required in advance of paving streets, roads and thoroughfares in new developments which will connect two collector streets, roads or thoroughfares.

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3.5. Underground System Protection

The underground four-wire distribution system has the same array of protective equipment available as the overhead. Feeder breakers, reclosers, and fusing are all present if the UG distribution has a portion of overhead upstream. However, the underground system faces its own unique challenges that drive some differences in system protection.

3.5.1 UG Fusing

The current limiting fusing (CLF) is different when mounting inside a manhole. 150E-EJO fuse types are used for CLF applications. Figure 56 shows an example of UG encapsulated CLF from Standard U-6215. Underground secondary networks are fused on the secondary side with network protector fuses and bayonet fuses are used in pad mount transformers to provide protection to the system should there be a primary or secondary fault at or downstream the transformer, see Table 14 in the appendix for details. For a subsurface or subway type transformer located in a manhole that is supplied from an overhead line, the bayonet fuse holder is to be slugged and there is to be a load break cutout fused on the pole only. An expulsion fuse, normal rated, is to protect the transformer and the backup (CL) fuse when there is overhead distribution upstream.

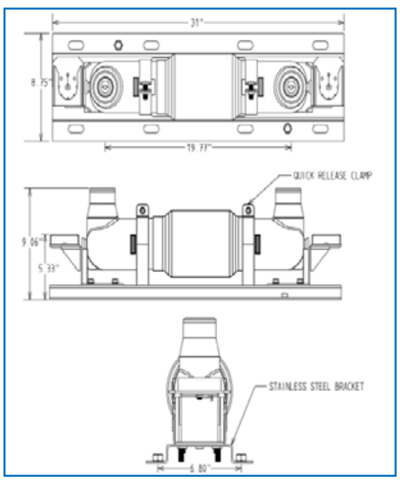

Figure 53: UG Current Limiting Fuse 150E-EJO

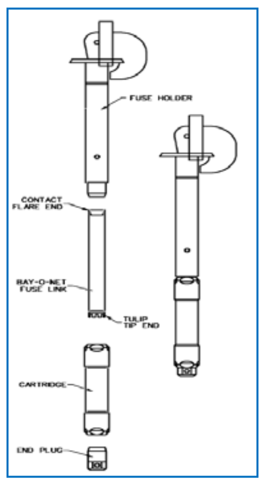

Figure 54: Bayonet Fuse

3.5.2 Underground Switches

Pad mounted and subway type load break gang switches are to be installed in accordance with approved guidelines for the application of 13 KV Oil Switch Guideline G-1443. On subway switch installations, phase and test modules are to be provided for all switch ways.

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Switches should always be installed with a test module that is used for phasing as well as testing for dead without the need for the crews to be in the manhole. Currently all ways on switches used on the system are 3 position – Open, Closed, and Ground.

While it's preferable to utilize pad mount equipment in most scenarios; certain cities, like DC and the City of Rockville do not allow any pad mounted equipment in the public space. In this case underground radial feeders requiring sectionalizing will require multiple switches along the trunk of the feeder. Unlike network feeders branch splices are prohibited on radial feeders. As seen in Figure 47, 4-way switches are installed along the main trunk of the feeder normally with the configuration of: an in, out, and two fused ways. However, since the switch isn't fused the switch could be used as an in, two out, and one fused way. The end of the underground radial feeder will have a normally open tie with another feeder from the same substation. Unused ways should be left in the open position.

3.5.3 Surge Protection

When an underground trunk is subjected to overhead exposure, submersible arresters should be provided as near as practical to the remote switch open points if such exist. Surge arresters are available for open points in the underground system in the form of 200 amp style elbow terminators. Arresters can be placed on test modules for vault based equipment or on four-way test modules for the new style of horizontal submersible single-phase transformers. Elbow arresters can be piggy-backed on 600 amp t-body elbows with a 200 amp tap at pad mounted switch terminals. They can also be used as test module bushing covers at subway switch installations. Further they can be placed on the second bushing of loop feed equipment. For pad mounted equipment the elbow arrester is to be used on the H1B bushing at open points at the end of the URD loop.

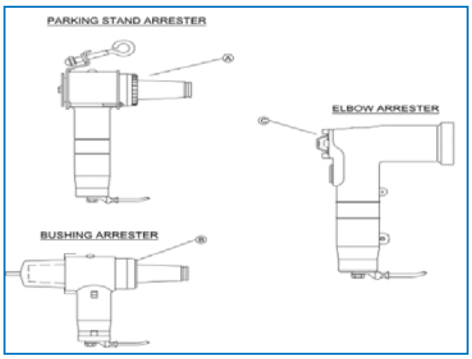

Figure 55: UG Surge Arrester Example Standard UG-6832

3.5.4 UG Fault Circuit Indicator

In order to reduce the duration of outages and improve the reliability of Pepco's distribution system, underground FCIs are to be installed on the outgoing feeders at the load break elbow, see Figure 55 from Standard UG-6050. It has similar ratings as the overhead FCI and it is important to ensure the neutral is not under the FCI. FCIs should be installed on elbows exiting transformers (pad mount, subway, or subsurface),

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switchgear, fuse enclosures (transclosures), and tap holes for underground and URD construction. The FCI identifies peak load current and automatically adjust to proper trip rating with minimum trip current of 200 A. It automatically resets after 8 hours or when load current reaches 5 A for small core and 10 A for large core. The FCI is powered by a non-replaceable battery with a 20 year shelf life and over 1500 hours of indicating time. They can also be equipped with an integral LED indicator. The indicator can be viewed remotely by means of a strategically placed fiber optic remote lead cable when the FCI is installed inside of a metal enclosure. If the indicator is installed inside an underground vault, the fiber optic cable is to be removed and an optical diffuser snapped into its place over the LED. 3-phase optical cables are ganged into a single indicator.

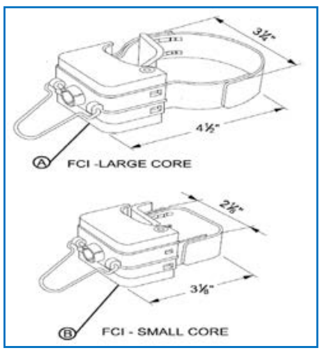

Figure 56: Examples of UG Fault Indicator

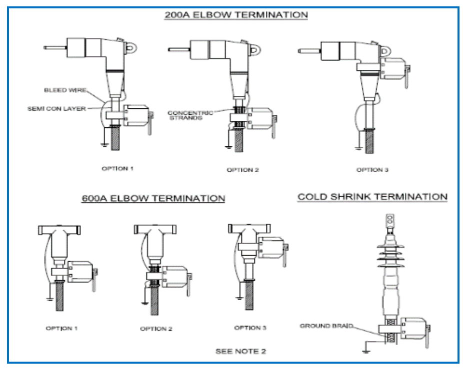

Figure 57: UG Fault Circuit Indicator on Elbow

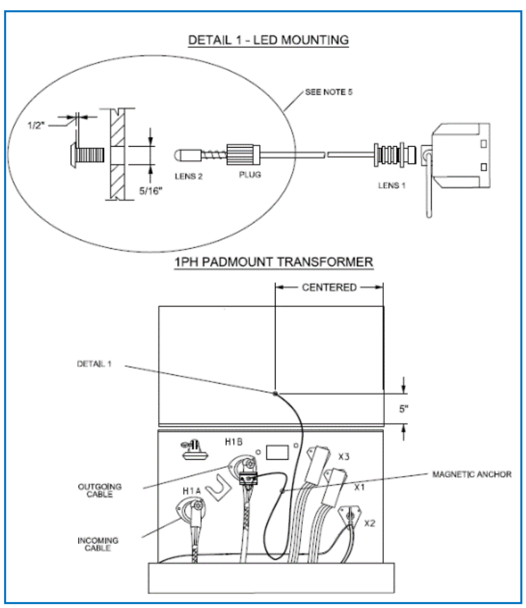

Figure 58 Example LED FCI w/ LED Light Install Standard UG-1130

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4. Underground Residential Distribution

4.1. URD Design

Underground residential distribution (URD) is a radial system that delivers power to the customers. Where URD four-wire distribution is installed, the accepted industry design ratings for 15 KV class URD equipment is 8 KV 200 amperes continuous and 10,000 RMS symmetrical amperes short circuit withstand and safe close for switching. These ratings place mandatory restrictions on distribution system design. Although the URD system is radial, it can be looped with a segment of URD of the same phase with a normally open point between to allow for load transfer for maintenance or emergency restoration.

Residential URD developments are looped when there are 30 customers or more, where a natural loop exists; and/or two or more entrances to the development. Commercial and industrial customers are looped when multiple customers are fed from 2 or more transformers. Looped design is also recommended for critical customers such as hospitals, airports, wastewater, and public safety. In general, looped primary cable should be installed in separate trenches where practical to prevent dig-ins or cable failures from damaging both cables in the loop, and to eliminate the need to de-energize both cables while isolating and identifying the faulted cable.

URD loops can be constructed in many ways. Common examples are 3-phase to 3-phase loops, 3-phase that branches out into multiple 1-phase loops of the same phase and 1-phase to 1-phase loops of the same phase. URD lateral loop switching is normally done with 200 A load break elbows. The loop open-point should, whenever practical, be made at a 3-phase device. This rule will generally negate the unsafe practice of having single phase loop tap cables of different feeders in a common trench which makes identification of cables difficult during maintenance. Further, this practice will minimize switching points for routine switching and emergency restoration. If a 3-phase transformer is not available, a tap hole should be used to provide the 3-phase open point. All 3-phase cables to a 3-phase transformer must originate at the same cable pole or transclosure.

Double cable poles, riser or transition poles with two or more sets of cables, shall not be built except where that is the only way to provide backup or a loop feed. Double cable poles are a single point of failure that can result in an interruption to the entire development negating the benefit of the loop feed design, and greatly obstructs climbing space.

The equipment short circuit ratings of 10,000 amperes with a capability of up to 40 kA requires that current limiting devices are placed upstream to reduce the effective available fault current to less than 10 kA. It is a standard practice on the Pepco URD system to install CLFs at the beginning of every URD half-loop.

The 8 KV line to neutral rating of the lateral tap CLF, dictates that all equipment beyond the loop-tap fuses be connected phase to neutral. Multi-phase lines must be effectively shielded to prevent phase to phase short circuits which do not involve the neutral. And, they should be designed so that back-up half loops are of the same phase from a different feeder from the same substation whenever practical.

The continuous current equipment rating of 200 A, when used in the open loop system, places a normal maximum design load restriction of 100 A, 800 connected KVA, on each phase of a half-loop tap. The full loop load of 200 A per phase can then be carried from either end, in an emergency, or on a planned outage, without loading the equipment beyond the design emergency rating. In addition, the lateral tap fuse can be subjected to transformer magnetizing inrush current and cold load pickup, which provides additional justification for limiting the aggregate of half-loop transformer name-plate ratings to approximately 800 KVA per phase connected. The 150E EJO CL fuse is a partial range or back-up fuse and is considered capable of withstanding a 33% overload of 200 A for an eight-hour period.

Capacity Planning requires that distribution feeders have no more than a difference of 45 A (360 KVA) between the highest and lowest loaded phases.

Connected KVA on multi-phase half loops shall be substantially balanced and the 800 KVA maximum per phase per half loop guideline still applies.

These values are maximum home counts for areas where geographical features ensure that no further construction will be added to the half-loops.

Type of Homes	1-Phase	2-Phase	3-Phase
Electric Heat	< 30	30-60	> 60
Non-Electric Heat	< 60	60-120	> 120
Townhouse Electric Heat	< 40	40-80	> 80
Townhouse Non-Electric Heat	< 80	80-160	> 160

Table 10: Number of Homes on Half Loops in Subdivisions

The limits shown above were calculated as follows:

$$\frac{45A \times 13.8kV}{\sqrt{3}} = 360kVA \text{ maximum unbalance}$$

Equation 1: Maximum Unbalance of 13.8 KV

Construction Type	Houses / Phase	KVA/Home
Single Family, Electric Heat	30	12
Townhouse, Electric Heat	40	9
Single Family, w/o Electric Heat	60	6
Townhouse, w/o Electric Heat	80	4.5

Table 11: Homes Allowed per Phase

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It should be noted that Planning is currently using the 2016 Facility Load Calculator worksheet to examine requirements for prospective new businesses. This worksheet looks at the building type and square footage of the building to calculate a power requirement. This worksheet will be approved for use by the design groups in Maryland and DC soon but was not included in this document as it is still under review.

Concurrence from Capacity Planning must be obtained prior to any configuration changes that would result in transferring load from one feeder to another feeder, one phase to another on the same feeder, or in supplying new customers from other than the recommended supply feeder.

URD loops tapped from overhead feeders will normally be made in accordance with Standards OH 1833 (0922) & OH 1811 (0923) for 3-phase and single-phase, respectively. Since overhead feeder trunk sectionalizing and backup is normally provided in the overhead system design, further overhead sectionalizing should not be required.

From the lateral tap CLF, the URD primary loop is extended radially, looped through each transformer, or tap hole for transformers in manholes, in one continuous line up and down streets in and out of cul-de-sacs as required to supply the required transformers. A single-phase half-loop will normally be a composite of single-phase loads and one-third portions of 3-phase loads. For DC, the installation is made in conduit, in public space, or in easements on private property as appropriate to physical conditions. Facilities should only be placed in public space when private property easements cannot be obtained. Maryland installs conduit in public space and direct buried in private space, see Guideline 1428 Conduit Construction and Trenching Practices for more details.

Where a planned single phase URD loop extension is relatively long and may be expected to be completed in more than one phase of construction, two or more cables should be extended so that loop feed can be maintained.

Where the URD loop tap cables would loop out and back in common trench, identification of cables buried randomly in trench would be difficult and unsafe to maintain. Provided that one of two cables or three of six cables for 3-phases can be place in a direct buried conduit from terminal to terminal for ready identification, a common trench can be utilized. Otherwise, the cables should be place on opposite sides of the street or in separate trenches or bores in the R/W with a minimum of three feet of horizontal separation.

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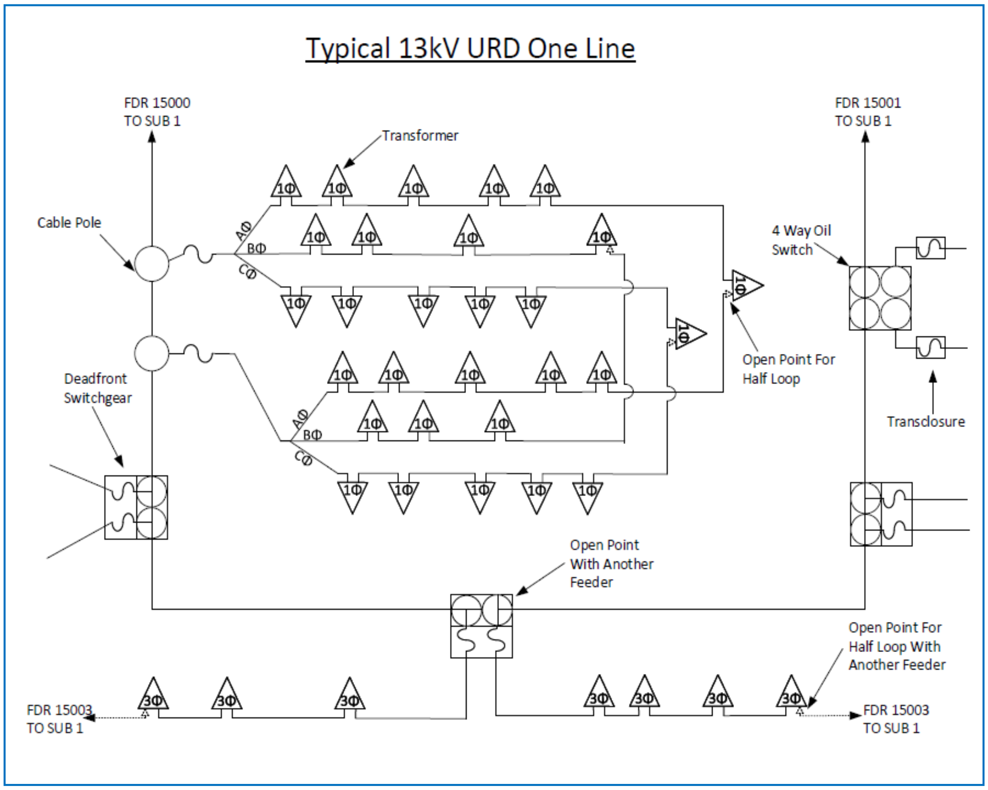

Figure 59: Example of URD Design

4.2. URD Cable

Pepco uses #2 7-stranded compressed copper with 133% IL EPR insulation for URD installations. The neutral is 15-#14 AWG concentric neutral wires. The jacket is 50 mils of linear low-density polyethylene (LLDPE). These cables are suitable for installation in conduit or direct buried in dirt.

4.3. URD Switching

Pepco has two available switches that can be used as means to isolate the URD system.

- One switch is the Padmount 4-way oil switch, Standard UG-3710. The oil switch is a load break device rated up to 64 KA symmetrical fault. If one or two of the ways of the oil switch will be suppling customer load than a pad mounted fuse cabinet, transclosure, will need to be installed nearby, Standard UG-6200.
- The other switch is the pad mount dead front air switch. The PME switch gear is a load break device rated up to 24 KA symmetrical fault and 600 A continuous current. The air switch is the preferred equipment for locations with fault current 25 KA and lower. The air switch comes in two variations: 2 switching ways and 2 fused ways, PME-9 Standard UG-3750, and 3 switching ways and 1 fused way, PME-11 Standard UG-3751. Padmount dead front air switches do not require a padmount fuse cabinet. Figure 59 shows an example of PME switch gear.

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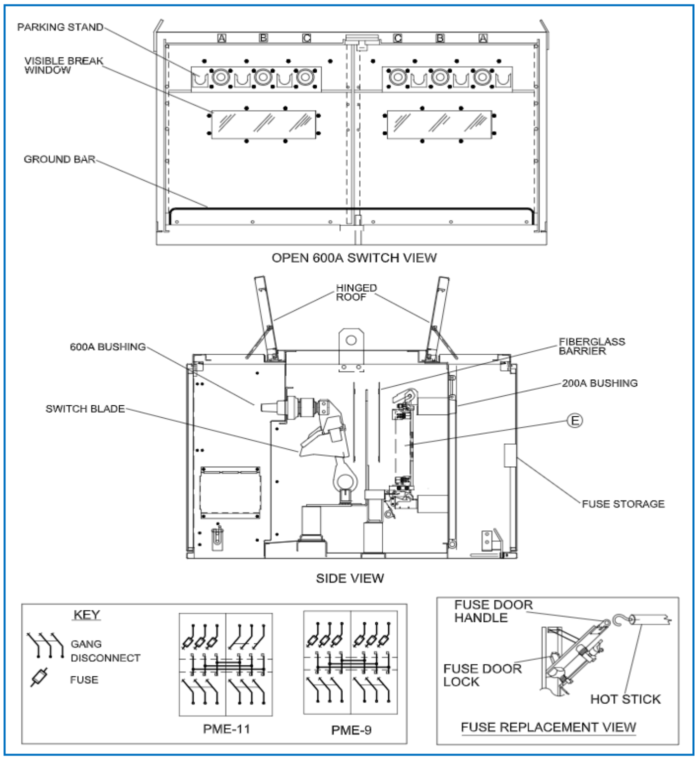

Figure 60: Dead Front PME Switchgear

URD loops can be constructed in many ways. Common examples are 3-phase to 3-phase loops, 3-phase that branches out into multiple 1-phase loops of the same phase and 1-phase to 1-phase loops of the same phase. URD lateral loop switching is normally done with 200 amp load break elbows. The loop open-point should, whenever practical, be made at a 3-phase device. This rule will generally negate the unsafe practice of having single phase loop tap cables of different feeders in a common trench which makes identification of cables difficult during maintenance. Further, this practice will minimize switching points for routine switching and emergency restoration. If a 3-phase transformer is not available, a tap hole should be used to provide the 3-phase open point. All 3-phase cables to a 3-phase transformer must originate at the same cable pole or transclosure.

Double cable poles, riser or transition poles with two or more sets of cables, shall not be built except where that is the only reasonable way to provide backup or a loop feed. Double cable poles are a single point of failure that can result in an interruption to the entire development negating the benefit of the loop feed design. Double cable pole construction greatly obstructs climbing space and is to be used only beside paved roads within ten feet of the curb or roadway and easy bucket truck access.

In locations where accessibility by a trouble bucket may be hindered, the URD tap should be made with a gang-switch accessible to an operator on the ground. The CL fuses would then be normally pad mounted or, if required, subway in manholes.

Branches on URD loops are to be made only with modules and load break connectors in tap holes or sectionalizing cabinets, and only to supply a single transformer or single feeder supply to a high voltage customer. Otherwise, “T” taps are prohibited.

URD tap holes are to be used for only three conditions:

1. Where construction delays would require the temporary test capping of two or 3-phases in common trench, a temporary tap hole should be used to provide for temporary emergency backup. This tap hole should be relocated or eliminated as construction progresses.
2. Tap holes or sectionalizing cabinets can be used as the loop feed through and tap for radial transformers in manholes where elbow switching at the transformer is not recommended.
3. In those instances where single phase open tie points would result in loop cables from different feeders being in a common trench, a 3-phase tap hole should be used to provide the open tie points. Except for these three conditions, tap holes should not be used for new work and removed during future system changes.

There are some unique scenarios when performing URD switching. When tying two circuits together from different substations, it may be necessary to take a momentary outage, break before make instead of make before break, to avoid overloading caused by circulating current. When closing an open point that would tie across a regulator, bi-directional or uni-directional, the regulator must be placed in the neutral position and the controls turned off prior to loop tie switching. It is common practice to only create loop tie points using the same phase to improve safety. However, there is one exception, for a two or 3-phase loop extension under construction in the same trench and in a temporary tap hole with phases clearly identified.

4.4. Transformers & Secondary Cables

Both Underground and URD construction utilize single phase pad mount, 3-phase pad mount, and single-phase subsurface transformers. Underground construction additionally uses 3-phase subsurface and single-phase subway type transformers for banking in manholes. Transformers on the 4-wire system are wye configured and on the 3-wire system can be wye or delta configured.

4.4.1 Pad Mount Transformers

Single phase pad mount transformers are available in sizes of 25, 50, 100, and 167 KVA with a 250/125 volt secondary. For new construction, single-phase pad mount transformer size should be limited to 100 KVA or smaller with 167 KVA units being held in reserve for heavy-up use. A 167 KVA single phase pad mount transformer is not available in dual voltage due to fuse coordination issues. Due to maintenance concerns of select existing silo style subsurface transformer installations, single-phase pad mount transformers mounted on flat concrete pads are a more reliable conversion option. (These conversions are made at the discretion of the construction crews.) 3-phase pad mount transformers are available in the sizes of 75, 150, 300, 500, 750, and 1000 KVA with a 216/125 volt secondary. The 460/265 secondary class adds the larger sizes of

1500, 2000, and 2500 KVA. Single-phase and 3-phase pad mount transformers are available in dual voltage units for use in areas converting from 4 KV primary voltage to standard 13 KV primary voltage. Below are some examples of pad mount transformers.

Figure 61: 1 PH Pad mount

Figure 62: 3 PH Pad mount

4.4.2 Subsurface Transformers

Legacy silo style single phase subsurface transformers are stocked in the sizes of 25, 50, 75, and 100 KVA with a 250/125 volt secondary, Standard UG-6722 (1424) maintenance only. Due to enclosure limitations 100 KVA is the largest size available. The new style "horizontal" single phase subsurface transformers Standard UG-3150 (1426) are the current standard and are available in 25, 50, 75, and 100 KVA. These transformers are solid insulation distribution transformers (SIDT) for various applications under separate stock numbers, Standard UG-6723. The SIDT transformers are protected by a full range current limiting fuse integrated into the elbow terminator. 3-phase subsurface transformers are stocked in 500, 750, and 1000 KVA with a 216/125 volt secondary and 750, 1000, 1500, 2000, 2500 KVA with a 460/265 volt secondary.

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Figure 63: Example 50 KVA SIDT Transformer

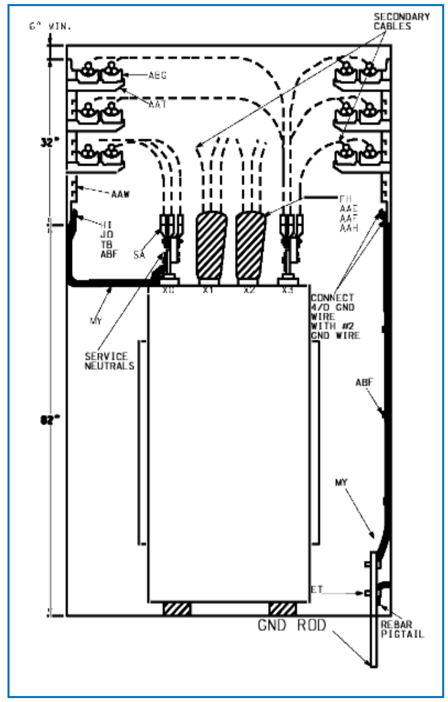

Figure 64: Subsurface Transformer, Standard UG-1323

4.4.3 Subway Transformers

Single phase subway transformers are suitable for banking. For the 125/250 service; 167, 250, and 333 KVA are offered. For the 460/265 volt service; 50, 100, 167, 250, 333 KVA are available. Pepco also stocks a 25 KVA step down transformer for converting the 13 KV to 4 KV. Single-phase subway type transformers larger than 167 KVA are to be used only for banking. 3-phase services served by subway transformers are limited to 3000 A.

4.4.4 Secondary Cables for Vaults

Copper secondary cables are used for network distribution and substation vault applications. Copper secondary cables are insulated with EPR ranging from 30 to 65 mils and then encased in between 15 to 65 mil TS-CPE fire retardant jacket depending on the cable size. The thermoset CPE jacket on these cables offers the "BEST" rating in the categories of fire resistance, oil/chemical resistance, flexibility, abrasion resistance, and temperature range. The reels of cable are available as three legs laid parallel and color coded red, green, and black or as single leg reels available in only black. A single legged 500KCMIL (1650119) white insulated cable is also available for service neutral identification where water proofing is required for a service which enters a building below grade.

CATID	Conductor	Rating (A) Direct/Duct
1650125	1500 KCMIL 1/C	1058 / 904
1650115	1000 KCMIL 1/C	882 / 741
1650130	500 KCMIL Network 3/Legs	621 / 508
1659837	500 KCMIL 1/C	621 / 508
1650127	250 KMCIL Network 3/Legs	425 / 341
1650120	250 KCMIL 1/C	425 / 341
1650090	4/0 AWG 3/C	391 / 311
1650122	2/0 AWG 1/C	303 / 238
1650101	1/0 AWG 1/C	267 / 208
1650121	#2 1/C	208 / 158
1650128	#4 1/C	162 / 122
1650123	#6 1/C	125 / 94
1650151	#10 1/C	47 / 40

Table 12: EPR CU Conductor Secondary Power Cables PHI SPEC S-1601

Underground secondary and service cables which are to be spliced in manholes or terminated at transformer terminals in manholes which require taping for insulation must be copper. See Standard OH-5000 (1744_C-501) for all secondary cable ampacities.

4.4.5 Secondary Cables for Direct Burial and URD

Ruggedized aluminum XLPE URD cables for pad mounted and subsurface single-phase transformers have been provided under PHI Spec 1605. The services have between 80 to 110 mils of XLPE insulation and are suitable for conduit or direct burial.

CATID	Conductor	Industry Code	Rating (A) Direct/Duct
1650134	500 KCMIL ALQUAD, 350 KCMIL NEU	WOFFORD	464 / 361
1650135	4/0 AWG AL QUAD, 2/0 NEU	WAKEFOREST	288 / 207
1650141	500 KCMIL AL TPLEX, 350 KCMIL NEU	RIDER	500 / 436
1650133	350 KCMIL AL TPLEX, 4/0 AWG NEU	WESLEYAN	415 / 344
1650132	4/0 AWG AL TPLEX, 2/0 AWG NEU	SWEETBRIAR	315 / 247
1650136	2/0 AWG AL TPLEX, 1/0 AWG NEU	CONVERSE	240 / 188
1650150	#10 AWG CU Conc. Neutral, 4-#14 AWG		47 / 40

Table 13: Secondary URD and Direct Buried Conductors, PHI SPEC S-3-1605

5. 4 KV System Considerations

Conversion of the existing 4 KV system to other higher voltages like 13 KV began in 1958. As the 4 KV system shrinks so does the stock of its associated equipment. A small amount of equipment is kept in stock for maintenance purposes with most of the equipment now dual voltage rated, for example 4 KV and 13 KV.

15 KV URD cable and cable accessories are being used with dual voltage transformers for 4 KV underground system maintenance and rearrangements in conformance with these guidelines. Since our 4 KV circuits are capable of providing more than 30,000 amperes at some locations the Bay-O-Net (expulsion) fuses and load break elbows rated for 10,000 amperes can be overloaded. The dual voltage subsurface and pad mounted transformers incorporate Bay-O-Net fuses which are rated for a fault clearing capability of 8,000 amperes or less at 4 KV. When the anticipated fault current will exceed 8,000 amperes, backup current limiting fuse protection is required. A 100E EJO 2.5 KV CL fuse (1656697) is in stock for this purpose which can be used with the standard transclosures or submersible 8 KV fuse enclosures.

If a transformer is to be placed within one half circuit mile of a substation, fault current calculations should be made or backup protection (current limiting) should be provided.

6. Development History

Revision 0	**Date: 11/30/2016**
Writer	Unknown
Reviewer(s)	
Reason written	The purpose of the document is to provide a general description of the Pepco 4-Wire 13 KV distribution system.

Revision 1	**Date: 1/1/2021**
Editor	David Andrews (Sr. Engineer, Overhead Standards)
Reviewer(s)	Stephen Park, Nicholas Cincotti, Robert Spelman
Major Changes	• Reformatted and reorganized document content and layout • Added pictorial representations of concepts • Updated content information and validated accuracy • Converted stock numbers to CATIDs and included new Standard Document numbering • Added new equipment

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7. Appendix

7.1. Pepco Transformer Fuse Sizing Chart

4 WIRE PRIMARY DISTRIBUTION TRANSFORMER FUSING SCHEDULE EFFECTIVE 01/01/99																					
	SUBWAY					POLE TYPE					URD SUBSURFACE & PADMOUNT						SUBWAY & URD WHEN FUSED ON POLE				
XFMR		4KV		13KV		4KV		13kV			4kV		13kV				4kV		13kV		
KVA	OFC	BAY-O-NET		BAY-O-NET		CUTOUT		CUTOUT		CL FUSE	BAY-O-NET		BAY-0-NET				CUTOUT		CUTOUT		CL FUSE
SIZE		DEBF	SEBF	DEBF	SEBF						DEBF	SEBF	DEBF		SEBF						
		NORM	EMRG	NORM	EMRG	NORM	EMRG	NORM	EMRG		NORM	EMRG	NORM		EMRG		NORM	EMRG	NORM	EMRG	
													CAT#	AMPS	CAT#	AMPS					
1PH																					
10	10A					10N	15N	5N	10N	25 K-MT											
15	15A					15N	20N	5N	10N	25 K-MT											
25	30A	C06	C08	C03	C04	20N	30N	5N	10N	25 K-MT	C06	C08	C03	8	C04	10	20N	30N	5N	10N	25 K-MT
37.5	30A					30N	40N	10N	15N	25 K-MT											
50	40A	C09	C10	C05	C08	40N	50N	15N	20N	25 K-MT	C09	C10	C05	15	C08	20	40N	50N	15N	20N	25 K-MT
75	50A	C11	C12	C06	C08	60N	70N	20N	30N	25 K-MT	C11	C12	C06	20	C08	20	50N	60N	20N	30N	25 K-MT
100	75A	C12	C14	C07	C10	85N	100N	25N	30N	25 K-MT	C12	C14	C07	25	C10	40	75N	85N	25N	30N	25 K-MT
150	125A					125N	150N														
167	125A	C03CB	C14	C09	C10	125N	150N	40N	50N	40 K-MT			C09	40	C10	40			40N	50N	40 K-MT
200	150A					150N	200N	50N	60N	40 K-MT											
250	150A	C05CB	C14	C11	C12			60N	75N	65 K-MT											
333				C12	C14			75N	85N	65 K-MT											
500								100N	100N	150E											
3PH																					
75											C07	C08	C04	10	C04	10	20N	30N	5N	10N	25 K-MT
150											C09	C10	C06	20	C08	20	40N	50N	15N	20N	25 K-MT
300											C14	C14	C09	40	C10	40	75N	85N	25N	30N	25 K-MT
500											C03CB	C14	C09	40	C10	40	125N	150N	40N	50N	40 K-MT
750											C05CB	C14	C12	80	C12	80	200N		60N	75N	65 K-MT
1000													C14	100	C14	100			75N	85N	65 K-MT
1500													C04CB	160	C14	100			100N		100E
2000													C05CB	200	C14	100			100N		125E
2500													C05CB	200	C14	100			100N		150E

Table 14: Pepco Fuse Sizing Chart

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1. OFC is an oil fuse cutout only for 4 KV subway transformer switching and fusing. When OFC's are used slug the Bay-O-Net. When switching is done by elbows, fuse the Bay-O-Net. Fuse the OFC or the Bay-O-Net but not both.
2. The Bay-O-Net under oil expulsion fuse normally uses a dual element, overload sensing fuse (DEBF) which is sensitive to hot oil.
3. In emergencies, extreme weather, where overloads may melt the (DEBF), substitute a single element, fault sensing only fuse (SEBF) to be found in and returned to the Tool room.
4. The numbers in the chart for the DEBF & SEBF are the fuse designating numbers at the end of the manufacturer catalog numbers printed on the fuse and are not to be confused with an ampere rating. Examples: Cat. #4038108C06 is a dual element link, 20 amperes, designated C06 in the chart; Cat. #4000353C08 is a single element, fault sensing link, 20 amperes designated C08 in the chart; Cat. #4038361C04CB is a dual element, overload sensing link, 160 amps designated C04CB in the chart. The C03CB, C04CB and C05CB whole cartridge must be replaced when they blow. The individual links are not replaceable in these three cartridges.
5. The underground, 4 KV oil fuse cutout fuse ratings are in amperes.
6. Subway transformers and 3-phase subsurface transformer are not to be overloaded and should be refused only with the proper (normal) "N" size fuse when fused on the pole.
7. Overhead cutout fuses are ANSI "N" type fuses. The "N" fuse ratings are in amperes.
8. The K-mate fuse number indicates only that it will coordinate over the equivalent "K" type of string fuse link. It will also coordinate over one size larger "N" link.
9. The 100E & 125E CL fuses are properly sized to protect the 1500 & 2000 KVA transformers respectively and the 150E CL fuse is properly sized for the 2500 KVA transformers as full range fuses and are to be used in the 150E fuse holder when fusing a single radial transformer not in a loop feed arrangement on a pole, in a transclosure or subway fuse box. These fuses are required for protecting transformers received prior to 1999 which are not equipped with the Bay-O-Net fuses.

CEG 10/01/99
RLH 07/01/12 Rev

Exhibit OPC (E)-5
Formal Case No. 1176

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 4

QUESTION NO. 7
Referencing Pepco Exhibit H-2 and project Investment Tracking Number ("ITN") 72525 - Mt. Vernon Sq Sub Construction 230/13kV Sub (Pepco Exhibit H-2 at page 15 of 216).

a. Provide updated and current long-term and short-term load forecasts for all substations affected by the addition of Mt. Vernon Substation which should include the Northwest Substation, 10th Street Substation, and Florida Substation.

b. Provide updated and current long-term and short-term forecasts for LVAC groups that are planned to be relieved by the Mt. Vernon Substation.

c. Has Pepco made any adjustments to its load forecasting methods since June 2018? If so, please provide the updated methods.

RESPONSE:

a. Please refer to the attachment labeled: FC 1176 OPC DR 4-7a.

   Please note: the Northwest Substation was interpreted as the Northeast Substation because Pepco does not have a Northwest Substation in the District and the Northeast Substation is associated with Mt. Vernon Square substation.

b. Please refer to the attachment labeled: FC 1176 OPC DR 4-7b.

c. Yes, as noted on pg. 13 of Company exhibit Pepco (H)-1, the forecasting began transitioning to a new Planning tool, the Distribution System Planning Load Forecasting (DSP-LF) program in 2021. The program compares the historical weather patterns for the previous year against a thirty-year record of weather patterns. Feeder and substation loads during the summer and winter periods are adjusted to match values expected during temperature extremes projected to occur once in a ten-year period. These historical values are projected by the program into the upcoming ten-year period by adding new customer load requests submitted by the developers and anticipated area growth trends beyond the submitted requests, including anticipated electric vehicle charging loads and fossil fuel heating system conversions.

SPONSOR: Jaclyn Cantler

SUBSTATION	FEEDER NUMBER	HISTORY 2020	2021	2022	HIGH KV	LOW KV	NORM RATG	EMER RATG	FIRM CAPACITY	SUMMER FORECASTED LOAD WITH DER (MVA) 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	AUTO XFRS	BUSCAP MVARS	GENS MWS
Tenth St Sub. 52		190.6	190.6	138.3	138.0	13.8			204.0	142.3	127.8	127.9	127.8	127.5	127.8	127.7	127.6	127.7	127.8	0.0	-15.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4	63.0	0.0
w/o gen or w/ auto xfr																																
13kV Distribution Feeders		26.7	26.7	20.0			37.5	42.5	34.0	21.3	6.0	6.0	6.0	5.9	6.0	5.9	5.9	5.9	5.9	0.0	-15.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
w/o gen or w/ auto xfr																																
w/o gen or w/ auto xfr	15204R	6.5	6.5	4.9		13.8	7.5	8.5		5.4	-	-	-	-	-	-	-	-	-		-5.4											
w/o gen or w/ auto xfr	15204W	6.3	6.3	3.2		13.8	7.5	8.5		3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2													
w/o gen or w/ auto xfr	15206	5.1	5.1	3.9		13.8	7.5	8.5		4.3	-	-	-	-	-	-	-	-	-		-4.2											
w/o gen or w/ auto xfr	15207R	5.0	5.0	4.8		13.8	7.5	8.5		5.6	-	-	-	-	-	-	-	-	-		-5.6											
w/o gen or w/ auto xfr	15207W	3.8	3.8	3.2		13.8	7.5	8.5		2.8	2.8	2.8	2.8	2.7	2.8	2.7	2.7	2.7	2.7													
Commercial High Voltage Feeder Group		26.5	26.5	11.9			37.5	45.0	36.0	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
w/o gen or w/ auto xfr																																
w/o gen or w/ auto xfr	14615W	5.2	5.2	1.6		13.8	7.5	9.0		1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7													
w/o gen or w/ auto xfr	14616W	5.5	5.5	2.6		13.8	7.5	9.0		2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8													
w/o gen or w/ auto xfr	14617	5.5	5.5	2.5		13.8	7.5	9.0		2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7													
w/o gen or w/ auto xfr	14618W	5.1	5.1	2.6		13.8	7.5	9.0		2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8													
w/o gen or w/ auto xfr	14619	5.2	5.2	2.6		13.8	7.5	9.0		2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8													
DC Convention Center CVG 468		10.1	10.1	9.2			40.0	54.0	40.5	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
w/o gen or w/ auto xfr																																
w/o gen or w/ auto xfr	14615R	5.2	5.2	4.6		13.8	10.0	13.5		4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6													
w/o gen or w/ auto xfr	14616R	1.7	1.7	0.8		13.8	10.0	13.5		0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8													
w/o gen or w/ auto xfr	14618R	1.2	1.2	1.8		13.8	10.0	13.5		1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8													
w/o gen or w/ auto xfr	15683	2.0	2.0	2.0		13.8	10.0	13.5		2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0													
West LVAC Network Group		33.4	33.4	23.6			42.0	51.0	42.5	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
w/o gen or w/ auto xfr																																
w/o gen or w/ auto xfr	15314	5.3	5.3	4.1		13.8	7.0	8.5		4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2													
w/o gen or w/ auto xfr	15315	6.6	6.6	3.6		13.8	7.0	8.5		3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8													
w/o gen or w/ auto xfr	15316	5.3	5.3	4.2		13.8	7.0	8.5		4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0													
w/o gen or w/ auto xfr	15317	5.5	5.5	3.8		13.8	7.0	8.5		3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9													
w/o gen or w/ auto xfr	15318	5.2	5.2	3.4		13.8	7.0	8.5		3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4													
w/o gen or w/ auto xfr	15319	5.5	5.5	4.5		13.8	7.0	8.5		4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5													
North LVAC Network Group		30.5	30.5	18.4			45.0	54.0	45.0	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
w/o gen or w/ auto xfr																																
w/o gen or w/ auto xfr	15321	4.8	4.8	2.7		13.8	7.5	9.0		2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7													
w/o gen or w/ auto xfr	15322	5.2	5.2	3.1		13.8	7.5	9.0		3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2													
w/o gen or w/ auto xfr	15323	4.9	4.9	3.4		13.8	7.5	9.0		3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4													
w/o gen or w/ auto xfr	15324	5.9	5.9	3.3		13.8	7.5	9.0		3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5													
w/o gen or w/ auto xfr	15325	5.3	5.3	3.8		13.8	7.5	9.0		3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7													
w/o gen or w/ auto xfr	15326	4.4	4.4	2.1		13.8	7.5	9.0		2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2													
East LVAC Network Group		35.3	35.3	24.7			45.0	54.0	45.0	25.8	26.0	25.9	25.9	25.8	25.8	25.9	25.8	25.9	25.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
w/o gen or w/ auto xfr																																
w/o gen or w/ auto xfr	15327	6.2	6.2	4.5		13.8	7.5	9.0		4.6	4.7	4.7	4.7	4.6	4.6	4.7	4.6	4.7	4.7													
w/o gen or w/ auto xfr	15328	5.7	5.7	3.6		13.8	7.5	9.0		3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9													
w/o gen or w/ auto xfr	15329	5.7	5.7	4.2		13.8	7.5	9.0		4.2	4.3	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2													
w/o gen or w/ auto xfr	15330	5.8	5.8	4.0		13.8	7.5	9.0		4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4													
w/o gen or w/ auto xfr	15331	5.8	5.8	3.4		13.8	7.5	9.0		3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5													
w/o gen or w/ auto xfr	15332	6.1	6.1	5.0		13.8	7.5	9.0		5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2													
Central LVAC Network Group		24.0	24.0	17.1			44.0	52.0	42.0	17.2	17.1	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
w/o gen or w/ auto xfr																																
w/o gen or w/ auto xfr	15445	4.3	4.3	3.1		13.8	5.0	6.0		3.2	3.1	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.1													
w/o gen or w/ auto xfr	15446	4.1	4.1	2.4		13.8	8.5	10.0		2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5													
w/o gen or w/ auto xfr	15447	3.7	3.7	2.9		13.8	5.0	6.0		2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0													
w/o gen or w/ auto xfr	15448	4.0	4.0	3.0		13.8	8.5	10.0		2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9													
w/o gen or w/ auto xfr	15449	3.9	3.9	3.0		13.8	8.5	10.0		3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0													
w/o gen or w/ auto xfr	15450	4.0	4.0	2.7		13.8	8.5	10.0		2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7													
South LVAC Network Group		27.7	27.7	19.0			44.0	50.0	41.5	19.1	19.0	19.1	19.0	18.9	19.1	19.0	19.0	19.0	19.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
w/o gen or w/ auto xfr																																
w/o gen or w/ auto xfr	14516	3.7	3.7	3.2		13.8	7.5	8.5		3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1													
w/o gen or w/ auto xfr	14517	3.6	3.6	2.5		13.8	7.5	8.5		2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6													
w/o gen or w/ auto xfr	14518	4.1	4.1	2.6		13.8	7.0	8.0		2.6	2.5	2.6	2.6	2.5	2.5	2.6	2.6	2.6	2.6													
w/o gen or w/ auto xfr	14519	4.4	4.4	2.7		13.8	7.0	8.0		2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8													
w/o gen or w/ auto xfr	14520	6.5	6.5	4.4		13.8	7.5	8.5		4.5	4.5	4.4	4.4	4.4	4.5	4.4	4.4	4.4	4.5													
w/o gen or w/ auto xfr	14521	5.4	5.4	3.6		13.8	7.5	8.5		3.5	3.5	3.6	3.5	3.5	3.6	3.5	3.5	3.5	3.5													
Archives MTPS CVG 371		0.6	0.6	0.6			17.0	20.0	10.0	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6		
w/o gen or w/ auto xfr																																
w/o gen or w/ auto xfr	15201R	0.3	0.3	0.3		13.8	8.5	10.0		0.3 0.6	0.3 0.6	0.3 0.6	0.3 0.6	0.3 0.6	0.3 0.6	0.3 0.6	0.3 0.6	0.3 0.6	0.3 0.6											0.3		
w/o gen or w/ auto xfr	15203R	0.3	0.3	0.3		13.8	8.5	10.0		0.3 0.6	0.3 0.6	0.3 0.6	0.3 0.6	0.3 0.6	0.3 0.6	0.3 0.6	0.3 0.6	0.3 0.6	0.3 0.6											0.3		
Gallery Place MTPS CVG 309		1.4	1.4	1.4			15.0	17.0	8.5	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4		
w/o gen or w/ auto xfr																																
w/o gen or w/ auto xfr	15201W	0.7	0.7	0.7		13.8	7.5	8.5		0.7 1.4	0.7 1.4	0.7 1.4	0.7 1.4	0.7 1.4	0.7 1.4	0.7 1.4	0.7 1.4	0.7 1.4	0.7 1.4											0.7		
w/o gen or w/ auto xfr	15202R	0.7	0.7	0.7		13.8	7.5	8.5		0.7 1.4	0.7 1.4	0.7 1.4	0.7 1.4	0.7 1.4	0.7 1.4	0.7 1.4	0.7 1.4	0.7 1.4	0.7 1.4											0.7		
Metro Center MTPS CVG. 326		0.4	0.4	0.4			15.0	17.0	8.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4		
w/o gen or w/ auto xfr																																
w/o gen or w/ auto xfr	15202W	0.2	0.2	0.2		13.8	7.5	8.5		0.2 0.4	0.2 0.4	0.2 0.4	0.2 0.4	0.2 0.4	0.2 0.4	0.2 0.4	0.2 0.4	0.2 0.4	0.2 0.4											0.2		
w/o gen or w/ auto xfr	15203W	0.2	0.2	0.2		13.8	7.5	8.5		0.2 0.4	0.2 0.4	0.2 0.4	0.2 0.4	0.2 0.4	0.2 0.4	0.2 0.4	0.2 0.4	0.2 0.4	0.2 0.4											0.2		
Northeast Sub. 212		141.3	153.6	115.7	69.0	13.8			214.0	124.2	119.3	127.7	144.3	144.3	144.3	144.3	144.3	144.3	144.3	0.0	-23.5	0.0	5.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.0	0.0
w/o gen or w/ auto xfr																																
13kV Distribution Feeders		9.9	10.4	7.4						10.5	10.5	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
w/o gen or w/ auto xfr																																
w/o gen or w/ auto xfr	15461	5.3	5.2	4.0		13.8	11.0	12.5		5.3	5.3	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4													
w/o gen or w/ auto xfr	15462	4.6	5.2	3.4		13.8	11.0	12.5		5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2													
North High Tension Feeder Group		14.7	14.7	7.7			22.5	28.5	19.0	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
w/o gen or w/ auto xfr																																

w/o gen or w/ auto xfr	15457	6.2	6.2	2.6		13.8	7.5	9.5		2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6													
w/o gen or w/ auto xfr	15458	5.0	5.0	1.7		13.8	7.5	9.5		1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7													
w/o gen or w/ auto xfr	15459	3.5	3.5	3.4		13.8	7.5	9.5		3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5													
West LVAC Network Group w/o gen or w/ auto xfr		32.6	34.9	23.8			54.0	69.0	57.5	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
w/o gen or w/ auto xfr	15475	6.0	6.2	2.7		13.8	9.0	11.5		2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7													
w/o gen or w/ auto xfr	15476	5.4	5.8	4.1		13.8	9.0	11.5		4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1													
w/o gen or w/ auto xfr	15477	4.7	5.2	3.7		13.8	9.0	11.5		3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7													
w/o gen or w/ auto xfr	15478	5.4	5.8	4.8		13.8	9.0	11.5		4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8													
w/o gen or w/ auto xfr	15479	5.3	5.7	3.7		13.8	9.0	11.5		3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7													
w/o gen or w/ auto xfr	15480	5.8	6.2	4.8		13.8	9.0	11.5		4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8													
South Spot Network Group w/o gen or w/ auto xfr		25.1	28.7	22.7			51.0	60.0	50.0	25.9	32.8	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
w/o gen or w/ auto xfr	15469	3.9	4.5	4.2		13.8	8.5	10.0		5.0	7.1	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6			-2.0										
w/o gen or w/ auto xfr	15470	2.4	3.0	2.2		13.8	8.5	10.0		3.0	3.9	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0			2.0										
w/o gen or w/ auto xfr	15471	5.6	6.2	4.6		13.8	8.5	10.0		4.8	4.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8			2.0										
w/o gen or w/ auto xfr	15472	4.3	4.9	4.1		13.8	8.5	10.0		4.9	6.7	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8			-2.0										
w/o gen or w/ auto xfr	15473	3.8	4.4	3.5		13.8	8.5	10.0		4.1	5.9	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1													
w/o gen or w/ auto xfr	15474	5.1	5.7	4.1		13.8	8.5	10.0		4.1	4.4	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7													
Southwest LVAC Network Group w/o gen or w/ auto xfr		35.5	37.6	27.5			51.0	60.0	50.0	27.9	12.0	12.0	29.4	29.4	29.4	29.4	29.4	29.4	29.4	0.0	-23.5	0.0	5.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
w/o gen or w/ auto xfr	15451	4.2	4.6	2.8		13.8	8.5	10.0		2.8	2.0	2.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0		-2.0											
w/o gen or w/ auto xfr	15452	7.0	7.4	5.4		13.8	8.5	10.0		5.4	2.0	2.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0		-5.0		1.0									
w/o gen or w/ auto xfr	15453	6.1	6.3	4.8		13.8	8.5	10.0		4.8	2.0	2.0	4.5	4.5	4.5	4.5	4.5	4.5	4.5		-4.0		0.5									
w/o gen or w/ auto xfr	15454	5.8	6.2	4.7		13.8	8.5	10.0		4.7	2.0	2.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0		-4.0		2.0									
w/o gen or w/ auto xfr	15455	6.3	6.6	5.0		13.8	8.5	10.0		5.0	2.0	2.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7		-4.5		0.7									
w/o gen or w/ auto xfr	15456	6.1	6.5	4.8		13.8	8.5	10.0		5.2	2.0	2.0	5.2	5.2	5.2	5.2	5.2	5.2	5.2		-4.0		1.2									
Southeast Spot Network Group w/o gen or w/ auto xfr		30.8	35.0	29.1			51.0	60.0	50.0	34.7	38.5	25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6	0.0	0.0	-13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
w/o gen or w/ auto xfr	15463	4.8	5.5	4.7		13.8	8.5	10.0		5.9	6.6	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5			-2.2										
w/o gen or w/ auto xfr	15464	5.7	6.4	5.7		13.8	8.5	10.0		6.6	7.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1			-2.3										
w/o gen or w/ auto xfr	15465	5.6	6.3	4.4		13.8	8.5	10.0		5.5	6.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5			-2.2										
w/o gen or w/ auto xfr	15466	4.6	5.3	4.3		13.8	8.5	10.0		5.0	5.6	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3			-2.3										
w/o gen or w/ auto xfr	15467	4.8	5.5	5.1		13.8	8.5	10.0		6.0	6.5	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3			-2.2										
w/o gen or w/ auto xfr	15468	5.3	6.0	4.9		13.8	8.5	10.0		5.7	6.2	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9			-2.3										
East LVAC Network Group w/o gen or w/ auto xfr		0.0	0.0	0.0			51.0	63.0	52.5	0.0	0.0	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
w/o gen or w/ auto xfr	15481	-	-	-		13.8	8.5	10.5		0.0	0.0	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2			2.2										
w/o gen or w/ auto xfr	15482	-	-	-		13.8	8.5	10.5		0.0	0.0	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3			2.3										
w/o gen or w/ auto xfr	15483	-	-	-		13.8	8.5	10.5		0.0	0.0	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2			2.2										
w/o gen or w/ auto xfr	15484	-	-	-		13.8	8.5	10.5		0.0	0.0	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3			2.3										
w/o gen or w/ auto xfr	15485	-	-	-		13.8	8.5	10.5		0.0	0.0	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2			2.2										
w/o gen or w/ auto xfr	15486	-	-	-		13.8	8.5	10.5		0.0	0.0	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3			2.3										
Florida Ave. Sub. 10 w/o gen or w/ auto xfr		158.1	157.3	131.4	69.0	13.8			215.0	135.2	116.8	121.8	125.9	128.7	129.7	130.9	131.3	132.7	133.7	-4.9	-21.7	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.6	45.0	0.0
13kV Distribution Feeders w/o gen or w/ auto xfr		34.1	34.0	29.8			58.0	75.0		31.3	31.4	31.3	31.3	31.4	31.1	31.5	31.3	31.3	31.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
w/o gen or w/ auto xfr	15761	3.8	3.8	3.6		13.8	10.0	13.5		4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1													
w/o gen or w/ auto xfr	15762	9.0	8.9	7.7		13.8	10.0	13.5		7.6	7.7	7.6	7.6	7.7	7.6	7.7	7.7	7.7	7.7													
w/o gen or w/ auto xfr	15763	6.7	6.7	5.5		13.8	10.0	12.0		5.9	5.9	5.9	5.9	5.9	5.8	5.9	5.8	5.8	5.8													
w/o gen or w/ auto xfr	15764	6.3	6.3	5.2		13.8	10.0	12.0		5.6	5.6	5.6	5.6	5.6	5.5	5.6	5.6	5.6	5.5													
w/o gen or w/ auto xfr	15765	0.1	0.1	0.1		13.8	9.0	12.0		0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.1													
w/o gen or w/ auto xfr	15766	0.0	0.0	0.0		13.8	9.0	10.5		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0													
w/o gen or w/ auto xfr	15769	4.8	4.8	4.7		13.8	9.0	12.0		4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7													
w/o gen or w/ auto xfr	15770	3.4	3.4	3.0		13.8	9.0	12.0		3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3													
North High Tension Feeder Group w/o gen or w/ auto xfr		33.1	33.1	29.7			54.0	69.0	57.5	30.9	31.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-30.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
w/o gen or w/ auto xfr	15771	6.2	6.2	5.4		13.8	9.0	11.5		5.7	5.7	-	-	-	-	-	-	-	-			-5.7										
w/o gen or w/ auto xfr	15772	4.9	4.9	4.0		13.8	9.0	11.5		4.2	4.2	-	-	-	-	-	-	-	-			-4.2										
w/o gen or w/ auto xfr	15773	6.8	6.8	6.2		13.8	9.0	11.5		6.9	6.9	-	-	-	-	-	-	-	-			-6.9										
w/o gen or w/ auto xfr	15774	4.9	4.9	4.4		13.8	9.0	11.5		4.5	4.6	-	-	-	-	-	-	-	-			-4.5										
w/o gen or w/ auto xfr	15775	6.9	6.9	6.8		13.8	9.0	11.5		6.8	6.8	-	-	-	-	-	-	-	-			-6.8										
w/o gen or w/ auto xfr	15776	3.4	3.4	2.9		13.8	9.0	11.5		2.8	2.8	-	-	-	-	-	-	-	-			-2.8										
West LVAC Network Group w/o gen or w/ auto xfr		31.8	31.8	24.4			51.0	60.0	50.0	26.2	26.7	28.9	31.4	32.7	32.8	32.9	32.8	32.9	32.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
										0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0														
w/o gen or w/ auto xfr	15333	4.6	4.6	3.4		13.8	8.5	10.0		3.8	3.8	4.3	4.9	5.2	5.2	5.2	5.2	5.2	5.2													
w/o gen or w/ auto xfr	15334	5.8	5.8	4.8		13.8	8.5	10.0		5.1	5.3	5.4	5.6	5.7	5.7	5.7	5.7	5.7	5.7													
w/o gen or w/ auto xfr	15335	5.4	5.4	4.1		13.8	8.5	10.0		4.4	4.4	5.1	5.8	6.2	6.2	6.3	6.2	6.3	6.3													
w/o gen or w/ auto xfr	15336	4.8	4.8	3.6		13.8	8.5	10.0		3.9	3.8	4.1	4.4	4.7	4.7	4.7	4.7	4.7	4.7													
w/o gen or w/ auto xfr	15337	5.4	5.4	3.9		13.8	8.5	10.0		4.0	4.2	4.7	5.2	5.4	5.4	5.4	5.4	5.4	5.4													
w/o gen or w/ auto xfr	15338	5.8	5.8	4.6		13.8	8.5	10.0		5.0	5.2	5.3	5.5	5.5	5.6	5.6	5.6	5.6	5.6													
South LVAC Network Group w/o gen or w/ auto xfr		26.2	27.2	21.0			51.0	59.5	49.5	24.9	25.7	27.7	29.8	31.5	32.7	33.6	34.4	35.6	36.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
w/o gen or w/ auto xfr	15339	4.7	4.7	4.4		13.8	8.5	10.0		5.5	5.7	6.1	6.4	6.6	6.9	6.9	7.1	7.3	7.5													
w/o gen or w/ auto xfr	15340	3.3	3.5	4.2		13.8	8.5	10.0		5.4	5.6	6.0	6.2	6.4	6.6	6.8	6.9	7.1	7.3													
w/o gen or w/ auto xfr	15341	6.0	6.2	3.2		13.8	8.5	10.0		3.8	4.0	4.4	4.9	5.2	5.4	5.5	5.6	5.8	6.0													
w/o gen or w/ auto xfr	15342	4.5	4.7	2.6		13.8	8.5	10.0		2.7	2.7	2.9	3.3	3.6	3.8	3.9	4.1	4.3	4.5													
w/o gen or w/ auto xfr	15343	3.7	3.9	4.1		13.8	8.5	9.5		4.7	4.6	5.0	5.3	5.7	5.8	6.1	6.2	6.4	6.6													
w/o gen or w/ auto xfr	15344	4.0	4.2	2.5		13.8	8.5	10.0		2.8	3.1	3.3	3.7	4.0	4.2	4.4	4.5	4.7	4.9													

East Commercial Feeder Group w/o gen or w/ auto xfr		**24.3**	**24.3**	**18.5**			**52.0**	**63.0**	**51.5**	**18.5**	**12.8**	**12.9**	**12.8**	**12.7**	**12.9**	**12.9**	**12.8**	**12.9**	**12.9**	**0.0**	**-5.7**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**		
w/o gen or w/ auto xfr	**15637**	5.7	5.7	2.4		13.8	8.5	10.0		2.4	3.6	3.6	3.6	3.5	3.6	3.6	3.6	3.6	3.6		1.2											
w/o gen or w/ auto xfr	**15638**	4.8	4.8	3.3		13.8	8.5	10.0		3.3	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2		-0.1											
w/o gen or w/ auto xfr	**15639**	4.3	4.3	2.4		13.8	8.5	10.0		2.4	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2		0.8											
w/o gen or w/ auto xfr	**15640**	5.5	5.5	3.7		13.8	8.5	10.0		3.7	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4		-2.3											
w/o gen or w/ auto xfr	**15641**	0.0	0.0	4.3		13.8	9.0	11.5		4.3	1.4	1.5	1.4	1.4	1.5	1.5	1.4	1.5	1.5		-2.9											
w/o gen or w/ auto xfr	**15642**	4.0	4.0	2.4		13.8	9.0	11.5		2.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		-2.4											
Columbia Hts. MTPS CVG 444 w/o gen or w/ auto xfr		**0.8**	**0.8**	**0.8**			**18.0**	**23.0**	**11.5**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.8**		
w/o gen or w/ auto xfr	**15767**	0.4	0.4	0.4		13.8	9.0	11.5		0.4 0.8	0.4 0.8	0.4 0.8	0.4 0.8	0.4 0.8	0.4 0.8	0.4 0.8	0.4 0.8	0.4 0.8	0.4 0.8											0.4		
w/o gen or w/ auto xfr	**15768**	0.4	0.4	0.4		13.8	9.0	11.5		0.4 0.8	0.4 0.8	0.4 0.8	0.4 0.8	0.4 0.8	0.4 0.8	0.4 0.8	0.4 0.8	0.4 0.8	0.4 0.8											0.4		
14th Street Spot Network Group w/o gen or w/ auto xfr		**11.8**	**11.8**	**9.1**			**28.0**	**34.0**	**25.5**	**9.7**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-9.7**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**		
w/o gen or w/ auto xfr	**15354**	3.5	3.5	2.9		13.8	7.0	8.5		3.2	-	-	-	-	-	-	-	-	-		-3.2											
w/o gen or w/ auto xfr	**15355**	2.3	2.3	1.3		13.8	7.0	8.5		1.4	-	-	-	-	-	-	-	-	-		-1.4											
w/o gen or w/ auto xfr	**15356**	3.2	3.2	2.3		13.8	7.0	8.5		2.4	-	-	-	-	-	-	-	-	-		-2.4											
w/o gen or w/ auto xfr	**15357**	2.8	2.8	2.6		13.8	7.0	8.5		2.7	-	-	-	-	-	-	-	-	-		-2.7											
13kV Distribution Feeders w/o gen or w/ auto xfr		**10.8**	**10.8**	**10.3**			**20.0**	**23.0**		**5.5**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-4.9**	**-5.5**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**		
w/o gen or w/ auto xfr	**15777**	5.2	5.2	4.6		13.8	10.0	11.5		-	-	-	-	-	-	-	-	-	-	-4.9												
w/o gen or w/ auto xfr	**15778**	5.6	5.6	5.5		13.8	10.0	11.5		5.5	-	-	-	-	-	-	-	-	-		-5.5											
w/o gen or w/ auto xfr	**15779**	0.0	0.0	0.2		13.8	9.0	12.0		0.0	-	-	-	-	-	-	-	-	-													
"U" St. MTPS CVG 412 w/o gen or w/ auto xfr		**0.8**	**0.8**	**0.8**			**18.0**	**24.0**	**12.0**	**0.8**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-0.8**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.8**		
w/o gen or w/ auto xfr	**15780**	0.4	0.4	0.4		13.8	9.0	12.0		0.4	-	-	-	-	-	-	-	-	-		-0.4									0.4		
w/o gen or w/ auto xfr	**15781**	0.4	0.4	0.4		13.8	9.0	12.0		0.4	-	-	-	-	-	-	-	-	-		-0.4									0.4		
Champlain LVAC Network Group w/o gen or w/ auto xfr		**0.0**	**0.0**	**0.0**			**51.0**	**57.0**	**47.5**	**0.0**	**0.0**	**18.8**	**18.7**	**18.8**	**18.7**	**18.7**	**18.7**	**18.7**	**18.8**	**0.0**	**0.0**	**18.8**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**		
w/o gen or w/ auto xfr	**15432**	0.0	0.0	0.0		13.8	8.5	9.5		-	-	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7			2.7										
w/o gen or w/ auto xfr	**15433**	0.0	0.0	0.0		13.8	8.5	9.5		-	-	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4			3.4										
w/o gen or w/ auto xfr	**15434**	0.0	0.0	0.0		13.8	8.5	9.5		-	-	3.4	3.3	3.4	3.3	3.3	3.3	3.3	3.4			3.4										
w/o gen or w/ auto xfr	**15435**	0.0	0.0	0.0		13.8	8.5	9.5		-	-	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2			2.2										
w/o gen or w/ auto xfr	**15436**	0.0	0.0	0.0		13.8	8.5	9.5		-	-	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7			4.7										
w/o gen or w/ auto xfr	**15437**	0.0	0.0	0.0		13.8	8.5	9.5		-	-	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4			2.4										
Champlain Distribution (13kV) w/o gen or w/ auto xfr		**0.0**	**0.0**	**0.0**			**18.5**	**22.0**	**47.5**	**0.0**	**0.0**	**12.2**	**12.3**	**12.3**	**12.3**	**12.3**	**12.3**	**12.4**	**12.3**	**0.0**	**0.0**	**12.2**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**		
w/o gen or w/ auto xfr	**15844**	0.0	0.0	0.0		13.8	9.5	11.5		-	-	5.5	5.6	5.6	5.6	5.6	5.6	5.7	5.6			5.5										
w/o gen or w/ auto xfr	**15845**	0.0	0.0	0.0		13.8	9.0	10.5		-	-	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7			6.7										
w/o gen or w/ auto xfr	**15846**	0.0	0.0	0.0		13.8	8.5	9.5		-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			0.0										
Belmont Road MTPS CVG 308 w/o gen or w/ auto xfr		**0.0**	**0.0**	**0.0**			**17.0**	**20.0**	**9.5**	**0.0**	**0.0**	**1.2**	**1.2**	**1.2**	**1.2**	**1.2**	**1.2**	**1.2**	**1.2**	**0.0**	**0.0**	**1.2**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**		
w/o gen or w/ auto xfr	**15643**	0.0	0.0	0.0		13.8	8.5	10.5		-	-	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6			0.6										
w/o gen or w/ auto xfr	**15644**	0.0	0.0	0.0		13.8	8.5	9.5		-	-	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6			0.6										

FC 1176
OPC DR 4-7b
Attachment
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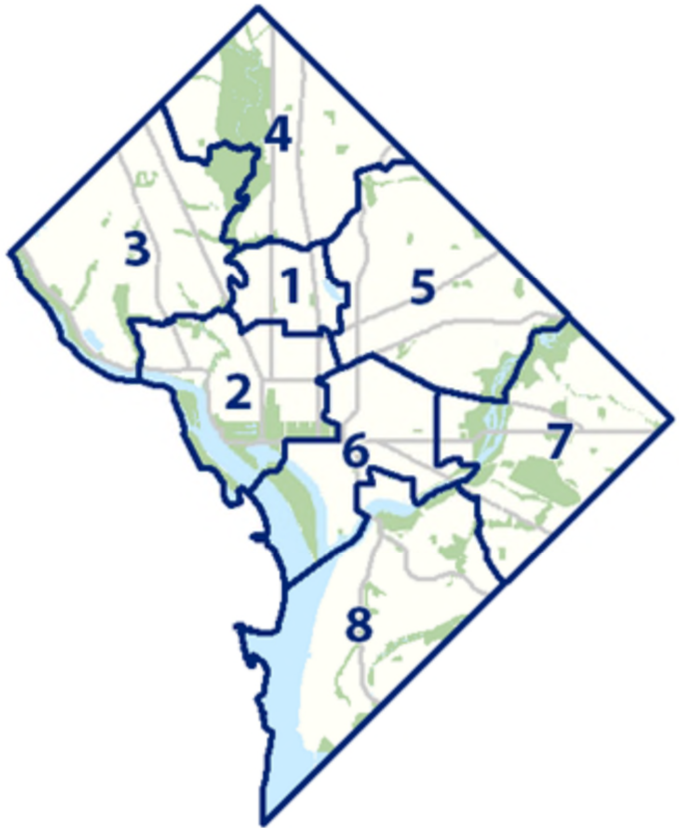
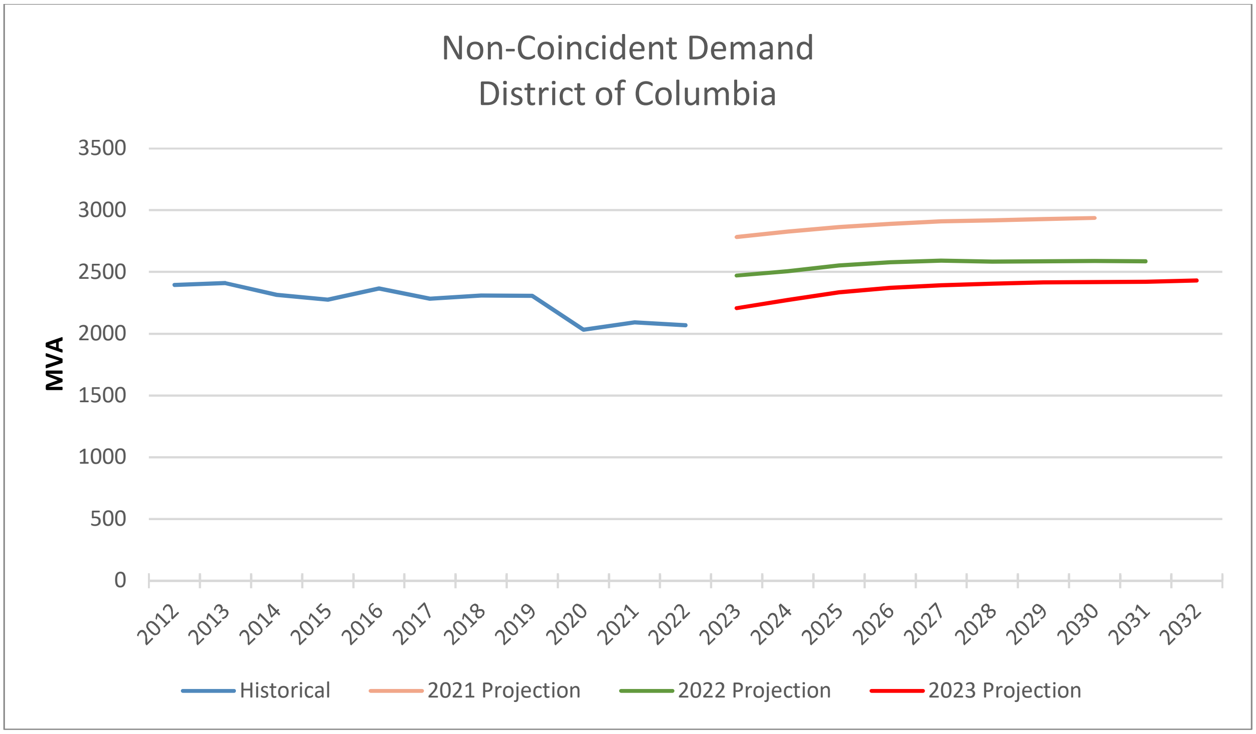
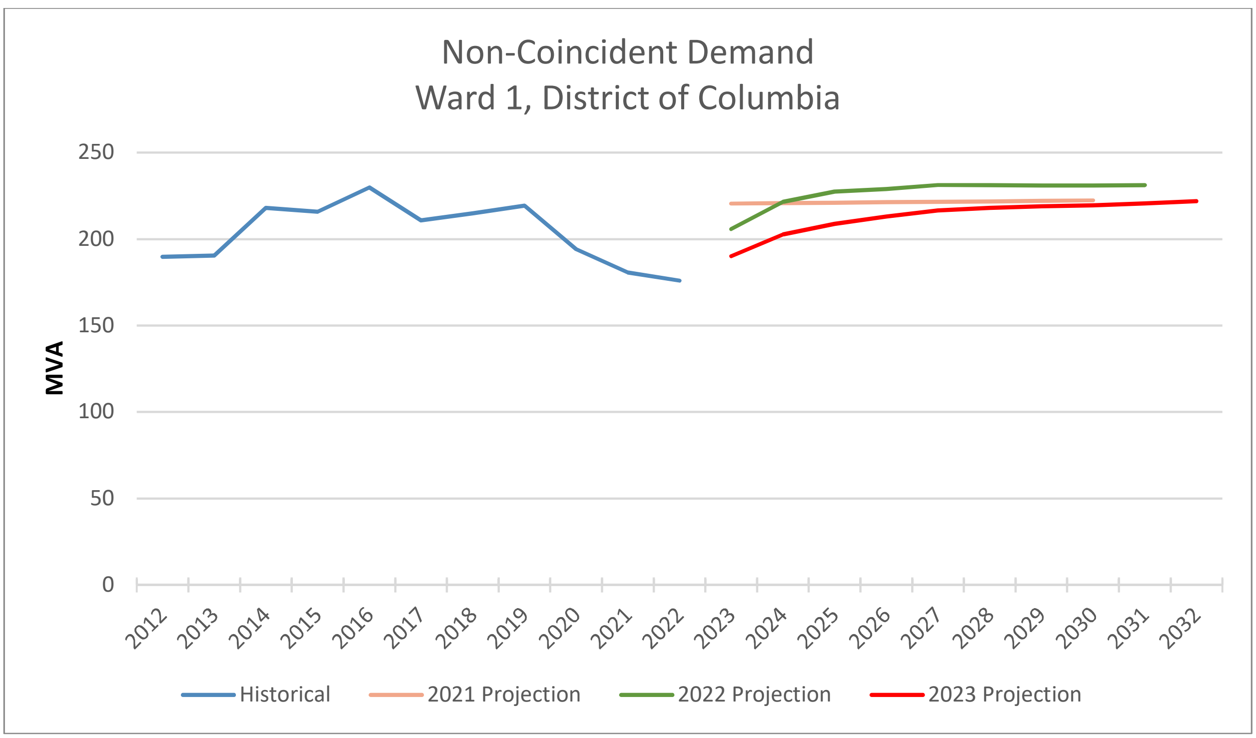
SUBSTATION	FEEDER NUMBER	HISTORY 2020	HISTORY 2021	HISTORY 2022	HIGH KV	LOW KV	NORM RATG	EMER RATG	FIRM CAPACITY	SUMMER FORECASTED LOAD WITH DER (MVA) 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	TRANSFERS/ADJUSTMENTS 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	AUTO XFRS	BUSCAP MVARS	GENS MWS
New Jersey Ave Sub. 161																																
w/o gen or w/ auto xfr																																
South LVAC Network Group w/o gen or w/ auto xfr		**40.4**	**40.4**	**29.1**			**48.0**	**57.0**	**47.5**	**35.6**	**38.0**	**39.7**	**41.1**	**41.1**	**41.1**	**22.9**	**22.9**	**22.9**	**22.9**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-20.0**	**0.0**	**0.0**	**0.0**	**0.0**		
w/o gen or w/ auto xfr	**14414**	7.4	7.4	5.6		13.8	8.0	9.5		7.1	7.5	7.7	8.0	8.0	8.0	4.9	4.9	4.9	4.9							-3.4						
w/o gen or w/ auto xfr	**14415**	7.2	7.2	4.9		13.8	8.0	9.5		6.1	6.7	7.0	7.3	7.3	7.3	4.2	4.2	4.2	4.2							-3.4						
w/o gen or w/ auto xfr	**14416**	5.4	5.4	4.9		13.8	8.0	9.5		5.8	6.2	6.5	6.7	6.7	6.7	3.7	3.7	3.7	3.7							-3.3						
w/o gen or w/ auto xfr	**14417**	6.9	6.9	3.8		13.8	8.0	9.5		4.8	5.2	5.5	5.7	5.7	5.7	2.7	2.7	2.7	2.7							-3.3						
w/o gen or w/ auto xfr	**14418**	6.4	6.4	5.1		13.8	8.0	9.5		6.1	6.5	6.8	7.0	7.0	7.0	4.0	4.0	4.0	4.0							-3.3						
w/o gen or w/ auto xfr	**14419**	7.1	7.1	4.8		13.8	8.0	9.5		5.7	5.9	6.2	6.4	6.4	6.4	3.4	3.4	3.4	3.4							-3.3						
East High Voltage Customer Group w/o gen or w/ auto xfr		**29.5**	**29.5**	**21.9**			**45.0**	**51.0**	**42.5**	**24.5**	**24.5**	**24.2**	**24.5**	**7.0**	**7.1**	**7.1**	**7.0**	**7.1**	**7.1**	**0.0**	**0.0**	**0.0**	**0.0**	**-18.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**		
w/o gen or w/ auto xfr	**14651**	5.2	5.2	3.9		13.8	7.5	8.5		4.8	4.8	4.8	4.8	2.0	2.0	2.0	2.0	2.0	2.0					-3.0								
w/o gen or w/ auto xfr	**14652**	4.0	4.0	2.7		13.8	7.5	8.5		3.0	3.0	3.0	3.0	0.2	0.2	0.2	0.2	0.2	0.2					-2.8								
w/o gen or w/ auto xfr	**14653**	4.4	4.4	2.9		13.8	7.5	8.5		3.2	3.2	3.2	3.2	0.2	0.2	0.2	0.2	0.2	0.2					-3.0								
w/o gen or w/ auto xfr	**14654**	5.8	5.8	4.9		13.8	7.5	8.5		5.2	5.2	5.2	5.2	2.0	2.0	2.0	2.0	2.0	2.0					-3.2								
w/o gen or w/ auto xfr	**14655**	5.6	5.6	4.3		13.8	7.5	8.5		4.5	4.5	4.5	4.5	1.5	1.5	1.5	1.5	1.5	1.5					-3.0								
w/o gen or w/ auto xfr	**14656**	4.5	4.5	3.2		13.8	7.5	8.5		3.8	3.8	3.5	3.8	1.1	1.1	1.1	1.1	1.1	1.1					-3.0								
Northeast Sub. 212																																
w/o gen or w/ auto xfr																																
Southwest LVAC Network Group w/o gen or w/ auto xfr			**37.6**	**27.5**			**51.0**	**60.0**	**50.0**	**27.9**	**12.0**	**12.0**	**29.4**	**29.4**	**29.4**	**29.4**	**29.4**	**29.4**	**29.4**	**0.0**	**-23.5**	**0.0**	**5.4**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**		
w/o gen or w/ auto xfr	**15451**		4.6	2.8		13.8	8.5	10.0		2.8	2.0	2.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0		-2.0											
w/o gen or w/ auto xfr	**15452**		7.4	5.4		13.8	8.5	10.0		5.4	2.0	2.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0		-5.0		1.0									
w/o gen or w/ auto xfr	**15453**		6.3	4.8		13.8	8.5	10.0		4.8	2.0	2.0	4.5	4.5	4.5	4.5	4.5	4.5	4.5		-4.0		0.5									
w/o gen or w/ auto xfr	**15454**		6.2	4.7		13.8	8.5	10.0		4.7	2.0	2.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0		-4.0		2.0									
w/o gen or w/ auto xfr	**15455**		6.6	5.0		13.8	8.5	10.0		5.0	2.0	2.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7		-4.5		0.7									
w/o gen or w/ auto xfr	**15456**		6.5	4.8		13.8	8.5	10.0		5.2	2.0	2.0	5.2	5.2	5.2	5.2	5.2	5.2	5.2		-4.0		1.2									

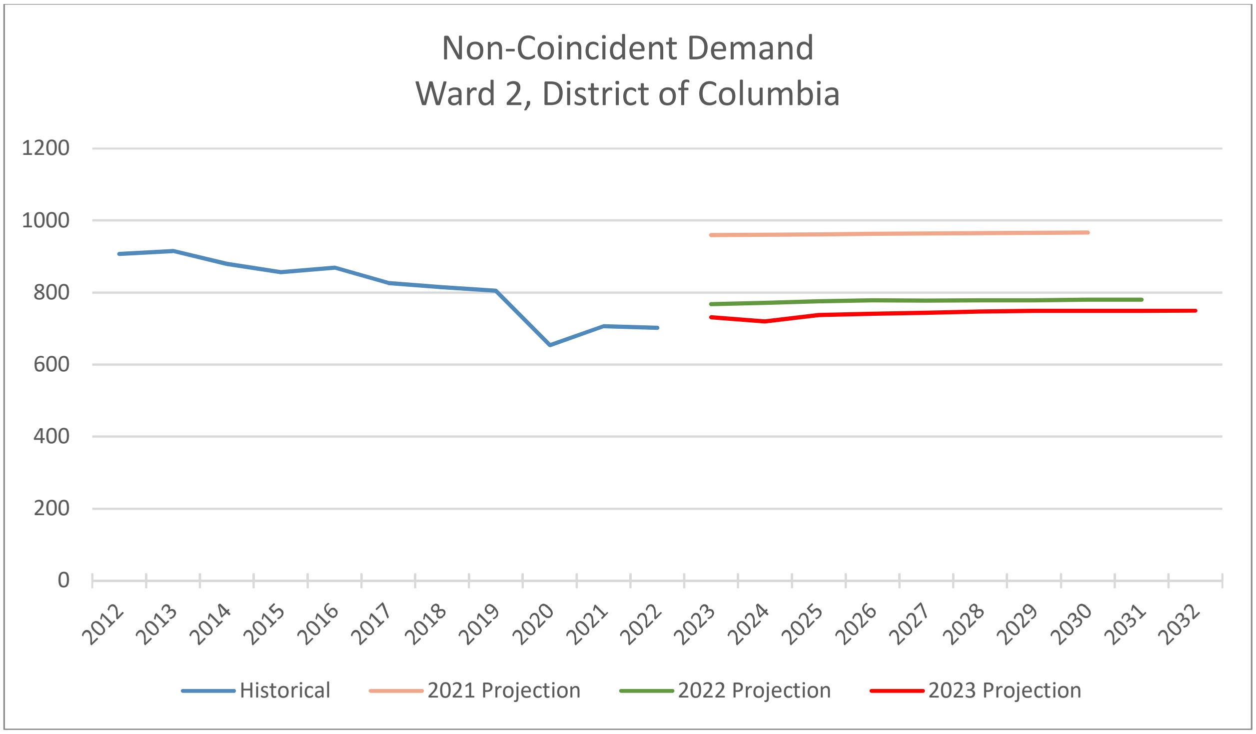


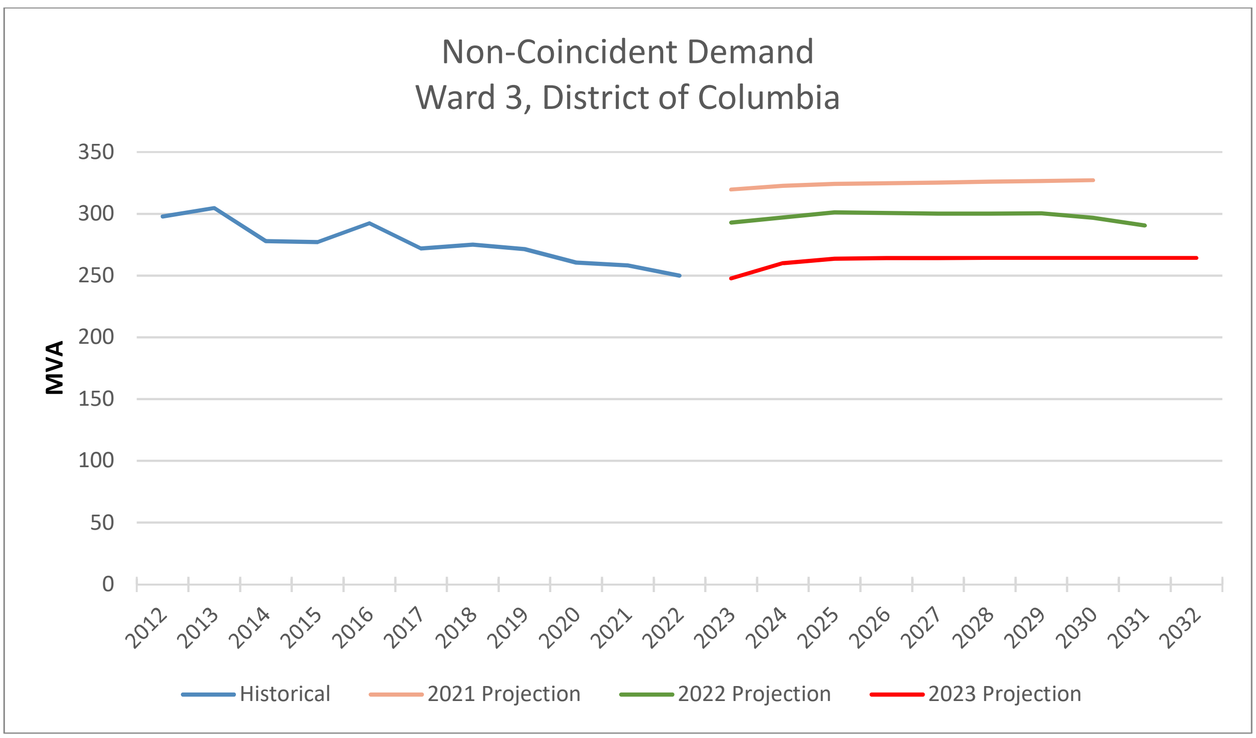
Wards of the District of Columbia [1]

[1] Source https://planning.dc.gov/whatsmyward


Non-Coincident Demand
District of Columbia
MVA
3500
3000
2500
2000
1500
1000
500
0
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032
Historical
2021 Projection
2022 Projection
2023 Projection


Non-Coincident Demand
Ward 1, District of Columbia
MVA
250
200
150
100
50
0
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032
Historical
2021 Projection
2022 Projection
2023 Projection


Non-Coincident Demand
Ward 2, District of Columbia
1200
1000
800
600
400
200
0
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032
Historical
2021 Projection
2022 Projection
2023 Projection


Non-Coincident Demand
Ward 3, District of Columbia
MVA
350
300
250
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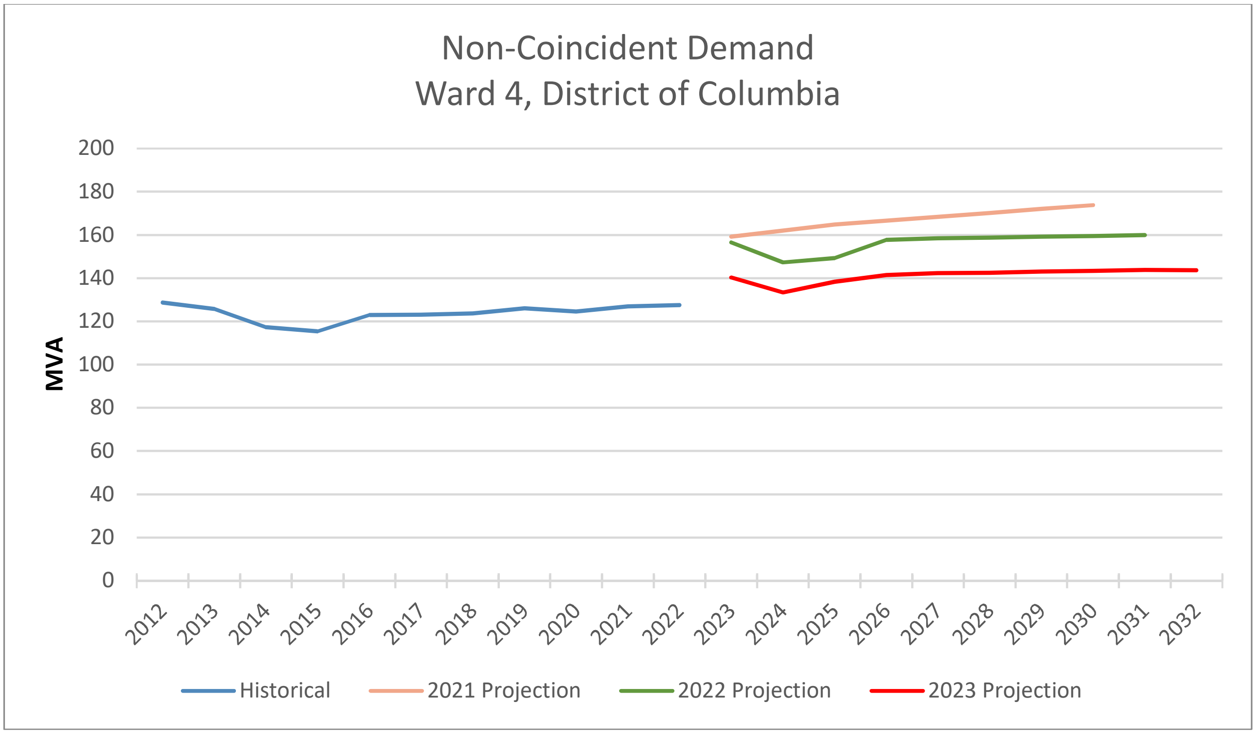
Non-Coincident Demand
Ward 4, District of Columbia
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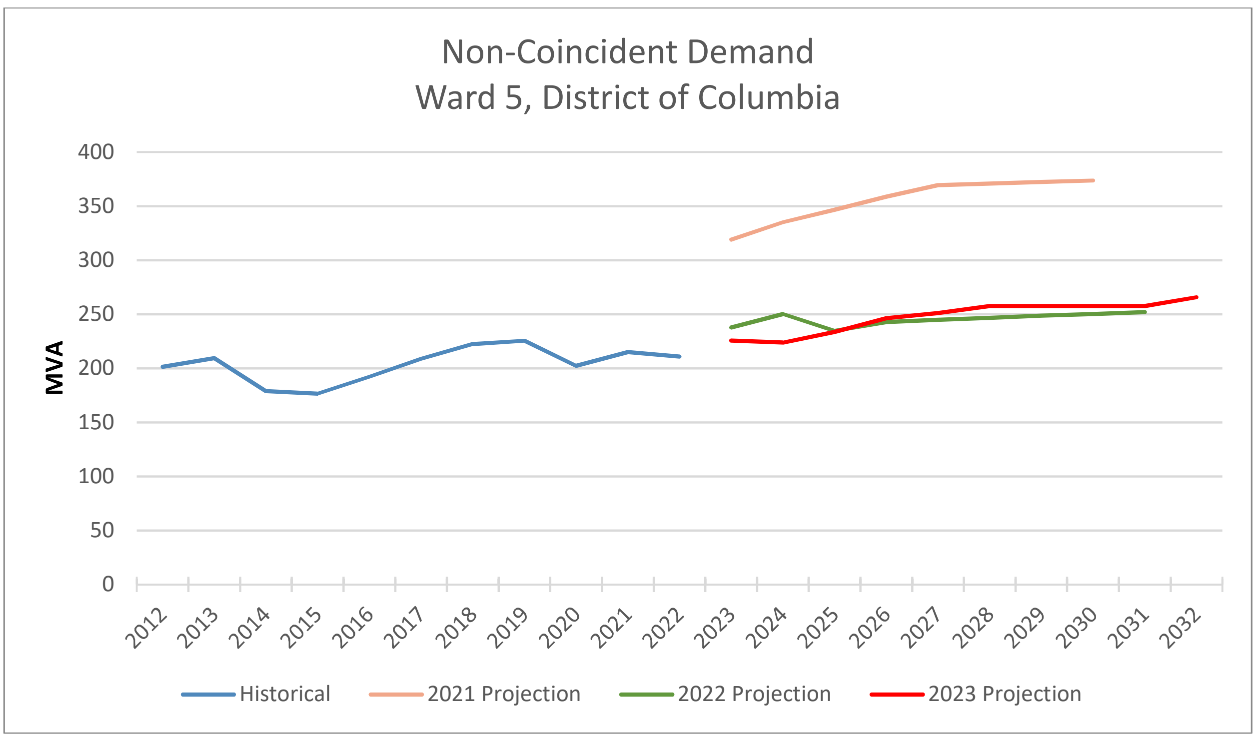
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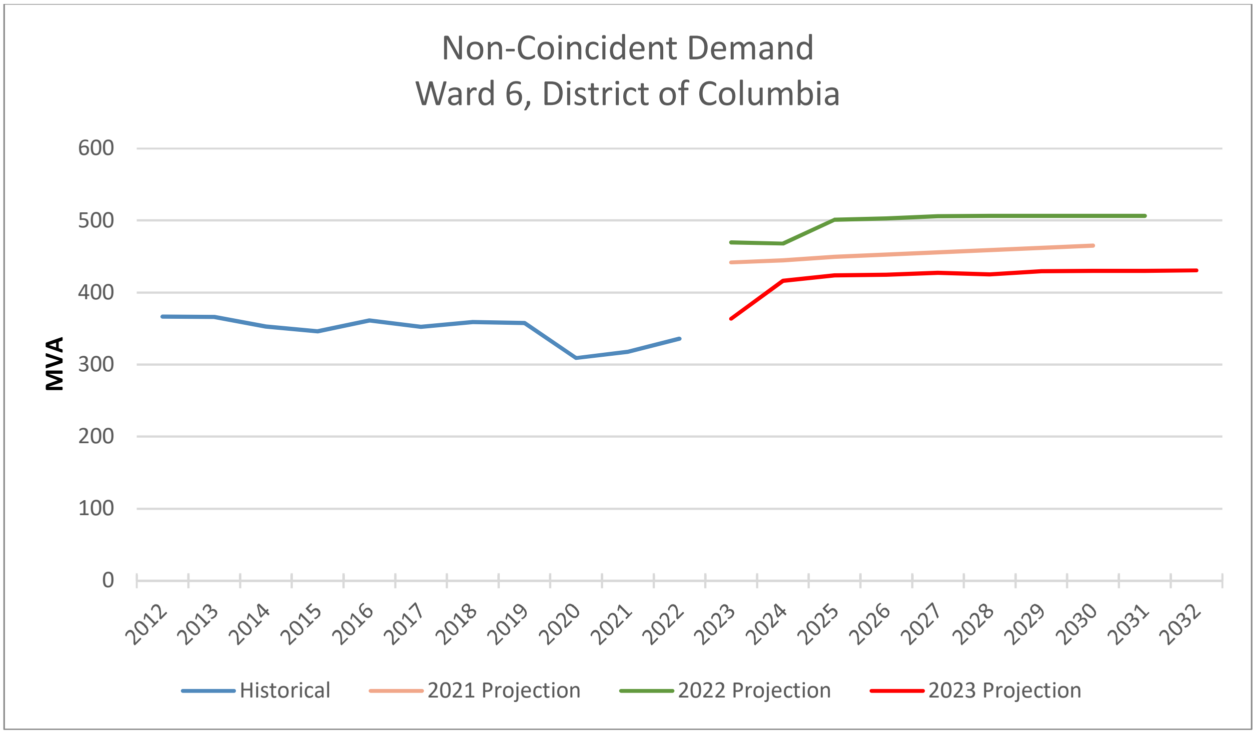
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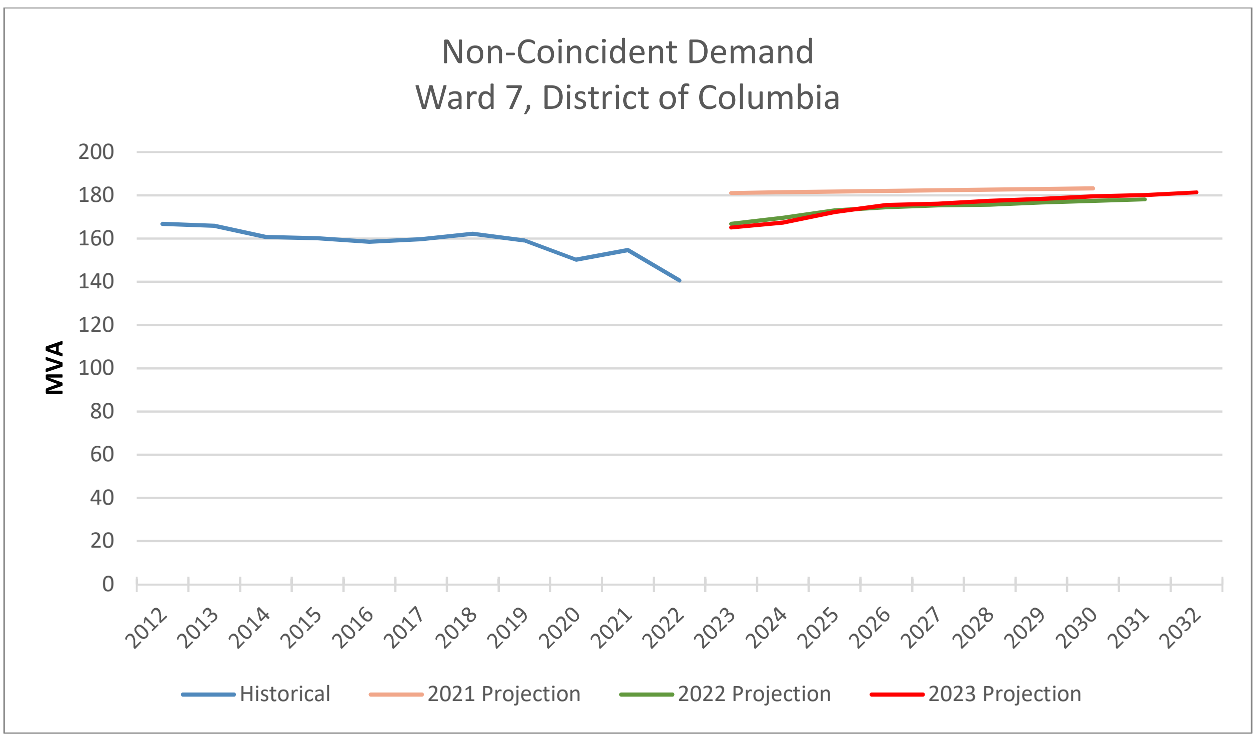
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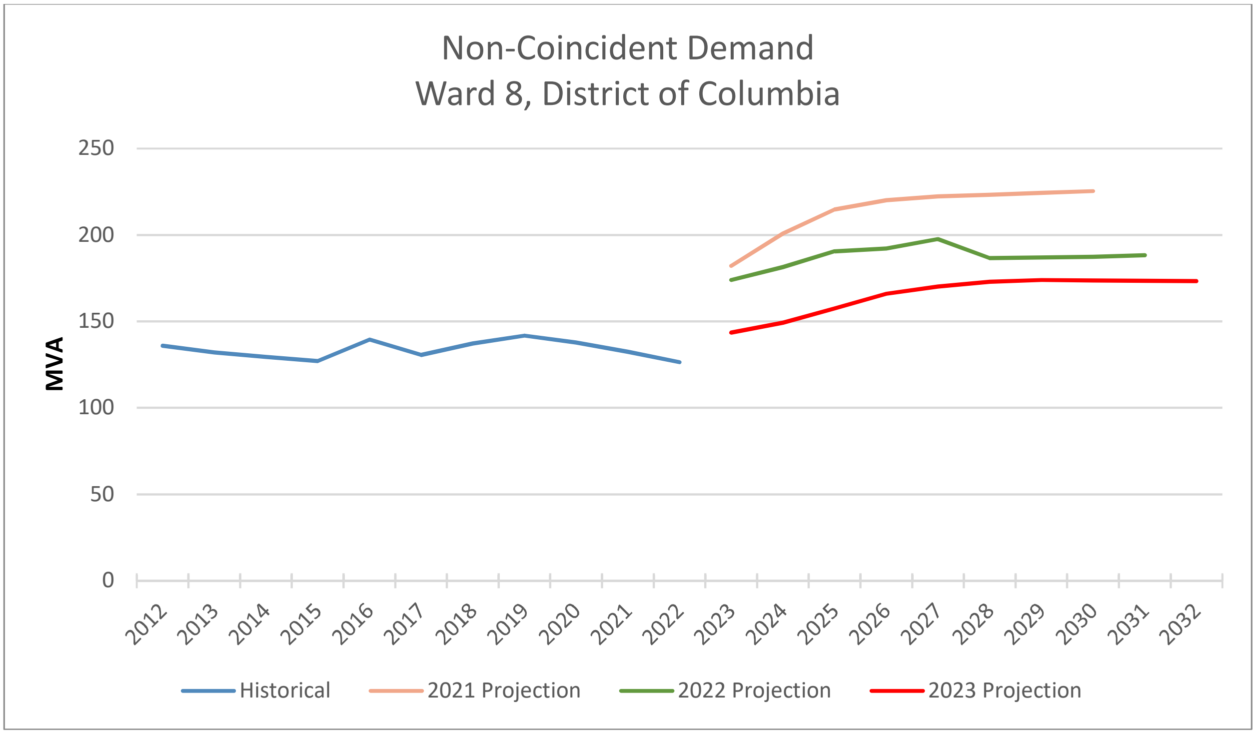
Non-Coincident Demand
Ward 8, District of Columbia
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Historical
2021 Projection
2022 Projection
2023 Projection

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO DCG DATA REQUEST NO. 5

QUESTION NO. 1
Provide Table 1: Historical District of Columbia Loads as presented in Exhibit PEPCO (H)-1 in Microsoft Excel format.

RESPONSE:

Please see the Company's attachment labeled FC 1176 DCG DR 5-1 Attachment.

SPONSOR: Jaclyn Cantler

Historical District of Columbia Loads

Loads in Mega-Volt-Amperes (MVA)

Ward 1	Sub. Number	2017	2018	2019	2020	2021	2022	
	10	125.6	127.1	127.5	140.1	134.2	131.4	
	13 (4.33kV)	3.1	2.5	2.2	0.0	0.0	0.0	
	13	31.9	34.3	33.6	7.6	0.0	0.0	
	25	50.2	51.0	56.0	46.4	46.5	44.5	
	Subtotal - Ward 1	**210.8**	**214.9**	**219.3**	**194.1**	**180.7**	**175.9**	Avg. Trend = -3.56%

Ward 2	Sub. Number	2017	2018	2019	2020	2021	2022	
	2	147.6	146.9	143.1	115.9	125.3	121.6	
	12	104.2	102.5	100.8	90.3	95.5	93.2	
	18	128.3	126.0	127.7	104.2	103.0	103.1	
	21	37.1	39.9	33.7	25.1	28.9	29.9	
	52	157.0	154.7	159.7	129.5	138.0	140.9	
	74	41.0	41.8	42.3	28.4	41.3	36.8	
	124	98.5	96.2	93.4	78.0	87.3	86.3	
	197	112.4	107.2	104.1	82.6	87.0	90.0	
	Subtotal - Ward 2	**826.1**	**815.2**	**804.8**	**654.0**	**706.3**	**701.8**	Avg. Trend = -3.21%

Ward 3	Sub. Number	2017	2018	2019	2020	2021	2022	
	38	37.5	36.7	38.7	38.3	41.2	39.6	
	77	64.3	64.9	66.9	65.8	61.7	60.4	
	93 (4.33kV)	3.0	3.4	4.4	3.2	3.4	3.4	
	129	159.3	162.7	153.5	144.6	143.1	139.3	
	145 (4.33kV)	2.4	2.6	2.5	3.3	4.1	2.9	
	146 (4.33kV)	5.4	4.8	5.4	5.4	4.9	4.4	
	Subtotal - Ward 3	**271.9**	**275.1**	**271.4**	**260.6**	**258.4**	**250.0**	Avg. Trend = -1.67%

Ward 4	Sub. Number	2017	2018	2019	2020	2021	2022	
	27	34.1	36.4	35.6	29.7	27.5	25.7	
	190	89.0	87.3	90.5	94.9	99.5	101.9	
	Subtotal - Ward 4	**123.1**	**123.7**	**126.1**	**124.6**	**127.0**	**127.6**	Avg. Trend = 0.72%

Historical District of Columbia Loads

Loads in Mega-Volt-Amperes (MVA)

	Sub. Number	2017	2018	2019	2020	2021	2022	
Ward 5	**Sub. Number**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	
	133	101.8	106.2	103.4	95.3	101.9	92.3	
	212	106.9	116.2	122.1	107.0	113.1	118.5	
	Subtotal - Ward 5	**208.7**	**222.4**	**225.5**	**202.3**	**215.0**	**210.8**	Avg. Trend = 0.20%
Ward 6	**Sub. Number**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	
	Sta. 'B'	123.1	56.5	55.7	23.6	26.8	17.0	
	33	16.4	16.1	15.8	0.0	0.0	0.0	
	117	104.5	101.4	105.7	82.3	81.7	95.6	
	161	108.5	107.1	103.1	86.1	87.9	93.9	
	223	0.0	78.0	77.5	117.2	121.5	129.6	
	Subtotal - Ward 6	**352.5**	**359.1**	**357.8**	**309.2**	**317.9**	**336.1**	Avg. Trend = -0.95%
Ward 7	**Sub. Number**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	
	7	159.7	162.3	159.1	150.3	154.7	140.6	
	Subtotal - Ward 7	**159.7**	**162.3**	**159.1**	**150.3**	**154.7**	**140.6**	Avg. Trend = -2.52%
Ward 8	**Sub. Number**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	
	8 (4.33kV)	1.2	0.9	0.8	0.7	1.5	0.7	
	8	17.5	22.5	24.4	25.7	18.3	16.4	
	136	91.2	93.4	93.9	93.2	93.1	90.9	
	168	20.6	20.5	22.7	18.1	19.6	18.4	
	Subtotal - Ward 8	**130.5**	**137.3**	**141.8**	**137.7**	**132.5**	**126.4**	Avg. Trend = -0.64%
	DC TOTAL	**2283.3**	**2310.0**	**2305.8**	**2032.8**	**2092.5**	**2069.2**	Avg. Trend = -1.95%

Notes: All substations supply 13.8kV of primary power unless otherwise noted.
Loads shown are actual readings taken during peak summer conditions.
Totals shown are the sum of undiversified peak loads and are not meant to be used as official Pepco system peak loads.
Trends shown are based on the straight line regression of the loads and include transfers amongst the substations.

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An Exelon Company

Dennis P. Jamouneau
Assistant General Counsel

EP9682
701 Ninth Street NW
Washington, DC 20068-0001

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pepco.com
djamouneau@pepcoholdings.com

April 15, 2021

Ms. Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 G Street N.W., Suite 800
Washington, DC 20005

Re: <u>PEPACR-2021-01 and Formal Case No. 1119</u>

Dear Ms. Westbrook-Sedgwick:

Attached please find Potomac Electric Power Company's 2021 Annual Consolidated Report. In addition, per Order No. 20203, Pepco has included Attachment F, which provides required information related to the Downtown Resupply Project.

Please feel free to contact me if you have any questions regarding this matter.

Sincerely,

/s/ *Dennis P. Jamouneau*

Dennis P. Jamouneau

Enclosures

cc: All Parties of Record

2021 CONSOLIDATED REPORT

· Comprehensive Plan
· Productivity Improvement Plan
· Manhole Event Report

Filed By

POTOMAC ELECTRIC POWER COMPANY

In accordance with

D.C. Formal Case No. 991, Order No. 12735 (Comprehensive Plan)

D.C. Formal Case No. 766, Order No. 7668 (Productivity Improvement Plan)

D.C. Formal Case No. 991, Order No. 13812 (Manhole Event Report)

D.C. Formal Case No. 766, Order No. 16975 (Consolidated Report)

D.C. Formal Case No. 991, Order No. 17074 (Consolidated Report)

D.C. Formal Case No. RM5-2014-01-E, Order No. 17684 (Consolidated Report)

D.C. Formal Case No. PEPACR-2014-01, Order No. 17816 (Consolidated Report)

D.C. Formal Case No. 1119, Order No. 18148 (Merger Order) and

D.C. Formal Case No. PEPACR-2015-01, Order No. 19119 (Consolidated Report)

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Contents

INTRODUCTION[1]

Potomac Electric Power Company (Pepco) herein presents its 2021 Consolidated Report combining three reporting requirements directed by the District of Columbia Public Service Commission (Commission) in Formal Case Nos. 766 and 991. The three reports comprising the Consolidated Report are identified respectively as the Comprehensive Plan for the Planning, Design, and Operation of the Distribution System within the District of Columbia (Comprehensive Plan), the Productivity Improvement Plan (PIP), and the annual Manhole Event Report. Additionally, a section of References has been included at the end of the report.

Additionally, Attachment D includes information related to Paragraph 60 of Attachment B to Order No. 18148 and discusses Pepco's 2020 safety performance and initiatives as well as a report by Exelon on existing safety and cybersecurity policies. References to previous Commission directives are included in footnotes or the body of the report, as noted throughout. Attachment E is included as Pepco's Vegetation Management attestation, in accordance with Paragraphs 98-99 of Order No. 19119. Attachment F provides the information required in the Commission's Order No. 20203 regarding the Downtown Resupply Project.

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[1] Order No. 18148, *In The Matter of the Joint Application of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC and New Special Purpose Entity, LLC for Authorization and Approval of Proposed Merger Transaction*, Formal Case No. 1119, at P 1 (March 23, 2016) ("Merger Order"). The Commission subsequently issued Order No. 18160 (April 4, 2016) correcting certain errors in the Merger Order and in Attachment B to the Merger Order (the "Merger Commitments").

Summary

The following is a brief description of the four parts of this Report:

Part 1: Comprehensive Plan

During Commission hearings on November 5-7, 2001, addressing Formal Case No. 991, the Commission issued directives, followed by Order No. 12293, requiring the Company to produce and submit its first Comprehensive Plan on February 8, 2002. Pepco's filed report presented a compilation of major elements of its underground distribution construction and plans as well as supporting technologies and conversion programs to improve system reliability. Over the years, the Comprehensive Plan has evolved with Commission orders to address current issues. In 2020, the Comprehensive Plan covers similar material to the 2019 Comprehensive Plan.

Part 2: PIP

On November 1, 1982, in Order No. 7668, the Commission adopted final rules regarding the submission of an annual PIP in Formal Case No. 766. These rules are codified in Title 15 of the District of Columbia Municipal Regulations, Chapter 5, Rules 502.1 and 502.2. Because of the divestiture or transfer to an affiliate of all of Pepco's generating stations, most of these rules are no longer applicable to Pepco's operations. Instead, this PIP was compiled pursuant to the latest requirements for Pepco to report on its transmission and distribution system operating performance and measures to improve service reliability.

Part 3: Manhole Event Report

In 2000 in Formal Case No. 991, the Commission issued Order No. 11716 requiring Pepco to file an annual Manhole Event Report on the previous year's manhole incidents. Part 3 of the Consolidated Report includes descriptive statistics regarding reportable events, a trend analysis for slotted manhole covers, and a listing of splice data. Appendix 3A contains a listing of 2020 Manhole Events. Appendix 3B includes a discussion of the 2020 Manhole Inspection Program including annual program results. Appendix 3C contains Pepco's update on implementation of its Network Accuracy Procedure.

Part 4: References

Part 4 of the filing contains a compilation of abbreviations, acronyms, and technical terms and diagrams; and a section providing Commission Order references delineating the history of the Consolidated Report requirements.

Attachments A – F

A. Vegetation Management Communications

B. Work Plan

C. Priority Feeder Maps

D. Cyber and Safety Statement

E. Vegetation Management Attestation

F. Downtown Resupply Description

PART 1: 2021 COMPREHENSIVE PLAN

SECTION 1.1– SYSTEM PLANNING[2]

[2] The initial requirements for the Comprehensive Plan section of the Consolidated Report were delineated in hearings taking place from November 5-7, 2001. The Commission requested that the Company provide a Comprehensive Plan detailing proposed changes to the electric system for the purposes of meeting load growth or maintaining system reliability. On pages 143-144 of the hearing transcript, Pepco's Witness Gausman explained the nature of the Company's existing plans for the distribution and transmission systems. The Company expanded its responses to the Commission's requests in the first filed Comprehensive Plan. Since that date, the Company's Comprehensive Plans have been expanded based on several Commission directives. The report that follows either expands upon the discussion in the initial hearings requesting the Consolidated Report or responds to subsequent Commission directives as cited below.

The following section of the report addresses system plans based on forecasted load growth. In Order No. 12804 paragraph 53 B, the Commission stated the following:

> *53. The 2003 PIP is hereby APPROVED, provided that PEPCO: (b) Submit quarterly reports to the PIWG as well as a report in the 2004 and subsequent PIPs on its plans for implementing the recommendations for alleviating the anticipated transmission constraints identified in the RTEP report.*

> *53. The 2003 PIP is hereby APPROVED, provided that PEPCO:*
>
> *(b) Submit quarterly reports to the PIWG as well as a report in the 2004 and subsequent PIPs on its plans for implementing the recommendations for alleviating the anticipated transmission constraints identified in the RTEP report.*

The mission of System Planning is to develop a rational and orderly plan for Pepco's existing and future electric system needs that will provide reliable electric service to customers and support load growth in a cost-effective manner. In order to accomplish this mission, the North American Electric Reliability Corporation (NERC) / Reliability First Corporation (RFC) Standards and Pepco's Planning Criteria for the transmission, subtransmission, and distribution systems govern the design of the electric system.

Pepco continuously analyzes the adequacy of its electric system to meet demand for energy on its system and to plan for future growth. The Company maintains engineering and operating criteria for use in the design of new and modified portions of the system. To provide for rational and orderly changes to the electric system, Pepco has developed engineering and operating criteria that it applies to the design of new and modified systems. The three major components of system planning criteria are (1) voltage and reactive support, (2) ratings of facilities, and (3) reliability. For example, voltage on a nominal 120-volt system must be maintained between 114 and 126 volts under normal conditions and between 105 and 126 volts under contingency conditions. Ratings of facilities include normal, emergency, and short-term emergency ratings on all facilities including feeders, power transformers, circuit breakers, for both summer and winter periods. In terms of reliability, the data that are reviewed and tracked include historical and forecasted load compared to capacity of the feeders, feeder groups, and substations.

1.1.1 The Current Load Forecasting Process[3]

Planning for future load growth starts with the development of load growth projections. A forward-looking 10-year peak load forecast is developed and maintained for each distribution system component such as feeders, substation transformers, and substations to plan for longer duration projects. Short-term, summer-peak forecasts are developed for three years to address the more frequent changes from new building construction and customer load growth that occurs across the distribution system. Long range forecasting (four to ten years) is used to develop advance plans for longer duration projects or

[3] In the initial November 5-7, 2001 hearings requiring the production of the Comprehensive Plan, the following topics were discussed, as cited on pages 141-144 of the hearing transcript:

- Comprehensive long-term planning on the underground system
- Pepco's 10-year construction plans
- Distribution load growth forecasts by substation
- Transmission/substation supply load growth forecasts

construction projects that require more than two or three years to complete, and to identify future capital projects in the Construction Budget Forecast process.

Forecasting begins with the examination of the summer historical loads for each feeder and substation on a two-year cycle. Further, actual new customer loads from submitted class of service forms and other available development reports, planned changes in feeder configuration and emergency transfers, and reductions due to distributed energy resources (DER) are also analyzed. The individual feeder and feeder group loads for each year are calculated and adjusted to produce the substation load predictions for each year of the plan.

As part of the 2022-2031 Ten-Year Load Forecast, which Pepco will provide in the 2022 ACR, Pepco will employ the results of its updated Distribution System Planning Load Forecasting (DSP-LF) program. The DSP-LF program is currently in the testing phase and is expected to be in use later in 2021. Please note that the updated and enhance load forecasting program will cause changes not just to the results of the forecasts themselves, but also the methodology and process. Thus, the information, data, and process contained in this 2021 report will be modified for the 2022 report.

The DSP-LF application will assist Capacity Planning engineers in evaluating plans that include Non-Wire Alternatives (NWA), satisfying the need for more improved modeling of the many time varying effects on system operation, such as PV generation and battery charge/discharge cycles; understanding the effects on both the seasonal peaks and the annual energy use; and considering the use of NWAs in solutions to load growth.

The DSP-LF application evaluates 8,760-hour DER, load and weather data, including future 8760-hour load, generation, and proposed system changes, and produces an 8,760-hour 90/10 forecast each year for 10 years into the future for feeders, substation power transformers, and substations.

1.1.2 Peak Load Forecasting Process

As described in Figure 1.2-A, the development of the peak load forecast is the first step in Pepco's distribution system planning process. The development of the forecast is a critical step, because it has

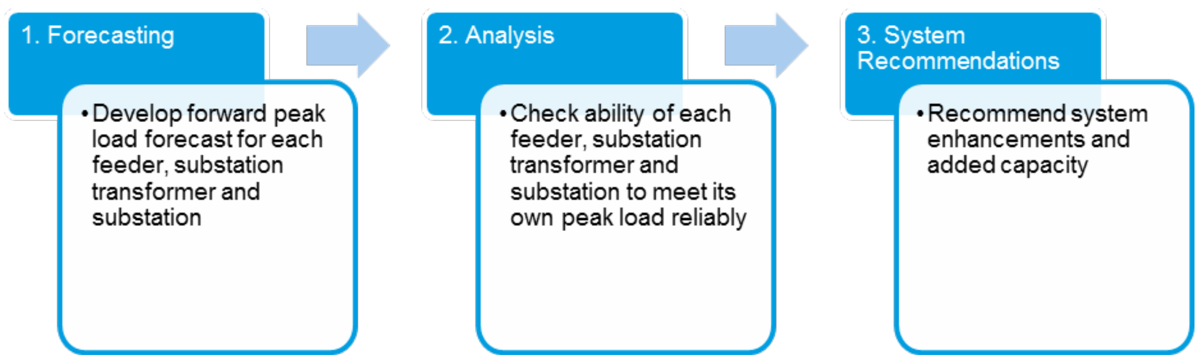
an impact on the outcomes of each subsequent step in the process and, ultimately, the timing and magnitude of the investments in the distribution system made by Pepco.[4] This section provides additional details on the analytical processes Pepco employs to develop its peak load forecast and the way in which DERs are incorporated into these processes.

[4] Consistent with PHI's regulatory obligations to provide safe, reliable electric service to its customers

It is important to note that Pepco must create more than just one peak load forecast. In fact, it creates many – one for each distribution feeder, individual substation transformer, and substation on its system. The creation of peak load forecasts for each distribution system component is needed to ensure that both individual system components are sized appropriately, and that the system as a whole will perform as it should.

This peak load planning process is depicted in the following figure:

Figure 1.1-A: General Planning Process for Distribution Feeders, Substation Transformers, and Substations

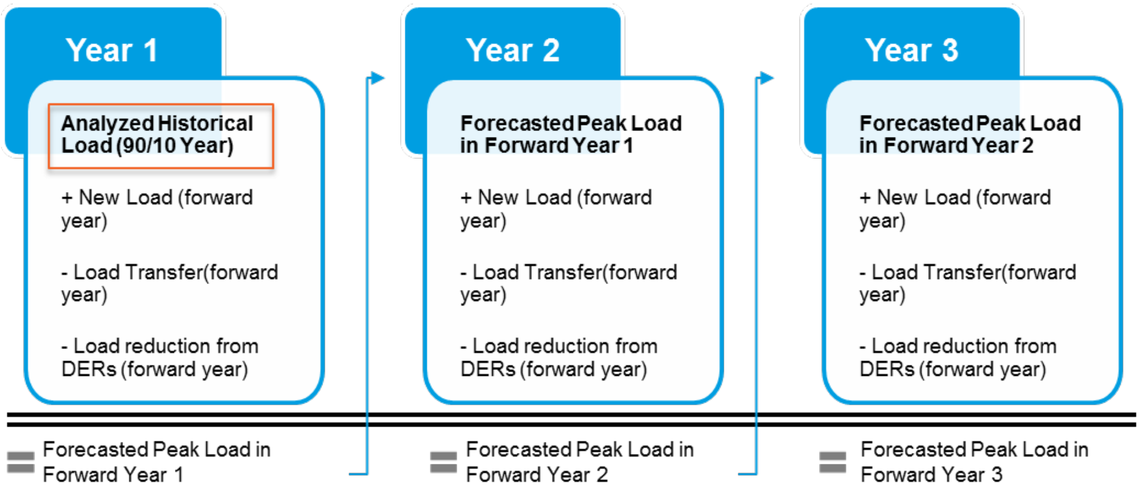


1.1.3 Short-Range and Long-Range Peak Load Forecasts

The peak load forecast is comprised of a short-range forecast for future years 1-3 and a long-range forecast for future years 4-10. This short-term forecast also serves as the basis for the development of the longer term 10-year plan. The former is a detailed, "bottom-up" analysis of historical peak load data, projected new load growth and energy reduction initiatives. The latter is a higher-level and "top- down" trending effort based on the PJM (the regional transmission operator or "RTO" responsible for maintaining the stability of the transmission system in Pepco's region) system peak load forecast. The short-range forecast is generally formulated in accordance with the calculation detailed in Figure 1.2-B[5].

[5] Specific circumstances may merit variations in this calculation process.

Figure 1.1-B: General Process for Creating Distribution Feeder, Substation Transformer, and Substation Short- Range Forecasts



For the purposes of this report, terms are defined as follows:

- **Analyzed Historical Peak Load** – This value serves as the base value from which future projections are calculated. This value is most often derived for each distribution system component by taking its actual historical peak load[6] in the hottest year within the last ten years,[7] and adding to it the incremental load changes (i.e., new loads, load transfers and load reductions from DERs) that have occurred between that hottest year and the year prior to the current year.[8]
- **New Load** – This represents additional new load that is anticipated to come online as a result of new building or development activities. At times and in some areas of Pepco's service territories, this value may be negative such as when an existing customer facility closes. New loads are

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[6] As recorded within the SCADA and AMI systems.

[7] Pepco plans to the hottest year in the last 10-years to develop its peak loads for each distribution system component in the short-term load forecast. Pepco uses the 90/10 forecast produced by PJM as the basis of its long-range growth forecast in order to ensure that each utility has adequate system capacity to meet area load needs during seasons with extremely hot weather. The 90/10 forecast is produced by PJM to depict peak loading that has a 10 percent probability of occurring in any given year. For capturing peak historical loadings, Pepco's methodology uses actual load readings for each component during years of extreme (one in ten year) weather. For years when less than extreme weather occurs, Pepco uses the load of the latest extreme summer, making adjustments to the load to account for prospective new businesses (PNBs), load transfers, DERs and other factors. By employing this historical loading methodology, Pepco can seamlessly transition from the historical loads used to develop its short-term plan to the long-term forecast using the PJM 90/10 loads as the basis for the trend in growth. This process also assures that no peak load used for future planning is more than 10 years old.

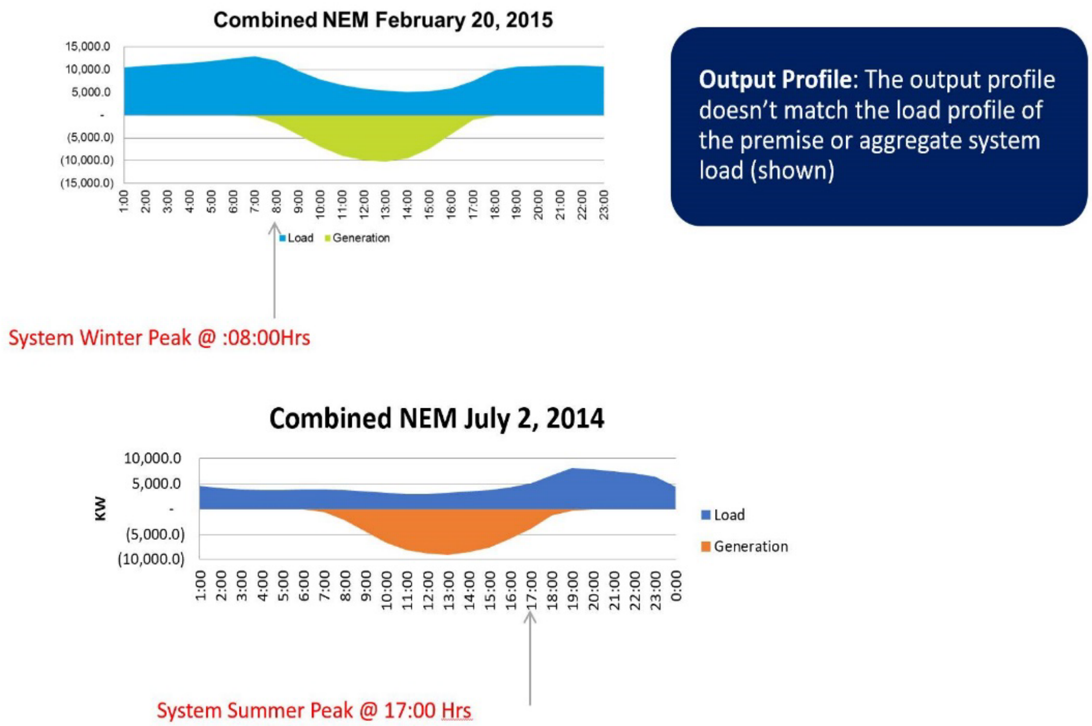
[8] On occasion, this method will result in a value that is less than the peak load encountered in the year prior to the current.This may occur because actual load growth on a feeder is greater than what Pepco would arrive at through its calculation (i.e., the addition of new load only from new build). In such cases, Pepco will use the actual peak load (i.e., via SCADA and AMI readings) from prior years as the Analyzed Historical Peak Load, to ensure that it is planning the distribution system to meet its maximum load requirement.

added at the anticipated level of load that Pepco expects a building of the same size and energy use would add to the distribution system.

- **Load Transfers** – These are projects that Pepco conducts to utilize available capacity in one portion of its distribution system to help meet a projected capacity shortfall in another part of the system. Such projects may include re-routing feeders from one substation to another or transferring a portion of one feeder to another feeder. These types of projects occur seasonally on the distribution system and are a way of managing load without undertaking more expensive upgrades or construction. Such projects are planned ahead of time and have an impact on the forecast in future years. As a result, these projects are accounted for in the process. These are permanent redistributions of load that must not cause a total projected load to exceed the normal rating of the component, as opposed to the contingency load transfers which occur during outages to help sectionalize and restore customers' service and can result in a component operating up to its emergency rating.
- **Load Reductions from DERs** – Distributed energy resources may, depending on their operation, reduce peak load. Whether or not these resources reduce peak load depends on the coincidence of the resource with the time of peak load on a particular distribution system component. The degree to which a DER contributes to a reduction in peak load depends on its output (which may be variable) and its contribution to total load at the time of peak load.

In addition, energy efficiency measures that are known are reflected in the historical loads that are being measured for each facility. Figure 1.2-C shows the effects of Net Energy Metering facilities on feeder peak loading.

Figure 1.1-C: Impacts of PV on Feeder Peak Loading



1.1.4 Long-Range Forecast

Upon completion of the short-range forecast, Pepco then completes the long-range forecast for years 4-10. Pepco's process for completing the long-range forecast generally occurs via the following steps:

1) Pepco first conducts a trending of the short-range forecast beyond its duration (within years 1-3) and into the window of the long-range forecast (years 4-10).
2) Pepco then adjusts this trending of peak load for each feeder, substation transformer, and substation for larger-scale system changes and factors that are known to be planned within the long-range forecast window. These changes may include considerations such as major long-term redevelopment initiatives within a geographical area
3) Finally, Pepco adjusts the projected year-by-year long-range peak load growth on each distribution system component such that the growth rate of the system-level peak load of Pepco's long-range forecast is reconciled with the rate of growth within the corresponding PJM long-range load forecast. Pepco reconciles the growth rate of its long-range forecast with PJM's 90/10 long-range forecast to ensure consistency across the planning process of the entirety of the power delivery system, inclusive of the distribution system under Pepco's purview and the transmission and generation systems under PJM's purview.

Pepco must plan for the reliable operation of each feeder, substation transformer, and substation at its individual peak load (MVA). These individual equipment peak loads generally do not coincide with one another and are thus generally referred to as being "non-coincident" peaks. Moreover, the sum of individual non-coincident equipment peaks generally exceeds the peak load demanded of the collective whole at any given time. In other words, Pepco must plan for its "non-coincident" peaks for each component of the distribution system while PJM must plan for the coincident peak that the transmission system is required to serve.

1.1.5 Feeder, Substation Transformer, and Substation Analysis Process

Once the peak load forecast is completed, Pepco analyzes the capabilities of each distribution system component to ensure that it can reliably meet its forecasted peak loads. Planners use the PNB and DER information gathered in the load forecasting process along with historical AMI customer load data, SCADA and electrical configuration information from Pepco's geographic information system (GIS) to model each feeder in its power flow analysis software. From this analysis, predicted system violations such as low voltage and thermal overloads are identified and resolved through the system recommendations process.

1.1.6 System Recommendations Process

Upon completing its analysis process, Pepco considers the specific predicted system violations to develop recommended actions, which may consist of:

1) Operational measures – Resetting relay limits, conducting phase balancing, or other measures;

2) Load transfers – Conducting field switching to transfer load from a higher loaded feeder to a lower loaded feeder;

3) Short-range construction projects – Feeder extensions, installation of capacitors or voltage regulators, reconductoring, NWA solutions; and

4) Long-range construction projects – New feeder extensions, new substation transformers or entirely new substations.

Once the recommended actions are identified, an area plan containing construction recommendations is issued.

1.1.7 Factors Guiding the Consideration of DERs in Pepco's Peak Load Forecast

DERs are considered in the peak load forecast and, therefore, are reflected in the entirety of the distribution planning process that follows. How or whether a DER is counted as providing a peak load reduction depends on the availability of that resource during the peak load time for the component of the distribution system being assessed. The magnitude of impact of a DER to be counted toward reducing load depends on the level to which that resource can be relied upon to provide a load reduction at that specific point in time when the peak load will occur on the component being assessed.

1.1.7.1 Availability of a DER at the time of Peak Load

A DER may or may not be available or in operation at the time of distribution feeder, substation transformer, or substation peak load. This is an important factor that has an impact on how the resource is considered in the peak load forecast, and ultimately the entirety of the planning process. The examples below illustrate some of the potential scenarios to be contemplated when incorporating DERs in the planning process:

- A customer completes an energy efficiency upgrade consisting of the installation of a new energy efficient air conditioning unit in place of an old unit – this would result in a permanent load reduction, and thus this DER (the EE upgrade)—if known to Pepco—would be fully available at the time of peak load on the distribution feeder, substation transformer, and substation from which this customer is provided service, and would thus be considered a resource that reduces peak load on these components.
- A commercial customer installs a large diesel generator that is run on occasion to supplement the customer's energy usage at the time of the customer's maximum energy demand, which occurs seasonally in mid-spring and not in the summer when the local distribution system experiences a peak load. Therefore, the diesel generator would not be a resource toward reducing peak load on the distribution feeder, transformer, and substation from which this customer is provided service.
- Several customers install small-scale residential solar systems on their roofs. In a given area, these DERs would be considered available at the time of peak load on the distribution feeder, substation transformer, and substation from which these customers are provided service. The total percentage of nameplate capacity considered to be available can be determined using a backcasting analysis that relates the hourly capacity factor9 of the DERs, the hour of the peak

[9] Capacity Factor is defined as the average power generated for a specified period of time divided by the rated nameplate power of the generating asset.

load on the component, and the total nameplate capacity on the component. Therefore, this would not be considered a firm resource counted toward reducing peak load on the distribution feeder, substation transformer, and substation from which this customer is provided service.

- A commercial developer installs a utility-scale battery system on a distribution feeder that is discharged during peak load periods on the transmission system. Therefore, most likely this would not be a resource counted toward reducing peak load on the distribution feeder, substation transformer, and substation from which this customer is provided service, because distribution system peaks do not necessarily coincide with the peak load on the transmission system.

In order to be considered as a planning resource, a DER must be "firm." In other words, it must be available at the time of peak load. Pepco's system planning criteria dictate that a DER is considered firm and is thus a dependable resource for peak planning purposes, if it is available (or coincides) 95% of the time with the peak on whichever component of the distribution system is being evaluated (feeder, substation transformer, or substation).

Planners, however, must also consider the consequences to the system when the DER is not available such as after restoration from a momentary or sustained power outage. For example, current industry standards and local electric codes mandate that all inverter-based systems (e.g., solar PV) automatically disconnect from the utility feeder upon loss of power.[10] When the feeder is reenergized, loading observed on that feeder is now the full load without the reduction from the solar generation until the inverters reconnect the customer PV back to the distribution system, which generally occurs after a minimum of five minutes. For planning purposes, the reduction from solar PV is added back into the loads of each distribution system component and those loads are compared to the emergency capacity ratings of the feeders and substation transformers and to the firm capacity rating of the substation. This Capacity Factor is defined as the average power generated for a specified period of time divided by the rated nameplate power of the generating asset.

This ensures that Pepco maintains adequate capacity during times when customer generation is unavailable, consistent with its regulatory obligation to provide safe, reliable electric service. Actions to be taken by the planners as a result of this analysis will depend on which component is overloaded and what actions that can be taken to mitigate the overload until the solar PV systems begin to generate and

[10] IEEE 1547.

reduce customer net loads. For example, if the only overload that exists is at the substation level, then restoration can be performed in stages to mitigate the risk of an overload and no further system enhancements would be needed.

Planners also consider the effects of distributed generation being offline during an outage event when automatic sectionalizing and restoration (ASR) schemes are operated through automated inline and tie switching devices. These ASR schemes are designed to automatically operate in order to isolate a fault during a feeder outage event and restore as many customers as possible. During the outage event, it is anticipated that all distributed generation on the affected feeder will have tripped off due to loss of utility power. Planners must analyze the potential transfers[11] to examine if the receiving feeder/substation transformer/substation can handle the extra load being transferred to it through automated switching. Planners design ASR schemes to maximize the amount of time during the year that there is adequate capacity to back-up an adjacent feeder.

1.1.7.2 Magnitude of Impact (kW) of a DER at the time of Peak Load

While some resources which meet the firm criteria are considered permanent load reductions (e.g., CVR, EMTs and other programmatic energy efficiency) additional analysis is required for other types of DERs to calculate the magnitude of the impact of the resource. This is particularly evident for variable generation sources such as solar PV. Over the course of a 24-hour period, hourly production of solar PV can range from 0% to 100% of nameplate capacity. Therefore, calculating the magnitude of the impacts requires considering several pieces of related information:

1) Actual or simulated production of the resource (in the case of distributed generation without dedicated metering and telemetry, a backcasting process is used to simulate production based upon conditions in a representative area);

[11] The total load to be transferred would be equal to the load that existed just prior to the outage plus the total available PV generation on the circuit. Once all load is transferred and customers are restored to service, the solar PV systems will be restored, and load will be reduced to pre-outage levels.

2) The amount of nameplate capacity of the DER interconnected to a distribution system component; and,

3) The hour and magnitude (MVA) of the peak for the distribution system component being evaluated.

1.1.8 Customer Growth Projections and Historical Comparisons[12]

Pepco's System Planning group forecasts electric load growth in order to plan for future additions to the electric system. Changes in the number of customers do not necessarily correspond to a similar change in load since neighborhoods containing specific types of customers may be redeveloped into ones containing different types of customers with different load characteristics. For example, former industrial zoned districts can be re-zoned to permit mixed use development. In addition, existing customers may increase their load, which has no effect on the customer count. Both new customer additions and increases in existing customer load are factors used in forecasting load growth. The increase or decrease in the number of customers can have an impact on system load. However, the more critical information is the amount of load that a customer uses. Thus, Pepco focuses on forecasting system load growth with future development and associated customer counts as an input.

District of Columbia customer counts for six years (2015-2020) are provided on a substation basis in Table 1.2-A. Substations have been assigned to District of Columbia wards based on their location rather than the area that they serve.

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[12] In Order No. 12735 issued on May 16, 2003, the Commission directed (paragraph 139) the following:

> *139. PEPCO shall file the additional information not included in its expurgated comprehensive plan as outlined below, within three months of the issuance date of this Report and Order:*
> *(a) Customer growth projections by District of Columbia wards (including historical comparisons);*
> *(b) Load growth projections encompassing commercial and residential development by District of Columbia wards (including historical comparisons);*
> *The summary should cover a 10-year planning horizon while historical comparisons should provide at least five years of history.* In Order No. 12804 (paragraph 53) the Commission directed the following:
>
> *53. The 2003 PIP is hereby APPROVED, provided that PEPCO:*
> *(a) Provide the projected zonal and projected default (i.e., SOS) load data for the District of Columbia to the PIWG on a quarterly basis as well as in the 2004 and subsequent PIPs;…*

1.1.9 Load Growth Projections and Historical Comparisons

Table 1.2-B provides six years of historical loads, and Table 1.2-C provides Pepco's projections for electric load growth in the District of Columbia for 2021 to 2030. The 33 substations listed in Table 1.2-B represent all the 13 kV distribution substations as well as the 4 kV substations not supplied by a listed 13 kV substation within the District of Columbia. Pepco tracks and projects load by substation. Substations have been assigned to one of the eight District wards based on the substations' locations rather than the area where they serve. Because feeders may cross ward boundaries, all feeders emanating from a substation will be assumed to supply load in the ward to which that substation is assigned.

The District has experienced uneven overall load growth from 2015 to 2020, as there are certain neighborhoods that have been growing relatively rapidly and other neighborhoods that have actually reduced load. Pepco attributes the reduction in loads to a marked increase in the number of customer owned photo voltaic (PV) solar generation connections and energy efficiency measures. Pepco's planning process examines historical load data on its substations and feeders, then examines PNB report data and internal and external reports regarding the load reductions due to DERs to develop a short-term forecast for each feeder and substation. Pepco uses trends developed in the short-term forecasting process combined with information about long-term neighborhood development projects and DERs to determine the long-term forecast for each feeder and substation. The trend analysis also takes into consideration energy efficiency activities that customers have supported during the past years and further uses AMI data from recently constructed buildings to refine expected loadings for new buildings. Developing energy usage trends will reflect these reductions in aggregate and are included in the decision-making process to determine when and where increased capacity is needed.

1.1.10 Incorporation of Field Information into the Planning Process[13]

Pepco's planning process incorporates equipment condition assessments (ECA) and other field information into its short-term and long-range plans, when applicable. The planning group creates long-range plans to upgrade or replace utility infrastructure evaluated to be approaching end-of-life.

The planning group is an active participant in ECA meetings and is the sponsor of substation transformer and switchgear replacement projects. The planning group participates in decision making regarding actions to take when equipment is evaluated to be near end-of-life, including whether to replace the equipment in kind or through a new capital project. The decision depends upon how close to failure a piece of equipment is evaluated to be, what other load-driven or reliability-driven capital projects are in the area, and the age and condition of other equipment in the substation.

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[13] Order No. 16975 states the following at paragraphs 89 and 116:

> *89. Decision: The Commission believes that OPC's recommendation has merit. However, we understand that equipment condition assessments may be included within the distribution system planning process, as shown in the description of the Pepco Planning Process provided by OPC at "Existing System Analysis." We direct Pepco to explain in the 2013 Consolidated Report the extent to which field information is considered within "Existing System Analysis."*
>
> *116. Pepco is DIRECTED to provide field information consistent with paragraph 89 herein;*

Table 1.2-A: DC Historical Customer Counts per Substation

TABLE 1.2-A: D.C. Historical Customer Counts per Substation

			2015			2016			2017			2018			2019			2020			2015 - 2020 Avg. Trend		
Ward 1	Substation Number	KVLEV	Res.	Comm.	Total	Res.	Comm.	Total	Res.	Comm.	Total	Res.	Comm.	Total	Res.	Comm.	Total	Res.	Comm.	Total	Res.	Comm.	Total
	10	13.8	20856	1487	22343	21159	1546	22705	20386	1441	21827	21026	1461	22487	21337	1461	22798	27218	1905	29123			
	13 (4kV)	4.33	2805	247	3052	2799	254	3053	750	74	824	670	76	746	654	69	723	0	0	0			
	13 (13kV)	13.8	7976	671	8647	7899	658	8557	8499	698	9197	8648	712	9360	8734	723	9457	0	0	0			
	25	13.8	10256	1099	11355	10494	1114	11608	12506	1213	13719	12911	1210	14121	13101	1221	14322	13041	1221	14262			
	Subtotal - Ward 1		**41893**	**3504**	**45397**	**42351**	**3572**	**45923**	**42141**	**3426**	**45567**	**43255**	**3459**	**46714**	**43826**	**3474**	**47300**	**40259**	**3126**	**43385**	**-0.79%**	**-2.26%**	**-0.90%**
Ward 2	Substation Number	KVLEV																					
	2	13.8	9816	1821	11637	9936	1908	11844	10256	1895	12151	10486	1915	12401	10558	1912	12470	10486	1877	12363			
	12	13.8	6316	1402	7718	6337	1467	7804	6340	1454	7794	6315	1466	7781	6688	1474	8162	6789	1441	8230			
	18	13.8	3274	494	3768	3270	577	3847	3318	534	3852	3351	540	3891	3494	550	4044	3695	550	4245			
	21	13.8	44	222	266	44	222	266	43	238	281	57	248	305	56	238	294	55	239	294			
	52	13.8	9059	1432	10491	8697	1500	10197	9399	1336	10735	9417	1350	10767	9528	1358	10886	9566	1345	10911			
	74	13.8	4	19	23	4	19	23	4	19	23	4	19	23	4	22	26	4	22	26			
	124	13.8	3023	1022	4045	3036	1073	4109	3108	1042	4150	3408	1049	4457	3257	1040	4297	3209	1035	4244			
	197	13.8	504	590	1094	510	697	1207	510	705	1215	514	730	1244	513	715	1228	501	692	1193			
	Subtotal - Ward 2		**32040**	**7002**	**39042**	**31834**	**7463**	**39297**	**32978**	**7223**	**40201**	**33552**	**7317**	**40869**	**34098**	**7309**	**41407**	**34305**	**7201**	**41506**	**1.38%**	**0.56%**	**1.23%**
Ward 3	Substation Number	KVLEV																					
	38 (13kV)	13.8	5385	358	5743	4861	288	5149	3420	268	3688	3410	270	3680	3425	253	3678	3443	257	3700			
	77	13.8	6217	585	6802	6242	619	6861	6068	616	6684	6081	617	6698	6079	616	6695	6066	616	6682			
	93	4.33	704	13	717	711	17	728	715	15	730	716	14	730	711	15	726	721	16	737			
	129	13.8	18060	1297	19357	18065	1351	19416	19071	1355	20426	19181	1333	20514	19022	1337	20359	19110	1338	20448			
	145	4.33	362	36	398	362	34	396	362	35	397	363	35	398	365	35	400	235	32	267			
	146	4.33	622	15	637	1147	60	1207	1129	59	1188	1132	63	1195	1127	61	1188	1131	60	1191			
	Subtotal - Ward 3		**31350**	**2304**	**33654**	**31388**	**2369**	**33757**	**30765**	**2348**	**33113**	**30883**	**2332**	**33215**	**30729**	**2317**	**33046**	**30706**	**2319**	**33025**	**-0.41%**	**0.13%**	**-0.38%**
Ward 4	Substation Number	KVLEV																					
	27	13.8	8115	621	8736	8128	633	8761	7565	564	8129	7161	513	7674	7192	522	7714	7190	526	7716			
	190	13.8	21126	1496	22622	22013	1558	23571	23098	1621	24719	23497	1612	25109	23435	1584	25019	28546	1987	30533			
	Subtotal - Ward 4		**29241**	**2117**	**31358**	**30141**	**2191**	**32332**	**30663**	**2185**	**32848**	**30658**	**2125**	**32783**	**30627**	**2106**	**32733**	**35736**	**2513**	**38249**	**4.09%**	**3.49%**	**4.05%**
Ward 5	Substation Number	KVLEV																					
	133	13.8	16507	1804	18311	16768	1761	18529	17385	1756	19141	17807	1797	19604	18124	1785	19909	17945	1785	19730			
	212	13.8	8873	369	9242	9475	454	9929	11065	718	11783	12226	789	13015	12625	812	13437	13771	831	14602			
	Subtotal - Ward 5		**25380**	**2173**	**27553**	**26243**	**2215**	**28458**	**28450**	**2474**	**30924**	**30033**	**2586**	**32619**	**30749**	**2597**	**33346**	**31716**	**2616**	**34332**	**4.56%**	**3.78%**	**4.50%**
Ward 6	Substation Number	KVLEV																					
	Sta. 'B'	13.8	13691	1315	15006	15191	1356	16547	15848	1226	17074	4075	187	4262	4068	188	4256	0	16	16			
	33	13.8	0	2	2	0	2	2	0	2	2	0	2	2	0	2	2	0	0	0			
	117	13.8	1259	351	1610	1266	428	1694	1275	376	1651	1270	396	1666	1275	383	1658	1274	383	1657			
	161	13.8	3425	663	4088	3319	724	4043	3319	640	3959	3339	627	3966	3336	625	3961	3393	610	4003			
	223	13.8	0	0	0	0	0	0	1482	160	1642	14876	1219	16095	16866	1237	18103	24209	1450	25659			
	Subtotal - Ward 6		**18375**	**2331**	**20706**	**19776**	**2510**	**22286**	**21924**	**2404**	**24328**	**23560**	**2431**	**25991**	**25545**	**2435**	**27980**	**28876**	**2459**	**31335**	**9.46%**	**1.07%**	**8.64%**
Ward 7	Substation Number	KVLEV																					
	7	13.8	40455	3108	43563	42594	3444	46038	43314	3439	46753	43022	3403	46425	43645	3398	47043	43619	3318	46937			
	Subtotal - Ward 7		**40455**	**3108**	**43563**	**42594**	**3444**	**46038**	**43314**	**3439**	**46753**	**43022**	**3403**	**46425**	**43645**	**3398**	**47043**	**43619**	**3318**	**46937**	**1.52%**	**1.32%**	**1.50%**
Ward 8	Substation Number	KVLEV																					
	8 (4kV)	4.33	353	95	448	358	97	455	371	93	464	9	55	64	12	51	63	12	48	60			
	8 (13kV)	13.8	7455	741	8196	7503	733	8236	5268	467	5735	5315	485	5800	5352	484	5836	5367	480	5847			
	136	13.8	15300	1260	16560	15324	1248	16572	17618	1515	19133	17934	1518	19452	17607	1466	19073	18336	1468	19804			
	168	13.8	5466	593	6059	5466	575	6041	5500	576	6076	5473	570	6043	5507	577	6084	5613	683	6296			
	Subtotal - Ward 8		**28574**	**2689**	**31263**	**28651**	**2653**	**31304**	**28757**	**2651**	**31408**	**28731**	**2628**	**31359**	**28478**	**2578**	**31056**	**29328**	**2679**	**32007**	**0.52%**	**-0.07%**	**0.47%**
	DC TOTAL		**247308**	**25228**	**272536**	**252978**	**26417**	**279395**	**258992**	**26150**	**285142**	**263694**	**26281**	**289975**	**267697**	**26214**	**293911**	**274545**	**26231**	**300776**	**2.11%**	**0.78%**	**1.99%**

Table 1.2-B: Historical District of Columbia Loads

Historical District of Columbia Loads									
Loads in Mega-Volt-Amperes (MVA)									
Ward 1	**Sub. Number**		**2015**	**2016**	**2017**	**2018**	**2019**	**2020**		
	10		135.7	143.0	125.6	127.1	127.5	140.1		
	13 (4.33kV)		9.4	9.9	3.1	2.5	2.2	0.0		
	13		31.7	33.0	31.9	34.3	33.6	7.6		
	25		39.1	44.0	50.2	51.0	56.0	46.4		
	Subtotal - Ward 1		**215.9**	**229.9**	**210.8**	**214.9**	**219.3**	**194.1**	Avg. Trend =	-2.11%
Ward 2	**Sub. Number**		**2015**	**2016**	**2017**	**2018**	**2019**	**2020**		
	2		151.7	154.1	147.6	146.9	143.1	115.9		
	12		105.9	106.6	104.2	102.5	100.8	90.3		
	18		126.9	134.3	128.3	126.0	127.7	104.2		
	21		36.4	36.3	37.1	39.9	33.7	25.1		
	52		175.9	175.8	157.0	154.7	159.7	129.5		
	74		43.8	43.3	41.0	41.8	42.3	28.4		
	124		99.7	101.5	98.5	96.2	93.4	78.0		
	197		116.5	117.5	112.4	107.2	104.1	82.6		
	Subtotal - Ward 2		**856.8**	**869.4**	**826.1**	**815.2**	**804.8**	**654.0**	Avg. Trend =	-5.26%
Ward 3	**Sub. Number**		**2015**	**2016**	**2017**	**2018**	**2019**	**2020**		
	38		46.3	47.3	37.5	36.7	38.7	38.3		
	38 (4.33kV)		0.0	0.0	0.0	0.0	0.0	0.0		
	77		70.0	68.7	64.3	64.9	66.9	65.8		
	93 (4.33kV)		3.2	5.4	3.0	3.4	4.4	3.2		
	129		151.5	162.1	159.3	162.7	153.5	144.6		
	145 (4.33kV)		2.5	3.1	2.4	2.6	2.5	3.3		
	146 (4.33kV)		3.6	5.8	5.4	4.8	5.4	5.4		
	Subtotal - Ward 3		**277.1**	**292.4**	**271.9**	**275.1**	**271.4**	**260.6**	Avg. Trend =	-1.22%
Ward 4	**Sub. Number**		**2015**	**2016**	**2017**	**2018**	**2019**	**2020**		
	27		31.4	34.1	34.1	36.4	35.6	29.7		
	190		84.0	88.9	89.0	87.3	90.5	94.9		
	Subtotal - Ward 4		**115.4**	**123.0**	**123.1**	**123.7**	**126.1**	**124.6**	Avg. Trend =	1.55%

Table 1.2-B (con't)

Historical District of Columbia Loads

Loads in Mega-Volt-Amperes (MVA)

		2015	2016	2017	2018	2019	2020		
Ward 5	**Sub. Number**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**		
	133	97.0	108.2	101.8	106.2	103.4	95.3		
	212	79.5	83.9	106.9	116.2	122.1	107.0		
	Subtotal - Ward 5	**176.5**	**192.1**	**208.7**	**222.4**	**225.5**	**202.3**	Avg. Trend =	2.77%
Ward 6	**Sub. Number**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**		
	Sta. 'B'	110.7	119.3	123.1	56.5	55.7	23.6		
	33	16.5	17.1	16.4	16.1	15.8	0.0		
	117	104.1	112.7	104.5	101.4	105.7	82.3		
	161	114.7	112.3	108.5	107.1	103.1	86.1		
	223	0.0	0.0	0.0	78.0	77.5	117.2		
	Subtotal - Ward 6	**346.0**	**361.4**	**352.5**	**359.1**	**357.8**	**309.2**	Avg. Trend =	-2.22%
Ward 7	**Sub. Number**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**		
	7	160.2	158.5	159.7	162.3	159.1	150.3		
	Subtotal - Ward 7	**160.2**	**158.5**	**159.7**	**162.3**	**159.1**	**150.3**	Avg. Trend =	-1.27%
Ward 8	**Sub. Number**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**		
	8 (4.33kV)	1.5	1.6	1.2	0.9	0.8	0.7		
	8	25.9	27.6	17.5	22.5	24.4	25.7		
	136	80.3	89.5	91.2	93.4	93.9	93.2		
	168	19.3	20.7	20.6	20.5	22.7	18.1		
	Subtotal - Ward 8	**127.0**	**139.4**	**130.5**	**137.3**	**141.8**	**137.7**	Avg. Trend =	1.63%
	DC TOTAL	**2274.9**	**2366.1**	**2283.3**	**2310.0**	**2305.8**	**2032.8**	Avg. Trend =	-2.23%

Notes: All substations supply 13.8kV of primary power unless otherwise noted.
Loads shown are actual readings taken during peak summer conditions.
Totals shown are the sum of undiversified peak loads and are not meant to be used as official Pepco system peak loads.
Trends shown are based on the straight line regression of the loads and include transfers amongst the substations.

Table 1.2-C: Forecasted District of Columbia Loads

Forecasted District of Columbia Loads

Loads in Mega-Volt-Amperes (MVA)

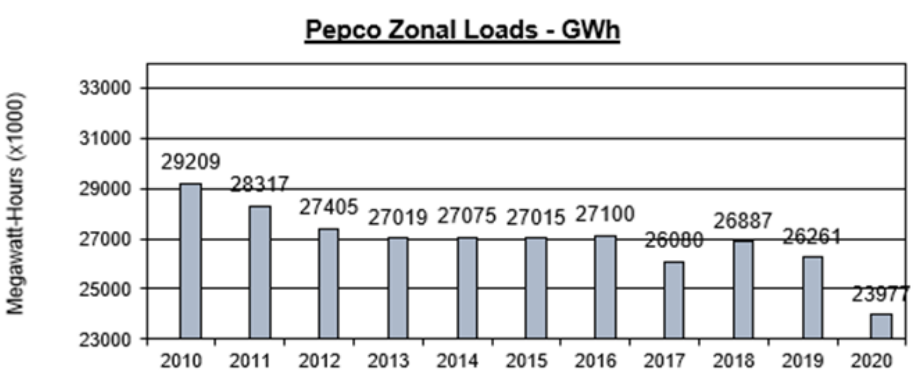
		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	
Ward 1	**Sub. Number**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	
	10	163.0	163.2	163.6	163.9	164.1	164.5	164.7	165.1	165.5	165.9	
	13 (4.33kV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	25	56.9	56.9	56.9	56.9	56.8	56.8	56.8	56.7	56.6	56.5	
	Subtotal - Ward 1	**219.9**	**220.1**	**220.5**	**220.8**	**220.9**	**221.3**	**221.5**	**221.8**	**222.1**	**222.4**	
										Avg. Trend =		0.13%
Ward 2	**Sub. Number**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	
	2	174.6	174.7	174.8	174.9	175.0	175.1	175.2	175.3	175.4	175.5	
	12	120.6	120.7	120.8	120.8	120.9	121.0	121.1	121.1	121.1	121.1	
	18	142.4	143.2	143.5	143.8	144.1	144.3	144.5	144.7	144.9	145.0	
	21	40.3	40.3	40.3	40.3	40.3	40.3	40.3	40.3	40.3	40.3	
	52	191.0	191.4	191.8	192.2	192.6	193.0	193.4	193.8	194.1	194.4	
	74	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	
	124	113.0	113.1	113.2	113.3	113.4	113.5	113.6	113.7	113.8	113.9	
	197	127.9	128.1	128.3	128.5	128.7	128.9	129.1	129.3	129.5	129.7	
	Subtotal - Ward 2	**956.5**	**958.2**	**959.4**	**960.5**	**961.7**	**962.8**	**963.9**	**964.9**	**965.8**	**966.6**	
										Avg. Trend =		0.12%
Ward 3	**Sub. Number**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	
	38	46.0	46.1	46.2	46.3	46.4	46.5	46.6	46.7	46.8	46.9	
	38 (4.33kV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	77	75.1	75.9	76.7	76.9	77.1	77.3	77.5	77.7	77.9	78.1	
	93 (4.33kV)	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	
	129	179.4	182.4	185.0	187.8	189.0	189.3	189.6	189.9	190.2	190.5	
	145 (4.33kV)	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	
	146 (4.33kV)	5.3	5.3	5.3	5.2	5.2	5.2	5.2	5.2	5.2	5.2	
	Subtotal - Ward 3	**312.3**	**316.2**	**319.7**	**322.7**	**324.2**	**324.8**	**325.4**	**326.0**	**326.6**	**327.2**	
										Avg. Trend =		0.52%
Ward 4	**Sub. Number**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	
	27	32.1	32.3	32.4	32.4	32.4	32.4	32.4	32.4	32.4	32.4	
	190	121.2	124.0	126.8	129.6	132.4	134.2	136.0	137.8	139.6	141.4	
	Subtotal - Ward 4	**153.3**	**156.3**	**159.2**	**162.0**	**164.8**	**166.6**	**168.4**	**170.2**	**172.0**	**173.8**	
										Avg. Trend =		1.40%

Table 1.2-C (con't)

Forecasted District of Columbia Loads												
Loads in Mega-Volt-Amperes (MVA)												
Ward 5	**Sub. Number**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	
	133	110.9	111.4	111.9	117.4	122.9	128.4	133.9	134.4	134.9	135.4	
	212	173.3	194.3	207.2	217.8	223.7	230.3	235.6	236.6	237.6	238.3	
	Subtotal - Ward 5	**284.2**	**305.7**	**319.1**	**335.2**	**346.6**	**358.7**	**369.5**	**371.0**	**372.5**	**373.7**	
											Avg. Trend =	3.09%
Ward 6	**Sub. Number**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	
	Sta. 'B'	31.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	33	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	117	122.5	122.6	122.7	122.8	122.9	123.0	123.1	123.2	123.3	123.4	
	161	119.4	120.0	121.0	121.6	123.7	124.6	125.5	126.1	126.7	127.3	
	223	164.4	195.7	198.1	200.4	202.8	205.1	207.4	209.8	212.1	214.4	
	Subtotal - Ward 6	**437.3**	**438.3**	**441.8**	**444.8**	**449.4**	**452.7**	**456.0**	**459.1**	**462.1**	**465.1**	
											Avg. Trend =	0.69%
Ward 7	**Sub. Number**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	
	7	172.4	178.3	181.1	181.4	181.7	182.0	182.3	182.6	182.9	183.2	
	Subtotal - Ward 7	**172.4**	**178.3**	**181.1**	**181.4**	**181.7**	**182.0**	**182.3**	**182.6**	**182.9**	**183.2**	
											Avg. Trend =	0.68%
Ward 8	**Sub. Number**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	
	8 (4.33 kV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	8 (13.8 kV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	136	132.8	143.3	158.3	175.8	188.3	192.3	193.3	194.3	195.3	196.3	
	168	23.8	23.8	23.8	25.1	26.4	27.7	29.0	29.0	29.0	29.0	
	Subtotal - Ward 8	**156.6**	**167.1**	**182.1**	**200.9**	**214.7**	**220.0**	**222.3**	**223.3**	**224.3**	**225.3**	
											Avg. Trend =	4.12%
	DC TOTAL	**2692.5**	**2740.2**	**2782.9**	**2828.3**	**2864.0**	**2888.9**	**2909.3**	**2918.9**	**2928.3**	**2937.3**	
											Avg. Trend =	0.97%
	Notes: All substations supply 13.8kV of primary power unless otherwise noted.											
	Totals shown are the sum of undiversified peak loads and are not meant to be used as official Pepco system peak loads.											
	Totals shown for first two years include planned transfers, DERs, NWAs and known new business loads; the last eight years do not show planned transfers but do incorporate forecasted DERs as well as planned and forecasted new business load.											

On a system basis, Pepco's control area loads over the ten-year period between 2010 and 2020 are provided below in Figure 1.2-D.

Table 1.2-D Pepco Zonal Load



Note: Zonal Load excluding SMECO.

Pepco's projected monthly and annual zonal loads for 2021 are provided in Table 1.2-E. Pepco's zonal loads are for the Pepco distribution system (Maryland and District of Columbia), excluding the Southern Maryland Electric Cooperative (SMECO) and include demands for Pepco distribution customers.

Table 1.2-E Pepco Zonal Load

2021 Forecast -- Pepco Zonal Load* (x 1,000)													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
MWh	2,058	1,841	1,885	1,606	1,726	2,018	2,328	2,272	1,905	1,772	1,755	2,001	23,166
*Excludes SMECO load													

Power Factors and Energy Loses[14]

Power Factors

The power factor provides one measure of how efficiently Pepco's electric system is being used. Substation load has two components: real power (kilowatts) and reactive power (kilovars). Real power is the power that serves the customers' end-use electrical devices. Reactive power does not serve customer requirements but decreases the substation's ability to deliver real power and increases system losses. This reduced ability to deliver real power is based on a substation's power delivery limitations. The power delivered is a combination of reactive and real power, so the greater the reactive power, the lower the real power that can be delivered. As the system power factor approaches unity, real power delivered is greater and system losses due to reactive power are reduced. By making appropriate use of capacitors, the reactive power flow on the electric system can be reduced such that it approaches zero. (When the reactive power flow is zero, the power factor is unity (*i.e.*, 1.0).) A unity power factor would be ideal and would result in the maximum usable power being delivered to the customers. However, a unity power factor is not technically or economically practical to maintain because of changing loads and system conditions.

Pepco plans for a 98% (.98) power factor or higher on its 4 kV and 13 kV distribution substations at

[14] n Order No. 10133 (at 10 and 12), the Commission directed Pepco to include performance factors relating to the transmission and distribution (T&D) system in future PIPs.By way of compliance with the above requirements, in the September 1993 PIWG Meeting, Pepco proposed reporting performance data on its 13 kV distribution substation power factors.

the summer peak. Table 1.2-F below provides the percent of all Pepco's 4 kV and 13 kV distribution substations that had power factors ≥ 91% at the summer peak hour for the years 2011 - 2020. In 2020, 90% of the 4 kV and 13 kV substations had a power factor of ≥ 0.91 at the summer peak hour.

% of Pepco Substations with Power Factors
Greater than 98% on Peak Summer Days
(System-wide)

Table 1.2-F: Power Factor

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
% of 4 kV and 13 kV Substations with Power Factor □ 0.98	95%	96%	97%	97%	97%	97%	96%	92%	89%	91%
Total Number of 4 kV and 13 kV Distribution Substations (Pepco system-wide)	116	116	115	115	113	112	112	113	113	112

Annual System Energy Losses[15]

Table 1.2-F shows a ten-year comparison of annual system energy losses for PJM and adjacent utilities. 2010 through 2019 were obtained from the Federal Energy Regulatory Commission (FERC) web site. All data are from FERC Form 1. A comparison of annual system energy losses over the past ten years is provided for PJM utilities and utilities adjacent to the Pepco service territory. Pepco's system energy losses for 2019 are 4.52% or approximately 17% lower than the group average of 5.28%.

% Annual System Energy Losses:

$$\text{\% Annual System Energy Losses} = \left(\frac{\text{Total Energy Losses (FERC Form 1, Line 27, page 401a)}}{\text{Total Energy (FERC Form 1, Line 28, page 401a)}} \right) \text{X } 100$$

[15] Industry comparison of annual system energy losses is presented in Table 1.2-G.

Table 1.2-G

UTILITY	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Atlantic City Electric Company	4.63%	5.61%	5.52%	5.15%	5.74%	5.78%	5.06%	6.27%	4.46%	5.88%
Baltimore Gas & Electric Co. #	5.77%	6.41%	6.17%	6.51%	6.24%	7.54%	6.36%	6.48%	6.67%	6.99%
Delmarva Power & Light Co.	5.25%	5.54%	4.52%	7.26%	5.39%	5.72%	7.92%	4.90%	4.77%	5.14%
Jersey Central Power & Light Co.	5.59%	6.35%	5.71%	8.39%	8.32%	8.60%	7.97%	7.99%	7.24%	6.27%
Metropolitan Edison Company	4.87%	4.71%	6.21%	5.30%	5.35%	7.41%	9.93%	7.95%	8.43%	7.32%
Pennsylvania Electric Company	5.45%	5.90%	6.08%	7.12%	8.23%	7.57%	6.35%	3.92%	6.67%	7.23%
PPL Electric Utilities Corp.	6.93%	6.55%	6.58%	6.66%	6.41%	6.07%	6.12%	6.12%	5.72%	5.93%
PECO Energy Company	5.25%	4.23%	5.67%	5.81%	5.69%	5.63%	5.69%	5.17%	5.13%	5.35%
Potomac Edison Company #	4.28%	2.07%	4.79%	5.12%	0.96%	1.96%	2.54%	3.09%	2.96%	2.42%
Potomac Electric Power Co.	4.38%	4.14%	4.12%	3.59%	4.01%	3.19%	2.90%	3.46%	3.79%	4.52%
Public Service Electric & Gas	4.13%	4.86%	3.99%	5.32%	4.25%	4.62%	4.58%	4.34%	3.78%	3.97%
Virginia Electric & Power Co. #	3.97%	3.12%	1.65%	2.07%	-0.79%	0.89%	-0.35%	1.20%	2.11%	2.29%
ANNUAL AVG.	**5.04%**	**4.96%**	**5.09%**	**5.69%**	**4.98%**	**5.42%**	**5.42%**	**5.07%**	**5.14%**	**5.28%**

ADJACENT UTILITY

Substation Additions and Enhancements[16]

The discussion below updates the information provided in the 2020 Consolidated Report. All planning data is based on current information and may be revised as the Company completes final designs, fully evaluates site conditions, receives permitting and zoning requirements and receives final contract and equipment bids. This information could impact both the costs and timing of a project. Costs presented reflect forecasts based on approved budgets and include related transmission, distribution, real estate, and permitting costs. Plans associated with the L Street Substation have been removed from this list as they are being rolled into the long-term Downtown Resupply plan described below.

Table 1.2-H reflects Pepco's planned substation additions and enhancements for the District of Columbia with their anticipated in-service dates based on current data and analysis as well as

[16] In the 2001 hearings requiring the production of the Comprehensive Plan, Commissioner Meyers stated the following (page 266 of the hearing transcript):
But what we were talking about here yesterday was that the comprehensive plan would include… any rebuilt substations you might have; any new substations you might have…
Moreover, Order No. 16975 states the following at paragraphs 50 and 101:
50. Decision: …Consequently, we require Pepco to include a report on substation additions and enhancements in future Consolidated Reports. In addition to the information provided in the 2012 Consolidated Report, the Commission requires that Pepco provide details concerning the justification for these projects, including, as applicable, load growth projections and equipment age and condition in future Consolidated Reports.
101. Pepco is DIRECTED to provide a report on substation additions and enhancements consistent with paragraph 50 herein;

approved budgets. In-service dates are, therefore, tentative and are adjusted as in-service dates become nearer.

Table 1.2-H: Substation Additions and Enhancements

#	Project Cost	Project Description	Projected In-Service Date	Areas Served
2	**$138.6 million**	**Mt. Vernon Square Sub.** – Build new substation to relieve predicted network overloads.	June 2023	NoMa, Mt. Vernon Triangle, Shaw
3	**$191.7 million**	**Harvard Sub. –** Upgrade Harvard as a new 230/13 kV substation to retire existing Harvard and Champlain substations.	June 2024	Columbia Heights, Adams Morgan
4	**$151.9 million**	**Champlain Sub. –** Upgrade Champlain as a new 230/69/34 kV substation to resupply downtown distribution substations.	December 2027	Downtown

Justification of Substation Additions and Enhancements

The new substation at Mt. Vernon Square is needed to provide capacity to the redeveloping Mt. Vernon Triangle and Shaw areas. The capacity improvements at the Harvard Substation are needed to replace aging infrastructure at the Harvard and Champlain Substations and to create capacity to serve the growing Columbia Heights area. The new upgraded substation at Champlain will be used to re-supply existing L Street, F Street, and Georgetown substations with new solid dielectric feeders. Pepco has also projected capacity constraints and, thus, a potential need for a load-driven substation in the 2026-2028 timeframe in the St. Elizabeth's and Columbian Quarter area of Ward 8. Future ACRs will discuss this project in more detail and as its load continues to develop.

1. **Construct New Mt. Vernon Square Area Substation (2023 Load Relief Project)**

Overview: This project consists of constructing a new 230/13 kV substation with an ultimate capacity of 210 MVA near Mt. Vernon Square. It is currently planned to initially have three 230/13 kV transformers for a firm capacity of 140 MVA. This substation will provide distribution capacity to the rapidly redeveloping area in and around the Mt. Vernon Triangle. Initially, approximately 58.0 MVA of load would be transferred from the Northeast Sub. 212 Southwest LVAC Network Group and Tenth Street Sub. 52 radial distribution in 2023.

Load Projections:

Facility: Northeast Sub. 212 Southwest LVAC Group

Summer Summer Rating = 50.0 MVA

	2020 History	2021 Anticipated	2022 Anticipated	2023 Anticipated	2024 Anticipated	2025 Anticipated	2026 Anticipated	2027 Anticipated	2028 Anticipated	2029 Anticipated	2030 Anticipated
Net Load Forecast (MVA)	35.5	43.4	47.5	49.2	53.4	56.3	57.5	59.0	61.5	63.0	64.5
Cumulative DER Impacts since 2011	0.6	0.6	0.6	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4

Facility: Northeast Sub. 212

Summer Summer Rating = 214.0 MVA

	2020 History	2021 Anticipated	2022 Anticipated	2023 Anticipated	2024 Anticipated	2025 Anticipated	2026 Anticipated	2027 Anticipated	2028 Anticipated	2029 Anticipated	2030 Anticipated
Net Load Forecast (MVA)	141.3	173.3	194.3	207.2	217.8	223.7	230.3	235.6	236.6	237.6	238.3
Cumulative DER Impacts since 2011	1.6	1.8	2.0	3.2	3.3	3.3	3.4	3.5	3.6	3.7	3.8

Magnitude of Load: Initially, approximately 58.0 MVA of load would be transferred from the Northeast Sub. 212 Southwest LVAC Network Group and Tenth Street Sub. 52 radial distribution in 2023.

Justification: The new Mt. Vernon Substation will provide relief to the Northeast Sub. 212 Southwest LVAC Network Group, which is expected reach 98% its firm capacity in 2023 and exceed its firm capacity approximately 7% in 2024. Northeast Sub. 212 is expected to be at 97% of its firm capacity by 2023. Due to space limitations in the streets around the Northeast substation, no new feeder groups can be extended to relieve these overloads.

Long-term growth exceeding 140 MVA is expected to come into service in the Mt. Vernon Triangle, NoMa, and Capitol Crossing areas over the next 8 years. This currently includes over 15,000 apartment type residential units, 1,300 hotel rooms, 2.5 million square feet of retail space and 6.5 million square feet of office space.

Total Planned Capital Investment (Includes A & G): $138.6 million

Current Status: In design stages.

In-service Date: June 2023.

Alternative: There were several alternatives provided by Pepco in Formal Case No. 1144, including to delay the construction of the facility until 2024. To facilitate this specific alternative, a series of cascading load transfers are required to relieve Northeast Sub. 212 using Florida Avenue Sub. 10. This alternative is not practical due to load proximity. The feeders being extended from Florida Avenue Sub. 10 will be less reliable due to length and would reduce area operating flexibility as Florida Avenue Sub. 10 and the other area substations will all be loaded near their full capacity.

Multiple sites were evaluated for locating the proposed Mt. Vernon Square Sub. An alternative substation location was investigated along New York Avenue in Northeast DC. It was determined that the primary amount of development and load center of the new substation was in the Mt. Vernon Triangle area. Several sites were investigated in the Mt. Vernon Triangle area, but alternatives were rejected as too expensive or not offering required access to the nearby streets.

2. Upgrade Harvard Sub. 13 (2024 Aging Infrastructure Project)

Overview: This project consists of removing the current 34kV/13kV substation at Harvard Sub. 13 and upgrading to a new 230/13kV substation with an ultimate Firm Capacity of 210 MVA. It will initially have three 230/13kV transformers resulting in a Firm Capacity of 140 MVA. The upgraded Harvard Sub. 13 will serve all 13kV load supplied from the existing Harvard Sub. 13 and will provide capacity to enable the transfer of load from Florida Avenue Sub. 10 and partial load from Champlain Sub. 25. The remaining load of Champlain Sub. 25 will be transferred to Florida Avenue Sub. 10, allowing for the transition of that facility from a distribution substation to a re-built subtransmission substation . The upgraded Harvard Sub. 13 will also provide capacity for future load growth in the Columbia Heights and Adams Morgan areas.

NOTE: Changes to the original plan for transferring all load of Champlain Sub. 25 to new Harvard Sub. 13 are due to feeder routing limitations discovered during field investigations.

Load Growth Projections:

Facility: Harvard Sub. 13

Summer Rating = 39.0 MVA

	2020 History	2021 Anticipated	2022 Anticipated	2023 Anticipated	2024 Anticipated	2025 Anticipated	2026 Anticipated	2027 Anticipated	2028 Anticipated	2029 Anticipated	2030 Anticipated
Net Load Forecast (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cumulative DER Impacts since 2011	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Magnitude of Load: During construction of the new Harvard substation, all load currently supplied from the existing Harvard Sub. 13 in 2020 will be transferred temporarily to nearby substations. After the upgraded Harvard Sub. 13 is placed in service, partial load from Florida Avenue Sub. 10 and Champlain Sub. 25 will be transferred to it. The remaining load supplied from Champlain Sub. 25 will be transferred to Florida Avenue Sub. 10, allowing for the transition of Champlain from a distribution substation to a new subtransmission substation.

Identified Need: This project is needed to retire aging infrastructure including Harvard Sub. 13 13 kV substation originally constructed in 1907, the 34 kV supplies to Harvard Sub. 13 from Buzzard Point Sta. "B", constructed around 1960, and Champlain Sub. 25 13 kV substation, constructed around 1954. This upgraded substation will also supply capacity to the growing Columbia Heights and Adams Morgan areas.

Justification: Harvard Substation 13 was initially built in 1907 with the substation having undergone several refurbishments with the latest taking place in the mid-1960s. The 34kV supplies to Harvard Substation 13 were constructed in the 1940s. The last incarnation of Champlain Substation 25 was put into service in the mid-1950s although some portions of the site are likely older. The substation does not meet Pepco's current standard for fault current withstand and are configured in a non-standard way that could lead to longer restoration times for failures experienced inside the substation. In addition, completion of this project along with the project to resupply L Street Sub. 21 (Downtown 34-69kV Resupply) and the retirements of Anacostia Sub. 8 and Navy Yard Sub. 33 will enable the retirement of Buzzard Point Sta. B 13/34 kV substation. The upgraded Harvard substation will provide capacity to accommodate projected load growth in the Columbia Heights area.

Total Planned Capital Investment (Includes A & G): $191.7 million (overall estimated cost of project increased due to inclusion of historic landmark nomination, demolition and civil engineering costs).

Current Status: In design stage

In-service Date: June 2024

Alternative: The alternative to rebuilding the Harvard Substation would require construction of a new 210 MVA, 138/34 kV substation near Buzzard Point, from which three (3) new 34 kV "radial" underground circuits would be extended approximately 5.3 miles to the Harvard Substation. All existing equipment would be upgraded at the Harvard Substation; however, the capacity of the substation would remain at 80 MVA. Upgrading the Harvard Substation would require replacement of individual transformers and switchgear. This alternative would cost more overall than the selected alternative and would not increase overall substation capacity as much as the selected alternative. Pepco currently does not have adequate substation capacity in the area to transfer the entire load from the Harvard and Champlain Substations to other substations.

3. Upgrade Champlain Sub. 25 to 230/69 kV substation (2027 Aging Infrastructure Project)

Overview: This project consists of removing the current 69 kV/13 kV substation at Champlain Sub. 25 and upgrading to a new 230 kV / 69 kV substation with an ultimate capacity of around 570 MVA. It will have three 230 kV / 69 kV transformers with room for a fourth 230 kV / 69 kV transformer. From the upgraded Champlain Sub. 25, four new 69 kV supplies will be extended to serve F Street Sub. 74 and Georgetown Sub. 12. The supply feeder replacements for F Street Sub. 74 and Georgetown Sub. 12 are recommended so the existing, aged, fluid self-contained 69 kV supplies from Potomac River Sta. C can be retired. These feeders have had increasing maintenance issues over the past several years. The new 34 kV supply feeders to L Street Sub. 21 from Champlain are recommended to retire the existing 34 kV feeders from Buzzard Point which restrict the firm capacity available at L Street Sub. 21.

Load Growth Projections:

Facility: F Street Sub. 74

Summer Rating = 82.0 MVA

	2020 History	2021 Anticipated	2022 Anticipated	2023 Anticipated	2024 Anticipated	2025 Anticipated	2026 Anticipated	2027 Anticipated	2028 Anticipated	2029 Anticipated	2030 Anticipated
Net Load Forecast (MVA)	45.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7
Cumulative DER Impacts Since 2011	0.3	0.4	0.4	0.5	0.6	0.6	0.7	0.8	0.8	0.9	1.0

Facility: Georgetown Sub. 12

Summer Rating = 134.0 MVA

	2020 History	2021 Anticipated	2022 Anticipated	2023 Anticipated	2024 Anticipated	2025 Anticipated	2026 Anticipated	2027 Anticipated	2028 Anticipated	2029 Anticipated	2030 Anticipated
Net Load Forecast (MVA)	121.5	120.6	120.7	120.8	120.8	120.9	121.0	121.1	121.1	121.1	121.1
Cumulative DER Impacts Since 2011	1.7	1.8	1.8	1.8	1.8	1.9	1.9	1.9	1.9	1.9	1.9

Facility: L Street Sub. 21

Summer Rating = 62.0 MVA

	2020 History	2021 Anticipated	2022 Anticipated	2023 Anticipated	2024 Anticipated	2025 Anticipated	2026 Anticipated	2027 Anticipated	2028 Anticipated	2029 Anticipated	2030 Anticipated
Net Load Forecast (MVA)	40.3	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2
Cumulative DER Impacts Since 2011	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2

Magnitude of Load: Approximately 211 MVA of load will be served from the upgraded Champlain Sub. 25 as the existing F Street Sub. 74, Georgetown Sub. 12 and L Street Sub. 21 will all be supplied from new 69 kV feeders extended from Champlain.

Identified Need: This project is needed to retire aging 69 kV supply feeders to Georgetown Sub. 12 and F Street Sub. 74 and the aging 34 kV supply feeders to L Street Sub. 21.

Justification: The last incarnation of the Champlain Substation was put into service in the mid-1950's, although some portions of the site are older. Further, many of the Champlain Substation's air circuit breakers were installed in 1960 and 1976. The Champlain Substation's transformers were installed in 1954. While Pepco's inspections have found that this equipment is in good condition due to Pepco's ongoing maintenance programs, it is all operating well beyond its recommended lifespans. In addition, the feeders are all over thirty years old. The 69 kV supply feeders are "self-contained" type cables, meaning that there is fluid contained inside the cable jacket for cooling purposes. There have been an increasing number of maintenance problems with this cable which require extended time and resources to resolve due to limited material availability and few contractors with expertise repairing this type of cable system. This increases customer outage risk as the feeder needs to be taken out of service for extended periods of time while repairs are made.

The new 69 kV supplies to L Street Sub. 21 will replace the solid dielectric and gas filled cables that are at least 30 years old. In addition, resupplying L Street will allow for the retirement of the Buzzard Point 13 kV and 34 kV substations, the former of which was originally built in the 1930's as a generating station. Another benefit of replacing the feeders is that the firm capacity at L Street will significantly increase.

Total Planned Capital Investment (Includes A & G): $151.9 million. The increase in cost is due to the inclusion of costs associated with Takoma Sub. 500MVA phase shifters.

Current Status: In the early design stages.

In-service Date: December 2027

Alternative: The alternative to rebuilding the Champlain Substation would require replacing the three existing 69 kV supply feeders from the Takoma Substation (5.4 miles) to Champlain Substation. The Champlain Substation would still need to be rebuilt, and, in addition, Pepco would need to build a new downtown substation. The new downtown substation would require the purchase of additional land. A new downtown substation would require extending three 230 kV "radial" underground circuits a total of approximately 5.0 miles from the Takoma Substation to the new downtown substation.

1.1.11 Distribution Projects[17][18]

Overhead and Underground Distribution Projects[19]

Pepco's overhead and underground distribution project budgets over the past six years are provided in Table 1.2-I.

Table 1.2-I: Historical Routine Overhead and Underground Distribution Projects

Pepco DC 2014 - 2020 Capital Budgets (Dollars in Millions)							
Distribution	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Customer Driven	$53.0	$55.4	$67.2	$68.7	$71.3	$85.4	89.3
Reliability	133.7	127.5	121.2	114.8	157.6	176.0	197.8

[17] In the initial November 5-7, 2001 hearings requiring the production of the Comprehensive Plan, Commissioner Meyers stated the following (pages 266-267 of the hearing transcript):
But what we were talking about here yesterday was that the comprehensive plan would include… anything that you might envision to account for distribution load growth…
[18] Order No. 16975 states the following at paragraphs 51, 52 and 102:
51. Staff Recommendation #7: Continue to provide annual updates of on-going and planned OH and UG distribution projects driven by customer, reliability, and load considerations in future Consolidated Reports. Include budget as well as actual spending for each of the three categories and explanation of significant differences in actual versus budgeted amounts…
85. Decision: The Commission adopts recommendation #7, noting that Section 1.2.4 of the Consolidated Report does not contain a comparison of actual vs. budgeted spending, nor does it include an explanation of any variances. Pepco is therefore directed to include this information in future Consolidated Reports. 102.Pepco is DIRECTED to continue providing updates of on-going and planned overhead and underground distribution projects consistent with paragraph 52 herein;
[19] In Order No. 12735 issued on May 16, 2003, the Commission stated the following at paragraphs 74 and 135:
74. During the November 2001 hearings the Commission requested that PEPCO submit a comprehensive plan to include a current assessment of, and future plans for, its underground distribution and network facilities.179 The Commission requested the plan as a tool to evaluate PEPCO's planning methodology and to assess PEPCO's ability to anticipate and respond to changing conditions in its underground distribution system…

135.PEPCO shall file the additional information not included in its expurgated comprehensive plan as outlined below, within three months of the issuance date of this Report and Order:
(c) Listing of underground distribution projects, such as the Adams-Morgan neighborhood project (including budgets, time schedules, and expected benefits) by secondary vs. primary system by District of Columbia wards affected, but not specific locations;
The summary should cover a 10-year planning horizon while historical comparisons should provide at least five years of history.

Load	36.4	51.8	45.0	20.4	71.9	62.9	71.9
TOTAL	$223.1	$234.7	$233.4	$203.9	$300.8	$324.3	$359

Pepco's overhead and underground distribution project budgets for the next five years are provided in Table 1.2-I. In developing forecasts, system planners review each component of the existing electric system, along with requirements for new service hook-ups, to develop the costs and schedules for changes to the electric system. Results are then proposed as candidates for inclusion in the construction budget process, which takes place during the second half of each year. The construction budget process culminates with the approval of the following year's budget and the selection of projects to be included in the budget and four-year forecast of electric system additions. Projects may be added or deleted from the budget and four-year forecast from year to year as required. The summary budget and four-year forecast for overhead and underground distribution projects, which identifies types of projects and their respective budgets and forecasts for the years 2020 through 2024, is provided as Table 1.2-J.

Table 1.2-J: Planned Overhead and Underground Distribution Projects

Distribution Construction	2021	2022	2023	2024
Customer Driven	74.68	80.08	71.99	81.18
Reliability	245.25	241.83	285.30	252.28
Load	84.22	49.48	70.95	55.80
TOTAL	404.15	371.39	428.24	389.25

Note: Pepco only prepares a four-year forecast. Potential emergency restoration work is included in the Reliability budget and forecast. Prospective work for the DC PLUG initiative has been included in this plan.

Section 1.1.12

Pepco's overhead and underground distribution project variances for 2020 are provided here in Table 1.2-K, in accordance with Order No. 18644.

Table 1.2-K: Routine Overhead and Underground Distribution Project Variances

Pepco DC 2020 Capital Budget Variances (Dollars in Millions)			
Distribution Construction	**2020 Budget**	**2020 Actual**	**Variance**
Customer Driven	$89.3	$86.7	($2.6)
Reliability	197.8	173.8	($24)
Load	71.9	39.3	(32.6)
TOTAL	$359	$299.9	($59.1)

SECTION 1.2 – MAINTAINING SYSTEM RELIABILITY

Pepco is committed to maintaining a safe and reliable electric distribution system and has programs in place that advance the operation of the electric distribution system by increasing the capabilities to monitor and analyze the performance of its system and enhance the ability to determine where to make modifications and additions to replace poorly performing equipment. Pepco monitors the performance of its distribution feeders system-wide. This process is performed annually and enables Pepco to analyze and determine the relative ranking of each feeder's performance from the least to the most reliable.

This section of the Consolidated Report addresses:

- Technology: Monitoring, Automation, and Information Systems;
- Equipment Standards and Inspections;
- Vegetation Management (VM) Program Detail;
- Industry Comparisons;
- Best Practices; and
- Storm Readiness.

1.2.1 Technology: Monitoring, Automation, and Information Systems

Systems and Technology[20]

The discussion below addresses the Company's technology initiatives that contribute to improved reliability performance.

1.2.2 SCADA[21]

The System Control and Data Acquisition (SCADA) System is the primary tool used by the System Operators to monitor and operate the electric system. This system provides the System Operator at the Control Center the ability to remotely monitor and operate all major equipment at all substations and selected equipment outside of the substations. It is through this system that the System Operator learns what is happening across the electric system and has the ability to take appropriate actions to maintain a safe and reliable system and restore service during outages.

The Remote Terminal Unit (RTU) at each substation gathers data from all substation monitored equipment and provides an interface to pass the data to the central computer system, Energy Management System (EMS), and to the System Operator, who can then remotely control devices at each substation. Major equipment status (open or closed) and equipment metering (watt, var, voltage and ampere) is monitored by the Operator. Additionally, there are specific equipment alarms that indicate abnormal conditions like high temperature, low oil pressure or overloads on a particular device or feeder.

Pepco maintains its own extensive communication system that allows for direct communication between the RTUs at the substations and the computer system at the Control Center.

The computer system at the Control Center gathers the data from all the RTUs, analyzes the data, displays results to the System Operators, and provides the interface for the System Operator to remotely operate the system to protect equipment. Any change of electric system status at the

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[20] In Order No. 12804 paragraph 53 E, the Commission ordered the following:
53. The 2003 PIP is hereby APPROVED, provided that PEPCO:
(e) Provide to the PIWG, quarterly status reports on the new Technology Initiatives being undertaken by Pepco. An annual status report should be included in the 2004 and future PIPs. The status reports should include current accomplishments, plans for the future, and anticipated completion dates.

[21] The initial requirements for the Comprehensive Plan section of the Consolidated Report were delineated in hearings taking place from November 5-7, 2001, at page 313.

substation is displayed to the System Operator within approximately 4 seconds. The system also provides various analyses. For example, it provides an indication if any substation equipment exceeds its capability limits. It does this by comparing the design limit of the equipment with the present loading. Through the SCADA system automatic switching activities can be performed or the System Operator can take action manually to protect remote system equipment and relieve the condition that caused the equipment to be operating outside of its limits.

All raw data from the SCADA system (meter values and status changes) are retained and made available to those areas (System Planning, Distribution and Engineering, etc.) that need the data for analysis. The available data consists of meter values (watts, vars, volts and amps) and status (open and closed) of various facilities, equipment and feeders.

1.2.3 Substation Automation[22]

Although all 13 kV substations have full SCADA control, some 4 kV substations have only limited monitoring capability and do not have the full RTU capability that provides remote control and operation. At these substations all equipment status indications are grouped together on a substation basis and when there is a change of status, a single alarm point provides a single substation alarm indication. Personnel are dispatched to the substation to determine the specific problem. A project is underway to install full RTU capability in the Company's 4 kV substations that are not scheduled for conversion and retirement by installing smart relays on all critical equipment. This will provide for improved restoration capability and hourly data for analyses.

The following is the schedule for substation automation as currently planned:

- Macarthur Boulevard Sub. 152 (Q1 2022)
- Texas Ave Sub. 111 (Q2 2022)
- Fort Dupont Sub. 58 (Q3 2022)
- Fort Davis Sub. 100 (Q4 2022)

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[22] Substation Automation and the following section, Distribution Automation, are also addressed in Sections 2.3.2.1 and 2.3.2.3, respectively, as PIP Projects.

In addition, conventional electro-mechanical relays are being replaced with new generation Smart Relays. Additional information provided by these relays is allowing for more effective and efficient operation. In certain applications, the smart relays can provide information with respect to the distance from the substation to the fault on the feeder. This will allow for faster troubleshooting of system problems, improved restoration capability and increased data for system analyses.

1.2.4 Distribution Automation (DA)

As part of the DA projects, eighteen 13 kV substations have been equipped with upgraded Smart Relays and enhanced RTUs for improved visibility and control at these locations. Additional information provided by these relays will allow for more effective and efficient operation and will support the operation of the Automatic Sectionalizing and Restoration (ASR) system being installed at each location. The following eighteen13kV substations, which supply load within the District of Columbia, have been equipped with enhanced RTUs and upgraded Smart Relays:

- 12th & Irving Substation
- Alabama Ave Substation
- Benning Substation
- Fort Slocum Substation
- Harrison Substation
- Little Falls Substation
- NRL Substation
- Van Ness Substation
- Beech Rd Substation (located in MD but serves some DC customers)
- Bladensburg Substation (located in MD but serves some DC customers)
- Grant Ave Substation (located in MD but serves some DC customers)
- Green Meadows Substation (located in MD but serves some DC customers)
- St. Barnabas Substation (located in MD but serves some DC customers)
- Takoma Substation (located in MD but serves some DC customers)
- Tuxedo Substation (located in MD but serves some DC customers)
- Walker Mill Substation (located in MD but serves some DC customers)
- Linden (located in MD but serves some DC customers)
- Wood Acres (located in MD but serves some DC customers)

Projects are underway to install additional 13 kV and 69 kV remotely operated switches on feeders in addition to the feeders associated with the ASR systems. The additional switches will allow more capability to isolate the faulted portion of the feeder and return more customers to service sooner. The remote-control capability of these switches allows the System Operator to perform switching without the need for field crews, thus reducing customer outage time.

Pepco has completed the installation, testing and integration of the network transformer remote monitoring system (RMS) on 53 network transformers in Buzzard Point network group, 86 network transformers in Sub 161 south group, 72 network transformers in Sub 18 Central group, 78 network transformers in Sub 212 South group, 61 network transformers in Sub 212 Southeast group, 56 network transformers in Sub 25 Central group, 59 network transformers in Sub 52 South group, 79 network transformers in Sub 52 West group, 29 network transformers in Sub 6 North group, 61 network transformers in Sub 7 Central group. Pepco has planned to complete the rest of 48 network transformers in Sub 6 North group in 2021.

These monitors will provide increased visibility and control capability for system operators to remotely open or close the network transformer protectors through two-way communications. Load, voltage, protector status, and equipment condition data are recorded for study and operating purposes, and for increased ability to schedule maintenance of this equipment. RMS will provide operational data to evaluate the performance of the transformer and protector, allowing Pepco to perform maintenance when needed and not just on an interval-based inspection schedule, and allow remote operation of the protector to disconnect network load from the transformer without the need to wait for a crew to manually operate the protector. This will provide great benefits during emergencies when there is a need to isolate a transformer very quickly from the network. The development of the RMS system and the initial installation at Buzzard Point were part of the Department of Energy Smart Grid Investment Grant (SGIG) that the Company received. The installations of RMS on these networks are part of the Company's long-term plan to install RMS in all of its 49 networks, which contain approximately 4,000 transformers.

1.2.5 Outage Management System (OMS)[23]

The OMS is the primary tool used to receive customer trouble reports, analyze reports, and provide summary reports for crew dispatching. Typically, the process starts with the customer reporting an outage

[23] In Order No. 13422 on the 2004 Consolidated Report, paragraph 66, the Commission ordered the following:
66. The 2004 Consolidated Report: Productivity Improvement Plan and Comprehensive Plan is hereby APPROVED, provided that PEPCO:
(a) Report in the 2005 Consolidated Report, due February 15, 2005, on the corrective actions taken to fix the OMS;

by calling the Pepco Call Center or from an Advanced Metering Infrastructure (AMI) meter reporting the loss of power. Information from that call or meter report is entered into the OMS system. The OMS database has the customer information, including customer phone number, address, and connected transformer. Additionally, the database contains the electrical network configuration of each feeder connecting each transformer to a feeder and the location of switches, fuses and taps. The system then analyzes all reported trouble by sorting the reports, prioritizing and grouping multiple problems to a common source. The analyzed data are then displayed to the System Operator for dispatch of crews to investigate and resolve the problem.

The SCADA system also provides input to the OMS. When a feeder breaker at a substation opens and the entire feeder is out, all customers connected to that feeder are known to be out of service. Information obtained from customers (pole struck, line down, tree limb on wire, etc.) in the OMS is then used to determine the source of the problem and to dispatch crews. For trouble involving these pieces of equipment, the customer trouble calls provide the data necessary to determine the problem. The OMS analyzes all the customer calls as well as AMI meter statuses and then determines the common source of the problem. Information is also passed back through the OMS to the Call Center to provide that information to the customer when they call in or review their account online. This information includes knowledge of current trouble and estimated restoration time under non-major storm outage conditions. No significant changes or additions were made to Pepco's OMS system in 2020.

1.2.6 Information Systems

<u>Asset Suite 8</u>

AS8 is the system used for construction, engineering, scheduled preventative maintenance and corrective work management at Pepco. Asset data is also maintained in the system. It is closely integrated with the Graphical Work Design (GWD) system and two new scheduling systems, Primavera P6 and Syntempo. AS8 replaced Pepco legacy systems WMIS and SAP in early 2019. They are still available in read-only mode for reference.

Primavera P6

Primavera P6 is the primary tool for T-Week scheduling for construction, engineering, and plant maintenance (preventative and corrective) work at Pepco and is closely integrated with the Asset Suite 8 and Syntempo systems.

Syntempo

Syntempo is the primary tool for underground New Business work at Pepco and is closely integrated with the Asset Suite 8 and Primavera P6 systems.

GIS/GWD System

Pepco continues to deploy new functions offered by the GIS vendor for greater use of GIS data throughout the company, primarily in the area of data visualization and easier access to GIS data across the organization. The GIS/GWD system continues to be Pepco's official database of field assets. The Exelon utilities are discussing and evaluating the roadmap for GIS technologies among each company in the coming years.

1.2.7 Power Delivery Information System Projects[24]

Pepco's Power Delivery Information System Projects are provided in Table 1.2-A. Included in Table 1.2-A are historical information system projects for the years 2016 - 2020. All costs are for those allocated to the District of Columbia.

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[24] In Order No. 12735, paragraph 139, the Commission ordered the following:
PEPCO shall file the additional information not included in its expurgated comprehensive plan as outlined below, within three months of the issuance date of this Report and Order:…
(d) Listing of power delivery information system projects with implementation schedules, annual costs, and milestones;
(e) Listing of new technology investigations with decisions, annual costs, and implementation schedules;
…The summary should cover a 10-year planning horizon while historical comparisons should provide at least five years of history.

Table 1.2-A: Historical Information System Projects

Rollup-1	Estimated DC Portion 2016	Estimated DC Portion 2017	Estimated DC Portion 2018	Estimated DC Portion 2019	Estimated DC Portion 2020
ROLLUP ($000s)					
Customer Systems	782	2,295	10,634	4,544	5,734
Smart Grid Systems	514	585	1,594	1,792	1,561
Meter Systems	0	0	0	0	74
Network Operating Center (NOC)	6	80	1	0	0
Energy Supply Systems	35	0	0	0	0
Operations Systems	102	1,176	1,147	143	765
Energy Management System (EMS)	1,298	742	2,023	2,301	4,200
Engineering Systems	260	33	38	422	680
Field technologies	0	133	0	0	0
Work Management	315	1,763	7,233	2,951	3,626
Planning and Performance	0	80	255	548	1,214
Subtotal IT Capital (DC Portion)	**3,312**	**6,886**	**22,925**	**12,701**	**17,855**

Note: List does not include Smart Grid meters, Smart Grid communication network, distribution automation, or Telecom.

Equipment Standards & Inspections

Equipment Inspections[25]

A proactive inspection and monitoring program reduces the possibility of unexpected failures and secondary damage to surrounding units, and increases the opportunities that Pepco can plan for the replacement of impending problem equipment. The frequency of inspections and monitoring is based on Pepco's experience, manufacturers' recommendations, and/or industry practices. Inspections may lead to repair or replacement of transmission and distribution system components to maintain safety and reliability of the system.

Inspection and modeling activities identify equipment to be replaced due to loading or condition. Distribution line equipment such as transformers, cable, and other components are not subject to detailed electrical testing and are replaced only when physical inspection indicates a need for replacement. Other than those inspections, equipment is replaced when it is upgraded, relocated or fails.

[25] In Order No. 16091, paragraphs 63 and 46, the Commission ordered the following:
63. Pepco is directed to provide a description of its maintenance policies and methodologies, consistent with paragraph 46 of this Order;
46. Decision. … we shall require that Pepco provide a list of the types of equipment for which a "run to failure" method applies and those for which a preventive method applies. (Footnote: If other maintenance methods are used, Pepco shall describe them as well.) The Commission requires that Pepco provide an explanation of why different maintenance methods apply to different types of equipment. We also require a description of the "test procedures" that Pepco uses to assess the performance and remaining life of the equipment. (Footnote: See Pepco comments at 7.) Further, Pepco shall provide an estimate of the current book value of equipment maintained under each method used by Pepco. The 2011 Consolidated Report shall include this description of maintenance policies and methods.\

As new technologies are installed, actual operational data will be available to better analyze the loading and performance of equipment. For example, load data from the AMI system can potentially identify overloaded transformers prior to failure.

Table 1.3-B below provides a range of inspection or maintenance cycles for different classes of equipment. These were developed by weighing factors such as criticality, duty cycle, varying manufacturer's recommendations, and technological differences.

The equipment types and asset groups listed on Table 1.3-B have been designated as either a "preventive" or a "predictive" maintenance. It should be noted that Pepco views its overall

maintenance methodology to be defined by "reliability-centered" practices, with predictive and preventive methodologies to be subsets of this reliability-centered focus

Table 1.3-B: Equipment Inspections

Equipment	**Inspection**	**Periodicity**	**Maintenance Methodology**
Substation	General Inspection	Every 2 months	Preventive
Substation Power Transformers	Predictive Maintenance Routine	Annually	Predictive
	Oil Collection and Analysis of Transformer Main Tank and Load Tap Changer (LTC)	Once a year or more frequently if triggered by the Equipment Condition Assessment (ECA) Process, or criticality of transformer	Preventive
	Routine Inspection and Test	Every 4, 8, or 16 years based on criticality, or more frequently as recommended by Equipment Condition Assessment Process.	Preventive
	LTC Filter Change	Where applicable and condition-based maintenance on high filter differential pressure	Preventive
	Routine Cooler Inspection	Annually	Preventive
Substation Capacitor Banks - Metal Enclosed	Routine Inspection	Annually or more frequently as recommended by Equipment Condition Assessment Process	Preventive
Substation Capacitor Banks - Open Rack	Routine Inspection	Annually or more frequently as recommended by Equipment Condition Assessment Process.	Preventive
Substation Capacitor Banks - Open Rack with Circuit Switcher	Routine Inspection	Annually or more frequently as recommended by Equipment Condition Assessment Process.	Preventive
	Predictive Maintenance (PDM) Tasks	Annually	Predictive

Substation Circuit Breakers – Air Magnetic	Routine Test	6 Years or more frequently as recommended by Equipment Condition Assessment Process.	Preventive

Equipment	**Inspection**	**Periodicity**	**Maintenance Methodology**
Substation Circuit Breakers – Oil	Oil Collection and Analysis Of OCB	Every 1, 2 or 3 years based on criticality, or more frequently as recommended by Equipment Condition Assessment Process	Predictive
	Predictive Maintenance (PDM) Inspections	Annually	Predictive
	Internal Inspection and Test	3 – 4 Years, or more frequently as recommended by Equipment Condition Assessment Process	Preventive
	Diagnostic Testing	3 Years	Preventive
	Compressor Inspection/Pre-Charge Inspection (as applicable)	2 Years	Preventive
Substation Circuit Breakers – SF6	Predictive Maintenance (PDM) Inspections – Non-intrusive	Annually	Predictive
	Routine Inspection – Intrusive	Single Pressure: 8 Years, Dual Pressure: 4 Years, or more frequently as recommended by Equipment Condition Assessment Process	Preventive
	Diagnostic Testing	Single Pressure: 8 Years, Dual Pressure: 4 Years, or more frequently as recommended by Equipment Condition Assessment Process	Preventive
Substation Circuit Breakers – Vacuum	Predictive Maintenance (PDM)	Annually	Predictive
	Routine Inspection	6 Years or more frequently as recommended by Equipment Condition Assessment Process	Preventive
Substation – 69 to 230kV High-Pressure Pipe-Type Potheads	Periodic Inspections where sample ports are available.	Every 4 to 6 years (230kV),	Preventive
		Every 6 to 8 years (115kV),	Preventive
		Every 8 to 10 years (69kV)	Preventive
Substation – Battery & Charger Systems	Visual & On-line Test/Inspection	Annually or more frequent as recommended based on an ECA.	Preventive
Substation – Building Heating, Ventilation and Air Conditioning (HVAC) System	Annual Inspection	Annually	Preventive

Equipment	Inspection	Periodicity	Maintenance Methodology
Substation – Emergency Generators	Start and Run Test	Up to 4 times per year: Routine Inspections; Annually: Standby Generator Inspection and Maintenance and Black Start Generator Test Inspections as recommended based on equipment condition.	Preventive

Equipment	Inspection	Periodicity	Maintenance Methodology
Substation – Fire Protection	Routine Inspection	Annually	Preventive
Right-of-Way Integrated VM (Transmission)	Routine Inspection	Interval based on Right-of-Way inspections and height of vegetation.	Preventive
Scheduled Tree Trimming - Overhead Distribution Feeders Not In Transmission Rights- of-Way	Routine and Condition-based Tree Inspection	4 Year trim cycle	Preventive
Protective Relays and Automatic Reclosing Relays	Preventive Maintenance	4 to 8 years based on system voltage class	Preventive
Under-Frequency Relays	Preventive Maintenance	8 years	Preventive
RTUs - SCADA	Predictive Maintenance	Failure to operate properly based on condition monitoring – self diagnostics, EMS trouble logs, real	Predictive
SCADA (Supervisory Control and Data Acquisition) Metering	Preventive Maintenance	Condition based maintenance	Preventive
Digital Fault Recorder	Preventive Maintenance	200kV and Above: 8 Years, Below 200kV: Failure to operate properly based on condition monitoring-self diagnostics, fault records, real time data analysis and remote communications.	Preventive
Power Line Carrier (PLC)	Preventive Maintenance	Every 24 Months	Preventive
Microwave Equipment	Preventive Maintenance	Every 24 Months	Preventive
Fiber Optic Equipment	Preventive Maintenance	Condition Based Maintenance	Preventive
Leased Line	Preventive Maintenance	Every 24 Months	Preventive

Equipment	Inspection	Periodicity	Maintenance Methodology
Pole-Type Recloser	Routine Inspection	Visual: 2 years Operational Test: Every 3 to 6 yrs.	Preventive
Pole-Type Regulators	Routine Inspection/Test	Every 24 months	Preventive
Critical (Hospital/Nursing Home) Network Transformers/Protectors	Routine Inspection	Every 3 years	Preventive
Distribution Manholes	Routine Inspection	Every 6 years	Preventive

Equipment	Inspection	Periodicity	Maintenance Methodology
Underground Network Transformers/Protectors	Routine Long Inspection	Every 5 years de-energized (Staggered w/Short Inspection so visits are 2.5 years apart). Inspection cycle for some locations may differ and be between 2 - 10 years based on: 1) criticality - hospital locations are inspected more frequently; 2) location type - sidewalk/roadway location or roof top/basement; and 3) installation type - junction	Preventive
Capacitor Banks – Pole Mounted	Routine Inspection	2 Years for Non-Distribution VAR Dispatch (DVD), DVD capacitors monitored near real-time.	Preventive
Distribution Pad mounted Transformers / Switchgear	Routine Inspection	5 Years	Preventive
Pipe-Type Cable Joint Sleeves in Manholes	Periodic Inspection	Every 5 to 10 years	Preventive
Wood Poles	Wood Pole Inspection, Remedial Treatment and Restoration	Every 10 years (starting in 2015)	Preventive
Power Line Over Navigable Waterway – Overhead Clearance	Routine Inspection	5 years	Preventive
High Voltage Transmission Structure Aviation Warning Lighting	Periodic Inspection	Annually	Preventive
High Voltage Transmission Structure Grounding	Periodic Inspection	Inspect Grounding System on a 5 – 10 year interval	Preventive

Equipment	Inspection	Periodicity	Maintenance Methodology
Microwave Tower and Aviation Warning Lighting	Periodic Inspection	Annual or as per Federal Aviation Administration(FAA)	Preventive
High Voltage Transmission Line Comprehensive Inspection	Aerial Inspection	6 Years	Preventive
Cathodic Protection	Substation Inspection and Manhole Survey	Condition based – Various intervals (based upon type of work involved)	Preventive
Cable Oil and Gas Alarms	Annual Inspection	Annually	Preventive
Fluid Pressurizing Plants for High- Pressure Pipe-Type Cables	Operational Test and Inspection	Every 1 to 2 weeks (chart replacement), Every 1 to 2 years (operational test)	Preventive

Table 1.3-C includes the book value of equipment as of December 31, 2020. Book values have been categorized by direct and allocable plant. The use of FERC Mass Asset Accounting does not allow any specific asset to be identified and linked to its accumulated depreciation and remaining useful life or to link it to the maintenance method applied to the equipment as assets are depreciated by account.

any specific asset to be identified and linked to its accumulated depreciation and remaining useful life or to link it to the maintenance method applied to the equipment as assets are depreciated by account.

Table 1.3-C: Distribution Equipment Net Book Value

Potomac Electric Power Company			
DC Distribution Plant, Reserve, Net Book Value - 2020			
DC DISTRIBUTION PLANT	**Book Cost**	**Reserve**	**Net Book Value**
E-3601-Land	91,672,521	-	91,672,521
E-3602-Land Rights	994,445	119,177	875,268
E-3610-Structures and Improvements	83,797,136	31,432,865	52,364,271
E-3620-Station Equipment	755,805,958	179,412,487	576,393,471
E-3640-Poles, Towers, and Fixtures	178,143,014	30,233,705	147,909,309
E-3650-O/H Conductors and Devices	191,377,663	48,267,417	143,110,246
E-3660-U/G Conduit	1,034,206,983	331,795,936	702,411,047
E-3670-U/G Conductors and Devices	1,099,235,393	258,570,773	840,664,620
E-3680-Line Transformers	625,433,827	178,446,315	446,987,512
E-3691-O/H Services	17,541,791	(1,371,260)	18,913,051
E-3692-U/G Services	121,187,298	74,045,561	47,141,737
E-3693-U/G Cable Services	179,783,761	68,175,670	111,608,091
E-3700-Meters	20,936,404	3,203,788	17,732,616
E-3701- AMI Meters	63,540,663	26,368,246	37,172,417
E-3711-Install on Customer Premises	1,367,203	1,250,913	116,290
E-3731-Overhead Street Lighting	201,953	(153,400)	355,353
E-3732-Underground Street Lighting	9,428,818	6,878,451	2,550,367
E-3734-Dusk to Dawn Street Lighting	50,315	32,601	17,714
Total DC Distribution Plant, Reserve, NBV	**4,474,705,146**	**1,236,709,245**	**3,237,995,901**

Overhead Feeder Inspection Program [26]

Pepco's Overhead Feeder Inspection Program was initiated in 2012 to improve overall system reliability and remediate potential safety issues. In the years since the initial inception, the Overhead Feeder Inspection Program has been refined to facilitate more aggressive inspection timelines and prioritization for remediation activities that addresses the criticality of infrastructure issues and is consistent with typical feeder improvement work.

Overhead Feeder Inspection Cycle

Pepco's Overhead Feeder Inspection Program ensures that all feeders with overhead exposure are inspected within a two-year period. Pepco currently has approximately 200 District of Columbia feeders with overhead exposure.

Overhead Feeder Inspection Components

The overhead feeder inspection consists of a mobile scan of all main line poles on a feeder, from ground line to the top of the pole, including the conductors from pole to pole, utilizing Ultrasonic and Infrared Non-Destructive Testing (NDT) methodology.

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[26] Order No. 16975 states the following at paragraphs 64 and 107:
64. Decision: Pepco is directed to report on the Overhead Feeder Inspection Program in future Consolidated Reports as recommended by OPC and the Staff, including results of the inspections, actual and incipient failures detected and remediation actions taken to correct the nonconformance items recorded. In particular, as requested by OPC, Pepco is directed to report on replacement of lightning arresters.
107.Pepco is DIRECTED to report on the Overhead Feeder Inspection Program consistent with paragraph 64 herein;

Visual inspection is performed on all feeder mainlines to determine feeder/equipment condition and identify immediate threats to reliability created on the following equipment:

- Cross-arms and braces
- Insulators
- Grounds
- Lightning arrestors
- Conductors
- Transformers
- Reclosers
- Capacitors
- Regulators
- Ancillary equipment
- Vegetation

Overhead Feeder Inspection Results

Overhead feeder inspection results required remediation work and completion status are tracked. Prioritization of remedial work is based on both safety and reliability attributes. Immediate or near-term response is assigned to those conditions that must be addressed to mitigate imminent safety or reliability issues. Less emergent conditions are required to be remediated within the typical design and build cycle for distribution projects. Conditions that do not pose a reliability or safety threat in neither the near-term nor long-term, are identified for possible upgrade in conjunction with other planned work.

Repairs or upgrades to correct or eliminate conditions observed during inspections are scheduled under the following guidelines.[27]

- Priority 10: A condition where upon inspection, a Pepco facility is deemed to present an imminent safety hazard to utility personnel and/or the public. In this case, steps shall be taken to immediately eliminate the hazard. Inspectors are required to immediately notify Pepco and to stand by until relieved by Pepco personnel.
- Priority 20: A condition where upon inspection, a component of an overhead feeder is observed and confirmed to pose a threat to service reliability but does not pose a direct public safety threat. Conditions under this category should be remediated within 90 days.
- Priority 30: A condition where damage or degradation exists on a component of an overhead feeder line, does not pose a direct public safety threat, and if left uncorrected, has the potential to affect service reliability under adverse system conditions. Conditions under this category should be remediated within 18 months.
- Priority 40: A condition that poses no threat to safety or reliability but does not conform to current Pepco standards. Conditions under this category should be corrected when other work presents the opportunity to bring the condition to current standards.

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[27] See APPENDIX 3B - MANHOLE INSPECTION PROGRAM (MIP) for a details of Exelon Utilities Corrective Maintenance Prioritization system.

Overhead Feeder Inspection Cycle:

Pepco inspects approximately half of its overhead feeders every other year resulting in a full inspection cycle being completed every two years.

Overhead Feeders Inspected 2020

In 2020, 101 District of Columbia feeders were inspected as part of the Overhead Feeder Inspection Program. Sixty-one (61) conditions were identified.

2020

Feeder	Condition
14058	Visual/Thermal scan identified-Split Cross Arm - Affecting Hardware
14058	Visual/Thermal scan identified-Loose Insulator
14058	Visual/Thermal scan identified-Split Cross Arm - Affecting Hardware (x2)
14058	Visual/Thermal scan identified-Insulator - Loose/Leaning
14200	Visual/Thermal scan identified-Floating Primary Wire
14200	Visual/Thermal scan identified-Broken/Loose Tie Wire
14200	Visual/Thermal scan identified-Floating Primary Wire
14200	Visual/Thermal scan identified-Broken/Loose Tie Wire
14716	Visual/Thermal scan identified-Broken Arrestor
14716	Visual/Thermal scan identified-Blown Arrestor
14716	Visual/Thermal scan identified-Blown Arrestor
00365	Visual/Thermal scan identified-Decayed Cross Arm
00365	Visual/Thermal scan identified-Missing Pole Tag
00365	Visual/Thermal scan identified-Split Cross Arm - Minor
00365	Visual/Thermal scan identified-Missing Pole Tag
00365	Visual/Thermal scan identified-Broken Cross Arm Brace (x2)

Feeder	Condition
00367	Visual/Thermal scan identified-Decayed Cross Arm
00367	Visual/Thermal scan identified-Broken Cross Arm Brace
00367	Visual/Thermal scan identified-Missing Pole Tag
00368	Visual/Thermal scan identified-Broken Insulator
00368	Visual/Thermal scan identified-Decayed Cross Arm
00368	Visual/Thermal scan identified-Floating Primary Jumper
00368	Visual/Thermal scan identified-Split Cross Arm – Affecting Hardware
00386	Visual/Thermal scan identified-Decayed Cross Arm
00099	Visual/Thermal scan identified-Decayed Cross Arm
00119	Visual/Thermal scan identified-Insulator - Wooden Deadend
00177	Visual/Thermal scan identified-Decayed Cross Arm
00229	Visual/Thermal scan identified-Decayed Cross Arm
00309	Visual/Thermal scan identified-Split Cross Arm – Affecting Hardware
00309	Visual/Thermal scan identified-Loose Insulator
00324	Visual/Thermal scan identified-Broken Cross Arm Brace
00345	Visual/Thermal scan identified-Decayed Cross Arm (x2)
00476	Visual/Thermal scan identified-Broken Cross Arm Brace (x2)
00495	Visual/Thermal scan identified-Cracked Cross Arm
14132	Visual/Thermal scan identified-Leaning/Bent Cross Arm
14133	Visual/Thermal scan identified-Broken Arrestor
14135	Visual/Thermal scan identified-Broken Cross Arm Brace
14146	Visual/Thermal scan identified-Broken/Loose Tie Wire (x2)
14146	Visual/Thermal scan identified-Floating Primary Wire (x2)

Feeder	Condition
14900	Visual/Thermal scan identified-Split Cross Arm - Major
14900	Visual/Thermal scan identified-Leaning Insulator
00366	Visual/Thermal scan identified-Split Cross Arm - Minor
15169	Visual/Thermal scan identified-Split Cross Arm - Minor
15169	Visual/Thermal scan identified-Broken/Loose Tie Wire
15170	Visual/Thermal scan identified-Broken/Loose Tie Wire
15174	Visual/Thermal scan identified-Fraying Primary Wire
15705	Visual/Thermal scan identified-Fraying Primary Wire
15001	Visual/Thermal scan identified-Loose Tie Wire
15001	Visual/Thermal scan identified-Floating Primary Wire
15001	Visual/Thermal scan identified-Floating Primary Wire
15001	Visual/Thermal scan identified-Split Cross Arm - Major
15001	Visual/Thermal scan identified-Loose Tie Wires (x2)
15001	Visual/Thermal scan identified-Missing Pole Tag
15001	Visual/Thermal scan identified-Split/Leaning Cross Arm
15010	Visual/Thermal scan identified-Damaged Insulator
15013	Visual/Thermal scan identified-Missing Pole Tag
15013	Visual/Thermal scan identified-Leaning Insulator
15013	Visual/Thermal scan identified-Decayed Cross Arm
15013	Visual/Thermal scan identified-Decayed Cross Arm
15755	Visual/Thermal scan identified-Broken Pole
15801	Visual/Thermal scan identified-Fraying Primary Wire

All conditions summarized in the table above were referred to the appropriate engineering area for further evaluation and remediation and have been remediated.

Overhead Feeder Inspection Schedule

The following Overhead Feeder Inspection Schedule is projected for the District of Columbia to ensure that all feeders will be inspected over the next two years.

2021

56	309	479	14136	14752	15012	15199
97	324	481	14139	14753	15013	15457
99	333	482	14140	14755	15014	15458
119	345	485	14145	14756	15130	15459
120	347	489	14146	14758	15165	15632
128	366	495	14150	14811	15169	15701
132	367	14006	14158	14812	15170	15705
167	368	14035	14159	14900	15171	15755
177	369	14054	14200	15001	15172	15756
178	385	14055	14713	15006	15173	15801
181	386	14058	14715	15007	15174	
183	388	14132	14716	15008	15175	
227	394	14133	14717	15009	15177	
229	413	14134	14718	15010	15197	
308	476	14135	14719	15011	15198	Total=100

2022

56	309	479	14136	14752	15012	15198
97	324	481	14139	14753	15013	15199
99	333	482	14140	14755	15014	15457
119	345	485	14145	14756	15085	15458
120	347	489	14146	14758	15130	15459
128	366	495	14150	14811	15165	15632
132	367	14006	14158	14812	15169	15701
167	368	14035	14159	14900	15170	15705
177	369	14054	14200	15001	15171	15755
178	385	14055	14713	15006	15172	15756
181	386	14058	14715	15007	15173	15801
183	388	14132	14716	15008	15174	
227	394	14133	14717	15009	15175	
229	413	14134	14718	15010	15177	
308	476	14135	14719	15011	15197	Total-101

1.2.8 VEGETATION MANAGEMENT PROGRAM DETAIL

Each year, Pepco's system reliability is impacted by trees and tree branches that have contacted, fallen on, or otherwise interfered with poles and wires, causing disruption of service. Due to the density of tree coverage in Pepco's District of Columbia service territory and public concerns relative to tree pruning, challenges exist when balancing the value of trees to customers and communities and the need for reliable electric service. The main objectives that the Vegetation Management (VM) program attempts to balance are safety, reliability, regulatory compliance, environmental stewardship, and customer satisfaction. Pepco's VM program includes tree pruning, tree removal, maintaining access and tree planting.

Pepco's VM priorities are:

- Achieving and maintaining a high degree of reliability across the entire electric system;
- Targeting areas of the electric system found to be most susceptible to outages and damage from trees;
- Performing cyclical pruning to maintain the stability of the system;
- Working with local stakeholders and property owners in the removal of hazard trees in close proximity to Pepco's electric lines;
- Communicating with customers through various media;
- Performing emergency tree and limb removal from electric lines; and
- Assuring that the VM work is performed consistently with good environmental stewardship.

Pepco's VM program in the District of Columbia includes:

- Scheduled two-year cyclical maintenance or routine scheduled pruning and removals;
- Planting of trees to mitigate the impact of VM work;
- Unscheduled (non-cycle) maintenance operations; and
- Selective application of herbicide.

Pepco's VM process can be summarized in the following steps:

- Establish an annual VM plan strategy in accordance with regulatory requirements, International Society of Arboriculture (ISA) Best Management Practices and Pepco VM goals;
- Plan Work – Inspect the feeder to develop a VM work plan that defines the work to be performed;

- Prune/Remove/Clear Trees – VM personnel engage qualified contractors and perform project management and contract administration to complete feeder maintenance as planned;
- Validate completion of work plan – Certified Arborist inspects to validate that work performed is completed in accordance with plan and American National Standards Institute (ANSI) standards; and
- Document and report progress.

Scheduled Pruning

Pepco's scheduled cycle tree maintenance program in the District of Columbia includes a comprehensive inspection by an ISA Certified Arborist to develop a work plan for each feeder on a two-year cycle in accordance with guidelines established in conjunction with the District of Columbia's Urban Forestry Administration (UFA) and American National Standards Institute (ANSI) standards, and International Society of Arboriculture (ISA) Best Management Practices (BMPs).

Coordination with:

DC Urban Forestry Administration (UFA) and others

The UFA is responsible for the management of the majority of public space trees that grow in proximity to Pepco overhead facilities. UFA also administers the tree protection laws and is responsible for issuing permits for tree removal on private property. Arborists from Pepco and UFA work to identify and eliminate hazardous tree conditions during cycle and unscheduled maintenance operations. Pepco also coordinates with natural resource managers from the National Park Service, the District of Columbia Department of Parks and Recreation, and private property owners.

Despite the good working relationship between Pepco and UFA, challenges remain, especially with respect to VM work associated with "legacy" trees. District of Columbia statutes and regulations from decades ago resulted in "legacy trees" that impact operations today and have historically limited the degree and technique of vegetation cutback from Pepco power lines. This has resulted in large trees growing through and in close proximity to conductors. Examples of the policies include the following:

1. Section 13 of "An Act for the Preservation of the Public Peace and the Protection of Property within the District of Columbia," approved July 29, 1892. (27 Stat. 324; District of Columbia Official Code § 22-3310) (Emphasis added.)

1892: *"An act for the preservation of the public peace and the protection of property within the District of Columbia" …unlawful for any person willfully* ***top****, cut down, remove, girdle,* ***break, wound, destroy, or in any manner injure*** *….any tree not owned by that person…"*

2. Policy produced by District of Columbia, June 9, 1960, "Trees in Public Space: Washington, DC," at pg. 17.

   1960: *"Utility lines must be cleared by the use of directional clearance methods only…..the removal of internal branches to permit passage of utility lines through the trees where necessary"*

Many of the older trees conflict with the Pepco distribution system such that the issues with the various trees cannot be resolved without cutting entire "legacy" trees down. No standardized practice or agreement currently exists to resolve these conflicts. Pepco continues to work with UFA to resolve these issues on a case-by-case basis and in accordance with the Vegetation Management Plan for Utility Tree Pruning – District of Columbia (2005 Plan).[28]

In 2016, the Urban and Forestry Protection Act of 2002 was amended." The 2016 changes heightened the requirements to obtain permits to remove private trees. A "Special Tree Permit" is required to remove private trees as small as 13.9" diameter and the fee increased by 63%.

Mitigation and Tree Planting Programs

Pepco's tree planting funding mitigates removals and promotes "Right Tree Right Place" best management practices around utility space. In 2020 Pepco planted 344 trees in the District of Columbia and contributed $8,294 to the DC Tree Fund (in the form of special tree removal permits).

Selective Application of Herbicide and Tree Growth Regulators

Pepco's VM program includes the use of herbicide and tree growth regulators. An herbicide plan is developed each year to control brush and sprout growth where trees have been previously cleared. Herbicide applications are used selectively on rights-of-way, easements and, when granted

[28] The 2005 Plan was produced as a result of a tree-trimming working group including members from the District Department of Transportation's Urban Forestry Administration and Pepco's Vegetation Management team. Pepco filed the 2005 Plan on March 17, 2005 in Formal Case No. 982.

permission, on private property, throughout the Pepco system in the District of Columbia. The use of herbicides follows a systematic approach with the aim of reducing woody stems from growing in the utility space. Herbicides and growth regulators used on Pepco's ROW are extremely low in toxicity and are biodegradable. Most herbicides affect treated plants by inhibiting the production of chemicals which plants need to produce chlorophyll, or by inhibiting the formation of leaf-buds. Without chlorophyll production, or functional leaves, the treated plant exhausts its stored food supply and dies.

Tree growth regulators reduce the cell elongation of trees, which can help to extend the cycle time that we need to return to prune a tree again. Only herbicides and growth regulators registered by the U.S. Environmental Protection Agency (EPA) and D.C. Department of Environment are applied in strict accordance with the label and under the regulation of United States Department of Agriculture (USDA). Pepco contract applicators are supervised by certified commercial pesticide applicators.

Customer Communication Materials

- Provide consistent notification to customers regarding Pepco's VM activities on their property and in their community;
- Provide information to customers explaining the VM program along with a schedule of trim and contact information;
- Make available Pepco forestry representatives to respond to inquiries as work is being done and scheduled;
- Encourage customers to access the Pepco website for more detailed educational material including links to ANSI A330 standards, Utility Arborist Association, and the "Right Tree, Right Place" program under the Arbor Day Foundation;
- Enable the planners to meet with customers and local officials, or correspond through mail, e-mail, and phone as needed;
- Enable work permits to be obtained in advance of scheduled work to allow work to continue in a coordinated and planned manner;
- Participate in community meetings; and
- Coordinate public awareness of Pepco's VM activities and programs through the use of door hangers that are placed on customer's door prior to start of VM work.

Customer Communications: VM

See Attachment A for an example of the Company's 2020 customer communications, which is an example of pertinent information that is relayed to customers as bill inserts and other means of communication.

Industry Comparisons[29]

The Industry Comparisons section contains industry comparisons of transmission and distribution operations and performance. The comparisons of reliability indices are provided in Figures 1.3-A through 1.3-C in response to Commission directives in Formal Cases No. 766 and 982.

Institute of Electrical and Electronics Engineers (IEEE) Benchmarking Survey Results

Each year, Pepco participates in the annual Transmission and Distribution System Benchmarking Study conducted by IEEE. Although Pepco's District of Columbia service territory did not participate separately in the study, the Company has calculated separate values for Pepco's District of Columbia territory in both 2019 and 2020, using the MSO reporting criteria and has indicated both of these reliability results on the following charts. Note that Pepco's 2020 reliability results that are reported in the following graphs are not directly comparable to the data used in the 2019 study. See Figure 1.3-A through Figure 1.3-C.

[29] In Order No. 15568 paragraph 57, the Commission ordered the following:
57. Pepco IS DIRECTED to provide a report on the Electric Utilities Best Practices, consistent with Paragraph 50 of this Order. This report shall be included in that 2010 Consolidated Report; and shall include the best practices of the electric utility industry on improving reliability and outage restoration (from the Benchmarking Studies). Pepco shall submit a continuous improvement plan, including resourcing, specific performance targets, and milestone dates to achieve the reliability and outage restoration performance of the best (quartile) performing (comparable) utilities in the Benchmarking Studies.

Figure 1.3-A

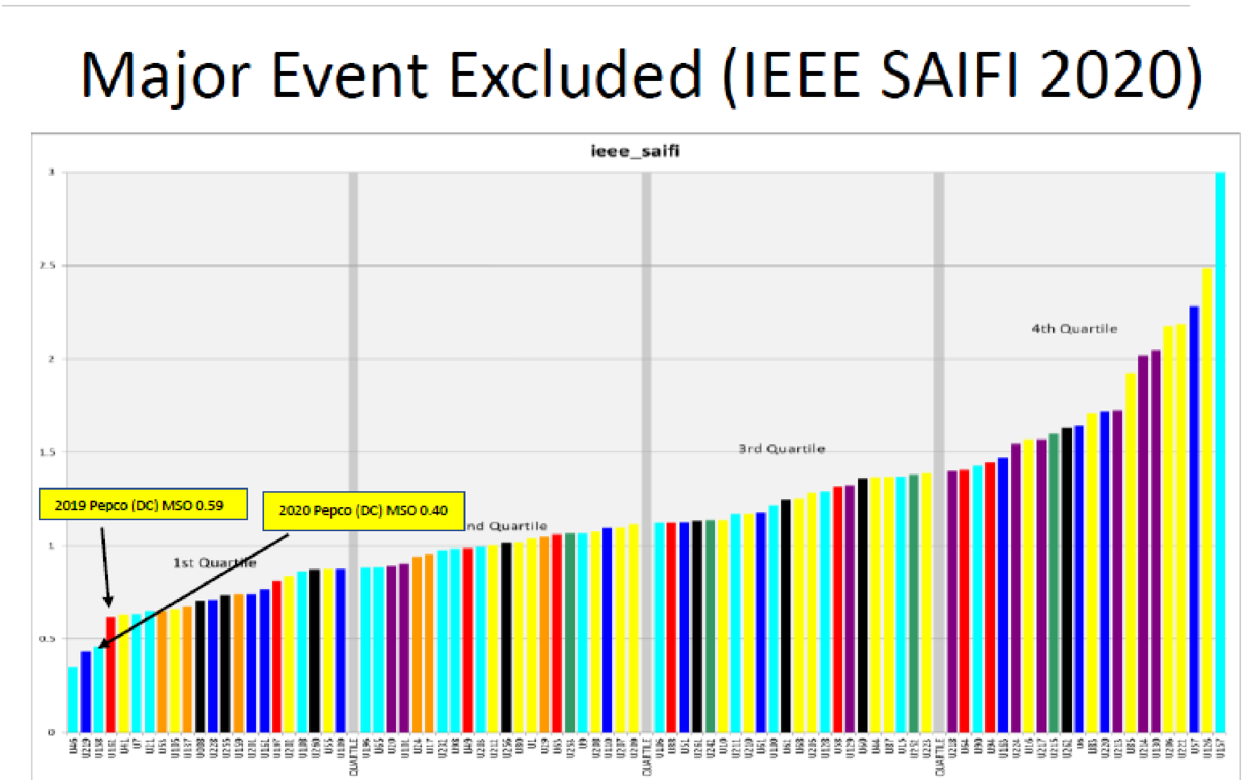

Figure 1.3-A

Figure 1.3-B

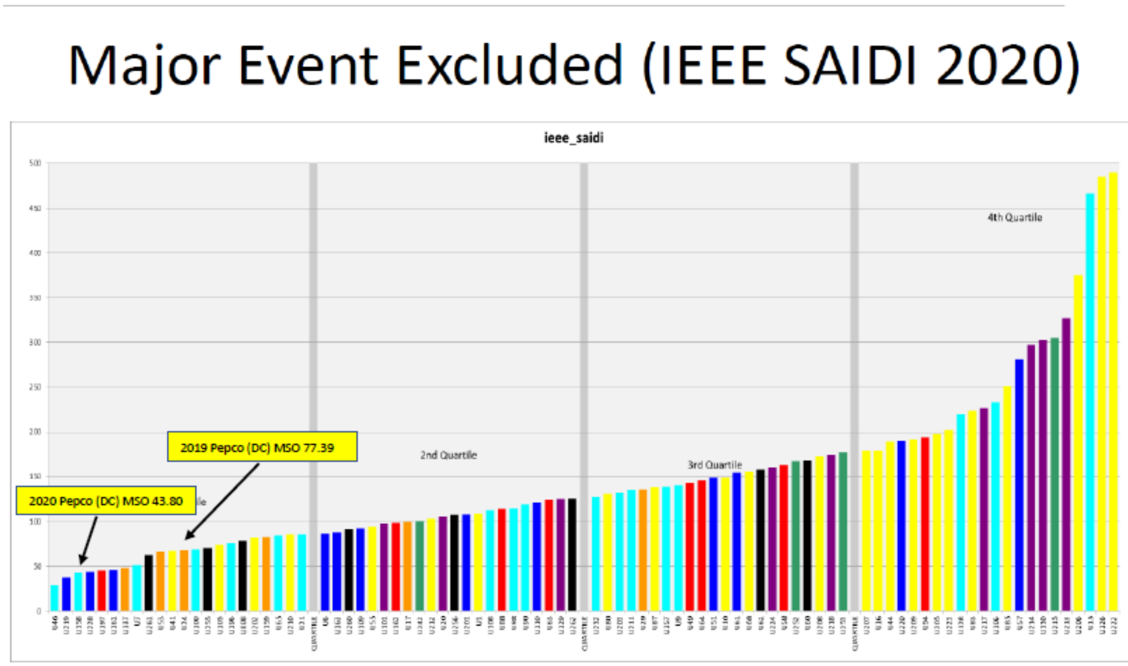

Figure 1.3-B

Figure 1.3-C

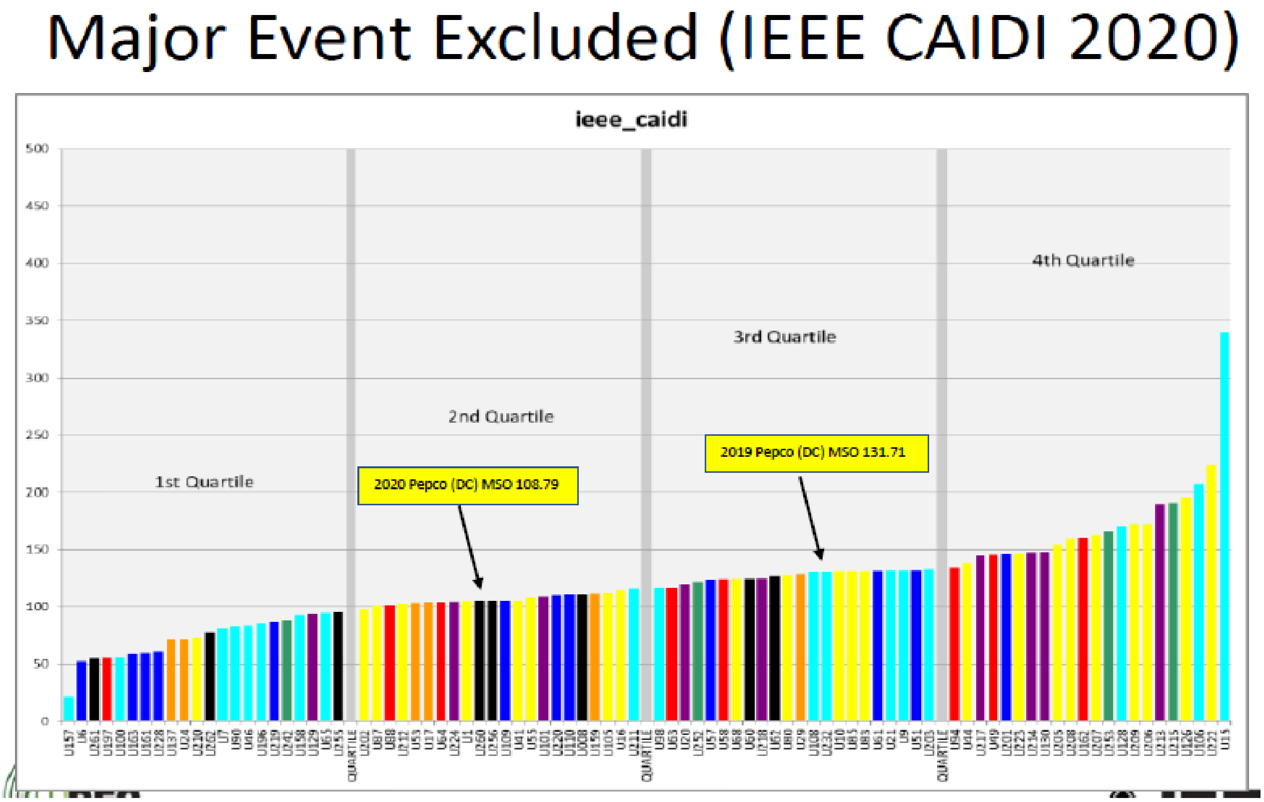

Figure 1.3-C

Best Practices

Implementation of Twenty Best Practices[30][31][32][33]

Pepco continues to follow the best practices discussed in the 2019 Consolidated Report. The status, maturity/implementation levels, and staffing impacts remain unchanged.

Approximate Costs Attributable to the District of Columbia

Regarding the costs of implementing best practices, Pepco must provide the following explanations:

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[30] In Order No. 16091 paragraph 61, the Commission stated the following:
61. Pepco IS DIRECTED to include a "2011 Best Practices Report" in its 2011 Consolidated Report describing its on-going implementation of no fewer than twenty of the best practices identified in the 2009 Polaris Program, consistent with Paragraph 22 of this Order;
22. Decision. First, we conclude that Pepco has complied with the requirements of Paragraphs 32 and 52 of Order No. 15568. Second, as to the Staff's Recommendation that Pepco file a "Best Practices Report" from the PA Consulting's 2009 Polaris Transmission and Distribution Benchmarking Program, we agree that a report may be helpful in assuring that best practices continue to be implemented. Therefore, the Commission shall require that Pepco include in its 2011 Consolidated Report a section entitled "2011 Best Practices Report" in which Pepco shall describe its on-going implementation of no fewer than twenty of the best practices identified in the 2009 Polaris Program included in the 2010 Consolidated Report as Appendix 2D. The twenty best practices selected by Pepco should be those judged to have the most impact on reliability and outage restoration performance. Pepco shall report on all its activities during 2010 to implement these best practices, including data on staffing levels, expenses and results. This requirement is separate from the requirement to produce a "Continuous Improvement Plan," as is described more fully in Section IV.A.1.f.

[31] In Order No. 15632 issued in these proceedings, the Commission states at paragraph 5 the following:
5. Pepco shall file with the Company's annual Consolidated Reports to the Commission data on the Company's measures to continue to address each of the recommendations made by PA Consulting and the effectiveness of the Company's approaches to improve CAIDI and SAIDI to at least the average of

[32] Order No. 16623 states the following at paragraphs 29 and 52:
29. Decision: The Commission agrees with the Staff that the information provided in the 2011 Consolidated Report does not allow a complete assessment of Pepco's progress in implementing the twenty "best practices." Therefore, we direct Pepco to provide further information for each "best practice," including staffing levels, expenses and schedules and percentage of completion. In those cases where no incremental expenses or staffing occurred, we require Pepco to identify the other activities with which these best practices were combined "for efficiency" and provide expenses and staffing levels associated with those activities. In order to provide a comparative analysis, we require Pepco to provide budget vs. actual expenses and staffing levels for the period 2007 to 2011. We also require Pepco to provide an assessment of the progress it has made in fully implementing each best practice. In addition we require Pepco to identify whether and how each best practice has been incorporated within its Comprehensive Reliability Plan.96 This information shall be included in the 2012 Consolidated Report.
52. Pepco is DIRECTED to prepare a report on best practices consistent with paragraph 29 herein;

[33] 35 Order No. 16975 states the following at paragraphs 85 and 114:
85. Decision: The Commission finds that Pepco has failed to comply completely and explicitly with the requirement that it identify "whether and how each best practice has been incorporated within its Comprehensive Reliability Plan." While Pepco includes some of its best practices as part of the REP, it does not discuss each best practice, as required by Order No. 16623. The Commission agrees with OPC that "including these practices within the REP would be an effective means for improving reliability." Pepco is required to fully address the role that each best practice has in the REP in its 2013 Consolidated Report and in future Consolidated Reports. If a best practice is not part of the REP, then Pepco shall explicitly state that fact.
114.Pepco is DIRECTED to address the role each best practice has in the Reliability Enhancement Plan consistent with paragraph 85 herein;

1. **Cost allocation across companies and jurisdictions:** Many of the activities associated with the best practices described herein are performed by centralized teams supporting all PHI companies or teams supporting Pepco system-wide. Budgets and expenditures of departments that serve all of PHI are not directly attributable to one jurisdiction or another.
2. **Redirection of resources:** The implementation of some best practices by these teams did not necessarily require additional resources, but rather either required the allocation of additional duties or a shift in duties from previous practices to the newly identified best practices. Further, activities supporting the best practices are only a subset of all work done by these departments, and the activities of many of the primary personnel involved in executing and advancing these best practices are allocated to general overhead accounts.
3. **Reported best practices costs:** The Company has attempted to allocate estimated resource hours and associated activity-based costs in these centralized functions to the District of Columbia where possible. (See Table 1.3-D.) Where defined expenditures for process and reliability improvement exist, Pepco cites these expenditures in the attached table.

Table 1.3-D: Approximate Costs Attributable to the District of Columbia

			Approximate Costs Attributable to District of Columbia											
			2015		2016		2017		2018		2019		2020	
Best Practice #	Activity Supporting Best Practices	Average Hourly ATP*	Hours	Cost	Hours	Cost	Hours	Cost	Hours	Cost	Hours	Cost	Hours	Cost
	Reliability Centered Maintenance (RCM) Planning	$96.00	2500	$240,000.00	2500	$240,000.00	2500	$240,000.00	2500	$240,000.00	2500	$240,000.00	2500	$240,000.00
4-Jan	Equipment Condition Assessment (ECA)	$96.00	2040	$195,840.00	2040	$195,840.00	2040	$195,840.00	2040	$195,840.00	2040	$195,840.00	2040	$195,840.00
	Dissolved Gas Analysis (DGA)	$96.00	500	$48,000.00	500	$48,000.00	500	$48,000.00	500	$48,000.00	500	$48,000.00	500	$48,000.00
5	Priority Feeder Analysis	$96.00	200	$19,200.00	200	$19,200.00	200	$19,200.00	200	$19,200.00	200	$19,200.00	200	$19,200.00
6	QA for VM work	$85.00	2000	$170,000.00	2000	$170,000.00	2000	$170,000.00	2000	$170,000.00	2000	$170,000.00	2000	$170,000.00
7	Responsible Engineer Assignments	$96.00	5500	$528,000.00	5500	$528,000.00	5500	$528,000.00	5500	$528,000.00	5500	$528,000.00	5500	$528,000.00
7	Large Project Management	$125.00	2000	$250,000.00	2000	$250,000.00	2000	$250,000.00	2000	$250,000.00	2000	$250,000.00	2000	$250,000.00
8	WMIS/SAP PM Integration	$96.00	1200	$115,200.00	1200	$115,200.00	1200	$115,200.00	1200	$115,200.00	1200	$115,200.00	1200	$115,200.00
9	Critical Customer Analysis	$85.00	122	$10,370.00	122	$10,370.00	122	$10,370.00	122	$10,370.00	122	$10,370.00	122	$10,370.00
10	ETR Process Improvement	$96.00	1500	$144,000.00	1500	$144,000.00	1500	$144,000.00	1500	$144,000.00	1500	$144,000.00	1500	$144,000.00
11	Shift coverage adequacy	Please see narrative for explanation of impacts												
12	Ongoing revision of Stepped restoration processes (Control Center allocation)	$85.00	200	$17,000.00	200	$17,000.00	200	$17,000.00	200	$17,000.00	200	$17,000.00	200	$17,000.00
13	SCADA upkeep O&M increment	$90.00	2000	$180,000.00	2000	$180,000.00	2000	$180,000.00	2000	$180,000.00	2000	$180,000.00	2000	$180,000.00
14-17	VM Program Management including hazard tree removal, monitoring preventative vs corrective efforts, maintaining specifications, and utilization of cycle based trimming	$85.00	1000	$85,000.00	1000	$85,000.00	1000	$85,000.00	1000	$85,000.00	1000	$85,000.00	1000	$85,000.00
18	Maintaining Metrics for VM	$85.00	125	$10,625.00	125	$10,625.00	125	$10,625.00	125	$10,625.00	125	$10,625.00	125	$10,625.00
20	Feeder Trimming Prioritization	$96.00	80	$7,680.00	80	$7,680.00	80	$7,680.00	80	$7,680.00	80	$7,680.00	80	$7,680.00

* The average fully loaded activity based cost for resources performing or the activity for 2014-2018

ECA Teams[34][35][36]

A discussion of costs and benefits, as required by Order No. 16975, is provided below.

ECA driven projects generally consist of planned projects to replace large, high cost, long lead time primary components within substations. Targets for these projects are usually selected by condition-based criteria such as dissolved gas in oil analysis. However, due to certain external drivers (such as load, location, environment, and system criticality), these replacements may also be triggered by historic performance of a component. These projects are primarily driven by Pepco's need to manage contingency risk and do not result from cost / benefit analyses. Replacements are usually in-kind or upgrades and depend on component availability at the time. System emergencies can alter the prioritization of these projects.

The utility's obligation to serve requires substation design criteria which provides redundancy and risk management. Although substation component failures are rare in comparison to feeder components, the loss of a critical substation asset could result in long term outages affecting thousands of customers. The provision of redundant components, backup sources, and minimization of single points of failure in substation designs reduces this risk and generally allows Pepco to perform routine maintenance and upgrades without the need for planned outages. This redundancy also allows Pepco to manage contingencies and continue service despite the loss of a major substation component. As such, substation reliability is maintained by keeping both the primary and redundant assets in good working condition. Therefore, condition and criticality of assets predominantly drives substation reliability programs and many projects in the substation reliability category do not directly translate to improvements in outage frequency and duration. This concept is known as Reliability Centered Maintenance (RCM), the principles

[34] Order No. 16975 states the following at paragraphs 39 and 98:
39. Decision: …Specifically, the Commission directs Pepco to report on the recommendations and actions taken by the ECA team, including membership lists, meeting dates and minutes, analyses of impact of the ECA team on maintenance or replacement policies and asset management strategy and tactics. We also require Pepco, to the extent not already included, to report on costs for recommended equipment replacements and the projected benefits of those replacements, as OPC suggests. Further, the Commission directs Pepco to provide an explanation of how the work of the ECA team relates to other Pepco reliability initiatives and include a discussion of the equipment failure analysis as part of future years' Consolidated Reports.
98. Pepco is DIRECTED to include a report on the results of its Equipment Condition Assessment work consistent with paragraph 39 herein;

[35] The ECA minutes have been modified in response to the Commission's directive "to include a brief description of the project status *(i.e*., whether it is deferred, completed or ongoing)," *In The Matter of the Annual Consolidated Report of the Potomac Electric Power Company*, Formal Case No. PEPACR-2014-01, Order No. 17816 at P 231 (February 27, 2015).

[36] Order No. 19119 also addressed the ECA minutes and directed Pepco and OPC to file comments on potential elimination and/or changes to the content of the ECA information presented in the ACR. The Commission has not yet issued a final order on this matter.

of which dictate that predictive maintenance activities serve to identify failing assets prior to catastrophic failure.

Substation assets are inspected under various inspection programs, including visual, infrared, and oil sampling where applicable. Based on observed condition and potential system risk, assets are cleared for normal duty, scheduled for closer monitoring, scheduled for maintenance, selected for immediate replacement, or added to prioritized programmatic replacement programs, as appropriate. Pepco's ECA process is the vehicle used to identify substation assets for condition-driven replacement in order to maintain the reliability of the substation. The ECA process cooperatively analyzes major equipment condition, makes major repair / replace decisions utilizing various subject matter experts and through consensus, prioritizes candidates for replacement on a quarterly basis.

Substation assets such as transformers, breakers, and larger components typically have long lead times and must be ordered well in advance (months to years) of anticipated need. For this reason, a number of replacement projects are kept in the project pipeline at any given time. This allows Pepco to substitute one project for another in situations where long lead times would subject the system and customers to significant reliability risk. Projects are engineered and built using standard designs and approved equipment.

Generally, substation reliability projects cannot be translated into measurable or forecasted SAIDI or SAIFI benefits. The presence of redundant systems within substations reduces or eliminates the direct threat to customer reliability from the loss of a single asset. However, the failure of such assets reduces the security of supply to feeders and elevates the risk of large-scale customer outages. Given the potential for customer impacts along with the long replacement cycle of major substation assets, Pepco replaces these assets proactively based on condition assessment and the desire to manage such contingency risk.

A summary of the four quarters of ECA meetings for 2020 are included below. The format has been changed to summarize the data while retaining requests for greater clarity regarding timing, costs, and completion of projects

Pepco-DC Region Equipment Condition Assessment

Meeting – 1st through 4th Qt. 2020

TRANSFORMERS:

Location	EPS	ITN	Position	2020 Spend	Status
Sub 083 Blue Plains	PC17SS102	70020	R-23106	$ 1,602,818	In-Progress
Sub 083 Blue Plains	PC17TS102	70021	R-23107	$ 252,773	Completed
Sub 092 Nebraska Ave	PC18QS008	70024	T1	$ 1,725,258	Completed
Sub 168 Naval Research	PC18QS128	73762	T1	$ 2,443,115	In-Progress
Sub 168 Naval Research	PC19QS056	73762	T2	$ 2,762	Completed
Sub 121 Bells Mill	PM17SS105	70045	T5	$ 2,766,470	In-Progress
Sub 121 Bells Mill	PM17QS172	70043	T1	$ 6,700	In-Progress
Sub 150 Twining City	PC18QS012	73734	T2	$ 639,534	Completed

BREAKERS:

Location	EPS	ITN	Position	2020 Spend	Status
Sub 162 Bowie	PM17SS140	73556	8A;4A	$ 97,700	Completed
Sub.123 Ritchie	PM18QS001	73758	69006	$ 69,816	Completed
Sub 118 Quince Orchard	PM19SS017	66860	2A	$ 69,718	In-Progress
Sub 002 O Street	PC17SS109	70006	1B	$ 40,531	In-Progress
Sub 002 O Street	PC17SS108	70006	2B	$ 69,094	In-Progress
Sub 002 O Street	PC17SS110	70006	3B	$ 41,637	In-Progress
Sub 002 O Street	PC17SS111	70006	4B	$ 30,784	In-Progress
Sub 121 Bells Mill	PM17SS123	73556	5B	$ 162,396	In Progress

BATTERIES:

Location	EPS	ITN	Position	2020 Spend	Status
Sub 72 Camp Springs	PM20QS012	70603	Z-072-1	$45,777	Completed
Sub 79 Hunting Hills	PM17QS173	70603	Z-079-1	$35,855	Completed
Sub 84 Palmers Corner	PM18QS011	70603	Z-084-1	$11,409	Completed
Sub 162 Bowie	PM17SS159	70605	Z-162-1	$19,664	Completed
Sub 7 Benning	PC19QS094	70602	Z-007-1	$83,665	Completed
Sub 7 Benning	PC19QS095	70602	Z-007-2	$20,292	Completed
Sub 124 22nd St	PC19QS096	70602	Z-124-1	$15,712	Completed
Sub 111 Texas Ave	PC20QS132	70602	Z-111-1	$15,063	Completed

Meeting Attendees:

1st through 4th Qt. 2020

Title	Department
Manager Transmission & Substation Engineering	PSC Equipment Standards
Principal Engineer	PSC Equipment Standards
Senior Engineer Standards	PSC Equipment Standards
Senior Engineer Standards	PSC Equipment Standards
Senior Engineer Standards	PSC Equipment Standards
General Engineer	PSC Equipment Standards
Engineer	PSC Equipment Standards
Associate Engineer	PSC Equipment Standards
Manager Transmission & Substation Engineering	PEPCO Substation Engineering
Supervisor of Engineering	PEPCO Substation Engineering
Senior Engineer	PEPCO Substation Engineering
Senior Engineer	PEPCO Substation Engineering
Senior Engineer	PEPCO Substation Engineering
Senior Engineer	PEPCO Substation Engineering
Manager Regional Capacity Planning	PEPCO Distribution Planning
Principle Engineer	PEPCO Distribution Planning
Senior Engineer	PEPCO Distribution Planning
Sr. Engineering Tech Specialist	PEPCO Distribution Planning
Manager Regional Electrical Operations	PEPCO Sub Construction & Maintenance
Sr. Engineer	PEPCO Sub Construction & Maintenance
Engineering Tech Specialist	PEPCO Sub Construction & Maintenance
Principle Project Outage Coordinator	PEPCO System Operations

1.2.9 STORM READINESS

Pepco's mandate is to provide safe and reliable electric service. This is the basis for all Company contingency operations, including storm restoration, and is the foundation for the storm restoration objective of safely restoring electric service to the greatest number of customers in a minimum amount of time. The Pepco District of Columbia Major Service Outage Restoration Plan (MSO Plan) uses these principles to assess damage across the entire Pepco service area and to establish restoration guidelines for preparedness, pre-storm planning, storm response, communications, and post-storm evaluations.

The PHI Crisis Management Plan and the MSO Plan necessarily modify the normal corporate organization, in accordance with the National Incident Management System's (NIMS) Incident Command System structure and manages this amended structure to accomplish storm restoration and emergency response. The Pepco Regional Incident Management Team (IMT) assigns personnel to this temporary structure to efficiently restore customer service. The overall governing principle of the Pepco IMT is to match resources to restoration requirements. The Pepco IMT is flexible in order to adjust resources to the various types of restoration efforts that may be required and to enable restoration activities to be prioritized to restore the largest number of customers first across Pepco's service territory. All Company resources, including Operations, Logistics, Planning &Analysis, and Finance and Administration are dedicated to customer service and the storm restoration effort.

Each branch of the Pepco IMT has the ability to expand or contract staffing for the response effort as necessary. Storm positions are activated based on the support or response functions required for efficient restoration. Pre-established storm duties are maintained for each storm position. The Staging Area branch of the IMT is activated under unique circumstances. The increased number of customer calls during storms requires additional staffing at the Customer Operations Call Center to answer customer inquiries and to supplement the automated entry of customer outage information. In the event of a major storm, Pepco's High-Volume Call

The increased number of customer calls during storms requires additional staffing at the Customer Operations Call Center to answer customer inquiries and to supplement the automated entry of customer outage information. In the event of a major storm, Pepco's High-Volume Call Answering (HVCA) System can be activated to takes the high volume of outage calls Pepco expects in the immediate aftermath of a major storm. This HVCA system is capable of answering more than 100,000 calls per hour to reduce the incidence of busy signals and hold times and is most efficient in the early stage of the restoration process. Once the initial outage reports are in, the Company has the ability to disable the automated call system and staffs the Pepco call center with additional employees who are trained to assist call center representatives in handling the increased volume of calls. All areas in the Customer Care Group, in performing their second roles, are required to provide support to the Call Center. Additional personnel across the Company provide assistance through their incident response role assignments and help to relay accurate information between customers and operations

Communication requirements for internal as well as external groups are identified in advance, planned for, and monitored for effectiveness during storm response. Accurate, timely and coordinated communications provide a vital link in the restoration response. Approximately 48 hours in advance of a significant major storm with predicted multi-day outages, Pepco notifies customers who are enrolled in Pepco's Emergency Medical Equipment Notification Program so they can prepare to implement their contingency plans in the event of power outages. Pepco also notifies regulatory and government officials and emergency management agencies of its storm preparations and to discuss any special concerns. Operational communications coordinate field restoration activities. Communication roles in the PHI Crisis Management Plan and the MSO Plan provide for a proactive and flexible communication strategy.

The Storm Restoration Objectives are to safely restore electric service to the largest number of customers in a minimum amount of time. This requires advance planning and pre-storm preparation. Advance planning during non-storm conditions enables operational readiness for restoration activities. In addition to drills and exercises designed to lead employees through a variety of emergency scenarios, Pepco also works with local emergency management agencies and a cross-section of community, government and business leaders in a collaborative effort to review restoration plans and practices to develop more effective ways to improve Pepco's response.

In addition, Pepco actively pursues a public education and awareness campaign that includes initiatives such as the "Weathering the Storm" brochure. These publications and additional brochures contain information about the Company's Emergency Medical Equipment Notification Program, tree trimming, and portable generator safety, all of which are available upon request as well as on Pepco's web site. These materials and information provided in Pepco's monthly newsletter that is mailed to customers with their bill provide information that help families and individuals prepare in advance for any emergency situation and are a significant component of Pepco's advance planning efforts. Additional preparedness information, as well as neighborhood outage maps, with information regarding each outage event, including the ETR, is also available on the Pepco web site.

Pre-storm preparation is the process of preparing for mobilization before a storm occurs. When a significant major storm threatens, Pepco begins preparations, when possible, by reviewing Pepco's inventory of storm repair materials and notifying vendors of the potential need for material procurement. To plan for sufficient staffing, Pepco informs employees of the pending storm and the potential for activation of their incident response second role assignments. The Company also alerts Pepco contractors and discuss plans for possible aid from the utilities within Pepco's participating mutual assistance groups. Both advance planning and pre-storm preparation activities enable a state of preparedness to transition smoothly to IMT operations and to minimize restoration time.

After a storm affects the electric system, assessment and restoration begins. Damage Assessment requires an on-going evaluation of the substations shut down, distribution feeders locked out, and feeders with damaged segments, as well as the areas and the number of customers affected. This continual process enables efficient and appropriate allocation of restoration resources. The IMT is activated to provide customer communications and to coordinate the mobilization of crews for system repairs. Since damage assessment is on-going and storm levels may change in intensity, the restoration strategy may be modified throughout the effort, and the level of mobilization may be adjusted to meet restoration requirements.

Adequate supplies of materials, tools, and equipment are necessary for restoration to proceed safely and efficiently. Logistics include procuring, maintaining, and transporting restoration resources, personnel and materials. Departments are responsible for determining logistics requirements on an on-going basis and maintaining procedures.

When major reconstruction work or significant outside resources are required for system restoration, a staging area may be established. Staging Areas are defined as sites where crews and materials are temporarily stationed in severely damaged areas of the service territory. Staging areas are set up to respond to specific restoration efforts with assigned crews and on-site materials. Sites are selected for their accessibility, parking, and space to store materials needed for reconstruction and restoration of customer service, and ability to house and feed crews.

During major outage events of extended duration Pepco can use resources from other PHI companies, if available, or request mutual assistance from one of several regional and national mutual assistance groups in which it participates. These groups meet periodically to review policies, procedures and work practices to ensure continued ability to provide mutual assistance between electric utility companies. Post-event evaluations following major service outages contribute to continuous improvements to the Pepco District of Columbia MSO Plan. Response activities are most likely to improve when recommendations are linked and incorporated into the plan and departmental support procedures. These links serve as the vehicle to enhance response plan capability. Trained personnel are essential for successful execution of storm response duties. Additional training requirements may be highlighted as a result of debriefings or drills.

Further, during major outage events, Pepco uses AMI to enhance storm restoration efforts. For example, during those major outage events, Pepco's AMI capability to "ping" meters help to determine whether a customer has electric service. This application of Pepco's AMI network contributes to reducing restoration times, and avoiding costs, without necessitating phone calls to customers thus minimizing unnecessary costs. It also materially reduces the number of truck rolls needed to verify customer restoration, helping ensure that crews are dispatched efficiently.

Drills and Functional Exercises

In 2020, Pepco held Service Center Drills at the Forestville Service Center on September 18 and at Rockville Service Center on September 25. In addition, the Pepco IMT (Incident Management Team) held their annual Drill on May 28 which satisfied their regional exercise requirements.

In conjunction with the MSO Plan, Pepco may also activate PHI's Crisis Management Plan. PHI's Crisis Management Plan defines the management structure and outlines response activities for extensive emergencies, including unplanned events that can cause significant injuries to employees, customers or the public; cause physical, environmental or technological damage; or can shut down the business or disrupt operations. This plan also provides general guidelines allowing PHI and Pepco sufficient flexibility to respond to any emergency condition promptly and effectively.

PART 2: 2020 PIP

SECTION 2.1 – Requirements

On November 1, 1982, in Order No. 7668, the Commission adopted final rules regarding the submission of an annual PIP in Formal Case No. 766. These rules are codified in Title 15 of the District of Columbia Municipal Regulations, Chapter 5, Rules 502.1 and 502.2. In 1982, the Commission also directed the Company to establish the PIWG, consisting of representatives from the Commission Staff, the Office of the People's Counsel (OPC), and Pepco to provide a setting for communication among all parties and Commission Staff during the developmental stage of the first annual PIP. With the divestiture or transfer to an affiliate of all of Pepco's generating stations, the primary focus of the PIP and PIWG has shifted instead to transmission and distribution operations, performance, and reliability.[37] Later, Order No. 16623 emphasized a focus on reliability for the ACR.

SECTION 2.2 – PIWG

As discussed above, the PIWG has evolved over the years since its establishment but continues to serve as a standing committee for collaboration among the Commission Staff, the OPC, and Pepco. The PIWG meetings address issues of interest to the Commission or PIWG members. Agendas and meeting frequency are determined according to issues of immediate concern to PIWG members and according to directives of the Commission. The PIWG generally meets no more frequently than monthly, but at least once per quarter. A discussion of the items on the next meeting's agenda usually occurs at the end of each PIWG

[37] In Order No. 15152 on the 2008 Consolidated Report paragraphs 68 the Commission stated the following:
68. The Productivity Improvement Working Group, which includes OPC, provided a reasonable definition of a productivity improvement project in 2006. Specifically, the PIWG states:
T&D productivity improvement projects were considered those projects that will increase T&D system efficiency by reducing losses and improve[ing] system reliability, and which may defer more costly additions to the electric system. (Footnote: F.C. No. 766, Decision on Consideration of OPC's T&D Productivity Improvement Working Group in Response to Commission Order No. 13754, filed July 6, 2006 ("2006 PIWG Report"), at 2.)
The power serving the District's Standard Offer Service customers is now procured through a wholesale procurement process by PEPCO and, as such, productivity improvement is applicable only to transmission and distribution issues. We find the PIWG's definition of a productivity improvement project workable and adopt it here.

2020 PIWG Activities

The PIWG met five times in 2020. The 2020 PIWG meeting dates and meeting minutes filing dates are as follows:

Table 2.1-A

2020 PIWG Meeting Dates and Meeting Minutes Filing Dates

Meeting Date	Filing Date of the Meeting Minutes (See Formal Case No. 766 and PEPPIWG)
Feb. 28	Mar. 13
May 8	May 21
Aug. 25	Sep. 3
Nov. 13	Nov. 20
Dec. 18	Dec. 31

SECTION 2.1 – PIP

In Order No. 16623 on the 2011 Consolidated Report, the Commission stated the following in paragraph 8: "As a preliminary matter, we note our continuing concern with the reliability of the Pepco electrical distribution system… It is through the prism of these [reliability] efforts that we consider the Pepco Consolidated Report." In accordance with the Commission's focus in Order No. 16623 and the guidance of the PIWG, the Company presented its 2020 PIP projects, with a strong emphasis on reliability.

The 2020 PIP projects were as follows:

- 4 kV Distribution Substation Automation Projects

- 4 kV to 13 kV Conversion Projects
- DA Projects
- Priority Feeder Projects

2.1.1 PIP Project Status

The year-end 2020 status of the 2020 PIP Projects is included in Table 2.1-A.

Table 2.1-A: 2020 PIP Projects

Item	Description	PIP Project Year	2020 Project Amounts[1] (x1000)		Cost Variance Actual from Budget
			Budget	Actual	
1	4 kV Distribution Substation Automation Projects[38]	2020	$574,193	$645,405	($71,212)
2	4 kV to 13 kV Conversion Projects	2020	$12,111	$4,738	($5,531)
3	Distribution Automation Projects	2020	$9,200	$3,400	($5,800)
4	Priority Feeder Projects	2020	$3,685	$1,352	($2,332)

2.1.2 PIP Project Detail

Detail addressing each of the 2020 PIP projects – including work completed in 2020, work forthcoming in 2021, and longer-term plans – is provided below.

[38] The 4 kV Distribution Substation Automation Projects in this table only includes ITN # 70187.

4 kV Distribution Substation Automation Projects

The substation automation work continues at Macarthur Boulevard Sub 152 and is expected to be completed in the spring of 2021. The construction at Texas Avenue Sub. 1 1 1 is expected to be completed in the summer of 2022.

4 kV to 13 kV Conversion Projects[39][40]

These projects are included in the Load Growth program.

Background: The 4 kV distribution system supplies load throughout various neighborhoods in the District of Columbia. The 4 kV system has provided an effective and reliable supply to Pepco customers for many years. However, the 13 kV system is capable of supplying a greater density of load and generally produces less electrical losses. Therefore, as load density increases locally, or the system requires more maintenance and replacement becomes the best economic alternative, the 4 kV system is gradually being replaced with a 13 kV distribution system.

Magnitude of the Conversion: There are presently 110.9 megawatts of 4 kV load on the Pepco system, mostly in the District of Columbia. Over the next ten years, approximately 22 megawatts (including growth) will be converted to 13 kV service. Allowing for load growth, approximately 100 megawatts

[39] In Order No. 16091 at paragraphs 50, 53, and 64, the Commission stated the following:
50. Decision. We agree with the Staff recommendation and require Pepco to provide justification for any deviations from the plan schedules and annual budgets for 4 kV to 13 kV conversion projects in its Consolidated Reports, excluding minor deviations of less than 5%. This information may be provided in the discussion of "Reliability Projects."
53. Decision. …we have not adopted the Staff's "replace or rebuild" recommendation. However, we agree that future Consolidated Reports should contain detailed schedules and budgets for Reliability Projects, as well as justification for deviations from those schedules and budgets. We shall require Pepco to submit such schedules in future Consolidated Reports.
64. Pepco IS DIRECTED to provide detailed schedules and budgets for conversion projects, as well as justification for any non-minor deviations from these , consistent with Paragraphs 50 and 53 of this Order;
[40] Commission Order No. 16623 states the following:
32. Staff Recommendation: Require Pepco to provide and submit a report as to whether the budgets and schedules for each of the four 4 kV to 13 kV conversion projects have undergone non-minor deviations from previous plans. Include the justification for such deviations.
33. We accept the Staff's recommendation and direct Pepco to include a complete update in the 2012 Consolidated Report, including changes in budgets and schedules and justification for each non-minor deviation.
54. Pepco is DIRECTED to provide a report of conversion projects consistent with paragraph 33;

are projected to remain on the 4 kV distribution system by 2029. This 4 kV load will be located primarily in Wards 3, 7 and 8 where the load is served by substations that have either multiple transformers or are networked together through the feeder primaries. These remaining 4 kV areas are considered reliable due to the shortness of the feeders and the availability of ready backup. Areas that are going to be maintained and not converted will involve upgrading of substantial transformer equipment and other supporting equipment.

Areas Scheduled for Conversion: Areas supplied by the following substations are scheduled to have conversion work performed in the next ten years:

- Georgetown Sub. 12 NW Underground conversion.
- Harvard Sub. 13 NW Underground conversion.
- North Capitol Sub. 40 NE Overhead conversion
- Twelfth Street Sub. 126 SW Underground conversion
- Anacostia Sub. 8 SE Overhead conversion
- G Street Sub. 28 NE Underground conversion

All of the projects described below are multi-year projects with multiple phases. Five of the six projects were initiated prior to 2015. G Street was accelerated to begin work in 2016 to build infrastructure to extend new 13 kV feeders. This was done because significant new loads are expected to materialize in the G Street area and the existing 4 kV infrastructure is inadequate to meet this expected new load. Dollars spent on these projects may fluctuate over the years to account for project phasing. The Anacostia, Harvard and North Capitol conversion work is scheduled to be completed during 2021. The overall budget for the 4 kV conversion projects is still in line with the Company's long-term conversion plan.

Status: In 2020 Pepco spent $4,737,629 on its 4 to 13 kV conversion projects, $7,374,277 less than the budget of $12,111,906. The deviation between the 2020 budget and actual expenditures is due to a combination of work being delayed by re-design, permitting and work time.

Convert a part of the load at Georgetown Sub. 12 from 4 kV to 13 kV and retire 4 kV Substation

A modernization of this area infrastructure started in 2001. It includes the 4 kV to 13 kV conversions that will ultimately retire the 4 kV radial distribution system supplied from Georgetown Sub. 12. The 4 kV to 13 kV conversion has been completed for the area between M Street to the south, P Street to the north, Wisconsin Avenue to the west and 27th Street, NW to the east, by extending two 13 kV distribution feeders from Georgetown Sub.

In addition, conversions along M Street, Prospect Street, and N Street west of Wisconsin Avenue were completed in 2010 and 2011. Conversions along O and P Streets west of Wisconsin Avenue concluded in 2012.

Existing Configuration: The 4 kV underground radial distribution system serves mostly residential and some small commercial loads. Moderate load growth is anticipated for this isolated area but there are basically no external ties to deliver this power. The existing underground infrastructure, conduit and cable are in need of remediation with a history of extended outages due to limited transfer capability and circuit configuration and conduit construction that limits the size of cable that can be installed and provides limited physical protection to the cables.

The Georgetown 4 kV substation was rebuilt in the 1980s however the 4 kV underground infrastructure is the original construction and is nearing its full capacity.

Proposed Enhancement: Convert all 4 kV load to 13 kV with the exception of Francis Scott Key Bridge which feeds Roosevelt Island where step-down transformers are being considered due to access limitations and the retirement of all 4 kV substation equipment.

Status: With the exception of a few remaining transformers, conversions of the area north of M Street were completed in 2016. Due to the unanticipated non-constructability of the previous plans, all construction was placed on hold and Pepco revised the conversion work and released a new Construction Recommendation Plan in 2020.

The revised plan is a combination of traditional 4kV conversion work, load transfers to neighboring LVAC networks and possible consideration of other solutions. The new designs plan around the

"K" Street bridge crossing and the re-supply of load from Feeders 29 and 91 to other substations. Under the current schedule, work to retire the remaining five feeders should be completed by 2023. However, Pepco continues to encounter delays due to the network conversion portion which requires checking customer premises. The 2020 budget was $154,598 and approximate spend for 2020 was $118,802.

Georgetown Sub. Conversion Budget:

2021 – 2025 Budget (Figures in Thousands of Dollars)

2021	2022	2023	2024	2025	Total
$2,335	$3,668	$3,769	$0	$0	$9,772

Convert load at Harvard Sub. 13 from 4 kV to 13 kV and retire 4 kV Substation

This project will initiate infrastructure upgrades to the existing 4 kV system in the Upper Shaw and Harvard/Columbia Heights areas. Two 13 kV Feeders were extended from Florida Avenue Sub. 10 in 2011 to provide capacity for the conversion and to allow load to be transferred to Sub. 10 from Sub. 13. Existing 13 kV Feeders from Sub. 13 and new 13 kV Feeders from Sub. 25 were used to convert the final portion of 4 kV load starting in 2015.

Existing Configuration: The existing 4 kV underground distribution system serves residential and small commercial loads. Modest load growth is anticipated for this area which is isolated from the rest of the system and has no external ties. The existing underground system experiences feeder overloads, voltage deficiencies and a greater than average number of underground cable outages due to the age and condition of the cable and limited transfer and switching capabilities.

Proposed Configuration: Convert 4 kV load to 13 kV distribution feeders and retire Harvard Sub. 13 which currently operates at 4 kV.

Status:

100% of the Harvard 4 kV load has been converted to 13kV by the summer of 2020. Recently completed phases of the project utilized existing 13kV feeders from Harvard Sub. 13 and Florida

Avenue Sub. 10 to complete the conversion of load along Irving Street, Warder Street, Quebec Place, and Florida Avenue. The 2020 budget was $1,446,574 and approximately $1,760,387 was spent in 2020.

Harvard Sub. Conversion Budget:

2021 – 2025 Budget (Figures in Thousands of Dollars)

2021	2022	2023	2024	2025	Total
$0	$0	0	$0	$0	$0

Convert load at North Capitol Sub. 40 from 4 kV to 13 kV and retire 4 kV Substation

This project relates to an extension of existing and new 13 kV feeders to convert all 4 kV load served by North Capitol Street Sub. 40 to 13 kV. The North Capitol Street 4kV system serves mostly residential and small commercial customers in the Manor Park, Fort Totten, and Petworth neighborhoods. The first phase of this project to convert load from portions of North Capitol Sub. 40 Feeders 482 and 485 along 4th Street, NW between Buchanan and Hamilton Streets, NW to Fort Slocum Sub. 190 - 13kV Feeders 15006, 15012 and 15015 was completed in 2013. 2014 saw the completion of conversions along Hamilton Street, NW, Hawaii Avenue, NE and Fort Totten Drive, NE. In 2015, conversions were completed along North Capitol Street and Rock Creek Church Road.

Existing Configuration: The North Capitol Sub. 40 4 kV system is an isolated area on the Pepco distribution system that is not connected to any other 4kV substations or systems. Recent substation inspections have revealed deteriorating circuit breakers. The Allis Chalmers switchgear necessitates the salvage of spare parts from like equipment because the original equipment manufacturer is no longer in business and other manufacturers no longer supply parts for this equipment.

Proposed Configuration: Convert all 4 kV loads to 13 kV distribution feeders and retire North Capitol Sub. 40 - 4 kV.

Status: The project is underway. As of the end of 2020, several 13 kV trunk extensions have been completed and approximately 7 MVA of the 4 kV load has been converted to 13 kV. In 2017, two new 13 kV feeders were extended from Fort Slocum Sub. 190 to facilitate conversions in the area bounded by Kansas Avenue, NW, New Hampshire Avenue, NW, 4th Street, NW, and Missouri Avenue, NW. The budget for 2020 was 2,057,735 Approximately $647,550 was spent in 2020. Currently, nearly 65% of the load has been converted to 13kV with approximately 4.0 MVA remaining. This remaining load is in the vicinity of North Capitol Street and 3rd Street, NW between Kennedy Street and Buchanan Street, NW and will be converted to existing 13kV feeders from Fort Slocum Sub. 190. The 4 to 13 kV conversions in this area are scheduled to be completed by the summer of 2021.

North Capitol Sub. Conversion Budget:

2021 – 2025 Budget (Figures in Thousands of Dollars)

2021	2022	2023	2024	2025	Total
$2,452	$0	$0	$0	$0	$2,452

Convert load at 12th Street Sub. 126 from 4 kV to 13 kV and retire 4 kV Substation

This project will extend two 13 kV feeders in order to convert and/or transfer all 4 kV load supplied by 12th Street Sub. 126.

The 12th Street 4 kV system serves residential and small commercial customers in Southwest area and National Park Service buildings, street lights and traffic signals in the National Mall area. The conversion and retirement of the 12th Street Sub. 126 will be done in two phases. Phase 1 will construct an 8-way conduit bank from 2nd and C street SW to the vicinity of 7th and Maryland Avenue SW. It will involve the construction of approximately 1 mile of 8-way conduit bank. Phase 2 will involve extending Feeders 15294 and 15295 to two new three-way switches. Loops will then be extended from the switches to supply load around the National Mall and Southwest Waterfront. The last phase will require extending Feeders 15294 and 15295 to two new 3-way switches and extending laterals to the area of Hains Point, the Tidal Basin and the 14th Street Bridge.

Existing Configuration: The 12th Street Sub. 126 contains oil circuit breakers that will be removed based on the review of condition and reliability. Both the 13 kV/4 kV transformers are identified as in need of eventual replacement. These oil circuit breakers are no longer manufactured, and the manufacturer no longer provides spare parts. As part of the conversion process, this substation will be retired.

Proposed Configuration: Convert all 4 kV loads to 13 kV distribution feeders and retire Twelfth Street Sub. 126 – 4 kV including the transformers and oil circuit breakers.

These projects are included in the Load Growth program.

Status: The remaining major scope of work includes installing approximately 20,000 feet of #2 EPJ cable, ten (10) tap holes, 4 stepdown transformers and two (2) – 50kVA B phase transformers to complete the conversion for feeders 232 and 233. The completion of this work is contingent upon the approval of the National Park permit to complete the conduit work at locations along East Basin Dr. SW adjacent to the George Mason Memorial and portions of Ohio Drive on the east side of East Potomac Park. All conduit designs have been prepared and are in the process of coordinating with NPS and DDOT (extra coordination needed due to construction being necessary into the 395 abutments on Arland Williams Bridge). Field work has also been difficult to obtain due to road grade being close to the water table and NPS coordination needed for occupancy. The project is nearly ready to move forward with conduit construction. Based on designs being mostly complete, project on track to complete the conversion by end of year 2021. The budget for 2020 was $6,864,818 Approximately $639,254 was spent in 2020.

12th Street Sub. Conversion Budget:

2021 – 2025 Budget (Figures in Thousands of Dollars)

2021	2022	2023	2024	2025	Total
$3,092	$0	$0	$0	$0	$3,092

Convert Load at Anacostia Sub. 8 from 4 kV to 13 kV and Retire 4 kV Substation

The project relates to the extension of 13 kV feeders from Alabama Avenue Sub. 136 in order to convert all 4 kV load from Anacostia Sub. 8 4 kV and retire the Anacostia Sub. 8 – 4 kV substation.

The Anacostia Sub. 8 4 kV system supplies residential and small commercial load in the Anacostia area of Southeast Washington, D.C. New and existing 13 kV overhead feeders from Alabama Avenue Sub. 136 will be extended in order to convert all 4 kV load.

Existing Configuration: Anacostia Sub. 8 is supplied by two 34 kV feeders from Buzzard Point Station B. Converting 4 kV load from Anacostia Sub. 8 will also relieve load from Buzzard Point Station B 13 kV substation, which is approaching its firm capacity. Review of the equipment at Anacostia Substation and the 34 kV supplies indicated the need to replace all this equipment for long term reliability. Instead of rebuilding this station, conversion of the 4 kV load and transfer of the 13 kV load to Alabama Avenue Substation will allow the retirement of both the substation and supplies and improve the overall reliability of the distribution system in this area.

Proposed Configuration: Convert all 4 kV loads to 13 kV distribution feeders and retire Anacostia Sub. 8 – 4 kV.

Status: Much of the Anacostia Sub. 8 4 kV load has been converted over the past several years as part of the 23rd Street and Anacostia 4 kV conversion projects. Construction for the Anacostia 4 kV conversion project began in 2012 and about 2.4 MVA load has been converted to 13 kV. The 2020 budget for this project was $241,631 and $19,833 was spent in 2020. The work to convert the remaining 0.9 MVA to Feeders 15173 and 15178 is scheduled to be completed in 2021. Anacostia substation will be retired after all Alabama Avenue substation and distribution work has been completed. New feeders were recommended to transfer/covert all load currently supplied from the Anacostia substation to Alabama Avenue Sub. 136. All work is scheduled to be completed by the end of 2021.

Anacostia Sub. Conversion Budget:

2021 – 2025 Budget (Figures in Thousands of Dollars)

2021	2022	2023	2024	2025	Total
$700	$0	$0	$0	$0	$700

Convert load at "G" Street Sub. 28 from 4 kV to 13 kV and retire 4 kV Substation

This project relates to an extension of existing and new 13 kV feeders to convert all 4 kV load served by "G" Street Sub. 28 to 13 kV.

The "G" Street 4kV system serves mostly residential and small commercial customers in the Capitol Hill, Barney's Circle and Navy Yard neighborhoods. The first phase of this project to convert load from portions of "G" Street Sub. 26 feeders 212, 223, 227 & 228 Street, supplying load east of 11th Street SE and south of Pennsylvania Avenue SE to new Southwest Sub. 18 – 13kV Feeders 15876 and 15877, which has been designed and released to construction and will be extended to make the first phase conversions. The next phases will consist of extending a third 13 kV feeder from Southwest Sub. 18 along with the initial two feeders to convert portion of "G" Street 4kV load north of Pennsylvania Avenue SE and South of Massachusetts Avenue SE. The remaining 4 kV load north of Massachusetts Avenue SE will be converted to Benning Sub. 7 feeders 14708 and 14152.

Existing Configuration: G Street Sub. 28, was built in 1965 and is an isolated 4kV system not connected to any other 4kV substation. The area is experiencing moderate load growth and the existing 4kV system cannot accommodate any large new business load. Furthermore, some of the 4kV Feeders have had voltage problems, and the existing conduit and cables are very old. Therefore, an upgrade of this system is underway to eliminate potential reliability concerns proactively.

Status: Project scope and estimate was reassessed in early 2019. The project was handed over to Project Management for execution. It is currently in design. Construction anticipated to begin in late

2021. The 2020 budget for this project was $1,346,550 and approximately $1,551,803 was spent in 2020.

G" Street Sub. Conversion Budget:

2021– 2025 Budget (Figures in Thousands of Dollars)

2021	2022	2023	2024	2025	Total
$7,341	$13,649	$13,549	$13,277	$14,834	$62,649

2.2 DA PROJECTS

Distribution Automation is the conversion of a manually operated distribution system with limited available status information and limited control to a system that not only is fully automated but also performs operations totally independent of any human intervention. Advancements in technologies have made these automation activities practical for the lower voltage systems and will significantly change the way the Company responds to outages and operates and restores the electric system.

Status: Refer to section 1.3.1 (Technology: Monitoring, Automation, and Information System) above for the status of the completed DA Projects. There are 28 more feeders identified for ASR activation in 2021. To identify candidate feeders, Pepco evaluated the performance history of individual substation main and feeder breakers, and automatic reclosers downstream on circuits. Specifically, Pepco targets feeders with some of the highest SPC values which consider the customer interruptions and duration of these interruptions over the last three years. The table below lists the candidate feeders for ASR feeder scheme deployment in 2021 timeframe. This set of feeders will primarily benefit customers in Ward 8.

ASR Feeders Planned for 2021 with their Historical Lockout Statistics

Substation	Feeder Number	Reliability Performance (SPC Value)
Alabama Ave	15166	0.001220816
Alabama Ave	15172	0.009402057
Alabama Ave	15173	0.014119247
Alabama Ave	15174	0.013754641
Alabama Ave	15175	0.001771977
Alabama Ave	15176	0.011980111
Alabama Ave	15177	0.018171942
St Barnabas 59	15082	0.001717662
St Barnabas 59	15083	0.003284233
St Barnabas 59	15084	0.001185329
St Barnabas 59	15085	0.00605845
St Barnabas 59	15086	0.001527037
St Barnabas 59	15087	0.005575771
St Barnabas 59	15088	0.0000595556
St Barnabas 59	15089	0.002815612
St Barnabas 59	15090	0.003304277
St Barnabas 59	15091	0.003304277
St Barnabas 59	15092	0.000896299
Beech road 159	14251	0.000759804
Beech road 159	14252	0.0000658919
Beech road 159	14253	0.001480944
Beech road 159	14255	0.001285892
Beech road 159	14256	0.001285892
Beech road 159	14257	0.002036395
Beech road 159	14258	0.000567704
Beech road 159	14259	0.001881188
Beech road 159	14260	0.000321852
Beech road 159	14261	0.009700642

PRIORITY FEEDER PROJECTS

These projects are included in the Feeder Improvement program.

Status: In response to the Commission's focus on preventing repeat Priority Feeders, Pepco has adjusted its feeder remediation strategy to a more comprehensive approach. Instead of focusing on locations where previous failures have occurred, the entire feeder is reviewed to address potential locations for future failures. The actual expenditure of the 2020 Priority Feeder Projects was approximately $1,500,000.

SECTION 2.3 – PERFORMANCE[41]

Priority Feeders & Aggressive Initiatives

Feeder Performance and Aggressive Initiatives

[41] Order No. 16975 states the following at paragraphs 58 and 59, 60, and 105:
58. Decision: …We therefore require Pepco to provide in the 2013 Consolidated Report, the information recommended by the Staff including an explanation of any discrepancies between work planned and work completed…. In Order No. 15941, the Commission required Pepco to provide specific information regarding any 4 kV feeder that has appeared on the Priority Feeder List three times or any 13 kV feeder that has appeared on the Priority Feeder List four times. On June 13, 2012, Pepco filed a report pursuant to that Order, providing information on two 13 kV feeders, 14717 and 14768. The Commission believes it is necessary to expand the scope of Pepco's reporting on feeder improvement to include any feeder that has appeared on the priority feeder list more than twice. Therefore, we require Pepco to provide the information required in paragraph 13 of Order No. 15941 in the future Consolidated Reports for any feeder appearing more than twice on the Priority Feeder List….
59. In future Consolidated Reports, Pepco shall include the following information about each feeder on the Priority Feeder List:
(1) a detailed description of outages, including causes and corrective actions taken;
(2) the SAIDI, SAIFI, number of interruptions, and number of hours of customer interruptions for that feeder for each year beginning with the year the feeder first appeared on the Priority Feeder list;
(3) a map showing the feeder service area, including affected neighborhoods;
(4) an analysis of why past corrective actions failed;
(5) Pepco's proposed solution to the feeder's reliability problem, including an explanation of options considered with the cost/benefit analysis of each and justification for the option recommended;
(6) a cost/benefit analysis of the solution, including budget and cash flows by year, as well as any impact on the revenue requirement; and
(7) a detailed justification for its aggressive feeder remediation measure of replacing open wire secondary with triplex secondary conductor.
60. The Commission notes that in recent PIWG meetings, Pepco has indicated its intention to change the methodology which it uses to determine Priority Feeders. A change in methodology would diminish the value of the Priority Feeder List in determining historically poorly performing feeders and would lessen our ability to track and compare the historical data. Therefore, we require Pepco to provide two Priority Feeder Lists, using both the historical (CPI) and any new methodologies in the 2013, 2014 and 2015 Consolidated Reports. In addition, the Commission requires Pepco to provide the information required by paragraph 13 of Order No. 15941 for any feeder appearing more than twice on the Priority Feeder List using either the historical or any new method.
105.Pepco is DIRECTED to provide information on Priority Feeders consistent with paragraphs 58-60 herein;

Feeder Performance

Each year Pepco analyzes the performance of its feeders to determine the relative ranking of each feeder from the best to the least reliable. From this ranking, Pepco selects the least reliable two percent (2%) of its feeders (excluding the selected feeders from the prior year study) to analyze and identify actions which likely will improve the reliability of the feeders, and therefore the system.

Beginning in 2013, the Company began using the SPC (System Performance Contribution), a method that provides greater system performance improvement potential. The SPC value for each feeder is calculated using the following equation:

SPC = 75% x (Feeder CI / System CI) + 25% x (Feeder CMI / System CMI),
Where

Feeder CI = Customer Interruptions of the feeder System CI = Customer Interruptions of the total system
Feeder CMI = Customer Minutes of Interruption of the feeder System CMI = Customer Minutes of Interruption of the total system.

In addition, when selecting the annual priority feeders, the selections are made based on the combination of the following criteria:

1) Feeders blended performance ranking by SPC values (i.e., individual feeder contribution to system SAIFI and SAIDI);
2) Feeders that are not repeated from the year prior;
3) Feeders with a minimum SAIFI value of 2.00; and
4) Feeders experienced at least 10 outage occurrences in the evaluation period.

Additional analysis at the feeder level is conducted to ensure the proper feeders are selected and corrective actions are reasonable (e.g., excluding feeders with abnormal configuration at the time of the outage occurrence, when outage causes were remediated during initial outage restoration work, etc.).

Excluded from this annual study are the Priority Feeders from the prior year, which typically would not show the full results of corrective actions until a full year following the completion of the corrective actions.

As of December 2020, there are 773 feeders (4 kV and 13 kV) in the District of Columbia. Sixteen feeders represent 2% of the 773-feeder total. The sixteen 2021 Priority Feeders, along with customers served, are provided in Section 2.4.1.2., and each includes a narrative outlining the initial measures necessary to improve performance. Additional corrective actions may result from continuing analysis of the outage data and detailed engineering. These feeders originate from seven different substations.

Attachment C contains maps of the 2021 Priority Feeders. The priority feeder program will be an enhanced initiative including both reliability work routinely performed on the selection of priority feeders supplemented with more aggressive initiatives.

Cost/Benefit Discussion

Order No. 16975 requires that Pepco provide the following in this and future Consolidated Reports (paragraph 59, item 6):

(6) a cost/benefit analysis of the solution, including budget and cash flows by year[44]*, as well as any impact on the revenue requirement;*

As described in previous ACRs, the measurement of benefits associated with feeder reliability projects generally depends on the outage history of the feeder and the likelihood that a portfolio of remediation activities will reduce or totally eliminate similar outages for the same or similar cause. Simply allocating a portion of the previous customer interruptions or customer minutes of interruption prior to the remediation activity is a way of qualifying the relative cost / benefit of individual remedial efforts. This is, however, not a dependable method of forecasting future feeder or aggregate system reliability because no remediation tactic is all inclusive of every possible outage cause. Likewise, this approach assumes all other inputs to system reliability are held constant (same weather, same animal events, same tree faults, etc.), which is unlikely.

Similarly, the measure and inclusion of cost/benefit per feeder or per individual initiative would potentially serve to reduce the field of options available to apply in feeder performance improvement. Some activities are not as efficient or economical as others based on a simple mathematical evaluation. However, the potential exclusion of these activities based on their relative inefficiency at the feeder or activity level would mean that the best overall portfolio of remedies could not be utilized in system level improvement. Further, with the advances in sectionalization technology, standard cost benefit analyses could drive a utility to employ only mitigation efforts rather than more appropriate but potentially more costly fault elimination tactics. Pepco evaluates each of these options and implements mitigation as well as elimination techniques when evaluating work to improve reliability of a feeder.

Aggressive Initiatives[42]

The Priority Feeder program is an enhanced initiative including both reliability work routinely performed on the selection of priority feeders supplemented with more aggressive initiatives.

Aggressive initiatives may include the following:

- Installation of tree wire in close configuration construction to replace bare wire through heavily treed areas where aggressive tree trim and standard cross-arm construction would have limited success or is restricted by ordinance or property owners.

[42] In Order No. 15152 paragraph 73, the Commission ordered the following:
73. Pepco is DIRECTED to investigate the viability of the "aggressive" initiatives for all least performing feeders, to file a progress report regarding the implementation of these initiatives where viable as part of the 2009 Consolidated Report, and to file quarterly progress reports thereafter, consistent with paragraph 62 of this Order;

In Order No. 15809 paragraph 11, the Commission ordered the following:
11. Pepco IS DIRECTED to include in its 2011 Consolidated Report a plan for development and application of "aggressive initiatives" to its underground distribution feeders;

- Installation of PAC for use as the main trunk of the feeder with the existing mainline reconfigured as fused laterals.
- Installation of automatic circuit reclosers (ACR) in loop scheme configuration to automatically sectionalize faulted sections of the feeder and provide automatic backup to unfaulted sections.
- Installation of remote operated load break switches into the loop scheme configuration with the automatic circuit reclosers.

Pepco's proposed aggressive initiatives to its underground distribution feeders are:

4 kV System

In addition to performing Very Low Frequency (VLF) testing and manhole inspections, the process of correcting identified issues also includes the following:

- Installation of tap-holes (switch points) at key locations to improve the ability to isolate problems as well as improving the ability to restore customers following each event.

- Perform a review of the failure history of the area for each failure and comparison of failure locations to replacement history. Perform proactive cable replacement of stretches that were not previously replaced in the area.

Regarding Commission's recommendation (per Order No. 16975) to add switch points to 4kV feeders, over time these 4kV feeders will be converted to 13kV, in which the loop alternate feed design is inherent. In the interim, all of the 4kV systems have backup supply for trunk outages. And for lateral outages, Pepco is replacing cable, installing tap holes, and ultimately converting all current underground 4kV feeders to 13kV feeders.

13 kV System

In addition to performing VLF testing and manhole inspection, correcting identified issues include the following:

- Perform a review of the failure history of the area for each failure and compare failure locations to replacement history. Perform proactive cable replacement of stretches that were not previously replaced in the area.
- Replace all of the problem sections of cable.

For various reasons, not all of the "Aggressive Initiatives" are applied to each of the Priority Feeders. For example, if a particular feeder is completely underground, installing tree wire, PAC, ACR and remote operated load-break switches would not be applicable as these types of equipment are not used on underground feeders. Similarly, if a feeder is already equipped with remote switching capabilities and the switches are functioning properly, then simply increasing the number of remotely operated switches will generally not yield improvement. Further, if the predominant outage cause for a feeder is not tree-related, installing tree wire along the previous outage locations, will not yield performance improvement.

Order No. 16975 states the following at paragraph 58:

58. …In addition to the information required by paragraph 13 of Order No. 15941, the Commission also requires that Pepco provide detailed justification for its aggressive feeder remediation measure of replacing open wire secondary with triplex secondary conductor, as recommended by the OPC response.

The following is Pepco's explanation for replacing open wire secondary conductors with triplex conductors:

Triplex conductors are less susceptible to mechanical damage such as trees, winds, etc. They increase the distance between the primary and neutral conductors, which reduces the opportunity for primary related tree outages. Other miscellaneous upgrades will also be performed such as pole, hardwire, and equipment replacements due to deterioration. Upgrading will significantly reduce future equipment failures. Should damage occur, restoration is faster with the triplex conductors. Therefore, customers will experience lower number of outages as well as a shorter duration of outages. The cost to replace open wire secondary conductors with triplex conductors is approximately $40,000 per mile.

Section 2.3.1 2020 PRIORITY FEEDER PROGRAM

Order No. 16975 requires that Pepco provide the following in this and future Consolidated Reports (paragraph 59, item 1):

(1) a detailed description of outages, including causes and corrective actions taken;

Table 2.3A: Priority Feeder program - Completed Corrective Actions

2020 Priority Feeder Program - District of Columbia - Corrective Actions Proposed vs. Completed				
Rank	**Feeder**	**Proposed Corrective Actions, as filed in the 2020 Consolidated Report**	**Detailed Corrective Actions - Completed**	**Explanation of Variances/ Comments**
	14035	• Install/Replace 1050' of Primary Wire •Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	• Install/Replace 1050' of Primary Wire •Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	No variance
	00328	• Install/Replace 4 Poles •Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	• Install/Replace 4 Poles •Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	No variance
	15867	•Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	•Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	No variance
	14136	•Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	•Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	No variance
	00211	•Due to ongoing work taking place under the G Street Conversion Program, no work is planned on this feeder under the 2020 Priority Feeder Program.	•No Work	No variance
	14711	•Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	•Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	No variance
	15130	• Install/Replace 1700' of Primary Wire •Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	• Install/Replace 1700' of Primary Wire •Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	No variance
	14261	•Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	•Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	No variance
	15702	• Install/Replace 1 Pole •Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	• Install/Replace 1 Pole •Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	No variance
	15710	•Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	•Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	No variance
	15021	• Install/Replace 4200' of Primary Wire •Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	• Install/Replace 4200' of Primary Wire •Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	No variance
	16002	• No mainline work proposed under the 2020 Priority Feeder Program	• No Work	No variance
	15015	•Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	•Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	No variance
	15707	•Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	•Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.	No variance
	15094	•Due to ongoing work taking place under the Ft Lincoln Area Reliability Improvement Plan, no work is planned on this feeder under the 2020 Priority Feeder Program.	• No Work	No variance
	16003	• No mainline work proposed under the 2020 Priority Feeder Program	• No Work	No variance

Proposed Corrective Actions for 2021 Priority Feeders[43]

The following information provides an overview of the outages and proposed corrective actions for the 2021 Priority Feeders and detailed information regarding the equipment related events and/or outages. Please see Attachment C for maps of the 2021 Priority Feeders reflecting overhead and underground portions, and the Priority Feeders by District of Columbia Ward.

Pepco's OMS assigns event numbers based on length of time between interruptions. Therefore, during the trouble locating and restoration process, more than one event number may be generated and counted. For the sections that explain equipment failures, for mainline feeders, line fuses and transformers, the events were grouped by incidents.

2021 Priority Feeders

The following 16 feeders have been identified as priority feeders. Please note that some feeders, as stated below, will not have work performed in 2021 under the Priority Feeder program; rather, as specified below, some feeders had corrective work performed coincident with the outage(s) that caused the feeder to be a priority feeder or whose work is subsumed in another reliability program.

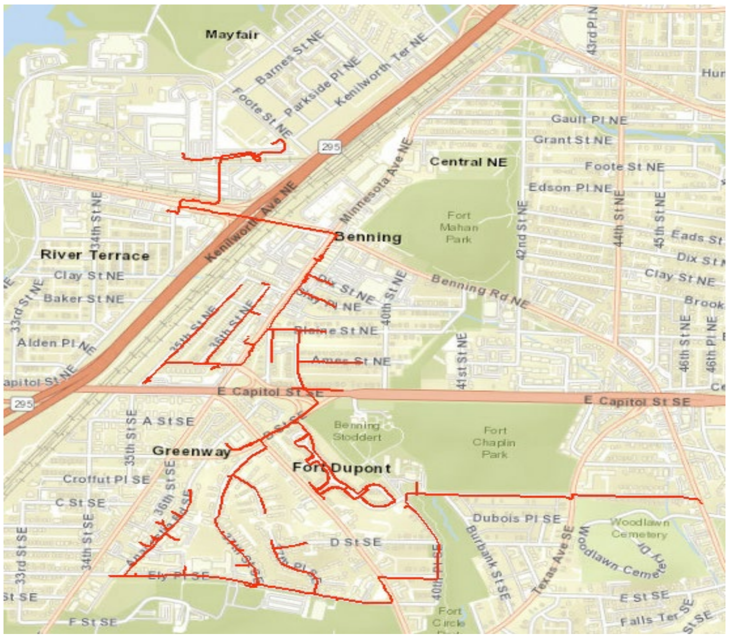
Please note that, in a change from previous years' reports, Pepco is now budgeting for the entire class of priority feeders rather than for each feeder. The 2021 budget for priority feeders is $1,832,735.[44]

Circuit: 15709

County	Substation	Customers Served	Number of Outages	Oct. 2019-Sept. 2020 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Benning (7)	2,768	23	1.994	65.2	32.7	62%	38%	9.39	N

[43] Actual equipment failures may be more or less than the number shown because a single event may give rise to more than one equipment failure and due to OMS limitations, that do not allow a single unique case to be identified in each line.
[44] The budget can be adjusted according to the needs of the program.

Feeder Map and Location:



Outage Data Summary (Past 3 years):

2018: (Oct 17-Sep 18) Thirty three percent (33%) of customer outages were due to three mainline events; one event was caused by weather/wind, another caused by vandalism, and the third event was caused by equipment failure. Sixty six percent (66%) of customer outages were due to six lateral events. Two events were caused by equipment failure, one event was caused by an animal, one event was caused by foreign contact, one event was caused by vandalism, and one event was caused by trees.

2019: (Oct 18-Sep 19) Thirty eight percent (38%) of customer outages were due to eight mainline events; four events were caused by equipment failure, two were caused by trees, one event was caused by an animal, and one outage event occurred with an unknown cause. Sixty two percent (62%) of customer outages were due to lateral events; eleven outages were due to equipment failure caused by underground cable and fuse events. One event was caused by vandalism, and one event was caused by trees.

2020: (Oct 19-Sep 20) Eighty seven percent (87%) of customer outages were due to twenty-five lateral events. Thirteen outage events were due to equipment failures resulting from issues with individual meters or transformers; three outages were caused by underground cable failure. Four lateral outage events were due to an unknown cause, and the remaining five lateral outages were due to foreign contact, animal, employee, load, and a cable cut. Thirteen percent (13%) of customer outages were caused by mainline events. Three events were caused by an equipment failure at a fuse location, and one event was caused by a breaker event during a scheduled outage.

Feeder Performance (Oct 19-Sep 20)

Outage Cause by SAIFI	**SAIFI**	**% of Feeder SAIFI**
Equipment Failure	1.061	53%
Animal/Bird	0.908	45%
Unknown	0.012	<1%%
Other	0.013	<1%

* Other Category Includes: Foreign Contact, Employee, Cable Cut, Load

<u>Field Observations:</u>

Feeder 15709 serves approximately 2,768 customers in the Benning, Dupont Park, Fort Dupont, Greenway, and River Terrace areas of Washington D.C. The feeder primarily consists of residential customers, with a mix of some commercial customers along the early part of the feeder. The mainline portion of the feeder runs underground from the Benning Substation up to Minnesota Ave NE, where it transitions to overhead and proceeds to run Southwest on Minnesota Ave NE. After turning off of Minnesota Ave NE, the feeder proceeds to run South following a path along Blaine St NE, Burns St NE, B St SE, and 37th St SE. Once the feeder reaches Ely Pl SE, it splits and runs to both the East and to the West. The portion of the feeder to the East runs along Ely Pl SE, Burns St SE, and C St SE, with only a few load points. Headed to the West, the feeder has a much higher customer count, feeding multiple apartment buildings off of Ely Pl SE, Minnesota Ave SE and B St SE. The mainline portion of the feeder is a mix of 477 ACSR Treewire,477 ACSR Bare wire, and PAC cable, with a majority of this being newer construction. There are opportunities to improve animal protection at all large equipment poles.

Previous Actions Taken (Past 3 years):

2018 Area Plan

Feeders 15709 and 14812 reconductored with 477 ACSR Tree wire from the North side of East Capitol St NW, heading southwest along B St SE, and then to the intersection of Ridge Rd SE and 37th St SE.

Reconductor two spans of mainline with 477 ACSR Tre wire along 37th St SE

Reconductor 14 spans of mainline with 477 ACSR Tree wire along Ely Pl SE

Install fuses at three unfused laterals.

Benning Feeder Extension

Convert single phase primary conductor along B St SE between Minnesota Ave SE and Railroad Tracks to three phase primary to allow for all load on feeder from N.C. Recloser on Ely Pl SE, east of Anacostia Rd SE, heading north along Minnesota Ave SE, and West on B St SE to be transferred to feeder 14806.

Planned Remediation (Current Year):

Mainline work includes addressing animal and BIL concerns at large equipment locations, installing fused cutouts, and installing phase spacers along spans with excessive slack.

Milestones/Schedule:

	Design Complete	**Permitting Complete**	**Release to Construction**	**Construction Complete**
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

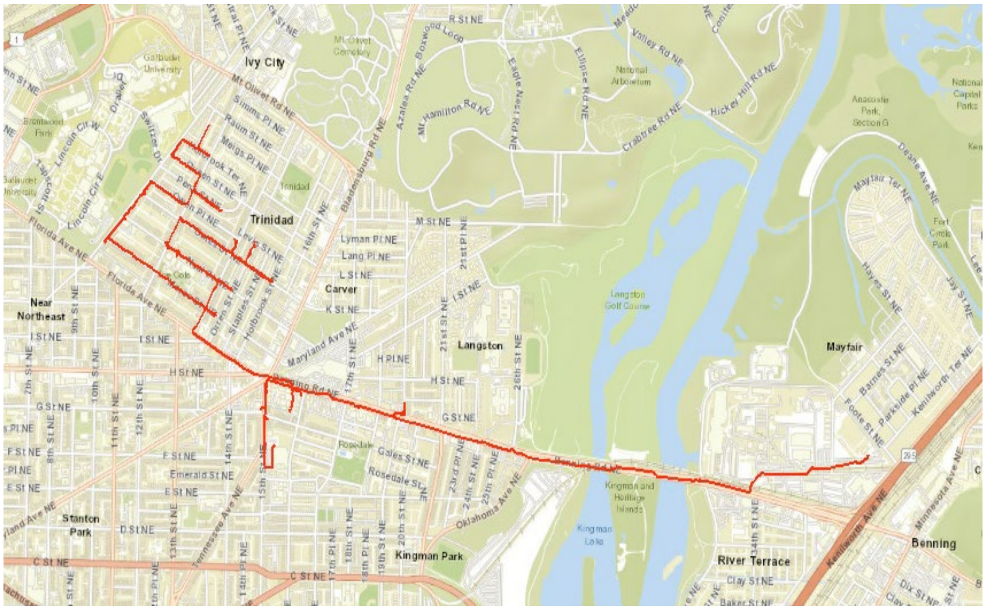
Anticipated Benefits:

The work planned will improve animal protection on the feeder, as well as added protection when high wind events occur, thereby improving the feeder performance.

Circuit: 14712

County	Substation	Customers Served	Number of Outages	Oct. 2019-Sept. 2020 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Benning (7)	1,359	15	2.911	342.2	117.6	0%	100%	5.51	N

Feeder Map and Location:



Outage Data Summary (Past 3 years):

2018: (Oct 17-Sep 18) One hundred percent (100%) of customer outages were fused lateral events; eight outage events were caused by equipment failure; three outages had an unknown cause, and two outages were due to cable cuts.

2019: (Oct 18-Sep 19) Forty percent (40%) of customer outages were mainline events. The two mainline outage events were caused by equipment failure. Sixty percent (60%) of customer outages were lateral events; two events caused by underground cable failure and one event caused by a cable cut.

2020: (Oct 19-Sep 20) Thirty three percent (33%) of customer outages were mainline events; eight events caused outages all relating to underground cable and transformer failures. Sixty six percent (66%) of customer outages were fused lateral events; ten events were caused by equipment failure; and six events were due to an unknown cause.

Feeder Performance (Oct 19-Sep 20)

Outage Cause by SAIFI	SAIFI	% of Feeder SAIFI
Equipment Failure	2.188	75%
Unknown	0.723	25%

Field Observations:

Feeder 14712 serves approximately 1,359 customers in the Carver/Langston and Kingman Park neighborhoods in NE Washington, DC. This feeder is 100% underground construction and feeds residential customers.

Previous Actions Taken (Past 3 years):

No work performed within the last 3 years.

Planned Remediation (Current Year):

Mainline:

Mainline work includes replacements and/or installation of crossarms, fused cut-outs, lightning arrestors, animal guards, down-guys, head-guys, anchors and fault indicators.

Milestones/Schedule:

Work on this feeder will require approximately 3 months to be completed.

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	3/15/2019	5/15/2019

Actual	N/A	N/A	N/A	N/A
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

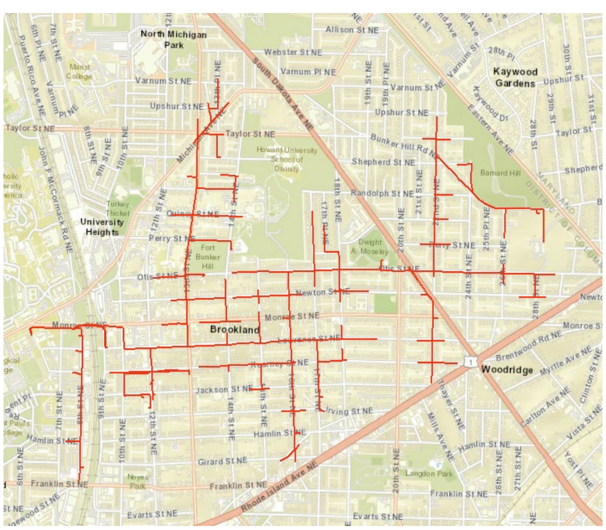
Anticipated Benefits:

The work on this feeder to address animal/BIL deficiencies will help to improve the resiliency of the feeder, thereby supplying a more reliable service to customers served by this feeder.

Circuit: 14022

County	Substation	Customers Served	Number of Outages	Oct. 2019-Sept. 2020 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	12th & Irving (133)	1,901	18	2.227	86.3	38.8	80%	20%	5.63	N

Feeder Map and Location:



Outage Data Summary (Past 3 years):

2018: (Oct 17-Sep 18) One hundred percent (100%) of eight customer outages were fused lateral events. Four outage events were caused by equipment failure; two were caused by trees; one outage event occurred due to lightning; and one outage had an unknown cause.

2019: (Oct 18-Sep 19) One hundred percent (100%) of ten customer outages were due to fused lateral events. Three of these outage events were caused by equipment failure; three outages were caused by lightning; two events were caused by animals. The remaining two events occurred for an unknown cause.

2020: (Oct 19-Sep 20) Thirty four percent (34%) of twenty-six customer outages were mainline events. Of the nine mainline outages, three were due to trees; three were caused by an unknown reason; the remaining three mainline outages were caused by animals, equipment failure, and weather. Sixty six percent (66%) of outages were lateral events. Five lateral outage events were caused by animals, four outages were caused by equipment failures, four outages were caused by trees, two outages were caused by weather, and the remaining two outages were caused by other factors.

Feeder Performance (Oct 19-Sep 20)

Outage Cause by SAIFI	**SAIFI**	**% of Feeder SAIFI**
Unknown	1.99	89%
Tree	0.138	6%
Equipment Failure	0.065	3%
Weather	0.027	1%
Animal	0.011	<1%
Other*	0.001	<1%

* Other Category Includes: Vandalism, Employee

Field Observations:

Feeder 14022 serves approximately 1,901 customers in the Brookland, Edgewood, and North Michigan Park neighborhoods in NE Washington, D.C. The overhead portion of the feeder that runs to the West, along 9th St NE, has been hardened in recent years and exclusively feeds industrial customers. The eastern portion of the feeder runs along Lawrence Ave NE and branches off in multiple directions to supply power to residential customers and create ties to other feeders in the surrounding area. These portions of the mainline branch off and run along 13th St NE, 16th Pl NE to the south, and 16th Pl NE to the north continuing along Otis St NE and 22nd St NE. A majority of the feeder has had work completed on it in recent years to reconductor the mainline with 477 ACSR Treewire. Areas of the mainline along 16th St NE, Otis St NE, and 22nd St NE contain older structures with copper wires, which leave the feeder vulnerable. There are also opportunities throughout the feeder to address animal and lightning concerns at large equipment poles.

Previous Actions Taken (Past 3 years):

No work performed within the last 3 years.

Planned Remediation (Current Year):

Mainline:

Reconductor ~724’ of existing 4/0 ACSR Treewire along Kearny St NE with 477 ACSR Treewire

Reconductor ~3,818’ of existing copper primary along 16th St NE and Otis St NE with 477 ACSR Treewire

Reconductor ~569' of existing copper primary along 22nd St NE with 477 ACSR Treewire

Install fused cutouts on unfused laterals and relocate existing cutouts to the mainline pole at laterals that are exposed to outage potential.

Address any animal, lightning, phase-to-phase, and phase-to-ground issues at large equipment locations.

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

Anticipated Benefits:

The reconductoring work will allow Feeder 14022 to reliably tie into and back feed from other feeders while also increasing resiliency against weather and any vegetation issues. The minor work being performed as part of the priority feeder program will further improve the feeder performance and animal/BIL deficiencies, thereby providing added resiliency and more reliable service to the customers served by this feeder.

Circuit: 14758

County	Substation	Customers	Number of	Oct. 2019-Sept. 2020 Reliability Indices	Feeder Miles	Repeated

		Served	Outages	(In Hours)						Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Nrl (168)	2,169	19	1.361	93.3	68.6	66%	34%	10.08	N

Feeder Map and Location:

Outage Data Summary (Past 3 years):

2018: (Oct 17-Sep 18) Fifty percent (50%) of twenty customer outages were mainline events. There were four outages caused by equipment failures; three outage events were caused by vandalism; two outages were caused by animals; one outage was caused by weather. Ninety percent (90%) of the ten lateral outage evens on this feeder were due to equipment failures; the remaining outage event was caused by vandalism.

2019: (Oct 18-Sep 19) Fourteen percent (14%) of seventy-four outage events were mainline events. Seven outage events were caused by equipment failures; two events were caused by foreign contact; one event was caused by a motor vehicle; and one event was caused by trees. Eighty-six percent (86%) of outage events on the feeder were fused lateral events. Of the lateral events that occurred, ninety-six percent (96%) of the outages were due to one isolated equipment failure. The remaining two outage events were separate events that were also caused by equipment failure.

2020: (Oct 19-Sep 20) Thirty-six percent (36%) of twenty-two outage events on this feeder were mainline outages. Three outages were caused by foreign contact; two outages were caused by equipment failure; another two outages were caused by trees, and one mainline outage event occurred due to an unknown cause. There were fourteen lateral outages on this feeder, making up sixty four percent (64%) of outage events. Eleven lateral outage events due to equipment failure; ten of these eleven outages were in relation to one isolated downed wire issue. The remaining three lateral outage events on this feeder were caused by animals.

Feeder Performance (Oct 19-Sep 20)

Outage Cause by SAIFI	SAIFI	% of Feeder SAIFI
Tree	0.976	72%
Unknown	0.287	21%
Equipment Failure	0.081	6%
Animal	0.016	1%
Foreign Contact	0.062	<1%

<u>Field Observations:</u>

Feeder 14758 serves approximately 2,169 customers in the Anacostia Naval Station – Bolling Air Force Base, Bellevue, and Washington Highlands neighborhoods in SE Washington D.C. The mainline portion of this feeder originates on Chesapeake St SW, just east of Interstate-295 and proceeds to run east along Chesapeake St SW. The mainline also runs to the south along Martin Luther King Jr Ave SW and branches in multiple directions including southwest along Blue Plains Dr SW to feed the Metro station, south along Martin Luther King Jr Ave supplying power to apartment buildings and industrial customers, and heading east along Galveston St SW to tie into multiple feeders along South Capitol St SW. The mainline portion of the feeder is about an equal split of newer construction that utilizes PAC cable for longer stretches where there is not any load present and older construction with copper wire still in place.

Previous Actions Taken (Past 3 years):

As a result of multiple outage events, ~1,750' of mainline conductor was reconductored with PAC cable along Martin Luther King Jr Ave SE between Chesapeake St SW and Galveston St SW.

Planned Remediation (Current Year):

Mainline:

Reconductor ~1,617' of copper wire with 477 Treewire along Galveston St SW, from Martin Luther King Jr Ave SW to S Capitol St SW.

Reconductor ~500' of copper wire with 477 Treewire within the ROW off DC Village Ln SW.

Address any animal, lightning, phase-to-phase, and phase-to-ground issues at large equipment locations.

Ongoing work is taking place on this feeder to convert the older construction to underground cable along Martin Luther King Jr Ave SW, as well as feeds to/within The Vista and The Gardens Apartment buildings.

Milestones/Schedule:

Work on this feeder will require approximately 3 months to be completed.

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

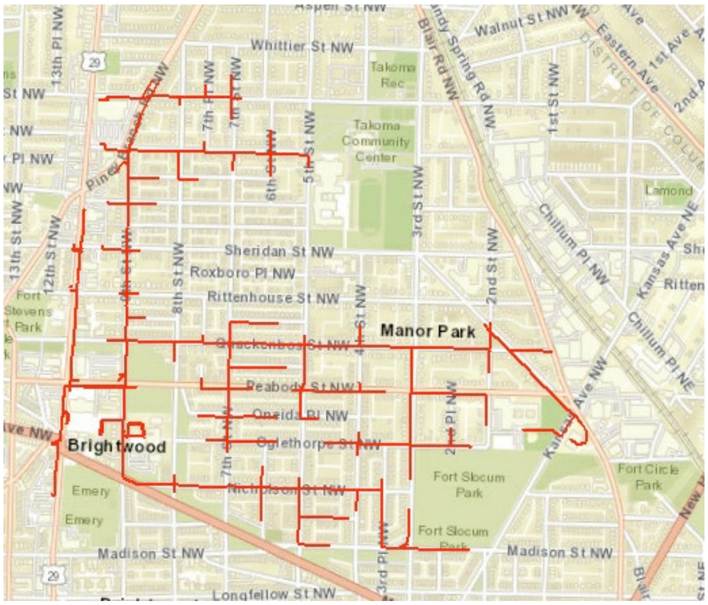
Anticipated Benefits:

The reconductoring work will allow Feeder 14758 to reliably tie into and back feed from other feeders in the surrounding area, while also increasing resiliency against weather and any vegetation issues. The other minor work on this feeder to address animal/BIL deficiencies will also help to improve the resiliency of the feeder, thereby providing a more reliable service to customers served by this feeder.

Circuit: 15010

County	Substation	Customers Served	Number of Outages	Oct. 2019-Sept. 2020 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Ft Slocum (190)	1,830	13	1.35	154	114.2	81%	19%	8.24	N

Feeder Map and Location:



Outage Data Summary (Past 3 years):

2018: (Oct 17-Sep 18) Twenty percent (20%) of fifteen customer outages were caused by three mainline events; one event was caused by equipment failure; one event was caused by weather; one event was due to an unknown cause. Eighty percent (80%) of customer outage events were due to fused lateral outages. Four outages were caused by equipment failures; four outages were caused by trees; two outages were caused by animals. The remaining two lateral outages were caused by weather and vandalism.

2019: (Oct 18-Sep 19) One hundred percent (100%) of fifteen customer outages were due to fused lateral events on this feeder. Nine outage events were caused by trees; four outages were caused by equipment failure; one outage was caused by weather, and one outage occurred due to an unknown cause.

2020: (Oct 19-Sep 20) Twenty percent (20%) of fifteen customer outages were due to mainline events. Two outages were caused by equipment failure; one outage was caused by weather. Eighty percent (80%) of customer outages on this feeder were caused by fused lateral events. Four outage events were caused by equipment failures; three outages were caused by trees; three outage events occurred due to animals; two outage events took place due to an unknown cause.

Feeder Performance (Oct 19-Sep 20)

Outage Causeby SAIFI	SAIFI	% of Feeder SAIFI
Equipment Failure	1.04	77%
Weather	0.147	11%
Tree	0.106	8%
Animal	0.034	3%
Unknown	0.016	1%

Field Observations:

Feeder 15010 serves approximately 1,830 customers in the Brightwood neighborhood in NW Washington D.C. The mainline portion of the feeder originates out of the Ft Slocum Substation and runs to the north on North Dakota Ave NW before heading to the west along Quackenbos St NW feeding residential customers along Quackenbos St NW. As the feeder reaches 9th St NW, it splits and heads both north and south along 9th St NW providing service to both residential and commercial customers along 9th St NW and Georgia Ave NW. A majority of the mainline portion of this feeder consists of older construction with copper wire within the breaker zone and along the feeder heading to the north along 9th St NW, while the portion of the feeder heading to the south is newer construction with 4/0 ACSR Bare wire and newer construction.

Previous Actions Taken (Past 3 years):

No work performed within the last 3 years.

Planned Remediation (Current Year):

Mainline:

Address any animal, lightning, phase-to-phase, and phase-to-ground issues at large equipment locations.

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

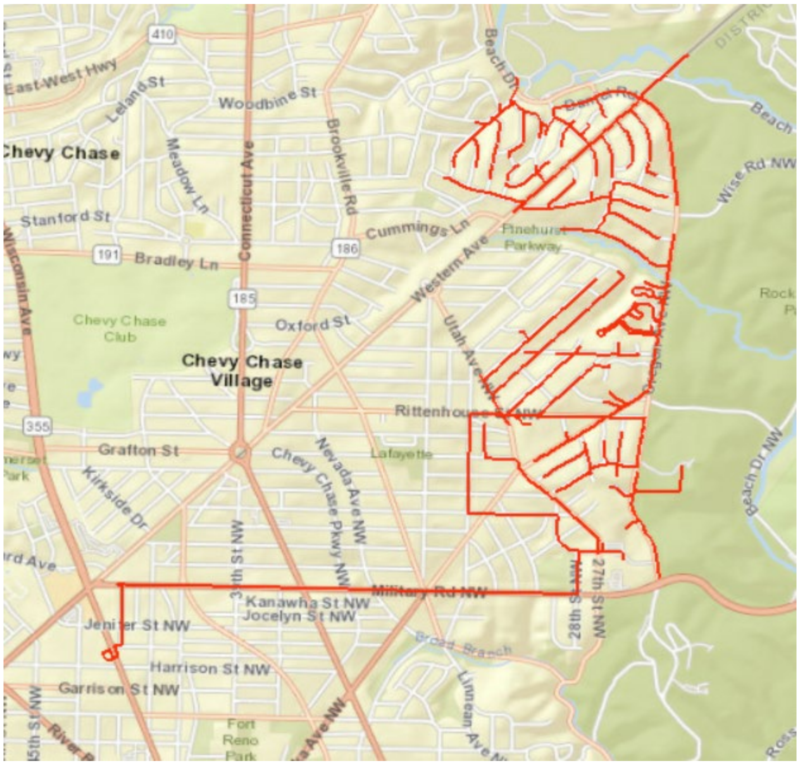
Anticipated Benefits:

The work on this feeder to address animal/BIL deficiencies will help to improve the resiliency of the feeder and provide a more reliable option to tie into and back feed from other feeders in the surrounding area, thereby providing a more reliable service to customers served by this feeder.

Circuit: 14900

County	Substation	Customers Served	Number of Outages	Oct. 2019-Sept. 2020 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Harrison (38)	1,348	20	1.82	198	109	74%	26%	17.18	N

Feeder Map and Location:



Outage Data Summary (Past 3 years):

2018: (Oct 17-Sep 18) Eight percent (8%) of customer outages were due to three mainline events. Two mainline outages were caused by equipment failure, and one outage was caused by trees. Ninety-two percent (92%) of customer outages were caused by fused lateral events. Fourteen outages were caused by equipment failure; seven outages were caused by trees; four outages were caused by animals; four outages occurred due to an unknown cause; one outage occurred due to weather and one outage was caused by a cable cut.

2019: (Oct 18-Sep 19) Twenty two percent (22%) of customer outages were due to mainline outages. One hundred percent (100%) of mainline outages were caused by trees. Seventy-eight percent (78%) of customer outages were due to fused lateral events. Seven outage events were caused by equipment failure; seven events were caused by trees; four outages occurred due to an unknown cause; three outages were caused by animals; two outages were caused by foreign contact; one outage was caused by weather.

2020: (Oct 19-Sep 20) Thirteen percent (13%) of thirty customer outages were mainline events. Three outages were caused by equipment failure; one outage was caused by trees. Eighty seven percent (87%) of customer outages were due to fused lateral events. Eight outage events were caused by weather; six outages were caused by equipment failure; five outage events were caused by trees; three outages occurred due to an unknown cause; two outages occurred due to animals and two outages were caused by overload.

Feeder Performance (Oct 19-Sep 20)

Outage Cause by SAIFI	SAIFI	% of Feeder SAIFI
Equipment Failure	1.015	55%
Weather	0.477	26%
Tree	0.216	12%
Unknown	0.096	5%
Animal	0.030	1%
Load	0.020	1%

Field Observations:

Feeder 14900 serves approximately 1,348 customers in the Barnaby Woods and Hawthorne neighborhoods in NW Washington D.C., extending into the Chevy Chase neighborhood in Montgomery County, MD. A majority of the breaker zone for this feeder consists of newer construction, utilizing both PAC Cable and 4/0 ACSR Treewire, that has been implemented to address heavy vegetation concerns along the pole line. The lone area within the breaker zone that consists of older construction with copper wire is along Utah Ave NW, from Rittenhouse St NW to the tie switch just northwest of 31st Pl NW. The laterals on this feeder run to residential customers and have sufficient fused cutouts in place to attempt to minimize any interruptions that may be experienced along the many laterals.

Previous Actions Taken (Past 3 years):

DC Plug program has ongoing work to convert a portion of this feeder along Oregon Ave NW to underground, to remediate heavy tree canopy along this roadway.

Planned Remediation (Current Year):

Mainline:

Reconductor ~825' of copper wire with 477 ACSR Treewire along Utah Ave NW, from Rittenhouse St NW to tie switch.

Relocate cutouts to mainline poles where potential threats exist at current locations.

Address any animal, lightning, phase-to-phase, and phase-to-ground issues at large equipment locations.

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

Anticipated Benefits:

The reconductoring work will allow Feeder 14900 to reliably tie into and back feed from other feeders in the surrounding area, while also increasing resiliency against weather and any vegetation issues.

Ongoing DC Plug work will provide a large benefit to the overall reliability of the feeder as well. The other minor work on this feeder to address animal/BIL deficiencies will also help to improve the resiliency of the feeder, thereby providing a more reliable service to customers served by this feeder.

Circuit: 15197

County	Substation	Customers Served	Number of Outages	Oct. 2019-Sept. 2020 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Ft. Slocum (190)	1,300	11	1.79	174	96.6	65%	35%	12.16	N

Feeder Map and Location:

Outage Data Summary (Past 3 years):

2018: (Oct 17-Sep 18) Twenty six percent (26%) of customer outages were due to five mainline events. Two outages were caused by animals; one outage caused by equipment failure; one outage caused by weather and one outage occurred due to an unknown cause. Seventy four percent (74%) of outages were due to fused lateral events. Seven fused lateral events were caused by equipment failure; three outages were caused by animals; three outages were caused by trees and one outage occurred due to an unknown cause.

2019: (Oct 18-Sep 19) Forty-two percent (42%) of twenty-eight outages occurred on the mainline of the feeder. Nine outages were caused by equipment failure; one outage was caused by a motor vehicle; one outage was caused by a tree and one outage occurred due to an unknown cause. Fifty eight percent (58%) of outages were caused by fused lateral events. Seven outages were caused by equipment failure; three outages occurred due to an unknown cause; two outages were caused by trees; two outages were caused by motor vehicles; one outage was caused by animals and one outage was caused by an overload.

2020: (Oct 19-Sep 20) Forty percent (40%) of twenty customer outages were caused by mainline events. Five outages were caused by equipment failures and three outages were caused by an unknown cause. Sixty percent (60%) of customer outages were fused lateral events. Five outages were caused by animals; four outages were caused by equipment failures; one outage was caused by weather; one outage occurred due to an unknown cause and one outage was caused by an employee.

Feeder Performance (Oct 19-Sep 20)

Outage Cause by SAIFI	**SAIFI**	**% of Feeder SAIFI**
Equipment Failure	1.109	62%
Unknown	0.656	36%
Animal	0.035	2%
Weather	0.008	<1%
Other*	0.008	<1%

* Other Category Includes: Employee

Field Observations:

Feeder 15197 serves approximately 1,300 customers in the Crestwood, Petworth, and Sixteenth Street Heights neighborhoods in NW Washington D.C. The mainline portion of the feeder originates out of the

Ft Slocum Substation and runs a significant distance transitioning back and forth between underground cable and PAC cable, while the PAC cable opens up to create taps to tie switches and residential customers along the way. The western most portion of the feeder does open up to an open wire configuration, with tree wire in place to address vegetation concerns as it enters into and serves residential customers in the Crestwood neighborhood. The mainline is well protected from vegetation threats and existing fused cutouts provide sufficient protection to vulnerabilities along laterals.

Previous Actions Taken (Past 3 years):

No work performed within the last 3 years.

Planned Remediation (Current Year):

Mainline:

Address any animal, lightning, phase-to-phase, and phase-to-ground issues at large equipment locations.

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

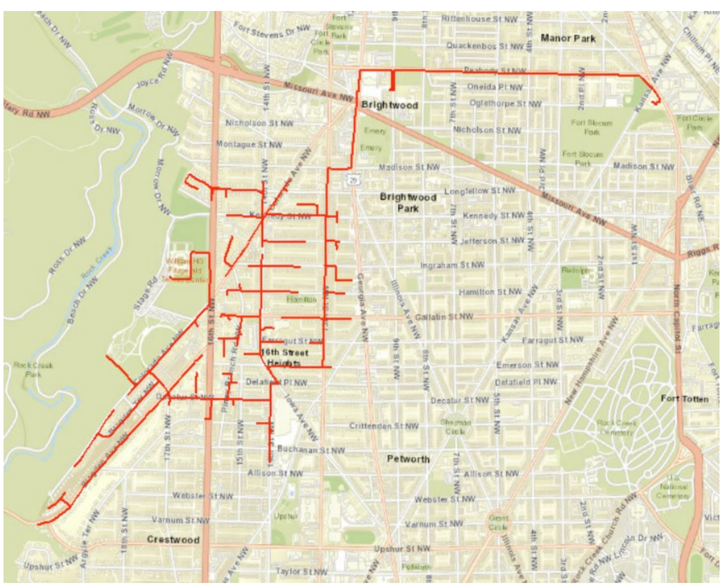
Anticipated Benefits:

The work on this feeder to address animal/BIL deficiencies will help to improve the resiliency of the feeder and provide a more reliably option to tie into and back feed from other feeders in the surrounding area, thereby providing a more reliable service to customers served by this feeder.

Circuit: 15001

County	Substation	Customers Served	Number of Outages	Oct. 2019-Sept. 2020 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Ft. Slocum (190)	1,341	24	1.59	130	81.8	76%	24%	9.62	N

Feeder Map and Location:



Outage Data Summary (Past 3 years):

2018: (Oct 17-Sep 18) One hundred percent (100%) of customer outages were fused lateral events on this feeder. Six outage events were caused by equipment failure; six outages were caused by trees; two outages were caused by weather; two outages were caused by motor vehicles; one outage was caused by animals and one outage was caused by an overload.

2019: (Oct 18-Sep 19) Forty five percent (45%) of customer outages were due to mainline events. Eight outage events were due to an isolated incident caused by trees and one outage was caused by animals. Fifty five percent (55%) of customer outages were due to lateral events. Five events were caused by equipment failures; two events occurred due to unknown causes; two events were caused by trees; one event was caused by animals and one outage was caused by a motor vehicle.

2020: (Oct 19-Sep 20) Ninety percent (90%) of thirty-two customer outages were lateral events. Ten outages were caused by equipment failure; six outages were scheduled outages; five outages were caused by trees; two outages were caused by animals; two outages were caused by motor vehicles; two outages were caused by load issues and two outages occurred due to an unknown cause. Ten percent (10%) of customer outages on this feeder were mainline events. Two outages were caused by animals and one outage occurred due to an unknown cause.

Feeder Performance (Oct 19-Sep 20)

Outage Cause by SAIFI	**SAIFI**	**% of Feeder SAIFI**
Equipment Failure	0.498	31%
Tree	0.349	22%
Scheduled	0.299	18%
Other*	0.297	18%
Unknown	0.149	11%

Field Observations:

Feeder 15001 serves approximately 1,341 customers in the Brightwood Park, Petworth, Sixteenth Street Heights, and Crestwood neighborhoods in NW Washington D.C. The mainline portion of this feeder originates out of the Ft Slocum Substation and runs west underground up to 13th St NW. The feeder transitions to overhead wire and runs south along 13th St NW, Emerson St NW, 14th St NW, and Decatur St NW serving a mix of residential and commercial customers along the entirety of the feeder. The mainline along 13th St NW is a mix of newer construction with 477 ACSR Treewire and older construction with copper wire, while the remainder of the mainline has been hardened with 4/0 ACSR Treewire to help remediate vegetation threats along the pole line.

Previous Actions Taken (Past 3 years):

No work performed within the last 3 years.

Planned Remediation (Current Year):

Mainline:

Reconductor ~2,300' of copper wire along 13th St NW from Kennedy St NW to Emerson St NW with 477 ACSR Treewire

Replace damaged or aged crossarms and poles throughout the mainline portion of the feeder.

Address any animal, lightning, phase-to-phase, and phase-to-ground issues at large equipment locations.

Milestones/Schedule:

Work on this feeder will require approximately 3 months to be completed.

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments				

Completed Remediation Work: N/A

Anticipated Benefits:

The reconductoring work on Feeder 15001 will address the remaining weak points along the mainline on this feeder, while also increasing resiliency against weather and any vegetation issues. The other minor work on this feeder to address animal/BIL deficiencies will also help to improve the resiliency of the feeder, thereby providing a more reliable service to customers served by this feeder.

Circuit: 14023

County	Substation	Customers Served	Number of Outages	Oct. 2019-Sept. 2020 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	12th & Irving (133)	529	17	3.43	480	139.9	39%	61%	5.78	Y

Feeder Map and Location:

Outage Data Summary (Past 3 years):

2018: (Oct 17-Sep 18) Sixty six percent (66%) of customer outages were due to eight mainline events. Three outages were caused by weather; three outages were caused by trees; one outage occurred due to an unknown cause and one outage occurred due to a cable cut. Thirty three percent (33%) of customer outages were caused by fused lateral events. Two outages were caused by animals; one outage was caused by an equipment failure and one outage was caused by trees.

2019: (Oct 18-Sep 19) Fifty percent (50%) of ten customer outages on this feeder were caused by mainline events. Three outage events were caused by weather and two outages were caused by equipment failures. The five lateral events on this feeder which made up fifty percent (50%) of outages were caused by two equipment failures; two tree incidents and one outage occurred with an unknown cause.

2020: (Oct 19-Sep 20) Thirty four percent (34%) of twenty-three customer outages were mainline events. Five mainline outage events were caused by equipment failures and three outage events were caused by weather. Sixty six percent (66%) of the twenty-three customer outages were fused lateral events. Five outage events were caused by animals; five outage events were caused by weather; four outages were caused by equipment failure and one outage was caused by an overload.

Feeder Performance (Oct 19-Sep 20)

Outage Cause by SAIFI	**SAIFI**	**% of Feeder SAIFI**
Equipment Failure	2.011	58%
Weather	1.368	40%
Animal	0..055	2%
Other*	0.149	<1%

*Other Category Includes: Load

<u>Field Observations:</u>

Feeder 14023 serves approximately 529 customers in the Brentwood, Brookland, and Eckington neighborhoods in NE Washington D.C. The mainline portion of the feeder originates out of the 12th & Irving Substation and runs along 10th St NE, Rhode Island Ave NE, 12th St NE and Brentwood Rd NE servicing mostly industrial and commercial customers, with some residential customers as well. The early portion of this feeder running along 10th St NE and Rhode Island Ave NE is a mix of old and new construction with existing copper wire still in place and has experienced a variety of issues that have led to outages. The remainder of the mainline is a mix of construction with 4/0 ACSR Bare wire in place along 12th St NE and Brentwood Rd NE.

<u>Previous Actions Taken (Past 3 years)</u>:

2019 – Reconductor six spans of mainline with Treewire along Brentwood Rd NE at 12th St NE

<u>Planned Remediation (Current Year):</u>

Mainline:

Reconductor 1,500' of 1/0 Copper Primary with 477 ACSR Tree Wire in Breaker Zone along 10th St NE and Rhode Island Ave NE.

Replace aged crossarms in Breaker Zone along Brentwood Rd NE.

Install Phase Spacers at midspan for spans that have excessive slack in the 2nd zone along Brentwood Rd NE.

Address any animal, lightning, phase-to-phase, and phase-to-ground issues at large equipment locations.

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	TBD	TBD
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

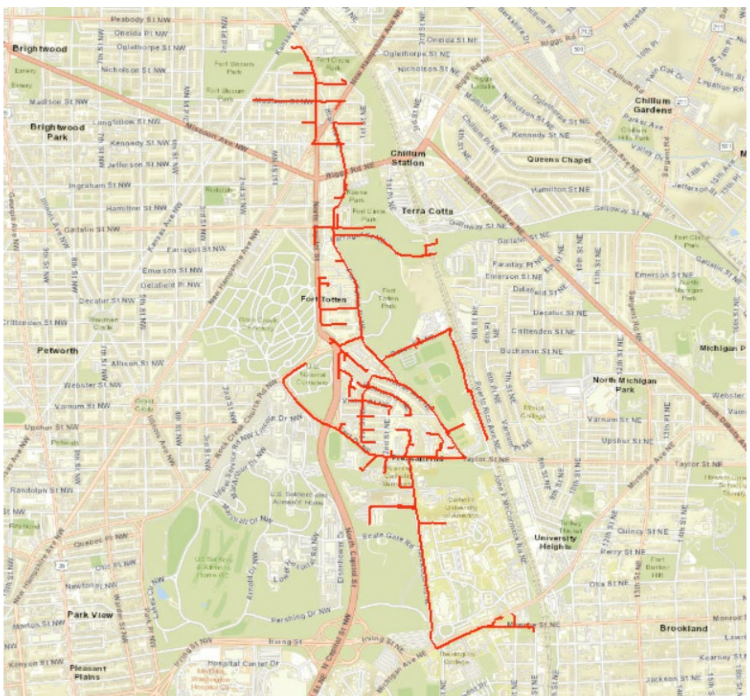
Anticipated Benefits:

The reconductoring work on Feeder 14023 will address the area at the beginning of the feeder that has experienced frequent issues that have resulted in outages to the entire feeder. Reconductoring portions of this feeder will also allow to reliably tie into and back feed from other feeders in the surrounding area, while also increasing resiliency against weather and any vegetation issues. Phase spacers along Brentwood Rd NE will increase resiliency of the feeder during high wind weather events.

Circuit: 15013

County	Substation	Customers Served	Number of Outages	Oct. 2019-Sept. 2020 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Ft Slocum (190)	1,824	43	1.20	61	50.7	75%	25%	10.12	Y

Feeder Map and Location



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Outage Data Summary (Past 3 years):

2018: (Oct 17-Sep 18) Twenty one percent (21%) of nineteen customer outages on this feeder were mainline events. Three outages were caused by weather and one event was caused by trees. Seventy nine percent (79%) of nineteen customer outages were due to fused lateral events. Eight outage events were caused by equipment failure; three outages were caused by weather; one outage was caused by vandalism; one outage was caused by an overload; one outage occurred due to an unknown cause and one outage was caused by trees.

2019: (Oct 18-Sep 19) Thirty five percent (35%) of fourteen customer outages were mainline events. Four outages were caused by one weather event, and one outage was caused by an equipment failure. Sixty five percent (65%) of fourteen customer outages on this feeder were lateral outages. Four lateral outages were caused by equipment failures; three outages were caused by animals; one outage was caused by a motor vehicle and one outage was caused by trees.

2020: (Oct 19-Sep 20) Six percent (6%) of forty-six customer outages on this feeder were mainline outage events. One outage was caused by an overload, one outage was caused by trees, and one outage was caused by animals. Ninety-four percent (94%) of the forty-six outages on this feeder were lateral events. Thirty-four outage events were caused by equipment failures, seventy six percent (76%) of which were due to a localized incident of a downed wire. Five outages were attributed to trees; two outages were caused by motor vehicles; one outage was caused by vandalism and one outage was caused by an overload.

Feeder Performance (Oct 19-Sep 20)

Outage Cause by SAIFI	SAIFI	% of Feeder SAIFI
Equipment Failure	1.002	83%
Load	0.075	6%
Tree	0.077	6%
Animal	0.040	3%
Other*	0.020	2%

*Other Category Includes: Motor Vehicle, Vandalism

Field Observations:

Feeder 15013 originates from the Fort Slocum substation in northwest Washington, DC, and serves approximately 1,824 customers. The feeder is 75% overhead and 25% underground and provides power to both residential and commercial customers. The mainline emerges from the substation along Blair Rd NW where the feeder runs south, continuing to North Capitol St NW The mainline trunk continues to the south until Kennedy St NE where it runs east, then heads to the southeast along Blair Rd NE. The mainline trunk of the feeder continues in this manner along Rock Creek Church Rd NE until the mainline trunk branches off onto Farragut St NE where the feeder ends at a riser pole. In the other direction, the line continues to the south along Fort Totten Dr NE with several lateral branches off the main trunk around Bates Rd NE, Allison St NE, and Hawaii Ave NE. The feeder continues down Fort Totten Dr NE until Taylor St NE, where the feeder then turns to the west and runs along Fort Dr NE up to Rock Creed Church Rd NW. The feeder also branches off of Taylor St NE along Harewood Rd NE to the south until turning to the east along Michigan Ave NE and ending underground in the vicinity of Michigan Ave NE and Monroe St NE.

Previous Actions Taken (Past 3 years):

No work performed within last 3 years.

Planned Remediation (Current Year):

Mainline:

Reconductor ~2,900' of primary conductor in the breaker zone to address areas of undersized conductors as well as bare conductor.

Additional work includes crossarms, fused cut-outs, lightning arrestors, animal guards, down-guys, head-guys, anchors and fault indicators.

Milestones/Schedule:

Work on this feeder will require approximately 3 months to be completed.

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A

Actual	N/A	N/A	N/A	N/A
Variance Comments				

Completed Remediation Work: N/A

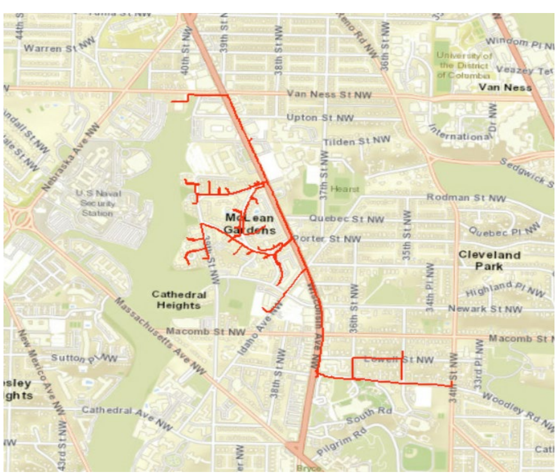
Anticipated Benefits:

Reconductoring in the breaker zone will help to harden areas that have shown vulnerability in the past and will help prevent as many future breaker events as possible. The minor work being performed as part of the priority feeder program will further improve the feeder performance and animal/BIL deficiencies, thereby providing added resiliency and more reliable service to the customers served by this feeder.

Circuit: 14150

County	Substation	Customers Served	Number of Outages	Oct. 2019-Sept. 2020 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Van Ness (129)	874	10	2.05[4]	224	109.2	13%	87%	4.37	N

Feeder Map and Location:



Outage Data Summary (Past 3 years):

2018: (Oct 17-Sep 18) There were 0 mainline events. One hundred percent (100%) of the twelve outages were caused by lateral outages. Six outages were caused by equipment failures; five outages occurred due to unknown causes; one outage was caused by vandalism.

2019: (Oct 18-Sep 19) Sixteen percent (16%) of eighteen outages on this feeder were mainline events. Two outages occurred due to an unknown cause and one outage was caused by an equipment failure. Eighty four percent (84%) of eighteen outages were lateral events. The outages were caused exclusively by two transformer events, resulting in the sole outage cause of equipment failure.

2020: (Oct 19-Sep 20) Thirty six percent (36%) of eleven customer outages on the feeder were mainline events. Two outages were caused by equipment failures; one outage was caused by animals and one outage was caused by an employee. Sixty four percent (64%) of eleven customer outages were lateral outages. All seven lateral outages were the result of an equipment failure during one localized event.

Feeder Performance (Oct 19-Sep 20)

Outage Cause by SAIFI	**SAIFI**	**% of Feeder SAIFI**
Employee	0.937	45%
Animal	0.924	45%
Equipment Failure	0.192	10%

Field Observations:

Feeder 14150 serves approximately 874 customers in Northwest Washington D.C. Originating from the Van Ness Substation; this circuit is 13% overhead and 87% underground. The mainline provides both residential and commercial service. In the small section with overhead there is insulated primary conductor with crossarm construction on poles in good condition.

Previous Actions Taken (Past 3 years):

No work performed within the last 3 years.

Planned Remediation (Current Year):

Mainline:

Installing fuses at unfused laterals to provide mainline protection from faults downstream and further sectionalize the feeder. Additional work includes crossarms, fused cut-outs, lightning arrestors, animal guards, down-guys, head-guys, anchors and fault indicators.

Milestones/Schedule:

Work on this feeder will require approximately 3 months to be completed.

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments				

Completed Remediation Work: N/A

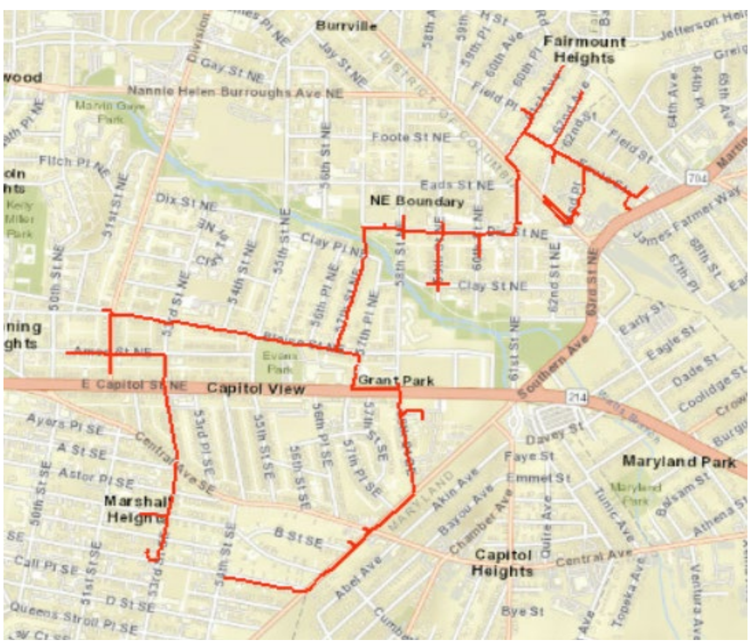
Anticipated Benefits:

The minor work being performed as part of the priority feeder program will further improve the feeder performance and animal/BIL deficiencies, thereby providing added resiliency and more reliable service to the customers served by this feeder.

Circuit: 00372

County	Substation	Customers Served	Number of Outages	Oct. 2019-Sept. 2020 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Seat Pleasant (30)	756	26	2.292	189	82.8	98%	2%	4.40	N

Feeder Map and Location:



Outage Data Summary (Past 3 years):

2018: (Oct 17-Sep 18) Twenty two percent (22%) of nine customer outages were due to mainline outage events. One outage event was due to trees, and one outage event occurred due to an unknown cause. Seventy eight percent (78%) of nine customer outages were due to lateral outages. Five outages were caused by equipment failure and two outages were due to foreign contact.

2019: (Oct 18-Sep 19) There were 0 mainline events on this feeder. One hundred percent (100%) of the six outage events on this feeder were lateral outages. Three outages were caused by equipment failure; one outage was caused by a motor vehicle; one outage event was caused by a tree and one outage event occurred due to trees.

2020: (Oct 19-Sep 20) Eighteen percent (18%) of the twenty-seven customer outages on this feeder were mainline events. Two outages were caused by motor vehicles; one outage was caused by equipment failure; one outage was caused by fire and one outage occurred due to an unknown cause. The lateral outage events attributed to eighty two percent (82%) of the outages on this feeder. Seventeen outages were caused by trees, exclusively caused by two isolated events. There were four outages caused by equipment failure and one outage caused by an employee.

Feeder Performance (Oct 19-Sep 20)

Outage Cause by SAIFI	SAIFI	% of Feeder SAIFI
Source Lost	1.002	44%
Fire	1.002	44%
Tree	0.232	10%
Motor Vehicle	0.011	<1%
Other*	0.039	<1%

*Other Category Includes: Equipment Failure, Employee

Field Observations:

Feeder 00372 serves approximately 756 customers in Northeast Washington D.C. Originating from the Seat Pleasant Substation; most of this circuit consists of overhead construction (98% overhead and 2% underground). The mainline provides both residential and commercial service. The mainline emerges from the substation on 59th St SE and heads north. The feeder then continues on Blaine St NE to the east, following to the south on 58th St SE and ending along Southern Ave. To the north of Blaine St NE, the feeder runs along 57th St NE. The mainline of the feeder then heads to the east along Dix St NE, proceeding until 61st St NE, then runs north along 61st St NE. The end of the feeder extends into Prince George's County, Maryland where it branches off and ends on Foote St and 61st Ave. The devices, poles, and conductor on this feeder are generally in good condition, however there are a couple of areas that have older poles and conductors.

Previous Actions Taken (Past 3 years):

This feeder was upgraded under the 2020 Comprehensive Feeder Program where wires, poles and equipment were upgraded to improve performance.

Planned Remediation (Current Year):

Mainline:

No work is being performed on this feeder.

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

Anticipated Benefits:

No work is being performed on this feeder under the Priority Feeder program.

Circuit: 15166

County	Substation	Customers Served	Number of Outages	Oct. 2019-Sept. 2020 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Alabama Ave (136)	1,251	11	1.31[7]	75	57.2	72%	28%	10.64	N

Feeder Map and Location:

Outage Data Summary (Past 3 years):

2018: (Oct 17-Sep 18) One hundred percent (100%) of thirteen customer outages on this feeder were lateral events. Five outage events were caused by equipment failure; four outages were caused by animals; two outages were caused by trees; one outage was caused by an employee and one outage occurred due to an unknown cause.

2019: (Oct 18-Sep 19) One hundred percent (100%) of five customer outages were fused lateral events. Three events were caused by equipment failure; one event was caused by a load issue and one outage event occurred due to an unknown cause.

2020: (Oct 19-Sep 20) Seventy four percent (74%) of eleven customer outages on this feeder were mainline events. Six outage events were caused by equipment failure and one outage on the mainline occurred due to vandalism. Thirty six percent (36%) of customer outages were fused lateral events. Three outages were caused by foreign contact and one outage was caused by equipment failure.

Feeder Performance (Oct 19-Sep 20)

Outage Cause by SAIFI	SAIFI	% of Feeder SAIFI
Foreign Contact	1.134	85%
Equipment Failure	0.182	14%
Vandalism	0.001	1%

Field Observations:

Feeder 15166 serves approximately 1,251 customers in southeast Washington D.C. Originating from the Alabama Ave Substation; this circuit provides service to both commercial and residential customers. This feeder is largely overhead (72% overhead and 28% underground), and emerges from the substation along Mississippi Ave SE near the intersection of 15th St SE. The mainline of the feeder takes off to the west along Mississippi Ave SE and branches off both north and south along 13th St SE as well as providing coverage to the north of Mississippi Ave NE along 6th St SE. Overall the condition of the poles, conductors, and equipment along this feeder are good and the areas that contain vegetation are well mitigated.

Previous Actions Taken (Past 3 years):

No previous actions have been taken on this feeder in the past three years.

Planned Remediation (Current Year):

Mainline:

Reconductor approximately 1,300’ of primary wire in the breaker zone and install fuses at unfused laterals.

Mainline work includes crossarms, fused cut-outs, lightning arrestors, animal guards, down-guys, head-guys, anchors and fault indicators.

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation: N/A

Anticipated Benefits:

The reconductoring work taking place on this feeder will improve the capacity of the conductor in the breaker zone of the feeder and will also provide covered conductors to mitigate issues with phase contact and tree issues. The minor work being performed as part of the priority feeder program will further improve the feeder performance and animal/BIL deficiencies, thereby providing added resiliency and more reliable service to the customers served by this feeder.

Circuit: 14766

County	Substation	Customers Served	Number of Outages	Oct. 2019-Sept. 2020 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Little Falls (77)	599	12	1.69[1]	81	48	30%	70%	9.67	N

Feeder Map and Location:

Outage Data Summary (Past 3 years):

2018: (Oct 17-Sep 18) One hundred percent (100%) of twenty-two customer outages on this feeder were lateral events. Thirteen outages were caused by equipment failure; three outages were caused by weather; two outages were caused by an employee; one outage was caused by animals; one outage occurred due to a load issue; one outage was caused by voltage and one outage was caused by trees.

2019: (Oct 18-Sep 19) Sixty six percent (66%) of nine customer outages were mainline outage events. Three outages were caused by animals and three outages were caused by equipment failure. Thirty three percent (33%) of customer outages were caused by lateral events. Two lateral outages occurred due to animals and one outage event occurred due to equipment failure.

2020: (Oct 19Sep 20) Forty one percent (41%) of twelve customer outages were mainline outage events. All five outages were caused by animals and are all part of one localized outage issue. Fifty nine percent

(59%) of customer outages were lateral events. Three outages were caused by animals; two outages were caused by trees; one outage was caused by equipment failure and one outage occurred due to an unknown cause.

Feeder Performance (Oct 19Sep 20)

Outage Cause by SAIFI	SAIFI	% of Feeder SAIFI
Animal	1.666	98%
Equipment Failure	0.017	1%
Tree	0.006	<1%
Unknown	0.002	<1%

Field Observations:

Feeder 14766 serves approximately 599 customers in northwest Washington D.C. Originating from the Little Falls Substation, most of this circuit consists of underground construction (30% underground, and 70% overhead). The Breaker Zone is almost entirely underground, rising up at the intersection of Fordham Rd NW and Tilden St NW then branching off to the north along Fordham Rd NW and running east along Upton St NW. The feeder also branches off through the mainline to several side streets. There is a large URD loop at the northwest end of the feeder. The feeder has consistent vegetation throughout the mainline, however the tree cover and undergrowth is not a substantial cause of issues on this circuit.

Previous Actions Taken (Past 3 years):

No work has taken place on this feeder in the previous three years.

Planned Remediation (Current Year):

Mainline:

Reconductor approximately 550’ of primary wire with covered treewire in the Breaker Zone and along 46th St NW.

Mainline work includes crossarms, fused cut-outs, lightning arrestors, animal guards, down-guys, head-guys, anchors and fault indicators.

Milestones/Schedule:

Work on this feeder will require approximately 3 months to be completed.

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments				

Completed Remediation Work: N/A

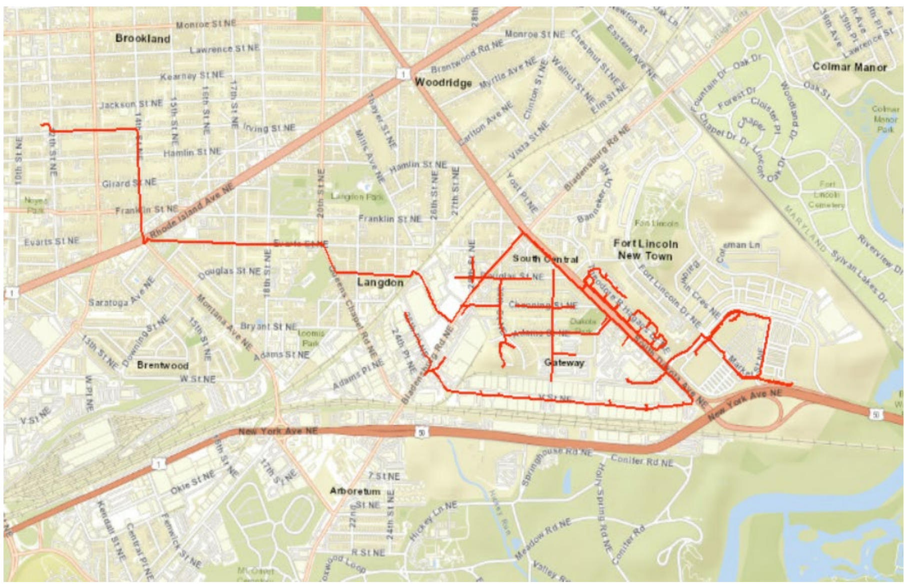
Anticipated Benefits:

Reconductoring the breaker zone portion of the feeder where copper primary wire exists will mitigate weak areas of the feeder and prevent issues with inadequate conductor size from causing issues on this feeder in the future. The minor work being performed as part of the priority feeder program will further improve the feeder performance and animal/BIL deficiencies, thereby providing added resiliency and more reliable service to the customers served by this feeder.

Circuit: 14005

County	Substation	Customers Served	Number of Outages	Oct. 2019-Sept. 2020 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	12th & Irving (133)	472	10	1.379	191	138.7	39%	61%	8.75	N

Feeder Map and Location:



Outage Data Summary (Past 3 years):

2018: (Oct 17-Sep 18) One hundred percent (100%) of three customer outages on this feeder were lateral events. One event was caused by a motor vehicle; one event was caused by equipment failure; and one event was caused by trees.

2019: (Oct 18-Sep 19) Thirty three percent (33%) of three customer outages were mainline outage events. The only mainline outage on the feeder for this year was caused by a motor vehicle. Sixty six percent (66%) of customer outages were lateral events, and both of these outages were caused by equipment failure.

2020: (Oct 19-Sep 20) Seventy three percent (73%) of fifteen customer outages were mainline events. Seven outages were caused by trees and four mainline outages were caused by motor vehicles. Twenty seven percent (27%) of customer outages on this feeder were fused lateral events. Two outages were caused by equipment failure; one outage was caused by a load issue and one outage was caused by trees.

Feeder Performance (Oct 19-Sep 20)

Outage Cause by SAIFI	**SAIFI**	**% of Feeder SAIFI**
Tree	1.235	89%
Motor Vehicle	0.139	10%
Equipment Failure	0.031	1%
Other*	0.002	<1%

*Other Category Includes: Load

<u>Field Observations:</u>

Feeder 14005 serves approximately 472 customers in northeast Washington D.C. Originating from the 12th & Irving substation, most of this circuit consists of underground construction (39% overhead, 61% underground). The breaker zone is almost entirely underground, rising near the intersection of Bladensburg Rd NE and Channing St NE. The mainline of the feeder splits off at 30th St NE and runs north-south from Douglas St NE to Adams St NE. The mainline of the feeder runs east along Adams St NE until it intersects with South Dakota Ave NE. The last portion of the feeder runs along South Dakota Ave NE with overhead along the mainline and URD loops spurring from it. The equipment and poles on this circuit are in condition throughout, however there are some areas of vulnerability due to conductor size and insulation and equipment protection.

Previous Actions Taken (Past 3 years):

No work is performed within the last 3 years.

Planned Remediation (Current Year):

Mainline:

Reconductor approximately 4,700' of primary wire with covered treewire along Adams St and along South Dakota Ave.

Mainline work includes crossarms, fused cut-outs, lightning arrestors, animal guards, down-guys, head-guys, and anchors.

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

Anticipated Benefits:

Reconductoring the undersized primary wire on this feeder will mitigate weak areas of the feeder and prevent issues with inadequate conductor size from causing issues on this feeder in the future. The minor work being performed as part of the priority feeder program will further improve the feeder performance and animal/BIL deficiencies, thereby providing added resiliency and more reliable service to the customers served by this feeder.

Circuit: 14133

County	Substation	Customers Served	Number of Outages	Oct. 2019-Sept. 2020 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Van Ness (129)	322	21	1.86[6]	203	108.9	59%	41%	7.23	N

Feeder Map and Location:

Outage Data Summary (Past 3 years):

2018: (Oct 17-Sep 18) Seventy four percent (74%) of twenty-three customer outages on this feeder were lateral events. Eight outages were caused by trees; four outages were caused by equipment failures; two outages were caused by animals; two outages were caused by weather and one outage event occurred due to an unknown cause. Twenty six percent (26%) of outages were mainline events. Three outages were caused by trees; two outages were caused by equipment failure and one outage event was caused by weather.

2019: (Oct 18-Sep 19) Sixty percent (60%) of fifteen customer outages were lateral outage events. Five outages were caused by trees; two outages were caused by weather; one outage was caused by animals and one outage was caused by equipment failure. Forty percent (40%) of customer outages were mainline events. All six mainline events were caused by trees.

2020: (Oct 19-Sep 20) Eighty six percent (86%) of twenty-three customer outages on this feeder were lateral events. Fifteen outages were caused by trees and five outages were caused by animals. Fourteen percent (14%) of customer outages were mainline outage events. Two outages were caused by animals and one outage event was caused by trees.

Feeder Performance (Oct 19-Sep 20)

Outage Cause by SAIFI	SAIFI	% of Feeder SAIFI
Animal	1.040	55%
Tree	0.826	45%

Field Observations:

Feeder 14133 serves approximately 322 customers in northwest Washington D.C. Originating from the Van Ness substation, most of this circuit consists of overhead construction (59% underground, and 41% overhead). The breaker zone is almost entirely underground, rising up approximately ten spans prior to the first recloser. The mainline emerges along Ablemarle St NW and heads directly east, then branches off to the north and runs along Linnean Ave NW. The mainline of the feeder also continues along Ablemarle St NW until the mainline ends shortly before Broadbranch Rd NW. This feeder is challenged by consistent tree outages along Broadbranch Rd NW, and the poles, devices, and conductors on the mainline of this circuit are in good condition.

Previous Actions Taken (Past 3 years):

No work is performed within the 3 years.

Planned Remediation (Current Year):

Mainline:

The mainline of this feeder will undergo a reconductoring upgrade to replace 1/0 Copper wire with 477 ACSR Treewire along Linnean Ave NW. Additionally, the feeder will be assessed for minor protection issues and will have lightning and animal protection improvements, as necessary. As a project separate from the 2021 Priority Feeder program, this feeder will be undergoing improvements along the lateral line on Broadbranch Rd NW. The existing conductor will be replaced with single phase spacer cable in order to mitigate tree risks.

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

Anticipated Benefits:

The performance of this feeder was driven by animal and tree issues. The proposed work to replace and upgrade these conductors, poles, and equipment will improve performance for customers fed by this feeder.

Review of 2019 Priority Feeder Program (Least Reliable Feeders)

Activities conducted to improve the performance of each of the feeders in the 2019 Priority Feeder Program are identified in Table 2.4-A

Table 2.4-A

2019 2% Priority Feeder Program - District of Columbia -Completed Corrective Actions							
Rank	Feeder ID	Substation	Category		SPC Value	Completion Time	Corrective Actions
			OH	UG			
	14014	12th Irving (133)	92%	8%	0.01621	N/A	•Feeder improvements being made separately under the 12th & Irving Area Reliability Improvement Plan
	14023	12th Irving (133)	43%	57%	0.00629	2nd Quarter 2019	•Install/Replace 525' of Primary Wire with Treewire •Install/Replace 525' of existing neutral with Triplex •Install/Replace 1 gang switch •Install/Replace 1 pole •Miscellaneous upgrades such as animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.
	14093	12th Irving (133)	78%	22%	0.01131	N/A	• No work was perfomred
	14132	Van Ness (129)	48%	52%	0.01022	2nd Quarter 2019	•Removal of Gang Switch •Install fused cutouts •Miscellaneous upgrades such as animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.
	14717	Benning (007)	87%	13%	0.04806	N/A	• Feeder improvements being made separately under the Benning Area Reliability Improvement Plan
	14786	New Jersey (161)	0%	100%	0.02308	N/A	• Feeder improvements being made separately under the New Jersey Area Reliability Improvement Plan
	14900	Harrison (038)	74%	26%	0.01314	N/A	• Underground cable upgrade performed outside of Priority Feeder program
	15003	Ft Stocum (190)	94%	6%	0.03066	N/A	• Feeder improvements made prior to 2019 Priority Feeder program due to major outage events
	15013	Ft Stocum (190)	75%	25%	0.02485	2nd Quarter 2019	• Install/Replace 560' of Primary wire with Treewire •Replace 1 Gang Switch •Replace 2 Poles •Replace 1 Transformer • Miscellaneous upgrades such as animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.
	15172	Alabama Ave (136)	82%	18%	0.01729	2nd Quarter 2019	• Install/Replace 2 fused cutouts • Miscellaneous upgrades such as animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.
	15176	Alabama Ave (136)	65%	35%	0.02059	2nd Quarter 2019	• Install/Replace 2980' of Primary wire with Treewire • Install/Replace 2670' of Secondary Wire with Tiplex • Replace 1 Pole • Miscellaneous upgrades such as animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.
	15177	Alabama Ave (136)	83%	17%	0.02023	2nd Quarter 2019	•Install/Replace 370' of Primary Wire with tree wire •Miscellaneous upgrades such as animal guards, lightning arrestors, crossarms, missing grounds, uninsulated down guys, etc.
	15764	Florida Ave (010)	0%	100%	0.03232	N/A	• No work was perfomred
	15197	Ft Stocum (190)	65%	35%	0.02302	2nd Quarter 2019	•Replace Gang Switch Drops •Miscellaneous upgrades such as animal guards, lightning arrestors, crossarms, etc
	16000	Waterfront (223)	84%	16%	0.01190	N/A	• Feeder is part of Waterfront project and is being addressed separately
	16001	Waterfront (223)	85%	15%	0.01080	N/A	• Feeder is part of Waterfront project and is being addressed separately

Aggressive Correction Action Program[45]

Annual Program for Repeat Priority Feeders

The review of the 16 feeders selected for the 2% Priority Feeder initiative with previous year selections show that three feeders (15021 and 15094) which were in the 2019 Priority Feeder Program reappeared on the 2021 Priority Feeder Program. When a feeder repeats, additional aggressive corrective actions are implemented. All of the corrective actions listed in Section 2.4.1.2 will be completed in 2021.

2.4.1 RELIABILITY STATISTICS*

<u>**Service Reliability Indices**</u>

SAIDI, SAIFI, and CAIDI are the specific indices used and provide information about both the duration and frequency of outages for customers. These indices are described as follows:

SAIDI - System Average Interruption Duration Index. Designed to provide information about the average time (in aggregate) that the customers served in a predefined area are interrupted.

SAIFI - System Average Interruption Frequency Index. Designed to give information about the average frequency of sustained interruptions per customer served in a predefined area.

CAIDI - Customer Average Interruption Duration Index. Designed to provide information about the average time required to restore service to the average customer experiencing a sustained interruption.

Each index is calculated several times; once with all outage data and then according to the specific significant event exclusions specified. The expectation is that the indices calculated with significant event related outage data excluded will provide a reflection of system performance under normal operating conditions. The indices calculated with all outage data will provide a

[45] In Order No. 15152 issued on Pepco's 2008 Consolidated Report, the Commission stated (at paragraph 72):

72. PEPCO is DIRECTED, beginning with the 2009 Consolidated Report, to identify the feeders that are part of the separate annual program of corrective actions for reappearing least reliable feeders, describe the corrective actions planned for each feeder and the projected dates for completion of the corrective actions and explain whether the corrective actions improved the performance of these feeders consistent with paragraph 59 of this Order.

reflection of the impact of significant events on the system. It is important to note that a year-to-year comparison of reliability indices calculated with all outage data would not be appropriate. The indices during a year in which major storms or events impact an electric utility will be substantially different from the indices during a year in which no such issues arise.

Service Outage Statistics [46][47]

The 2020 year-end actuals for SAIFI and SAIDI were 0.40 and 44 respectively.

Presented in Table 2.4-B1-B2 are the SAIDI, SAIFI and CAIDI values for the past five years at IEEE- 2.5 Beta Criteria. These reliability indices are provided for all sustained interruptions and all sustained interruptions excluding major events. A sustained interruption is defined as an

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[46] In Order No. 16623 paragraphs 48, 62 and 63, the Commission stated the following:
48. …Therefore, we hereby require that Pepco include reliability calculations using District of Columbia-only data and relying on a Major Service Outage exclusion in the 2012 Consolidated Report and in future Consolidated Reports. We also require that Pepco include in its 2012 Consolidated Report a revised version of its reliability calculations from the 2010 and 2011 Consolidated Reports using D.C.-only data and excluding Major Service Outages. Pepco shall also include calculations of reliability indices for the entire Pepco system using system-wide data and Major Event Day exclusions, as well as reliability indices for Pepco D.C. using D.C.- only MEDs in the 2012 Consolidated Report and in future Consolidated Reports, so that we may make comparisons. For purposes of this requirement, the "reliability calculations" contained in the Consolidated Report include all calculations of SAIDI, SAIFI and CAIDI, discussion of failure rate data, and selection of Priority Feeders. (Footnote: Because the Aggressive Corrective Action Program requires the identification of feeders that have been listed as Priority Feeders in the past using system-wide, MED-excluding data, we will allow Pepco to continue to select ACAP feeders using that data. However, we require that a list of Priority Feeders using the new method of calculation be included in the 2012 Consolidated Report.)
62. Pepco is DIRECTED to include in the 2012 Consolidated Report reliability calculations using District of Columbia-only data and excluding Major Service Outages consistent with paragraph 48;
63. Pepco is DIRECTED to include in the 2012 Consolidated Report a revised version of the reliability calculations contained in the 2010 and 2011 Consolidated Report using District of Columbia-only data and excluding Major Service Outages consistent with paragraph 48

[47] In Order No. 16700 issued February 12, 2012, paragraphs 10 and 11, the Commission stated:
10. In establishing out new reliability performance standards, we decided that Pepco should be given a reasonable amount of time to "ramp up" to our new requirements. Therefore, we made the new SAIDI and SAIFI standards effective beginning in 2013. By replacing the prior rule with a new one, and giving Pepco a transition period, we created a "gap" in reliability measures. We saw no harm in a temporary suspension of reliability benchmarks, recognizing that the standards in effect for 2013 through 2020 would require significant improvement on Pepco's part, starting at once. For example, in order to meet our 2013 SAIDI target, Pepco must make either about a 9% improvement in both 2012 and 2013 or about an 18% improvement in 2013. Therefore, we saw no risk that Pepco would suffer a significant "backslide" in reliability because there were no effective standards in place for 2011 or 2012.
11. We do not believe that reestablishment (for the years 2011 and 2012) of the standards to which Pepco was previously held is necessary. (Footnote: We note that not all states have Electric Quality of Service Standards. For example, Pepco presently operates in Maryland without standards but is required to provide annual reliability indices pursuant to COMAR 20.50.07.06.) Nor has Pepco provided any reason for that reestablishment. Consequently, we decline to make the clarification that Pepco requests. However, we do expect that Pepco will continue to report on its reliability performance in its annual Consolidated Report and we concur with OPC in its suggestion that Pepco coordinate its data reporting so that Pepco calculations are a consistent "apples to apples" comparison from 2011 through 2013 and beyond. Therefore, as OPC has requested, we require Pepco to include in its annual report a description of its performance and a calculation of whether it would have met the appropriate SAIFI, SAIDI and CAIDI standards had they been in effect.
14. Pepco shall include in its 2012 and 2013 annual Consolidated Reports calculations of SAIDI, SAIFI, and CAIDI as described in paragraph 11.

interruption of five (5) minutes or greater. Table 2.4-B1 shows performance indices including and excluding PEPCO major event days. Table 2.4-B2 shows performance indices including and excluding District of Columbia major event days only.

Table 2.4-B1

Pepco System Indices 2016-2020 2.5 Beta (MED Exclusive - IEEE 1366-2012 Std, Pepco System Wide Based)					
SAIFI	**2016**	**2017**	**2018**	**2019**	**2020**
Sustained Outages	0.98	0.68	0.90	0.73	0.58
Sustained Less Major Storms	0.98	0.68	0.71	0.65	0.54
SAIDI (HOURS)	**2016**	**2017**	**2018**	**2019**	**2020**
Sustained Outages	1.81	1.03	2.70	1.22	0.92
Sustained Less Major Storms	1.81	1.03	0.98	0.97	0.78
CAIDI (HOURS)	**2016**	**2017**	**2018**	**2019**	**2020**
Sustained Outages	1.85	1.52	3.02	1.67	1.59
Sustained Less Major Storms	1.85	1.52	1.37	1.49	1.45

Table 2.4-B2

District of Columbia System Indices 2016-2020 2.5 Beta (MED Exclusive - IEEE 1366-2012 Std, District of Columbia System Wide Based)					
SAIFI	**2016**	**2017**	**2018**	**2019**	**2020**
Sustained Outages	0.82	0.55	0.64	0.59	0.40
Sustained Less Major Storms	0.82	0.55	0.54	0.49	0.37
SAIDI (HOURS)	**2016**	**2017**	**2018**	**2019**	**2020**
Sustained Outages	1.92	0.96	1.82	1.29	0.73
Sustained Less Major Storms	1.92	0.96	0.88	0.92	0.65
CAIDI (HOURS)	**2016**	**2017**	**2018**	**2019**	**2020**
Sustained Outages	2.35	1.73	2.83	2.20	1.81
Sustained Less Major Storms	2.35	1.73	1.64	1.86	1.74

Presented in Table 2.4-B3-B4 are the SAIFI, SAIDI and CAIDI values for the past five years at IEEE- using MSO Criteria. Please note that the data presented in Tables 2.4-B3 and 2.4-B4 provide data using a different methodology (MSO criteria) than previous years. This change in the presentation of data can cause changes to historically reported data due to the different exclusion criteria**.**

Table 2.4-B3

Pepco System Indices 2016-2020 MSO Criteria (MED Exclusive - IEEE 1366-2012 Std, Pepco System Wide Based)					
SAIFI	**2016**	**2017**	**2018**	**2019**	**2020**
Sustained Outages	0.98	0.68	0.90	0.73	0.58
Sustained Less Major Storms	0.98	0.66	0.69	0.73	0.55
SAIDI (HOURS)	**2016**	**2017**	**2018**	**2019**	**2020**
Sustained Outages	1.81	1.03	2.70	1.22	0.92
Sustained Less Major Storms	1.80	1.01	0.93	1.22	0.82
CAIDI (HOURS)	**2016**	**2017**	**2018**	**2019**	**2020**
Sustained Outages	1.85	1.52	3.02	1.67	1.59
Sustained Less Major Storms	1.85	1.52	1.35	1.67	1.48

Table 2.4-B4

District of Columbia System Indices 2016-2020 MSO Criteria (MED Exclusive - IEEE 1366-2012 Std, District of Columbia System Wide Based)					
SAIFI	**2016**	**2017**	**2018**	**2019**	**2020**
Sustained Outages	0.82	0.55	0.64	0.59	0.40
Sustained Less Major Storms	0.82	0.55	0.53	0.59	0.40
SAIDI (HOURS)	**2016**	**2017**	**2018**	**2019**	**2020**
Sustained Outages	1.92	0.96	1.82	1.29	0.73

Sustained Less Major Storms	1.92	0.96	0.86	1.29	0.73

CAIDI (HOURS)	2016	2017	2018	2019	2020
Sustained Outages	2.35	1.73	2.83	2.20	1.81
Sustained Less Major Storms	2.35	1.73	1.63	2.20	1.81

Order No. 16975 states the following at paragraphs 62 and 106:

*62. **Decision:** The Commission directs Pepco to provide SAIDI and SAIFI statistics in the future Consolidated Reports calculated by both including and excluding cross- border feeders. Pepco shall identify which feeders it treats as "cross-border" for this purpose.*

*106. Pepco is **DIRECTED** to provide SAIDI and SAIFI information consistent with paragraph 62 herein;*

District of Columbia Reliability Inclusive and Exclusive of Cross-Border Feeders (2020)

Table 2.4-B5

2020 IEEE MED Exclusive		
District of Columbia Reliability Statistics	SAIFI	SAIDI (Hours)
Excluding all cross-border feeders	0.29	0.55
Including all cross-border feeders	0.44	0.75

2020 DC MSO (& COMAR) Exclusive		
District of Columbia Reliability Statistics	SAIFI	SAIDI (Hours)
Excluding all cross-border feeders	0.31	0.61
Including all cross-border feeders	0.47	0.83
Table 2.4- B5		

*Note- COMAR is a Maryland criteria and MSO is a DC criteria.
MSO and COMAR are not compatible with each other.

Comparison of Cross-Border Feeder Reliability Performance[48]

Pepco calculates reliability indices on a feeder level in the same way regardless of the location of a feeder. For feeders that have customers in both the District of Columbia and Maryland, the indices for these feeders are included for reporting purposes with the jurisdiction in which the majority of customers on these feeders reside. Because feeders may switch between jurisdictions over time, to make their impact on reliability performance clear, Pepco presents system reliability performance both with and without both feeders assigned to the District of Columbia and Maryland, thereby allowing comparisons across different years.

Note: Feeders with two source substations listed are 4 kV primary network feeders and are supplied from two substations.

[48] The following is in response to the Commission's directive to:
[I]include in its 2015 Annual Consolidated Report an explanation of the metric or metrics it will use to report upon the reliability performance of its cross-jurisdictional feeders. This explanation is also to describe how Pepco's chosen metric(s) will allow reliability performance to be compared from year-to- year, when the jurisdictional status of a feeder changes between Maryland and the District
In The Matter of the Annual Consolidated Report of the Potomac Electric Power Company, Formal Case No. PEPACR-2014-01, Order No. 17816 at P 241 (February 27, 2015).

Table 2.4-B6

PEPCO 4 & 13KV CROSS JURISDICTIONAL FEEDERS SERVING MAJORITY DC CUSTOMERS

(Based on customers served, not physical presence)

Feeder No.	Substation Name	Substation No.	Substation Name	Substation No.	MD Customers	DC Customers	% UG	% OH
120	Chesapeake Street	181	-	-	3	545	4%	96%
183	Chesapeake Street	181	-	-	148	378	13%	87%
205	Seat Pleasant	30	Fort Chaplin	70	4	486	1%	99%
308	Harrison	38-6	Westmoreland	93	4	569	72%	28%
327	Fort Dupont	58	Texas Ave.	111	59	249	5%	95%
328	Fort Dupont	58	Fort Davis	100	54	356	2%	98%
333	Chesapeake Street	181	-	-	60	488	9%	91%
366	Seat Pleasant	30	53rd Street, SE	48	2	489	3%	97%
368	53rd Street, SE	48	Fort Davis	100	64	529	4%	96%
372	Seat Pleasant	30	53rd Street, SE	48	198	580	4%	96%
388	53rd Street, SE	48	-	-	3	625	3%	97%
451	Fort Davis	100	Texas Ave.	111	84	130	4%	96%
476	Quesada	89	Oliver Street	146	3	305	17%	83%
14014	12th & Irving	133	-	-	697	1379	9%	91%
14015	12th & Irving	133	-	-	108	856	17%	83%
14016	12th & Irving	133	-	-	25	683	34%	66%
14031	Suitland	134	-	-	264	1013	13%	87%
14035	Suitland	134	-	-	390	851	36%	64%
14261	Beech Road	159	-	-	373	990	7%	93%
14352	Harrison	38	-	-	4	28	100%	0%
14717	Benning	7	-	-	32	1529	26%	74%
14758	N.R.L.	168	-	-	2	2171	33%	67%
14890	Harrison	38	-	-	151	180	32%	68%
14893	Harrison	38	-	-	6	8	100%	0%
14900	Harrison	38	-	-	290	1070	25%	75%
14987	Grant Avenue	183	-	-	935	1190	24%	76%
15085	St. Barnabas Road	59	-	-	767	823	37%	63%
15094	Bladensburg	175	-	-	1031	1485	61%	39%
15130	Walker Mill Road	15	-	-	769	1275	31%	69%
15171	Alabama Avenue	136	-	-	7	1822	42%	58%
15198	Takoma	27	-	-	97	1615	18%	82%
15199	Takoma	27	-	-	252	1780	29%	71%
15648	Little Falls	77	-	-	0	1	100%	0%
15649	Little Falls	77	-	-	1	0	100%	0%
15711	Benning	7	-	-	86	1573	12%	88%
15944	Van Ness	129	-	-	84	1752	12%	88%

Note: Feeders 15648 and 15649 supply the Dalecarlia Pumping Station (DC) and the Army Map Service (MD)

Note: Feeders with two source substations listed are 4 kV primary network feeders and are supplied from two substations.

Table 2.4-B7

PEPCO 4 & 13KV CROSS JURISDICTIONAL FEEDERS SERVING MAJORITY MARYLAND CUSTOMERS

(Based on customers served, not physical presence)

Feeder No.	Substation Name	Substation No.	Substation Name	Substation No.	MD Customers	DC Customers	% UG	% OH
152	Fort Dupont	58	Randle Highlands	71	190	151	2%	98%
365	53rd Street, SE	48	Fort Dupont	58	515	227	13%	87%
14032	Suitland	134	-	-	564	74	26%	74%
14033	Suitland	134	-	-	1696	261	13%	87%
14102	Tuxedo	148	-	-	927	69	10%	90%
14263	Linden	156	-	-	1811	66	20%	80%
14270	Linden	156	-	-	741	6	44%	56%
14271	Linden	156	-	-	724	622	22%	78%
14593	Sligo	9	-	-	140	3	100%	0%
14595	Sligo	9	-	-	113	1	100%	0%
14768	Little Falls	77	-	-	1270	8	26%	74%
14769	Little Falls	77	-	-	1279	1	19%	81%
14896	Harrison	38	-	-	613	354	14%	86%
14949	Wood Acres	154	-	-	1392	21	7%	93%
14979	Grant Avenue	183	-	-	1050	200	6%	94%
15082	St. Barnabas Road	59	-	-	2028	187	61%	39%
15086	St. Barnabas Road	59	-	-	610	192	32%	68%
15090	St. Barnabas Road	59	-	-	1408	62	12%	88%
15100	Bladensburg	175	-	-	665	653	45%	55%
15131	Walker Mill Road	15	-	-	1295	337	42%	58%
15132	Walker Mill Road	15	-	-	1834	105	20%	80%
15200	Takoma	27	-	-	835	605	14%	86%
15264	Takoma	27	-	-	998	653	14%	86%
15501	Little Falls	77	-	-	36	22	100%	0%
15502	Little Falls	77	-	-	16	7	100%	0%
15503	Little Falls	77	-	-	19	3	100%	0%
15504	Little Falls	77	-	-	152	1	100%	0%
15505	Little Falls	77	-	-	39	0	100%	0%
15506	Little Falls	77	-	-	430	9	100%	0%

15501- 15506 are part of the Little Falls Network Group and all are involved in serving at least one DC customer

14593 is part of the Sligo South LVAC Network group that supplies mainly Maryland Customers.

2.4.2 NEIGHBORHOOD ANALYSIS

Starting with Order No. 16623, the Commission has required a specific focus on neighborhoods in the Consolidated Report. This section addresses each of the neighborhood subjects required by the Commission.

In response to the Commission's requirements for reporting the neighborhoods impacted by reliability issues and remediation work, Pepco developed a comprehensive list of the feeders serving District of Columbia customers and the neighborhoods served by each in May of 2012. In order to provide neighborhood identification that is both accurate and consistent from one submission to another, Pepco is now using assessment neighborhoods as defined by the District of Columbia Office of Tax and Revenue (OTR) Real Property Tax Administration (RPTA). Pepco is assessing new methods to programmatically identify the neighborhoods each Pepco feeder serves and plans to further discuss these plans in the future.

Neighborhood Analysis Requirements

(A) Neighborhoods warranting infrastructure improvements due to increased load growth[49]

Response: See discussion for Neighborhood Item A below.

(B) Neighborhoods with decreased planned spending on 4 kV to 13 kV conversions[50]

(C) Neighborhoods with decreased planned spending on 4 kV to 13 kV conversions that are among previously identified Most Susceptible Neighborhoods[51]

(D) Explanation of how reduced conversion spending will improve reliability in Most Susceptible Neighborhoods[52]

Response: See discussion for Neighborhood Items B, C, and D below.

(E) Neighborhoods served by Priority Feeders

Response: See Priority Feeder discussion.[53]

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[49] Order No. 16623 states the following at paragraph 35:
35. We find Pepco's explanation to be credible, but require further information on the neighborhoods in the District impacted by Pepco's changed plans. Specifically, we direct Pepco to identify those neighborhoods which warrant further infrastructure improvements due to increased load growth, including any explanation and data on Pepco's forecasts of load growth in those neighborhoods. (Footnote: In identifying neighborhoods, Pepco should use the methodology it used for defining and selecting neighborhoods in its May 20, 2011 submission to the Commission, or provide an explanation of why that methodology was not used. See F.C. Nos. 766, 982 and 991, Response of the Potomac Electric Power Company to Order No. 16347, May 20, 2011, Attachment 2.)…

[50] Order No. 16623 states the following at paragraph 35:
…Similarly, we require Pepco to identify those neighborhoods where planned spending on 4 kV to 13 kV conversion projects has decreased…

[51] Order No. 16623 states the following at paragraph 35:
…Further, we require that Pepco indicate if any of the neighborhoods it identifies pursuant to this paragraph is among the Most Susceptible Neighborhoods identified in Order No. 14626, Appendix A. (Footnote: See F.C. Nos. 766, 982, and 991, Order No. 16426, July 7, 2011, Appendix A.)…

[52] Order No. 16623 states the following at paragraph 35:
If any of the neighborhoods identified in this paragraph is among those Most Susceptible Neighborhoods, Pepco is directed to provide a full explanation of how its changed plans will improve reliability in that neighborhood.

[53] Order No. 16623 states the following at paragraph 46:
46. In connection with the second prong of our reliability efforts, our neighborhood initiative, we believe it is important to know whether any of the Priority Feeders are the feeders which serve the Most Susceptible Neighborhoods in the District. Beginning in the 2012 Consolidated Report, we require that Pepco identify the neighborhoods served by any Priority Feeders…

(F) Neighborhoods served by Repeat Priority Feeders[54]

Response: See Repeat Priority Feeder discussion.

(G) Neighborhoods served by equipment subject to failure data rate analysis[55]

Response: See Failure Data Rate Analysis discussion.

(H) Updated list of Most Susceptible Neighborhoods for Calendar Year 2011[56]

Response: See Neighborhood Item H, Most Susceptible Neighborhoods update below.

(I) Neighborhood information to be included in 2012 Consolidated Report[57]

Response: This information was included in the 2012 Consolidated Report as specified above.

(J) Directive to identify neighborhoods affected by changed plans[58]

Response: See discussion for Neighborhood Items A, B, C, and D below.

(K) Directive to provide information on neighborhoods[59]

Response: See discussion for Neighborhood Items E, F, G, H, and I.

Neighborhood Item A.

Neighborhoods with Increased Load Growth

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[54] Order No. 16623 states the following at paragraph 46:
…and any Repeat Priority Feeder (those in the ACAP program). (Footnote: In identifying neighborhoods, Pepco should use the methodology it used for defining and selecting neighborhoods in its May 20, 2011 submission to the Commission, or provide an explanation of why that methodology was not used. See F.C. Nos. 766, 982 and 991, Response of the Potomac Electric Power Company to Order No. 16347, May 20, 2011, Attachment 2.)...

[55] Order No. 16623 states the following at paragraph 46:
…Further, we require that Pepco identify the neighborhoods served by any equipment subject to the failure data rate analysis proposed by Pepco at the October 18, 2011 PIWG meeting for inclusion in the 2012 Consolidated Report. (Footnote: See October 18, 2011 PIWG Meeting Minutes at 1.)…

[56] Order No. 16623 states the following at paragraph 46:
We also require Pepco to update its list of Most Susceptible Neighborhoods to identify the neighborhood in each Ward experiencing the most frequent non-major outages in Calendar Year 2011.

[57] Order No. 16623 states the following at paragraph 46:
…This information should be included in the 2012 Consolidated Report

[58] Order No. 16623 states the following at paragraph 55:
55. Pepco is DIRECTED to identify neighborhoods affected by changed plans consistent with paragraph 35;

[59] Order No. 16623 states the following at paragraph 60:
60. Pepco is DIRECTED to provide information on neighborhoods consistent with paragraph 46;

Pepco forecasts load by substation using identified PNB load along with the load reducing effects of net energy metering and conservation programs (and DERs generally) to develop short term forecasts and uses trends plus knowledge of future planned development to develop a long term forecast for each substation in the Pepco system.

There are areas where Pepco anticipates above average load growth, and these include the Mt. Vernon Square/Convention Center neighborhood (R.L.A.[60] (N.E.) assessment neighborhood), NoMa (R.L.A. (N.E.) assessment neighborhood), the Washington Navy Yard/Southwest (R.L.A. (S.W.) assessment neighborhood) neighborhood and the area around St. Elizabeth's Hospital and Columbia Heights.

Neighborhood Items B, C, D.

Neighborhoods with Decreased Planned Spending on 4 kV to 13 kV Conversions

Pepco does not currently estimate a material decrease in planned spending in 2021 compared to 2020 as conversions continue in the 12th Street SW, Georgetown, and North Capitol areas. Conversions will continue in North Capitol and 12th St. substations areas in 2021with the goal to have all load served by Spring of 2021 and Fall of 2021, respectively. Pepco is planning to complete the Anacostia 4 kV conversion project in 2021 with the conversion of the last remaining 4kV Feeder supplied from Anacostia Sub. 8.

Neighborhood Item F.[61]

Table 2.4-C lists the feeders that have appeared more than once on the 2% Priority Feeder list, the years they appeared, and the neighborhoods they serve.

[60] Redevelopment Land Agency.
[61] In Order No. 15941 issued on August 18, 2010, the Commission stated at paragraphs 13 and 16, the following:

Table 2.4-C

Feeder	Years Appeared on Priority Feeder List Since 2001	Neighborhoods
27	2003, 2007, 2009	Shaw
53	2009, 2014	Columbia Heights, Park View
82	2007, 2015	Chevy Chase, Forest Hills, North Cleveland Park, Tenleytown Wakefield
211	2015, 2020	Capitol Hill
212	2014, 2016	Capitol Hill
227	2003, 2016	Barney Circle, Capitol Hill
228	2011, 2017	Barney Circle, Capitol Hill, Navy Yard
233	2010, 2016	East Potomac Park, LadyBird Johnson Park, National Mall - West Potomac Park, Southwest Federal Center
14001	2011, 2013	Bloomingdale, Eckington, Edgewood, Ledroit Park, Pleasant Plains
14004	2002, 2006	Bloomingdale, Eckington, Ledroit Park
14005	2001, 2021	Fort Lincoln, Gateway, Langdon
14006	2002, 2013, 2015	Brookland, Edgewood, Stronghold
14007	2001, 2003, 2005, 2008	Brookland, Michigan Park, Woodbridge, Catholic University, North Michigan Park
14008	2002, 2004, 2008, 2011	Brentwood, Ivy City, Langdon
14009	2013, 2017	Brookland, Catholic University, Eckington, Edgewood, Stronghold
14014	2001, 2004, 2006, 2013, 2017, 2019	Brookland, Langdon, Woodridge
14015	2001, 2004, 2009	Brookland, Michigan Park, Woodbridge, Catholic University, North Michigan Park
14016	2003, 2016	Arboretum, Fort Lincoln, Gateway, Ivy City, Langdon, National Arboretum, Woodridge
14017	2006, 2015	Brookland, Catholic University, Michigan Park, Stronghold
14023	2006, 2019, 2021	Brentwood, Brookland, Eckington
14031	2014, 2018	Dupont Park, Fairfax Village, Good Hope, Hillcrest, Naylor Gardens, Penn Branch
14054	2004, 2007	Columbia Heights, Sixteenth Street Heights
14093	2001, 2019	Arboretum, Brentwood, Brookland, Gateway, Langdon, National Arboretum
14133	2011, 2021	Forest Hills, North Cleveland Park
14136	2010, 2012, 2014, 2020	Cathedral Heights, Cleveland Park, Glover Park, McLean Gardens
14146	2002, 2005	Georgetown, Observatory Circle, Woodland-Normanstone Terrace, Woodley Park
14150	2012, 2021	American University Park, Cleveland Park, McLean Gardens
14200	2009, 2011, 2013, 2015, 2018	Bloomingdale, Brookland, Catholic University, Edgewood, Stronghold
14261	2017, 2020	Garfield Heights, Good Hope, Hillcrest, Naylor Gardens
14701	2001, 2003, 2010, 2012, 2017	Buena Vista
14702	2015, 2017	Anacostia, Fairlawn, Good Hope, Greenway, Baylor Gardens, Randle Highlands, Twining
14712	2007, 2021	Kingmand Park, Mayfair, Near Northeast, Trinidad
14717	2001, 2003, 2007, 2009, 2012, 2014, 2017, 2019	Burrville, Deanwood, East Corner, Lincoln Heights, Mayfair
14729	2004, 2006	Columbia Heights, Park View, Petworth, Sixteenth Street Heights
14753	2003, 2009, 2014, 2017	Bellevue, Washington Highlands
14755	2002, 2017	Bellevue, Congress Heights, Washington Highlands
14758	2003, 2012, 2014, 2017, 2021	Anacostia Naval Station - Bolling Air Force Base, Bellevue, Washington Highlands
14766	2002, 2006, 2021	American University Park, Potomac Heights, Spring Valley
14767	2002, 2008, 2015, 2018	Berkley, Kent, Potomac Heights, The Palisades, Wesley Heights
14786	2007, 2013, 2016, 2019	Brentwood, Capitol Hill, Gallaudet, Judiciary Square, Mount Vernon Square, Near Northeast
14787	2005, 2008, 2013	Capitol Hill, Gallaudet, Mount Vernon Square, Near Northeast, NoMa
14788	2007, 2013	Capitol Hill, Near Northeast, NoMa
14890	2008, 2011	American University Park, Chevy Chase, Friendship Heights
14900	2002, 2007, 2009, 2011, 2013, 2016, 2019, 2021	Bamaby Woods, Chevy Chase, Hawthorne
15009	2005, 2009, 2012, 2014	Manor Park, Riggs Park, Takoma
15011	2001, 2003, 2008, 2016	Brightwood, Sixteenth Street Heights
15012	2001, 2005	Manor Park, Petworth, Sixteenth Street Heights
15013	2003, 2006, 2017, 2019, 2021	Catholic University, Fort Totten, Manor Park, Pleasant Hill, Riggs Park, Stronghold
15014	2009, 2012, 2015, 2017	Fort Totten, Manor Park, Riggs Park
15016	2002, 2005	Manor Park, Riggs Park
15021	2005, 2014, 2018, 2020	Brightwood, Brightwood Park, Manor Park, Shepherd Park
15085	2014, 2017	Washington Highlands
15094	2012, 2018, 2020	Fort Lincoln, Woodridge
15130	2014, 2016, 2020	Benning Ridge, Civic Betterment, Fort Davis, Marshall Heights
15166	2010, 2013, 2021	Congress Heights, Shipley Terrace, Washington Highlands
15170	2006, 2010, 2015, 2018	Douglas, Good Hope, Naylor Gardens, Skyland
15171	2002, 2005, 2014	Congress Heights, Shipley Terrace, Washington Highlands
15172	2006, 2010, 2012, 2019	Buena Vista, Douglas, Saint Elizabeths
15173	2014, 2018	Anacostia, Buena Vista, Douglas, Garfield Heights, Knox Hill, Naylor Gardens, Shipley Terrace, Woodlands
15174	2010, 2013, 2015, 2018	Garfield Heights, Knox Hill, Shipley Terrace, Skyland, Woodlands
15197	2001, 2007, 2005, 2019, 2021	Crestwood, Petworth, Sixteenth Street Heights
15199	2001, 2004, 2010, 2012, 2014	Brightwood, Colonial Village, Riggs Park, Shepherd Park, Takoma
15206	2008, 2010	Bloomingdale, Ledroit Park, Logan Circle, Mount Vernon Square, Shaw, Tuxton Circle
15701	2001, 2003, 2005, 2010, 2015	Brentwood, Carver, Gallaudet, Ivy City, Kingman Park, Langston, Trinidad
15702	2005, 2012, 2016, 2020	Capitol Hill, Carver, Langston, National Arboretum, Near Northeast, Trinidad
15703	2004, 2006	Bamey Circle, Capitol Hill, Carver, Kingman Park, Langston
15705	2003, 2009, 2011, 2013, 2017	Deanwood, Eastland Gardens, Kenilworth, Mayfair
15706	2009, 2011, 2016	Benning, Benning Heights, Benning Ridge, Fort Dupont, Hillbrook, Mahaning Heights, Marshall Heights
15707	2007, 2010, 2013,2016, 2020	Deanwood, Hillbrook, Lincoln Heights, Mahaning Heights
15709	2004, 2006, 2008, 2010, 2018, 2021	Benning, Dupont Park, Fort Dupont, Greenway, River Terrace
15710	2013, 2017, 2020	Benning, Benning Heights, Fort Dupont, Greenway, Kingman Park, Mahaning Heights, River Terrace
15801	2002, 2005, 2008, 2010, 2013	Kent, Potomac Heights, The Palisades
15867	2002, 2008, 2014, 2020	Cleveland Park, Forest Hills, North Cleveland Park, Woodland-Norman stone Terrace, Woodley Park
15943	2008, 2010, 2012, 2016	Burleith, Georgetown, Glover Park
15945	2011, 2013, 2015, 2018	American University Park, Tenleytown

Neighborhood Item H.

Most Susceptible Neighborhoods by Ward with Most Frequent Non-Major Outages in 2020

Most Susceptible Neighborhood Analysis

Pepco was directed to provide analysis regarding the neighborhoods that were most susceptible to outages as determined by outage data. Pepco's original approach as previously filed was based upon identifying where there was a SAIFI / SAIDI impact on a Ward basis based upon the feeders that served specific neighborhoods in that Ward. Pepco has now taken a more defined geospatial approach of determining the most susceptible neighborhoods based on customer's experiencing multiple interruptions (CEMI) within that individual neighborhood. Neighborhoods in which greater than 250 customers experienced 3 or more outages in a single year within the last two years were selected. The outage analysis is inclusive of major service outages (MSOs) in order to capture the true experience of the customer. See Table 2.4D for the analysis of the most susceptible neighborhoods.

Table 2.4-D

Neighborhood	Ward	CEMI3+ 2019	CEMI3+ 2020	Priority Feeders 2020	Priority Feeders 2021
American University Park	Ward 3	43	955		14150,14766
Trinidad	Ward 5	8	935	15702	14712
Brookland	Ward 5	1	456		14022,14023
Cleveland Park	Ward 3	576	308	15867,14136	14150
Washington Highlands	Ward 8	0	276		14758,15166
Congress Heights	Ward 8	0	268		15166
Bellevue	Ward 8	630	190		14758
Deanwood	Ward 7	914	102	15707	
Benning Ridge	Ward 7	482	14	15130	
Anacostia	Ward 8	1,089	5		14758
Fort Dupont	Ward 7	370	4	15710	15709
Capitol Hill	Ward 6	2,486	0	211,15702,16002,16003	
Civic Betterment	Ward 7	357	0	15130	
Fort Davis	Ward 7	363	0	14035,328,15130	
Fort Lincoln	Ward 5	1,020	0	15094	14005
Marshall Heights	Ward 7	366	0	15130	372
Southwest Waterfront	Ward 6	701	0		

Table 2.4-E CEMIn Including Storms (MSO)

Year	CEMI3
2012	25.73%
2013	10.93%
2014	7.15%
2015	6.75%
2016	8.73%
2017	5.11%
2018	7.44%
2019	3.99%
2020	2.12%

From the analysis above, the 17 worst neighborhoods between 2019 and 2020 combined yielded 10 unique feeders to be remediated in 2021. Most of the feeders have been selected as part of a recent reliability program that also represents each neighborhood in this list. Additionally, the neighborhood list presented in this analysis represents 48% of the total DC customers that experienced three or more outages in 2020. See summary below:

- Feeders 15702, 15867, 14136, 15707, 15130, 15710, 00211, 16002, 16003, 14035, 00328, and 15094 were part of the 2020 Priority Feeder Program. The benefits on this work and other coincident work will be realized in 2021 and beyond.
- All remaining priority feeders are part of the 2021 Priority Feeder Program. The remediation work on these feeders is described above.

EQUIPMENT FAILURE RATES[62]

Pepco continues improvements to the quality of outage data. Outage data records are screened at multiple check points for accuracy. Control Center personnel review outage data daily for accuracy and make necessary edits to reflect actual circumstances. Asset Management staff performs several validation screens monthly to catch other data entry errors. Reliability Engineering staff daily review outage data and field crew comments as part of outage reviews, reliability improvement programs and when questionable data is encountered and works with Control Center staff to resolve remaining issues.

Analysis of Top Three Equipment Failure Modes[63]

This information identifies and analyzes the top three equipment failure modes in the District of Columbia with regards to total customers affected. In addition, it identifies feeders for corrective actions to remediate these failures in the future based on root cause determination where appropriate.

Analysis of Top Three Equipment Failure Modes[64]

This information identifies and analyzes the top three equipment failure modes in the District of Columbia with regards to total customers affected. In addition, it identifies feeders for

[62] Order No. 16975 states the following at paragraphs 95 and 118:
85. Decision: In its Comments, OPC identifies several instances in which outage data is inconsistent or erroneous. Pepco itself has identified several areas in which it can improve outage data quality. In an effort to ensure that the Commission and OPC is receiving accurate outage data, the Commission requires Pepco to report in its 2013 Consolidated Report on its efforts to improve the collection and accuracy of information regarding outages.
114.Pepco is DIRECTED to report on outage data quality improvement consistent with paragraph [95] herein.

[63] In Order No. 16091, the Commission stated among other things, at paragraph 59, the following:
59. …(5)…If data on failure rates for all variables is available for manhole events, Pepco shall include such information in its 2011 Consolidated Report. If such data is unavailable, we require the members of PIWG to discuss the need for and the availability of such data include in the 2011 Consolidated Report the PIWG conclusions and recommendations, if any.

[64] In Order No. 16091, the Commission stated among other things, at paragraph 59, the following:
59. …(5)…If data on failure rates for all variables is available for manhole events, Pepco shall include such information in its 2011 Consolidated Report. If such data is unavailable, we require the members of PIWG to discuss the need for and the availability of such data include in the 2011 Consolidated Report the PIWG conclusions and recommendations, if any.

corrective actions to remediate these failures in the future based on root cause determination where appropriate.

For purposes of this analysis, the following definitions are established.

- Events – number of outage events
- CI – number of customers interrupted
- CMI – Customer minutes of interruption
- SAIFI – System Average Interruption Frequency Index
- SAIDI – System Average Interruption Duration Index
- CAIDI – Customer Average Interruption Duration Index

Table 2.4-E details the reliability impacts of primary equipment failures tracked by Pepco

Table 2.4-E – Event Detail for Equipment Failures

Equipment Type	Number of Outages	% NI	CI	% CI	CMI	% CMI	SAIFI	CAIDI	SAIDI
Cable	201	22.38%	12241	42.09%	1996401.15	43.11%	0.04	163	6.41
Wire - Bare	37	4.12%	2212	7.61%	255531.33	5.52%	0.01	116	0.82
Switch	32	3.56%	1680	5.78%	214468.30	4.63%	0.01	128	0.69
Transformer	81	9.02%	1573	5.41%	530138.47	11.45%	0.01	337	1.70
Joint Failure	12	1.34%	1381	4.75%	432113.00	9.33%	0.00	313	1.39
PAC / Spacer Cable	7	0.78%	1305	4.49%	118861.62	2.57%	0.00	91	0.38
Connection(i.e. Loose)	63	7.02%	1039	3.57%	131488.68	2.84%	0.00	127	0.42
Wire - Covered	36	4.01%	829	2.85%	24475.12	0.53%	0.00	30	0.08
Pole	7	0.78%	812	2.79%	226831.07	4.90%	0.00	279	0.73
Fuse	45	5.01%	652	2.24%	88638.78	1.91%	0.00	136	0.28
ACR	3	0.33%	584	2.01%	50510.93	1.09%	0.00	86	0.16
Capacitor	1	0.11%	546	1.88%	45318.00	0.98%	0.00	83	0.15
Crossarm	10	1.11%	474	1.63%	10225.35	0.22%	0.00	22	0.03
Cutout	27	3.01%	394	1.35%	48222.73	1.04%	0.00	122	0.15
Transformer - Subsurface	8	0.89%	295	1.01%	104286.08	2.25%	0.00	354	0.33
Bushing	25	2.78%	140	0.48%	34913.00	0.75%	0.00	249	0.11
None	5	0.56%	118	0.41%	5939.00	0.13%	0.00	50	0.02
Splice	7	0.78%	87	0.30%	2877.00	0.06%	0.00	33	0.01
Service	4	0.45%	25	0.09%	2141.08	0.05%	0.00	86	0.01
Distr. Ckt. Breaker	2	0.22%	5	0.02%	3151.90	0.07%	0.00	630	0.01
Meter	4	0.45%	4	0.01%	434.08	0.01%	0.00	109	0.00
Lightning Arrestor	2	0.22%	2	0.01%	215.78	0.00%	0.00	108	0.00
Termination	1	0.11%	1	0.00%	175.85	0.00%	0.00	176	0.00
Elbow Insert	1	0.11%	1	0.00%	505.00	0.01%	0.00	505	0.00
Total Primaries	621	69.15%	26400	90.77%	4327863.32	93.45%	0.08	164	13.89

Total Secondaries	277	30.85%	2686	9.23%	303235.68	6.55%	0.009	113	0.973

Total Primaries & Secondaries	898	100.00%	29086	100.00%	4631099.00	100.00%	0.093	159	14.86

Based on the number of customer outages, as shown above in highlighted rows, the top three classes of primary equipment failures contributing to SAIFI are cable, bare wire and switch issues, accounting for 55.5% of total customers impacted and 53.3% of total customer minutes of interruption.

Cable Failure Analysis

Based on OMS data, the District of Columbia experienced 201 primary outages caused by cable failures during the period of analysis which affected 12,241 customers. There were 3 significant events that occurred accounting for 31.3% of the cable failure customer interruptions and 12.3 % of the cable failure customer minutes of interruption. The first event occurred on 6/4/2020 out of the Ft Slocum substation. A primary cable failure event occurred on feeder 15011 due to a getaway fault causing 1,473 customer interruptions and 34,026 customer minutes of interruption. Crews patrolled circuit, isolated and tagged OH cable before fully restoring load. A second event occurred on 9/12/2020 out of the Benning substation. A primary cable failure event occurred on feeder 14712 tripped due to getaway fault causing 1,319 customer interruptions and 196,726 customer minutes of interruption. Crews isolated UG cable repaired multiple faults and restored load. A third event occurred on 11/4/2020 out of the 12th & Irving substation. A primary cable failure event occurred on feeder 14008 due to a getaway fault causing 1,036 customer interruptions and 14,499 customer minutes of interruption. Crews isolated OH cable, repaired fault, and restored load.

Cables are selected for remediation based on outage history and repeat outages on sections of cable or repeat outages in neighborhoods. A program is in place to install interrupters on underground primary cable. An interrupter is a similar device to the recloser in that it can isolate the fault and restore service to customers that are not on the same section of the feeder as the outage. This will reduce the number of customer interruptions caused by cable failures and assist repair crews in locating the outage.

Table 2.4-F – Cable Failure Rates

2020 (Jan 1 - Dec 31)	Mode of Failure: Cable Failure (Primary)			
	CI	%	CMI	%
YE Total	12,241	42.09%	1,996,401	43.11%
3 Major Events*	3,828	31.27%	245,251	12.28%

Analysis of these 201 cable failure events as reported by OMS revealed that 31.3% of the customers impacted by cable failure can be attributed to three events. See summary below:

Table 2.4-F1 details the primary cable failure events causing the largest customer impact.

Table 2.4-F1 – Event Detail for Cable Failures

Feeder	Substation	Date	CI	CMI	Cause	UG Miles	UG%	Comment
15011	Ft Slocum	6/4/2020	1473	34,026	Getaway fault	2.99	43%	Load restored, no further action required
14712	Benning	9/12/2020	1,319	196,726	Cable fault between two tapholes	5.53	100%	Repair made, no further action required
14008	12th & Irving	11/14/2020	1036	14,499	Feeder tripped due to getaway fault	3.06	42%	Repair made, no further action required
Total:			**3,828**	**245,251**				

Loose Connections Analysis

Based on OMS data, the District of Columbia experienced 37 bare wire related outages during the period of analysis which affected 2,212 customers. There were four significant events that attributed to 90.6% of the customers impacted and 89% of the customer minutes of interruption. The first event occurred on 5/19/2020 out of the 12th & Irving substation. Wires down on feeder 14023 accounted for 541 customer interruptions an d118,424 customer minutes of interruptions. Crews made repairs and restored all customers. The second event occurred on 8/2/2020 out of the 12th & Irving substation. A and C phase wires down on feeder 14023 accounted for 519 customer interruptions and 35,176 customer minutes of interruption. Crews made repairs and restored all load. The third event occurred on 7/2/2020 out of the Randle Hiland substation. C phase wires down on feeder 00118 accounted for 487 customer interruptions and 11,688 customer minutes of interruption. Crews repaired the C phase wire and restored all customers. The fourth event occurred on 6/12/20 out of the Benning substation. C phase wires down on feeder 15711 accounted for 456 customer interruptions and 62,184 customer minutes of interruption. Crews made repairs and restored all customers.

Table 2.4-G – Loose Connections Rates

2020 (Jan 1 - Dec 31)	Mode of Failure: Wire-Bare (Primary)			
	CI	%	CMI	%
YE Total	2,212	7.61%	255,531	5.52%
X Major Events*	2,003	90.55%	227,472	89.02%

* % related to the total number of primary joint failure events

Analysis of these 37 events as reported by OMS revealed that 90.6% of the customers impacted by bare wires can be attributed to four events. See summary below:

Table 2.4-G1 details the primary loose connections events causing the largest customer impact.

Table 2.4-G1 – Event Detail for Loose Connections

Feeder	Substation	Date	CI	CMI	Cause	UG Miles	UG%	Comment
14023	12th & Irving	5/19/2020	541	118,424	All 3 phases down	3.04	57%	Repair made, no further action required
14023	12th & Irving	8/2/2020	519	35,176	A and C phases down	3.04	57%	Repair made, no further action required
00118	Randle Hiland	7/2/2020	487	11,688	C phase down	0.11	3%	Repair made, no further action required
15711	Benning	6/12/2020	456	62,184	C phase down	1.35	12%	Repair made, no further action required
Total:			**2,003**	**227,472**				

Switch Failure Analysis

Based on OMS data, the District of Columbia experienced 32 switch related outages during the period of analysis which affected 1,680 customers. There were 2 significant events that accounted for 61% of the customer interruptions and 48% of the customer minutes of interruption. The first event occurred on 12/3/2020 out of the Florida Ave substation. A blown fuse box was found on feeder 15770 accounting for 584 customer interruptions and 82,147 customer minutes of interruption. Crews made ties to restore the load. The second event occurred on 7/4/2020 out of the Van Ness substation. An open switch was found on feeder 14146 accounting for 447 customer interruptions and 21,098 customer minutes of interruption. Crews made repairs and restored load to all customers.

Table 2.4-H Switch Failure Rates

2020 (Jan 1 - Dec 31)	Mode of Failure: Switch (Primary)			
	CI	%	CMI	%
YE Total	1,680	5.78%	214,468	4.63%
X Major Events*	1,031	61.37%	103,245	48.14%

* % related to the total number of primary bare wire events

Analysis of these 32 events as reported by OMS revealed that 61% of the customers impacted by switch failure can be attributed to two events. See summary below:

Table 2.4-H1 details the primary switch failure events causing the largest customer impact.

Table 2.4-H1 Event Detail for Switch Failure Rates

Feeder	Substation	Date	CI	CMI	Cause	UG Miles	UG%	Comment
15770	Florida Ave	12/3/2020	584	82,147	Blown fuse box	5.17	100%	Repair made, no further action required
14146	Van Ness	7/4/2020	447	21,098	Open switch	3.97	48%	Repair made, no further action required
Total:			**1,031**	**103,245**				

Order No. 16975 states the following at paragraphs 68 and 109:

68. Decision: *Pepco is directed to report on efforts to reduce equipment failure in the 2013 Consolidated Report and in future Consolidated Reports*.

109. Pepco is **DIRECTED** *to report on its efforts to reduce equipment failure consistent with paragraph 68 herein;*

Analysis of effort to reduce equipment failure rates

The analysis of the top three causes of equipment failure outages in the District of Columbia shows the impacts of ongoing efforts to improve Pepco's overall system and the effectiveness of numerous programs currently in progress as part of Pepco's Reliability program. As shown in the detail above, most of the issues that contributed to the top three equipment failure modes during the evaluation period have been or are scheduled to be addressed in various elements of the Reliability program. All other issues occurred on feeders with historically good performance and were repaired permanently at the time of the restoration and require no further action.

Improvements in the overall impact of equipment failures bear testament to the effectiveness of Pepco's Reliability program in identifying and remediating the most impactful equipment failure modes, ideally those which contribute to most customer outages. Programs such as DC PLUG, priority, and comprehensive feeder remediation, and recloser installation and ASR schemes are mitigating the impacts of equipment failures and providing better overall reliability for DC customers. Other pilot programs such as installing interrupters on the underground system are being analyzed to determine the benefits and how to employ them in the near future.

As noted in the above analysis, cable failure remains the largest contributor to customer outages caused by equipment failure. From this analysis there is no identifiable trend for the cable failures. Pepco is continuing to look at cable failures to identify sections of cable that have failed multiple times and is taking a proactive approach with its URD cable replacement program.

2.4.3 OUTAGE CAUSES

Interruptions to electric service can be caused by a range of occurrences, such as downed trees or limbs on power lines; high winds and lightning; heavy rain, snow, or ice; animals on equipment or power lines; traffic accidents that damage poles and equipment; underground construction accidents; and equipment failures.

The eight main outage causes in the OMS are:

- Animal – Outage caused by contact between Birds, Squirrels, Snakes and Other small animals and the distribution system;
- Equipment Failure - Includes Equipment Failures Only;
- Equipment Hit - Includes Cable Cuts, Motor Vehicle Hits and Foreign Contact;
- Others - Includes Employee, Fire, Load Shedding, Source Lost, Vandalism, Voltage;
- Overload - Includes Overloading only;
- Tree - Includes Outside ROW- Limb, Outside ROW-Down, Inside ROW-Limb, and Inside ROW-Down;
- Unknown - Includes Unknown Only indicates that the field responder did not know the cause of the outage; and
- Weather - Includes Flood, Ice, Lightning, Wind.

The following table reflects the outage cause options from which crews select when entering data into the Mobile application at the time of restoration. Through the Mobile NMS (Network Management System) completion window, crews have the ability to enter the event restoration information through drop down menus that are represented in the following table as well as any additional information through a free form text field. The outage cause selections are later classified into the categories above for reporting purposes. The detailed outage causes are maintained to assist in analysis of not only the cause of the outage but also the corrective actions necessary to reduce future outages.

An explanation of the selection categories from the drop-down menus follows Table 2.4-I below.

Table 2.4-I

Select 1	Select 1	Select 1	Select 1	Select up to 3	Select 1	Select 1	Select 1	Select up to 7	Select up to 4
NON PHI	**Weather**	**Class**	**Device**	**Action**	**Cause/Problem**	**Equipment Failure** Select if Equipment Failure Cause selected	**Phase**	**Manhole**	**Follow-Up Area**
APGE	Clear	Dist Primary - OH	ACR	Assisted	Animal/Bird	ACR	A	Cable Burnout Visible	ACE - Cape May
Bad Address	Extreme Cold	Dist Primary - UG	Autotransformer	Braced	Animal/Other	Autotransformer	B	Cable Smoking	ACE - Glassboro
Cust Equip	Extreme Heat	Dist Primary - URD	Bushing	Bypassed	Animal/Snake	Bushing	C	Cover - Double Action	ACE - Operations
FD Disconn- Left Disconn	Ice	Dist Secondary - OH	Cable	Closed	Animal/Squirrel	Cable	ABC	Cover - Rdwy Grate	ACE - Pleasantville
FD Disconn- Reconnected	Fog	Dist Secondary - UG	Capacitor	Cleared/Cut in Clear	Avoided Dispatch	Capacitor	+/-	Cover - Sdwk Grate	ACE - Winslow
N/R (No Response)	Rain	Dist Secondary - URD	Connection (i.e. Loose)	Disconn	Cable Cut - Billable	Connection (i.e. Loose)	AB	Cover - Slotted	Bay - Centreville
N/R Volt Checks OK	Snow	Network	Crossarm	Isolated	Cable Cut - Marked Wrong	Crossarm	AC	Cover Displaced	Bay - Exmore
No Access	Windy	St. Lgt	Cutout	Jumpered	Cable Cut - Unknown	Cutout	BC	Gas Present	Bay - Harrington
Ok by Phone	Thunder/Lightning	Substation	Distr. Ckt. Breaker	Left MLSO	Employee	Distr. Ckt. Breaker	A, +/-	Joint Smoking	Bay - Millsboro
Ok on Arrival		Sub-Transmission	Elbow/Insert	Made Safe	Equipment Failure	Elbow/Insert	B, +/-	MH Fire	Bay - Operations
Utility - CATV		Traffic Signal	Fuse	Made Tie	Fire	Fuse	C, +/-	MH Smoking	Bay- Salisbury
Utility - Phone		Transmission	Insulator	Notified Customer	Foreign Contact	Insulator	AB, +/-	Structure Damage	Claims
Utility - Other			Joint Failure	Perm Repairs	Load	Joint Failure	AC, +/-	Water Above Cable	Forestry
			Lightning Arrestor	Reconnected	Load Shedding	Lightning Arrestor	BC, +/-	Water Below Cable	NC - Christiana
			Meter	Referred	Motor Vehicle	Meter	ABC, +/-	Other	NC - North East
			Meter - Primary	Removed	Scheduled	Meter - Primary			NC - Operations
			"Mole"	Repaired	Source Lost	"Mole"			Pepco - BSID
			None	Replaced	Tree ROW - Limb	None			Pepco - Conduit
			PAC/ Spacer Cable	Temp Repairs	Tree ROW - Down	PAC/ Spacer Cable			Pepco - Cust Design DC
			Pole	Voltage Check	Tree Outside ROW - Limb	Pole			Pepco - Cust Design MD
			Regulator		Tree Outside ROW - Down	Regulator			Pepco - Cust Operations
			Relay		Unknown	Relay			Pepco - Distribution Test
			Sectionalizer		Vandalism	Sectionalizer			Pepco - Line Clearance
			Service		Voltage - F/L or H/L	Service			Pepco - Meter
			Splice		Weather / Flood	Splice			Pepco - OH Forestville
			Street Light / Traffic		Weather / Ice	Street Light / Traffic			Pepco - OH Rockville
			Switch		Weather / Lightning	Switch			Pepco - Operations
			Switch - Gang Op		Weather / Salt	Switch - Gang Op			Pepco - UG Benning
			Termination		Weather / Wind	Termination			Pepco - UG Rockville
			Transclosure			Transclosure			Pepco - URD - Rockville
			Transformer			Transformer			Pepco - URD Forestville
			Transformer - Padmount			Transformer - Padmount			
			Transformer - Subsurface			Transformer - Subsurface			
			Wire - Bare			Wire - Bare			
			Wire - Covered			Wire - Covered			

- **Non-PHI** - If the event is not caused by Pepco equipment or if it is impossible to complete the request (e.g. bad address) crews must select one item from the Non-PHI list box of the MDS restoration screen indicating the circumstances, such as other utility, customer equipment, APGE (advise party to get electrician). If a selection is made from this list, the crew can complete and close ticket without further information. If no selection is made, then the event is on Pepco equipment and additional information is needed to complete the record.
- **Weather** - Crew must select from the list the observed weather conditions at the time of the outage.
- **Class** - Crew must select one item from the drop-down list describing the

construction type.

- **Device** - Crew must select the clearing device.
- **Action** - Crew selects the action taken to restore the event/outage.
- **Cause/problem** - Crew must select the cause of the event. A ticket cannot be closed without a cause selection if the event was on Pepco equipment.
- **Equipment Failure** - Crew must enter information about the failed device related to the event if equipment failure is the cause / problem selected.
- **Phase** - Selection box for the phase(s) impacted by the event/outage.
- **Manhole** - Selection box for items describing the contents of a manhole.
- **Follow-up Area -** For an event that needs additional work but does not require immediate attention, a crew may select a follow-up area. For example, in the case of a URD cable failure where all load is restored through a common tie, the event would have a follow-up selection.

The most common causes of power outages are equipment failures and vegetation. High winds, heavy rain or snow and ice can cause trees or branches to topple and tear down power lines. Tree limbs brushing or resting on the lines cause short circuits and blown fuses. As shown in Table 2.4-I, there are several different equipment types that fall under the "Equipment Failure" category. One such type is fuse-related outages. The job of the fuse is to protect equipment. If a fuse blows, it is not an equipment failure but rather the fuse is performing its designed function. As a result, there are fewer actual "Equipment Failures" than are captured by the OMS.

If a non-Pepco construction crew digs a foot or two in the wrong direction, damage to an underground power line could cause an instant disruption of electric service or could cause damage that may not result in a power outage until days, weeks or months later.

Vehicles that damage utility poles or equipment can also cause power outages. Small animals, like squirrels, sometimes chew into lines or come into contact with a piece of equipment and an energized line, causing a fault and subsequent interruption of electric service.

An event classified as "Unknown" indicates that the field responder did not know the cause of the outage and this classification is used most frequently where a service interruption results from the operation of a protective device such as a fuse or recloser. These devices protect the electric distribution system from damage by sensing fault current on a particular circuit and activating a break in the flow of current. Typically, if there is no discernable damage to the circuit and the cause of the fault is not evident in the vicinity of the protective device that was activated, the device will be replaced or reset and the circuit re-energized. If the device holds (no fault current is detected), the field responder may report “Equipment Failure” or "Unknown" as a cause and move on to the next trouble call assigned. The operation of these protective devices are not equipment failures because the fuse or recloser is operating correctly when it opens to isolate a fault further down the line. Occasionally, the field responder may find a probable cause some distance from the protective device involved (such as a tree branch on the ground underneath the overhead lines), but, for the most part, crews are focused on restoration of service rather than full investigation of the cause of any interruption (where this is not immediately evident).

Tables 2.4-J contains District of Columbia outage cause data for calendar year 2020.

Table 2.4-J

Equipment Type	NI	% NI	CI	% CI	CMI	% CMI	SAIFI	CAIDI	SAIDI
ACR	3	0.33%	584	2.01%	50510.93	1.09%	0.00	86	0.16
Bushing	25	2.78%	140	0.48%	34913.00	0.75%	0.00	249	0.11
Cable	201	22.38%	12241	42.09%	1996401.15	43.11%	0.04	163	6.41
Capacitor	1	0.11%	546	1.88%	45318.00	0.98%	0.00	83	0.15
Connection(i.e. Loose)	63	7.02%	1039	3.57%	131488.68	2.84%	0.00	127	0.42
Crossarm	10	1.11%	474	1.63%	10225.35	0.22%	0.00	22	0.03
Cutout	27	3.01%	394	1.35%	48222.73	1.04%	0.00	122	0.15
Distr. Ckt. Breaker	2	0.22%	5	0.02%	3151.90	0.07%	0.00	630	0.01
Elbow Insert	1	0.11%	1	0.00%	505.00	0.01%	0.00	505	0.00
Fuse	45	5.01%	652	2.24%	88638.78	1.91%	0.00	136	0.28
Joint Failure	12	1.34%	1381	4.75%	432113.00	9.33%	0.00	313	1.39
Lightning Arrestor	2	0.22%	2	0.01%	215.78	0.00%	0.00	108	0.00
Meter	4	0.45%	4	0.01%	434.08	0.01%	0.00	109	0.00
None	5	0.56%	118	0.41%	5939.00	0.13%	0.00	50	0.02
PAC / Spacer Cable	7	0.78%	1305	4.49%	118861.62	2.57%	0.00	91	0.38
Pole	7	0.78%	812	2.79%	226831.07	4.90%	0.00	279	0.73
Service	4	0.45%	25	0.09%	2141.08	0.05%	0.00	86	0.01
Splice	7	0.78%	87	0.30%	2877.00	0.06%	0.00	33	0.01
Switch	32	3.56%	1680	5.78%	214468.30	4.63%	0.01	128	0.69
Termination	1	0.11%	1	0.00%	175.85	0.00%	0.00	176	0.00
Transformer	81	9.02%	1573	5.41%	530138.47	11.45%	0.01	337	1.70
Transformer - Subsurface	8	0.89%	295	1.01%	104286.08	2.25%	0.00	354	0.33
Wire - Bare	37	4.12%	2212	7.61%	255531.33	5.52%	0.01	116	0.82
Wire - Covered	36	4.01%	829	2.85%	24475.12	0.53%	0.00	30	0.08
Total Primaries	621	69.15%	26400	90.77%	4327863.32	93.45%	0.08	164	13.89
Total Secondaries	277	30.85%	2686	9.23%	303235.68	6.55%	0.01	113	0.97
Total Primaries & Secondaries	898	100.00%	29086	100.00%	4631099.00	100.00%	0.09	159	14.86

VM BUDGET, TREE-RELATED OUTAGES[65][66]

Table 2.4-K1 shows District of Columbia distribution tree trimming expenses (not including poles, substation mowing, or storm-related tree trimming) and budgets. Provided are actual and budgeted amounts for 2013-2020 and the 2021 budget.

Pepco's VM program includes increased trimming above all three-phase and single-phase lines. For three-phase lines it also includes the removal (with permission) of any limbs identified by Pepco Arborist planners that have a probability of breaking and falling into the conductors.

[65] In Order No. 16623 at paragraphs 37 and 56, the Commission ordered the following:
37. Decision: …We require Pepco to explain why it has decreased its budget for tree trimming over the last seven years, if tree trimming is the most important factor impacting customers suffering from power outages. Pepco should include that explanation in the 2012 Consolidated Report.
56. Pepco is DIRECTED to provide an explanation of its budget for tree trimming consistent with paragraph 37.
[66] Order No. 16975 states the following at paragraphs 43 and 99:
43. Decision: The Commission finds Pepco's explanation of its budget variance for the single year 2011 insufficient to explain budget variances that totaled 26.9% below budget for five of the last six years. Therefore, the Commission requires Pepco to explain the budget variances that have occurred from 2006-2011 in its 2013 Consolidated Report. Additionally, we agree with Staff Recommendation #3 and require Pepco to include an explanation of any budget variance in its vegetation management expenditures and its EIVM expenditures in future years' Consolidated Reports. We are extremely concerned about the explanation provided in the Consolidated Report for why vegetation management expenditures were below budget in five of the last six years. Pepco stated that "while actual expenditures were below budget, work was completed consistent with planning." This is an inadequate explanation for a repeated failure to spend budgeted amounts on tree-trimming – arguably, the "most important factor impacting customers suffering from power outages." We therefore require Pepco to expand upon its explanation. If Pepco means that, through efficiencies, all the work intended to be accomplished in the budget was actually accomplished for less, then we direct Pepco to document what was intended to be included in the budget and what efficiencies were achieved so that the budgeted work was accomplished at a lower cost. The Commission also requires Pepco to explain what impact these efficiencies had on the budget process in subsequent years. If Pepco's statement about planning has some other meaning, we direct Pepco to provide it and to show what "planning" was involved, by whom and when. We also expect a precise and detailed explanation of why such planning would result in expenditures consistently, and significantly, below the budgeted amounts for a number of years. Further, we agree with OPC's suggestion that Pepco explain why its program does not include increased trimming above the three phase tap line or the single tap lines. Pepco is directed to provide this information in the 2013 Consolidated Report.
99. Pepco is DIRECTED to provide an explanation of budget variances for its own vegetation management work as directed in paragraph 43 herein;

Explanation of Variance in Pepco D.C. O&M Tree Trimming Costs

In 2020, there was variance of $316,388 (underspent), or approximately 13% percent, from the annual VM budget. Due to vegetation management's aggressive routine maintenance program, the cyclical costs associated with the program have reduced. Since DC is on a two-year schedule, all feeders are inspected and maintained every two years. This has resulted in less associated maintenance costs for the program.

Table 2.4-K1

Pepco District of Columbia O & M Tree Trimming Costs								
	2013	2014	2015	2016	2017	2018	2019	2020
Actual								
Tree Trimming - DC	$2,352,567	$2,164,336	$2,238,654	$2,269,634	$2,365,759	$1,705,410	$2,124,929	$2,052,518
Budget/Forecast								
Tree Trimming - DC	$2,218,342	$2,113,300	$2,324,572	$2,335,008	$2,412,774	$2,480,616	$2,522,296	$2,368,906
Variance	($134,225)	($51,036)	$85,918	$65,374	$47,015	$775,206	$397,367	316,388
Tree Trimming - DC								
Notes:								
1. Excludes pole inspections, substation mowing costs								

Yearly Data on Tree Trimming & Tree-Related Outages

In accordance with Order No. 15621,[67] presented in the following tables, is Pepco's "yearly data on vegetation management by feeder and wards (or multiple wards) compared to the Company's tree down and tree limb outage causes listed in its monthly power outage reports." The tables list the outages coded as tree-related in 2020, also sorted by feeder, allowing for a comparison between the two sets of tables. It is possible that additional outages may have been caused by trees but with causes coded as weather or unknown if fallen trees or limbs were not found at the site.

[67] In Order No. 15621 at paragraph 5, the Commission ordered the following:
5. Pepco shall file within the Company's annual Consolidated Reports to the Commission, yearly data on tree trimming by feeder and wards (or multiple wards) compared to the Company's tree down and tree limb outage causes listed in its monthly power outage reports beginning with the Company's 2010 Consolidated Report.

Circuit	Voltage	Ward
52	4 KV	DC WARD 3
56	4 KV	DC WARD 8
58	4 KV	DC WARD 2
60	4 KV	DC WARD 3
63	4 KV	DC WARD 3
64	4 KV	DC WARD 3
65	4 KV	DC WARD 3
75	4 KV	DC WARD 3
82	4 KV	DC WARD 3
87	4 KV	DC WARD 3
97	4 KV	DC WARD 7
101	4 KV	DC WARD 3
102	4 KV	DC WARD 3
104	4 KV	DC WARD 3
119	4 KV	DC WARD 8
120	4 KV	DC WARD 8
128	4 KV	DC WARD 3
144	4 KV	DC WARD 3
164	4 KV	DC WARD 8
165	4 KV	DC WARD 8
167	4 KV	DC WARD 7
178	4 KV	DC WARD 8
181	4 KV	DC WARD 3
183	4 KV	DC WARD 8
205	4 KV	DC WARD 7
292	4 KV	DC WARD 3
294	4 KV	DC WARD 8
309	4 KV	DC WARD 3
323	4 KV	DC WARD 8
324	4 KV	DC WARD 8
329	4 KV	DC WARD 8
332	4 KV	DC WARD 8
333	4 KV	DC WARD 8
366	4 KV	DC WARD 7
372	4 KV	DC WARD 7
394	4 KV	DC WARD 3
411	4 KV	DC WARD 8
467	4 KV	DC WARD 3
14002	13 KV	DC WARD 5
14005	13 KV	DC WARD 5
14006	13 KV	DC WARD 5
14007	13 KV	DC WARD 5
14008	13 KV	DC WARD 5
14009	13 KV	DC WARD 5
14010	13 KV	DC WARD 5
14014	13 KV	DC WARD 5
14015	13 KV	DC WARD 5

Circuit	Voltage	Ward
14016	13 KV	DC WARD 5
14017	13 KV	DC WARD 5
14019	13 KV	DC WARD 5
14020	13 KV	DC WARD 5
14021	13 KV	DC WARD 5
14022	13 KV	DC WARD 5
14023	13 KV	DC WARD 5
14054	13 KV	DC WARD 4
14055	13 KV	DC WARD 7
14058	13 KV	DC WARD 7
14093	13 KV	DC WARD 5
14132	13 KV	DC WARD 3
14133	13 KV	DC WARD 3
14134	13 KV	DC WARD 3
14135	13 KV	DC WARD 4
14136	13 KV	DC WARD 3
14139	13 KV	DC WARD 3
14140	13 KV	DC WARD 3
14144R	13 KV	DC WARD 3
14145	13 KV	DC WARD 3
14146	13 KV	DC WARD 3, DC WARD 2
14150	13 KV	DC WARD 3
14159	13 KV	DC WARD 7
14200	13 KV	DC WARD 5
14261	13 KV	DC WARD 8, DC WARD 7
14701	13 KV	DC WARD 8
14702	13 KV	DC WARD 8, DC WARD 7
14707	13 KV	DC WARD 8
14709	13 KV	DC WARD 8
14711	13 KV	DC WARD 7
14713	13 KV	DC WARD 7, DC WARD 5
14716	13 KV	DC WARD 7
14717	13 KV	DC WARD 7
14718	13 KV	DC WARD 8
14719	13 KV	DC WARD 8
14752	13 KV	DC WARD 8
14753	13 KV	DC WARD 8
14755	13 KV	DC WARD 8
14756	13 KV	DC WARD 8
14758	13 KV	DC WARD 8
14765	13 KV	DC WARD 3
14766	13 KV	DC WARD 3
14767	13 KV	DC WARD 3
14768	13 KV	DC WARD 3
14806	13 KV	DC WARD 7
14808	13 KV	DC WARD 7
14809	13 KV	DC WARD 7
14811	13 KV	DC WARD 7
14812	13 KV	DC WARD 7
14813	13 KV	DC WARD 7
15085	13 KV	DC WARD 5, DC WARD 4

Circuit	Voltage	Ward
15178	13 KV	DC WARD 8
15179	13 KV	DC WARD 8
15198	13 KV	DC WARD 5, DC WARD 4
15199	13 KV	DC WARD 4
15200	13 KV	DC WARD 4
15264	13 KV	DC WARD 5, DC WARD 4
15457	13 KV	DC WARD 5
15701	13 KV	DC WARD 5
15702	13 KV	DC WARD 5
15705	13 KV	DC WARD 7
15706	13 KV	DC WARD 7
15707	13 KV	DC WARD 7
15709	13 KV	DC WARD 7
15710	13 KV	DC WARD 7, DC WARD 5
15711	13 KV	DC WARD 7
15801	13 KV	DC WARD 3
15867	13 KV	DC WARD 3
15943	13 KV	DC WARD 3, DC WARD 2
15944	13 KV	DC WARD 3
15945	13 KV	DC WARD 3
15946	13 KV	DC WARD 3
15947	13 KV	DC WARD 3
15949	13 KV	DC WARD 3
15950	13 KV	DC WARD 3
15997	13 KV	DC WARD 3
34927	34 KV	DC WARD 7

Tree-Related Outages in 2020 (Inclusive IEEE 1366 – 2012 Std)

Table 2.4-K2

Event ID	Date of Outage	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Customers Affected	Customer Minutes	Feeder
2647402	1/16/2020	10:44	13:45	181	Dist Primary - OH	Tree ROW - Limb	5	905	144
2647402	1/16/2020	12:29	13:45	76	Dist Primary - OH	Tree ROW - Limb	6	456	144
2652713	2/5/2020	13:31	14:22	51	Dist Secondary - OH	Tree Outside ROW - Limb	1	51	14767
2655070	2/14/2020	6:22	7:09	47	Dist Primary - OH	Tree Outside ROW - Down	24	1128	14261
2655107	2/14/2020	6:22	8:40	138	Dist Primary - OH	Tree Outside ROW - Down	12	1656	14261
2655103	2/14/2020	6:22	7:26	64	Dist Primary - OH	Tree Outside ROW - Down	22	1408	14261
2656830	2/20/2020	10:16	13:53	217	Dist Secondary - OH	Tree ROW - Limb	1	217	14900
2659558	3/3/2020	8:53	10:29	96	Dist Secondary - OH	Tree ROW - Limb	1	96	14007
2659645	3/3/2020	13:01	13:17	16	Dist Primary - OH	Tree ROW - Limb	94	1504	14765
2659786	3/3/2020	22:12	1:00	167.58333	Dist Secondary - OH	Tree ROW - Limb	4	670.3333333	15946
2665398	3/28/2020	10:56	12:42	105.2	Dist Secondary - OH	Tree Outside ROW - Limb	1	105.2	414
2666506	4/2/2020	14:27	16:02	94.033333	Dist Secondary - OH	Tree Outside ROW - Limb	1	94.03333333	380
2667529	4/8/2020	4:20	4:31	10.033333	Dist Primary - OH	Tree Row - Down	387	3882.9	15945
2667529	4/8/2020	4:20	4:30	9.0333333	Dist Primary - OH	Tree Row - Down	611	5519.366667	15945
2667535	4/8/2020	4:23	6:53	149.63333	Dist Primary - OH	Tree Row - Down	112	16758.93333	308
2667535	4/8/2020	4:23	8:36	252.08333	Dist Primary -	Tree Row - Down	58	14620.83333	308

Event ID	Date of Outage	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Customers Affected	Customer Minutes	Feeder
					OH				
2667569	4/8/2020	4:31	17:37	786	Dist Secondary - OH	Tree Outside ROW - Down	1	786	15945
2667545	4/8/2020	4:31	17:39	787.46667	Dist Primary - OH	Tree Row - Down	13	10237.06667	14767
2667549	4/8/2020	4:32	10:33	361	Dist Primary - OH	Tree Outside ROW - Down	7	2527	15944
2667550	4/8/2020	4:33	13:23	530	Dist Secondary - OH	Tree Outside ROW - Down	2	1060	309
2667559	4/8/2020	4:37	13:55	558	Dist Primary - OH	Tree Row - Down	18	10044	15945
2667570	4/8/2020	4:50	13:12	501.21667	Dist Secondary - OH	Tree Outside ROW - Down	15	7518.25	15945
2667611	4/8/2020	5:59	6:05	6	Dist Primary - OH	Tree Outside ROW - Down	10	60	15944
2667720	4/8/2020	10:26	10:39	13	Dist Secondary - OH	Tree Outside ROW - Down	1	13	309
2667746	4/8/2020	11:07	16:49	341.66667	Dist Primary - OH	Tree Row - Down	1	341.6666667	14767
2667559	4/8/2020	11:43	13:55	132	Dist Primary - OH	Tree Row - Down	12	1584	15945
2667770	4/8/2020	12:15	13:53	98	Dist Primary - OH	Tree Row - Down	1	98	15946
2667782	4/8/2020	12:40	17:31	291	Dist Secondary - OH	Tree Outside ROW - Down	13	3783	15945
2674434	4/8/2020	13:00	14:08	68	Dist Secondary - OH	Tree Outside ROW - Down	1	68	309
2670659	4/9/2020	14:21	15:17	56	Dist Primary - OH	Tree ROW - Limb	1	56	15174
2668329	4/9/2020	15:18	17:28	129.35	Dist Primary - OH	Tree ROW - Limb	12	1552.2	82
2668335	4/9/2020	15:24	17:28	123.86667	Dist Primary - OH	Tree ROW - Limb	9	1114.8	82
2668354	4/9/2020	15:32	17:28	115.95	Dist Primary -	Tree ROW - Limb	8	927.6	102

Event ID	Date of Outage	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Customers Affected	Customer Minutes	Feeder
					OH				
2668431	4/9/2020	16:26	17:00	34	Dist Secondary - OH	Tree ROW - Limb	1	34	14016
2668848	4/10/2020	11:58	13:29	91	Dist Secondary - OH	Tree Outside ROW - Limb	18	1638	15013
2669098	4/10/2020	14:10	16:14	123.11667	Dist Secondary - OH	Tree ROW - Limb	1	123.1166667	369
2669224	4/11/2020	8:00	8:19	19	Dist Secondary - OH	Tree Vine	10	190	451
2669697	4/13/2020	13:51	15:51	119.81667	Dist Secondary - OH	Tree Row - Down	1	119.8166667	327
2669964	4/13/2020	15:43	16:38	54.15	Dist Secondary - OH	Tree Row - Down	19	1028.85	387
2670031	4/13/2020	16:30	17:45	74.4	Dist Secondary - OH	Tree Outside ROW - Limb	1	74.4	15013
2670198	4/13/2020	19:50	21:28	97.466667	Dist Primary - OH	Tree Outside ROW - Down	8	779.7333333	14767
2670203	4/13/2020	20:04	21:28	84	Dist Primary - OH	Tree Outside ROW - Down	1	84	14767
2670204	4/13/2020	20:04	21:28	83.3	Dist Primary - OH	Tree Outside ROW - Down	1	83.3	14767
2670266	4/14/2020	5:40	7:37	116.15	Dist Secondary - OH	Tree ROW - Limb	1	116.15	15012
2671370	4/18/2020	14:56	20:45	349.51667	Dist Primary - OH	Tree Outside ROW - Down	51	17825.35	14133
2671395	4/18/2020	16:28	20:45	257.51667	Dist Primary - OH	Tree Outside ROW - Down	17	4377.783333	14133
2671391	4/18/2020	16:28	16:38	10.8	Dist Primary - OH	Tree Row - Down	147	1587.6	14133
2671397	4/18/2020	16:39	20:45	246.76667	Dist Primary - OH	Tree Outside ROW - Down	7	1727.366667	14133
2671412	4/18/2020	20:23	21:25	62	Dist Primary - OH	Tree Outside ROW - Down	521	32302	347
2671428	4/18/2020	20:23	5:47	564	Dist Primary -	Tree Row - Down	65	36660	347

Event ID	Date of Outage	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Customers Affected	Customer Minutes	Feeder
					OH				
2672089	4/21/2020	16:05	16:10	5.15	Dist Primary - OH	Tree ROW - Limb	337	1735.55	102
2673143	4/26/2020	6:38	8:33	114.38333	Dist Primary - OH	Tree Vine	4	457.5333333	15944
2673940	4/29/2020	15:46	19:08	202	Dist Primary - OH	Tree Row - Down	5	1010	14987
2674024	4/29/2020	17:57	19:08	71	Dist Primary - OH	Tree Row - Down	4	284	14987
2674354	4/30/2020	18:12	18:54	41.366667	Dist Primary - OH	Tree ROW - Limb	16	661.8666667	15010
2675115	5/4/2020	0:54	1:44	50	Dist Secondary - OH	Tree Outside ROW - Down	1	50	15085
2677246	5/9/2020	9:08	10:23	75	Dist Primary - OH	Tree Outside ROW - Limb	22	1650	15012
2679869	5/10/2020	7:01	9:22	141	Dist Primary - OH	Tree ROW - Limb	1	141	14133
2677390	5/10/2020	7:01	9:20	139	Dist Primary - OH	Tree ROW - Limb	9	1251	14133
2677390	5/10/2020	8:59	9:20	21	Dist Primary - OH	Tree ROW - Limb	6	126	14133
2679870	5/10/2020	8:59	9:22	23	Dist Primary - OH	Tree ROW - Limb	1	23	14133
2678130	5/12/2020	12:13	12:20	7	Dist Secondary - OH	Tree Outside ROW - Down	1	7	118
2678487	5/13/2020	14:49	15:07	18	Dist Secondary - OH	Tree ROW - Limb	1	18	132
2678928	5/15/2020	10:27	12:10	102.1	Dist Primary - OH	Tree ROW - Limb	10	1021	65
2679601	5/17/2020	9:13	9:24	11	Dist Primary - OH	Tree ROW - Limb	36	396	102
2680652	5/19/2020	17:25	20:52	207.13333	Dist Primary - OH	Tree Row - Down	1	207.1333333	14806
2680958	5/19/2020	17:25	11:29	1083.2667	Dist Primary -	Tree Row - Down	1	1083.266667	14806

Event ID	Date of Outage	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Customers Affected	Customer Minutes	Feeder
					OH				
2680658	5/19/2020	17:26	18:56	90	Dist Primary - OH	Tree Row - Down	436	39240	99
2680755	5/19/2020	17:46	18:10	23.55	Dist Primary - OH	Tree Row - Down	165	3885.75	15801
2680763	5/19/2020	17:46	19:08	82.516667	Dist Primary - OH	Tree Row - Down	822	67828.7	15801
2680869	5/19/2020	18:28	22:18	230	Dist Secondary - OH	Tree Row - Down	1	230	308
2680923	5/19/2020	19:23	22:59	216.5	Dist Primary - OH	Tree Row - Down	1	216.5	15801
2680961	5/19/2020	20:57	23:02	124.33333	Dist Primary - OH	Tree Row - Down	1	124.3333333	14806
2681103	5/20/2020	1:43	3:02	79	Dist Primary - OH	Tree Row - Down	1	79	14987
2681370	5/20/2020	14:19	19:41	322	Dist Primary - OH	Tree Outside ROW - Down	21	6762	132
2682083	5/22/2020	14:02	15:39	97	Dist Secondary - OH	Tree Outside ROW - Limb	1	97	467
2682285	5/23/2020	5:47	8:05	137.16667	Dist Secondary - OH	Tree ROW - Limb	1	137.1666667	15006
2683699	5/28/2020	16:55	17:34	39	Dist Secondary - OH	Tree Outside ROW - Limb	1	39	15707
2684098	5/29/2020	14:28	17:18	169.68333	Dist Secondary - OH	Tree ROW - Limb	1	169.6833333	388
2684255	5/29/2020	23:27	2:03	156	Dist Primary - OH	Tree Outside ROW - Down	9	1404	14133
2685629	6/2/2020	16:27	17:33	65.533333	Dist Primary - OH	Tree Vine	13	851.9333333	15172
2686201	6/3/2020	17:37	19:26	109	Dist Primary - OH	Tree Outside ROW - Limb	13	1417	14987
2687063	6/5/2020	2:28	3:36	67.9	Dist Secondary - OH	Tree Outside ROW - Limb	1	67.9	15801
2687312	6/5/2020	10:51	17:47	416	Dist Secondary -	Tree Outside ROW - Limb	9	3744	14022

Event ID	Date of Outage	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Customers Affected	Customer Minutes	Feeder
					OH				
2687424	6/5/2020	15:49	19:10	200.23333	Dist Secondary - OH	Tree Row - Down	1	200.2333333	476
2687556	6/5/2020	19:59	20:57	57.4	Dist Primary - OH	Tree Outside ROW - Down	93	5338.2	14765
2688198	6/7/2020	9:01	9:11	10	Dist Secondary - OH	Tree Outside ROW - Limb	1	10	15173
2688545	6/8/2020	15:14	15:41	27	Dist Secondary - OH	Tree ROW - Limb	1	27	14766
2688653	6/9/2020	1:24	3:55	151	Dist Primary - OH	Tree Outside ROW - Down	67	10117	15001
2688675	6/9/2020	1:24	5:40	256	Dist Primary - OH	Tree Outside ROW - Down	7	1792	15001
2692955	6/16/2020	20:38	21:06	28	Dist Secondary - OH	Tree Outside ROW - Limb	1	28	15175
2693649	6/17/2020	20:29	21:09	39.416667	Dist Primary - OH	Tree Outside ROW - Limb	15	591.25	14035
2694491	6/19/2020	19:45	20:04	19	Dist Secondary - OH	Tree ROW - Limb	1	19	15015
2696684	6/24/2020	16:39	17:33	54	Dist Secondary - OH	Tree ROW - Limb	1	54	15021
2697381	6/25/2020	19:05	5:00	595	Dist Secondary - OH	Tree Outside ROW - Down	1	595	15944
2697776	6/26/2020	5:23	5:43	20	Dist Secondary - OH	Tree ROW - Limb	9	180	102
2698408	6/27/2020	17:15	20:37	201.3	Dist Primary - OH	Tree Outside ROW - Limb	20	4026	15009
2698433	6/27/2020	17:30	20:04	153.85	Dist Primary - OH	Tree ROW - Limb	49	7538.65	15018
2698447	6/27/2020	17:31	20:49	198	Dist Secondary - OH	Tree Outside ROW - Limb	1	198	15009
2698905	6/28/2020	20:44	22:47	122.56667	Dist Secondary - OH	Tree Outside ROW - Limb	1	122.5666667	65
2701834	7/4/2020	19:55	22:43	167.91667	Dist Primary -	Tree Outside ROW - Limb	28	4701.666667	15018

Event ID	Date of Outage	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Customers Affected	Customer Minutes	Feeder
					OH				
2702701	7/6/2020	18:47	1:47	419.81667	Dist Primary - OH	Tree ROW - Limb	26	10915.23333	15175
2702741	7/6/2020	18:47	14:15	1167.15	Dist Primary - OH	Tree Outside ROW - Limb	13	15172.95	15171
2702850	7/6/2020	18:51	1:47	416.23333	Dist Primary - OH	Tree ROW - Limb	13	5411.033333	15175
2702809	7/6/2020	18:52	4:01	548.06667	Dist Primary - OH	Tree Outside ROW - Limb	131	71796.73333	15171
2702848	7/6/2020	18:56	1:29	392.15	Dist Primary - OH	Tree ROW - Limb	15	5882.25	15175
2702889	7/6/2020	19:01	4:54	592.75	Dist Primary - OH	Tree Outside ROW - Down	8	4742	144
2702919	7/6/2020	19:04	21:29	144.96667	Dist Primary - OH	Tree Outside ROW - Down	111	16091.3	347
2702985	7/6/2020	19:06	17:10	1323.9833	Dist Secondary - OH	Tree ROW - Limb	1	1323.983333	15944
2703119	7/6/2020	19:09	22:11	182	Dist Primary - OH	Tree Outside ROW - Down	48	8736	495
2703118	7/6/2020	19:10	22:11	181	Dist Primary - OH	Tree Outside ROW - Down	16	2896	496
2703005	7/6/2020	19:10	5:40	2070	Dist Primary - OH	Tree Outside ROW - Limb	1	2070	15173
2703023	7/6/2020	19:11	20:48	1537	Dist Primary - OH	Tree Outside ROW - Down	34	52258	15171
2703048	7/6/2020	19:14	1:29	375	Dist Primary - OH	Tree ROW - Limb	118	44250	15175
2703117	7/6/2020	19:20	22:11	170.26667	Dist Primary - OH	Tree Outside ROW - Down	23	3916.133333	15170
2703115	7/6/2020	19:21	15:04	1183	Dist Secondary - OH	Tree Row - Down	9	10647	15711
2703543	7/6/2020	20:43	21:29	45.5	Dist Primary - OH	Tree Row - Down	17	773.5	347
2703530	7/6/2020	20:43	21:29	45.366667	Dist Primary -	Tree Row - Down	194	8801.133333	347

Event ID	Date of Outage	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Customers Affected	Customer Minutes	Feeder
					OH				
2703545	7/6/2020	20:44	21:29	44.966667	Dist Primary - OH	Tree Row - Down	31	1393.966667	347
2703534	7/6/2020	20:44	21:29	44.666667	Dist Primary - OH	Tree Row - Down	17	759.3333333	347
2703535	7/6/2020	20:44	21:29	44.416667	Dist Primary - OH	Tree Row - Down	29	1288.083333	347
2703550	7/6/2020	20:45	21:29	43.866667	Dist Primary - OH	Tree Row - Down	17	745.7333333	347
2703541	7/6/2020	20:45	22:11	85.1	Dist Primary - OH	Tree Outside ROW - Down	34	2893.4	347
2703542	7/6/2020	20:46	22:11	84.833333	Dist Primary - OH	Tree Row - Down	33	2799.5	347
2703547	7/6/2020	20:47	22:11	83.833333	Dist Primary - OH	Tree Row - Down	14	1173.666667	347
2703557	7/6/2020	20:49	22:11	81.75	Dist Primary - OH	Tree Row - Down	22	1798.5	347
2703569	7/6/2020	20:49	22:11	81.5	Dist Primary - OH	Tree Row - Down	23	1874.5	347
2703571	7/6/2020	20:52	22:11	78.55	Dist Primary - OH	Tree Row - Down	15	1178.25	347
2703601	7/6/2020	21:00	22:11	70.516667	Dist Primary - OH	Tree Row - Down	17	1198.783333	347
2703602	7/6/2020	21:02	22:11	69	Dist Primary - OH	Tree Row - Down	16	1104	347
2703622	7/6/2020	21:09	22:11	62	Dist Primary - OH	Tree Row - Down	1	62	347
2704052	7/7/2020	0:14	12:33	739	Dist Secondary - OH	Tree ROW - Limb	1	739	499
2704069	7/7/2020	0:35	1:02	26.75	Dist Primary - OH	Tree Outside ROW - Down	416	11128	368
2704133	7/7/2020	0:35	1:02	26.75	Dist Primary - OH	Tree Outside ROW - Down	416	11128	368
2704072	7/7/2020	0:38	1:02	23.683333	Dist Primary -	Tree Outside ROW - Down	13	307.8833333	368

Event ID	Date of Outage	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Customers Affected	Customer Minutes	Feeder
					OH				
2704077	7/7/2020	0:40	1:02	21.433333	Dist Primary - OH	Tree Outside ROW - Down	15	321.5	368
2704079	7/7/2020	0:42	1:02	19.9	Dist Primary - OH	Tree Outside ROW - Down	14	278.6	368
2704084	7/7/2020	0:43	1:02	18.1	Dist Primary - OH	Tree Outside ROW - Down	16	289.6	368
2704085	7/7/2020	0:44	1:02	17.766667	Dist Primary - OH	Tree Outside ROW - Down	11	195.4333333	368
2704105	7/7/2020	0:55	1:02	7	Dist Primary - OH	Tree Outside ROW - Down	1	7	368
2704102	7/7/2020	0:55	1:02	7	Dist Primary - OH	Tree Outside ROW - Down	5	35	368
2704103	7/7/2020	0:55	1:02	7	Dist Primary - OH	Tree Outside ROW - Down	1	7	368
2704107	7/7/2020	0:55	1:02	7	Dist Primary - OH	Tree Outside ROW - Down	9	63	368
2704109	7/7/2020	0:55	1:02	7	Dist Primary - OH	Tree Outside ROW - Down	1	7	368
2704106	7/7/2020	0:55	1:02	7	Dist Primary - OH	Tree Outside ROW - Down	1	7	368
2704100	7/7/2020	0:55	1:02	7	Dist Primary - OH	Tree Outside ROW - Down	11	77	368
2704098	7/7/2020	0:55	1:02	7	Dist Primary - OH	Tree Outside ROW - Down	6	42	368
2704108	7/7/2020	0:55	1:02	7	Dist Primary - OH	Tree Outside ROW - Down	6	42	368
2704104	7/7/2020	0:55	1:02	7	Dist Primary - OH	Tree Outside ROW - Down	12	84	368
2704099	7/7/2020	0:55	1:02	7	Dist Primary - OH	Tree Outside ROW - Down	5	35	368
2704101	7/7/2020	0:55	1:02	7	Dist Primary - OH	Tree Outside ROW - Down	1	7	368
2704130	7/7/2020	1:12	7:32	379.95	Dist Secondary -	Tree ROW - Limb	23	8738.85	15170

Event ID	Date of Outage	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Customers Affected	Customer Minutes	Feeder
					OH				
2704206	7/7/2020	1:58	13:12	673.46667	Dist Primary - OH	Tree ROW - Limb	49	32999.86667	14767
2704222	7/7/2020	2:04	13:14	669.6	Dist Primary - OH	Tree ROW - Limb	8	5356.8	14767
2704274	7/7/2020	2:15	13:16	661	Dist Primary - OH	Tree ROW - Limb	3	1983	14767
2704408	7/7/2020	3:53	4:05	11.783333	Dist Primary - OH	Tree Outside ROW - Down	22	259.2333333	15171
2704463	7/7/2020	4:56	11:15	378.25	Dist Primary - OH	Tree Row - Down	156	59007	15172
2705097	7/7/2020	5:06	11:15	369	Dist Primary - OH	Tree Outside ROW - Down	157	57933	15172
2704885	7/7/2020	9:26	22:40	2233.5333	Dist Primary - OH	Tree Outside ROW - Limb	8	17868.26667	144
2704889	7/7/2020	9:36	14:48	311.1	Dist Primary - OH	Tree Vine	19	5910.9	15172
2703023	7/7/2020	11:48	20:48	539.83333	Dist Primary - OH	Tree Outside ROW - Down	34	18354.33333	15171
2705138	7/7/2020	11:52	2:50	897.86667	Dist Secondary - OH	Tree ROW - Limb	1	897.8666667	14031
2705169	7/7/2020	12:06	18:40	394	Dist Secondary - OH	Tree ROW - Limb	1	394	15949
2705623	7/7/2020	19:47	23:20	212.31667	Dist Secondary - OH	Tree Outside ROW - Down	25	5307.916667	14765
2707372	7/11/2020	15:20	22:57	456.56667	Dist Primary - OH	Tree ROW - Limb	1	456.5666667	14017
2709117	7/16/2020	17:30	18:22	51.266667	Dist Primary - OH	Tree ROW - Limb	18	922.8	15013
2709164	7/16/2020	20:41	21:42	60.216667	Dist Primary - OH	Tree Outside ROW - Limb	1	60.21666667	14133
2709163	7/16/2020	20:42	21:42	60	Dist Primary - OH	Tree ROW - Limb	2	120	14133
2709162	7/16/2020	20:42	21:42	60	Dist Primary -	Tree ROW - Limb	1	60	14133

Event ID	Date of Outage	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Customers Affected	Customer Minutes	Feeder
					OH				
2709944	7/19/2020	6:57	9:30	152.63333	Dist Secondary - OH	Tree Outside ROW - Down	27	4121.1	372
2710624	7/20/2020	9:45	14:05	260	Dist Secondary - OH	Tree Outside ROW - Down	1	260	308
2711743	7/21/2020	23:12	1:56	164	Dist Primary - OH	Tree ROW - Limb	34	5576	345
2711805	7/21/2020	23:12	2:29	197	Dist Primary - OH	Tree ROW - Limb	235	46295	345
2711755	7/21/2020	23:19	0:04	45	Dist Secondary - OH	Tree Outside ROW - Limb	1	45	75
2711938	7/22/2020	9:24	15:11	346.46667	Dist Primary - OH	Tree Vine	13	4504.066667	15172
2712154	7/22/2020	13:45	16:57	191.76667	Dist Secondary - OH	Tree Outside ROW - Limb	1	191.7666667	292
2712297	7/22/2020	15:51	20:55	303.8	Dist Primary - OH	Tree Outside ROW - Limb	17	5164.6	52
2712371	7/22/2020	16:03	22:44	400.65	Dist Primary - OH	Tree ROW - Limb	16	6410.4	496
2712384	7/22/2020	16:04	17:28	83.2	Dist Primary - OH	Tree ROW - Limb	22	1830.4	15012
2712604	7/22/2020	16:30	2:14	583.31667	Dist Primary - OH	Tree ROW - Limb	1	583.3166667	15950
2712816	7/22/2020	17:14	0:34	439.55	Dist Primary - OH	Tree Outside ROW - Limb	5	2197.75	15001
2713120	7/22/2020	17:35	0:38	423	Dist Primary - OH	Tree Outside ROW - Limb	2	846	15001
2713842	7/23/2020	11:27	11:34	7	Dist Secondary - OH	Tree Outside ROW - Limb	23	161	14987
2714162	7/23/2020	18:50	20:01	70.1	Dist Secondary - OH	Tree Outside ROW - Limb	1	70.1	75
2714195	7/23/2020	20:36	22:04	87.15	Dist Primary - OH	Tree ROW - Limb	11	958.65	144
2714202	7/23/2020	20:44	22:05	80.083333	Dist Primary -	Tree ROW - Limb	3	240.25	144

Event ID	Date of Outage	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Customers Affected	Customer Minutes	Feeder
					OH				
2714203	7/23/2020	20:47	21:38	50.85	Dist Primary - OH	Tree Outside ROW - Limb	1872	95191.2	14758
2714203	7/23/2020	20:47	23:06	139.18333	Dist Primary - OH	Tree Outside ROW - Limb	245	34099.91667	14758
2714207	7/23/2020	20:49	0:54	245	Dist Primary - OH	Tree Outside ROW - Down	605	148225	14755
2714207	7/23/2020	20:49	22:47	118.75	Dist Primary - OH	Tree Outside ROW - Down	624	74100	14755
2714930	7/23/2020	20:51	22:47	115.83333	Dist Primary - OH	Tree Outside ROW - Down	65	7529.166667	14755
2714212	7/23/2020	20:52	22:05	72.683333	Dist Primary - OH	Tree Outside ROW - Limb	7	508.7833333	144
2714248	7/23/2020	20:58	3:04	366	Dist Primary - OH	Tree ROW - Limb	148	54168	14022
2714248	7/23/2020	20:58	11:06	848	Dist Primary - OH	Tree ROW - Limb	11	9328	14022
2714248	7/23/2020	20:58	23:46	168	Dist Primary - OH	Tree ROW - Limb	48	8064	14022
2714248	7/23/2020	20:58	3:04	366	Dist Primary - OH	Tree ROW - Limb	21	7686	14007
2714248	7/23/2020	20:58	9:52	774	Dist Primary - OH	Tree ROW - Limb	7	5418	14022
2714248	7/23/2020	20:58	10:05	787	Dist Primary - OH	Tree ROW - Limb	32	25184	14022
2720617	7/23/2020	21:58	1:43	225	Dist Primary - OH	Tree Outside ROW - Limb	1	225	372
2720611	7/23/2020	21:58	1:43	225	Dist Primary - OH	Tree Outside ROW - Limb	1	225	372
2720595	7/23/2020	21:58	1:43	225	Dist Primary - OH	Tree Outside ROW - Limb	1	225	372
2720603	7/23/2020	21:58	1:43	225	Dist Primary - OH	Tree Outside ROW - Limb	1	225	372
2720608	7/23/2020	21:58	1:43	225	Dist Primary -	Tree Outside ROW - Limb	1	225	372

Event ID	Date of Outage	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Customers Affected	Customer Minutes	Feeder
					OH				
2720597	7/23/2020	21:59	1:44	225	Dist Primary - OH	Tree Outside ROW - Limb	1	225	372
2714789	7/23/2020	22:03	1:45	222	Dist Primary - OH	Tree Outside ROW - Limb	119	26418	372
2714834	7/23/2020	22:08	1:43	214.88333	Dist Primary - OH	Tree Outside ROW - Limb	16	3438.133333	372
2714248	7/23/2020	23:39	9:52	613	Dist Primary - OH	Tree ROW - Limb	8	4904	14022
2714207	7/24/2020	0:32	0:54	21.683333	Dist Primary - OH	Tree Outside ROW - Down	57	1235.95	14755
2720612	7/24/2020	0:33	0:41	8	Dist Primary - OH	Tree Outside ROW - Limb	1	8	372
2720605	7/24/2020	0:34	0:41	7	Dist Primary - OH	Tree Outside ROW - Limb	1	7	372
2720604	7/24/2020	0:34	0:41	7	Dist Primary - OH	Tree Outside ROW - Limb	1	7	372
2720598	7/24/2020	0:34	0:41	7	Dist Primary - OH	Tree Outside ROW - Limb	1	7	372
2720594	7/24/2020	0:34	0:41	7	Dist Primary - OH	Tree Outside ROW - Limb	1	7	372
2720610	7/24/2020	0:34	0:41	7	Dist Primary - OH	Tree Outside ROW - Limb	1	7	372
2720591	7/24/2020	0:34	0:41	7	Dist Primary - OH	Tree Outside ROW - Limb	1	7	372
2720621	7/24/2020	0:34	0:41	7	Dist Primary - OH	Tree Outside ROW - Limb	1	7	372
2715347	7/24/2020	9:34	21:47	732.76667	Dist Secondary - OH	Tree Outside ROW - Limb	1	732.7666667	15867
2718359	7/30/2020	18:53	19:18	25	Dist Secondary - OH	Tree Outside ROW - Limb	1	25	14017
2719960	8/4/2020	3:25	4:30	64.133333	Dist Secondary - OH	Tree ROW - Limb	1	64.13333333	14031
2720111	8/4/2020	9:06	11:14	128	Dist Primary -	Tree Outside ROW - Limb	211	27008	499

Event ID	Date of Outage	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Customers Affected	Customer Minutes	Feeder
					OH				
2720107	8/4/2020	9:10	10:53	102.56667	Dist Primary - OH	Tree Vine	1	102.5666667	14133
2720252	8/4/2020	10:02	19:36	573.15	Dist Primary - OH	Tree Outside ROW - Down	5	2865.75	144
2722070	8/8/2020	3:17	5:42	144.55	Dist Primary - OH	Tree Outside ROW - Down	186	26886.3	14900
2722243	8/9/2020	0:10	11:30	679.81667	Dist Primary - OH	Tree Outside ROW - Down	2	1359.633333	15950
2722231	8/9/2020	0:10	2:56	166.4	Dist Primary - OH	Tree Outside ROW - Down	56	9318.4	15950
2722231	8/9/2020	0:11	2:56	165.48333	Dist Primary - OH	Tree Outside ROW - Down	16	2647.733333	15950
2722311	8/9/2020	11:14	12:11	57	Dist Primary - OH	Tree Row - Down	1	57	15711
2722344	8/9/2020	13:27	19:50	383	Dist Primary - OH	Tree Outside ROW - Down	12	4596	14900
2722974	8/10/2020	18:03	21:16	193	Dist Primary - OH	Tree Outside ROW - Down	90	17370	14900
2722987	8/10/2020	18:22	21:20	178	Dist Primary - OH	Tree Outside ROW - Down	1	178	14900
2723457	8/12/2020	9:45	10:22	37	Dist Secondary - OH	Tree ROW - Limb	1	37	14261
2725297	8/16/2020	22:50	0:13	82.466667	Dist Secondary - OH	Tree Outside ROW - Limb	1	82.46666667	15085
2725375	8/17/2020	8:02	14:58	415.88333	Dist Primary - OH	Tree Row - Down	1	415.8833333	14016
2726672	8/20/2020	19:49	20:01	12	Dist Secondary - OH	Tree ROW - Limb	1	12	117
2728980	8/27/2020	23:49	0:21	31.466667	Dist Secondary - OH	Tree Outside ROW - Limb	87	2737.6	15013
2731328	9/2/2020	16:14	17:55	100.71667	Dist Secondary - OH	Tree ROW - Limb	1	100.7166667	15130
2735117	9/3/2020	17:25	4:02	637	Dist Secondary -	Tree Outside ROW - Limb	1	637	117

Event ID	Date of Outage	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Customers Affected	Customer Minutes	Feeder
					OH				
2732092	9/3/2020	17:36	2:51	555	Dist Primary - OH	Tree ROW - Limb	9	4995	14767
2732606	9/3/2020	17:44	4:30	646	Dist Primary - OH	Tree Outside ROW - Down	7	4522	14005
2731811	9/3/2020	17:45	18:02	17.2	Dist Primary - OH	Tree Outside ROW - Down	65	1118	14005
2731811	9/3/2020	17:45	18:50	65.066667	Dist Primary - OH	Tree Outside ROW - Down	35	2277.333333	14005
2731811	9/3/2020	17:45	2:54	548.9	Dist Primary - OH	Tree Outside ROW - Down	71	38971.9	14005
2731811	9/3/2020	17:45	18:01	16	Dist Primary - OH	Tree Outside ROW - Down	155	2480	14005
2732132	9/3/2020	17:45	5:21	695.86667	Dist Primary - OH	Tree ROW - Limb	1	695.8666667	14133
2732120	9/3/2020	17:46	21:45	238.76667	Dist Primary - OH	Tree Outside ROW - Down	53	12654.63333	14005
2732238	9/3/2020	17:56	6:37	761	Dist Secondary - OH	Tree Outside ROW - Limb	15	11415	490
2732421	9/3/2020	19:00	19:05	5.3333333	Dist Primary - OH	Tree Outside ROW - Down	83	442.6666667	14005
2732460	9/3/2020	19:12	4:07	534.13333	Dist Secondary - OH	Tree Outside ROW - Limb	1	534.1333333	14014
2735120	9/4/2020	1:43	2:36	53	Dist Secondary - OH	Tree Outside ROW - Limb	1	53	117
2732889	9/4/2020	3:00	4:18	77.9	Dist Primary - OH	Tree Outside ROW - Down	114	8880.6	14005
2736948	9/14/2020	12:07	13:28	80.4	Dist Primary - OH	Tree Outside ROW - Limb	1	80.4	476
2737864	9/14/2020	17:16	17:48	32	Dist Secondary - OH	Tree Outside ROW - Limb	1	32	347
2738358	9/18/2020	17:21	19:31	129.28333	Dist Secondary - OH	Tree ROW - Limb	1	129.2833333	14009
2738497	9/19/2020	11:19	12:59	99.416667	Dist Primary -	Tree Outside ROW - Limb	1	99.41666667	15950

Event ID	Date of Outage	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Customers Affected	Customer Minutes	Feeder
					OH				
2738500	9/19/2020	11:52	13:01	68.366667	Dist Primary - OH	Tree Outside ROW - Limb	1	68.36666667	15950
2740269	9/25/2020	11:12	12:36	84	Dist Secondary - OH	Tree Outside ROW - Limb	1	84	14900
2740492	9/26/2020	3:21	4:37	75.85	Dist Secondary - OH	Tree Outside ROW - Limb	1	75.85	14031
2741395	9/30/2020	8:00	10:40	159.91667	Dist Secondary - OH	Tree Outside ROW - Limb	1	159.9166667	102
2741468	9/30/2020	11:19	13:24	124.58333	Dist Primary - OH	Tree Outside ROW - Limb	1	124.5833333	14987
2742041	10/2/2020	12:19	12:58	39	Dist Secondary - OH	Tree Outside ROW - Limb	10	390	14261
2743762	10/8/2020	13:56	17:36	219.16667	Dist Secondary - OH	Tree Outside ROW - Down	1	219.1666667	467
2744426	10/8/2020	6:46	8:55	128.86667	Dist Primary - OH	Tree ROW - Limb	6	773.2	15950
2746847	10/21/2020	9:21	10:24	62.633333	Dist Primary - OH	Tree ROW - Limb	13	814.2333333	15018
2749045	10/29/2020	7:22	10:43	201.66667	Dist Secondary - OH	Tree ROW - Limb	1	201.6666667	14093
2749104	10/29/2020	11:18	12:40	82	Dist Primary - OH	Tree Outside ROW - Limb	1	82	15013
2749262	10/29/2020	18:45	1:15	390	Dist Primary - OH	Tree Outside ROW - Down	7	2730	64
2749873	11/1/2020	13:41	13:54	13	Dist Secondary - OH	Tree Outside ROW - Down	1	13	15175
2750066	11/1/2020	21:34	2:35	301	Dist Primary - OH	Tree Row - Down	63	18963	15801
2750319	11/1/2020	21:34	2:35	301	Dist Primary - OH	Tree Row - Down	33	9933	15801
2750315	11/1/2020	23:20	9:51	631	Dist Primary - OH	Tree Outside ROW - Down	4	2524	15867
2750340	11/1/2020	23:34	2:25	170.11667	Dist Secondary -	Tree ROW - Limb	1	170.1166667	15130

Event ID	Date of Outage	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Customers Affected	Customer Minutes	Feeder
					OH				
2750431	11/2/2020	5:13	9:09	235.81667	Dist Primary - OH	Tree Outside ROW - Limb	1	235.8166667	14900
2750888	11/2/2020	8:20	10:42	141.51667	Dist Secondary - OH	Tree ROW - Limb	1	141.5166667	15711
2750996	11/2/2020	9:45	10:37	52.5	Dist Primary - OH	Tree Outside ROW - Limb	188	9870	14900
2751818	11/3/2020	6:53	12:51	358.03333	Dist Primary - OH	Tree Outside ROW - Down	1	358.0333333	14133
2753919	11/11/2020	9:00	9:37	36.033333	Dist Primary - OH	Tree ROW - Limb	351	12647.7	15018
2753875	11/11/2020	9:00	9:37	36.766667	Dist Primary - OH	Tree ROW - Limb	265	9743.166667	15018
2753938	11/11/2020	10:31	12:45	134	Dist Primary - OH	Tree ROW - Limb	17	2278	14093
2753961	11/11/2020	11:17	14:01	164	Dist Primary - OH	Tree Outside ROW - Limb	54	8856	14900
2753961	11/11/2020	11:17	11:30	13	Dist Primary - OH	Tree Outside ROW - Limb	405	5265	14900
2754017	11/11/2020	11:53	12:45	51.966667	Dist Primary - OH	Tree Outside ROW - Limb	12	623.6	14093
2754105	11/11/2020	12:22	14:01	98.9	Dist Primary - OH	Tree Outside ROW - Limb	40	3956	14900
2754105	11/11/2020	12:22	14:10	107.9	Dist Primary - OH	Tree Outside ROW - Limb	11	1186.9	14900
2754105	11/11/2020	12:22	15:19	176.9	Dist Primary - OH	Tree Outside ROW - Limb	2	353.8	14900
2754626	11/12/2020	8:26	10:05	98.533333	Dist Primary - OH	Tree Vine	39	3842.8	14767
2755677	11/15/2020	19:23	21:04	101.1	Dist Primary - OH	Tree ROW - Limb	888	89776.8	14987
2755677	11/15/2020	19:23	19:53	30	Dist Primary - OH	Tree ROW - Limb	1233	36990	14987
2756460	11/17/2020	16:13	16:43	29.383333	Dist Secondary -	Tree Vine	25	734.5833333	15001

Event ID	Date of Outage	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Customers Affected	Customer Minutes	Feeder
					OH				
2757951	11/23/2020	4:22	6:33	130.16667	Dist Secondary - OH	Tree Outside ROW - Limb	1	130.1666667	15021
2758040	11/23/2020	11:04	12:00	56	Dist Secondary - OH	Tree Outside ROW - Limb	1	56	15006
2758386	11/24/2020	14:54	18:39	224.85	Dist Secondary - OH	Tree ROW - Limb	1	224.85	82
2759333	11/30/2020	7:25	11:41	255.78333	Dist Primary - UG	Tree Outside ROW - Down	13	3325.183333	75
2759531	11/30/2020	11:19	11:44	25.433333	Dist Primary - UG	Tree Outside ROW - Down	1	25.43333333	75
2764338	12/16/2020	16:54	18:12	77.283333	Dist Primary - OH	Tree ROW - Limb	62	4791.566667	14133
2764379	12/16/2020	18:07	18:54	46.216667	Dist Secondary - OH	Tree Outside ROW - Down	11	508.3833333	451

Pepco tracks the District of Columbia System Tree SAIFI and SAIDI to measure the effectiveness of VM. Tree SAIFI and SAIDI measures the level of vegetation-caused outages. The following tables present data showing the System Tree SAIFI and SAIDI (in minutes) for the Pepco District of Columbia service territory for 2015 to 2020, based on the Major Service Outage ("MSO") exclusion criteria.

Table 2.4-K4

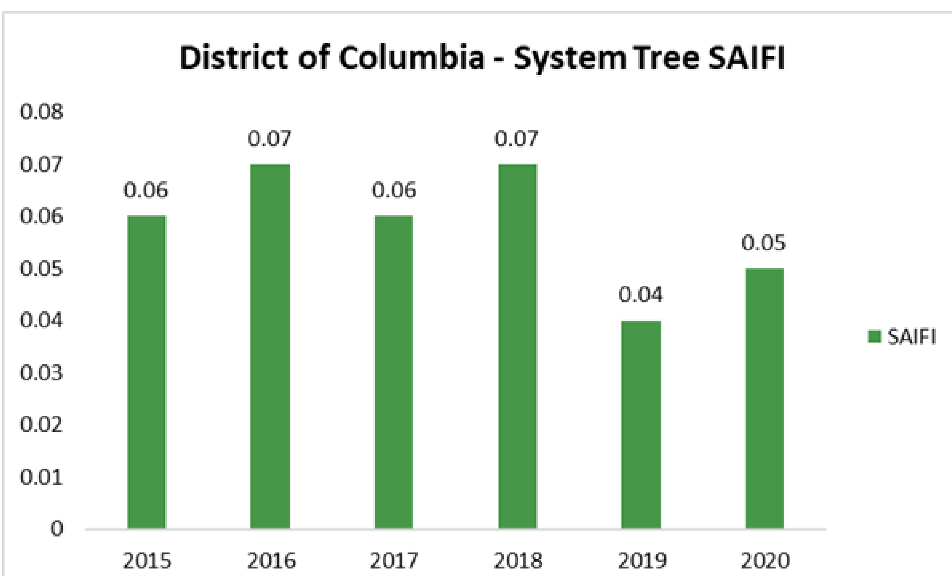
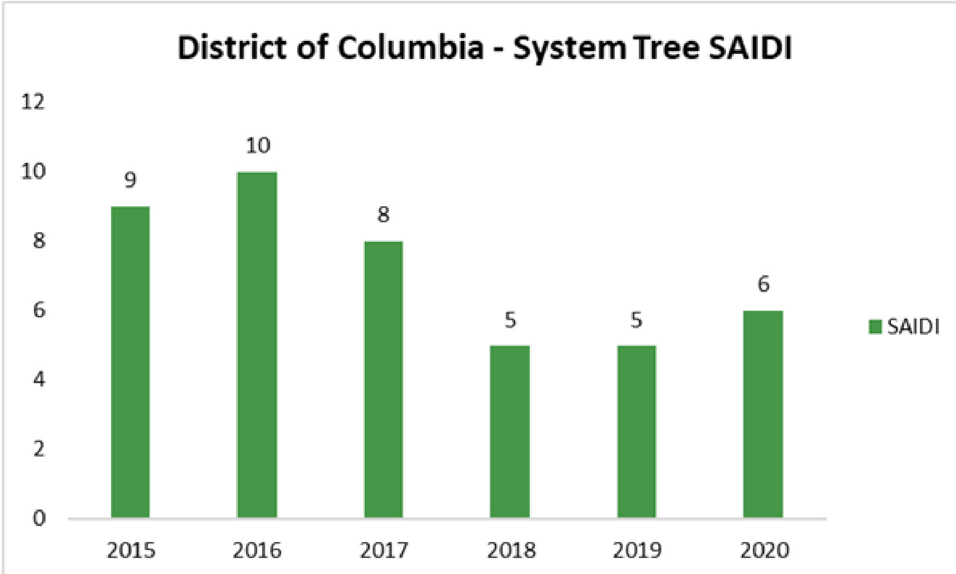


Table 2.4-K5



2.4.4 ELECTRICITY QUALITY OF SERVICE STANDARDS (EQSS)

The Commission introduced the EQSS to establish standards and requirements for ensuring that electric utilities operating in the District of Columbia meet an adequate level of quality and reliability in the electric service provided to District residents. On February 29, 2008, the Commission issued a Notice of Final Rulemaking (NOFR) on the EQSS. The EQSS are now adopted as Chapter 36, Electricity Quality of Service Standards in Title 15 of the District of Columbia Municipal Regulations. Subsequently on July 25, 2008, the Commission issued a NOFR on Compliance Reporting. Pepco and all electricity suppliers within the District of Columbia were directed to collect EQSS data on a monthly basis and retain the reporting data for seven (7) years. Further, quarterly submissions, containing monthly data, are to be filed with the Commission on April 30, July 30, October 30 and January 30 for the prior three (3) months respectively. Specific Consolidated Report requirements from the EQSS portion of the D.C.M.R. are listed on the footnote.[68]

[68] Progress on current corrective action plans [on customer calls answered] shall be included in the utility's annual Consolidated Report.

Electricity Quality of Service Standards Results

January – December 2020 Aggregate Totals

The utility shall report the actual call center performance during the reporting period in the annual Consolidated Report of the following year.

Progress on any current corrective action plans [on call abandonment rates] will be included in the utility's annual Consolidated Report.

The utility shall report the actual performance obtained during the reporting period in the annual Consolidated Report of the following year.

The utility shall complete installation of new residential service requests within ten (10) business days of the start date for the new installation.

Progress on any current corrective action plans [on new residential service installation requests] will be included in the utility's annual Consolidated Report.

The utility shall report the actual performance obtained during the reporting period in the annual Consolidated Report of the following year.

3603.5 The utility shall report on the progress of the corrective action plan [on repeat least performing feeders] in the Annual Consolidated Report submitted to the Commission.

The utility shall report on the number and percentage of non-major service outages that extend beyond the twenty-four (24) hour standard and the reasons each such outage extended beyond the twenty-four (24) hour standard.

The report drafted pursuant to Section 3603.8 shall be included in the annual Consolidated Report on reliability data.

The utility shall report on the progress of the corrective action plan [on SAIFI, SAIDI and CAIDI benchmarks] in the annual Consolidated Report submitted to the Commission.

The utility shall also, per the orders of the Commission, continue current requirements of reporting annual reliability indices of SAIFI, SAIDI and CAIDI (with and without major events) in the annual Consolidated Report of the following year.

3601	**Reporting Requirements for Service Outages, Incidents and Power Quality Complaints**							
	Standards		**2020 Aggregate Totals**					
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3601.2/ 3601.6	Report major and non-major service outages by telephone and e-mail within one (1) hour after the utility has determined that a major service outage occurred or after the utility becomes aware of the incident.	Report by telephone and e-mail **within one (1) hour.**	247	100%	See FC Nos. 982 & 1002, Pepco's Quarterly EQSS filings dated April 30, 2020; July 30, 2020; October 30, 2020; and February 1, 2021.		
3601.3/ 3601.8	Each telephone and e-mail report on major and non-major outages should contain a) the location, b) Wards affected, c) # of customers out of service, d) cause of the outage, e) the estimated repair time, and, for major outages, f) notification of progress to major outage status.	Each 3601.3 report must contain **(a) - (f)**, each 3601.8 report must contain **(a) - (e)**.	247	100% (Except for ward data)	See FC Nos. 982 & 1002, Pepco's Quarterly EQSS filings dated April 30, 2020; July 30, 2020; October 30, 2020; and February 1, 2021.		
3601.4	Report periodically (frequency to be determined by the Commission's Office of Engineering) regarding the status of the major service outage.	**TBD**	NA	NA			

3601	**Reporting Requirements for Service Outages, Incidents and Power Quality Complaints**						
	Standards		**2020 Aggregate Totals**				
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3601.5	Specific restoration information, including restoration times, shall be provided to District customers by customer service representatives and the automated voice response unit.	**TBD**	NA	NA			
3601.9/ 3601.11	Report by telephone all manhole incidents (smoking manholes, manhole fires, manhole explosions) and all incidents that result in the loss of human life and/or personal injury requiring hospitalization within thirty (30) minutes upon receiving notice of the incident.	Report **within 30 minutes** of receiving **notice of incident.**	5	100%	See FC Nos. 982 & 1002, Pepco's Quarterly EQSS filings dated April 30, 2020; July 30, 2020; October 30, 2020; and February 1, 2021.		
3601.10/ 3601.12	Telephone and e-mail reporting of incidents to include: a/b) location/description of the incident, b/c) Ward, c/d) customers and/or persons affected, d/e) cause of incident, e) estimated repair and/or restoration time (for manhole incidents), and f) steps utility will take to provide assistance (for personal injury incidents).	**Each 3601.10 report must contain (a) - (e)**, each 3601.12 report must contain **(a) - (f)**.	5	100% (Except for ward data)	See FC Nos. 982 & 1002, Pepco's Quarterly EQSS filings dated April 30, 2020; July 30, 2020; October 30, 2020; and February 1, 2021.		

3601	**Reporting Requirements for Service Outages, Incidents and Power Quality Complaints**							
Standards			**2020 Aggregate Totals**					
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3601.13/ 3601.15	Written reports concerning non-major service outages and/or manhole incidents shall be submitted to OE and OPC within five (5) days from the date of the event occurrence. Written reports on the loss of human life/personal injury shall be submitted within five (5) days of receiving notice of the incident.	Submit 3601.13 report **within 5 days of event,** and 3601.15 report **within 5 days of receiving notice.**	247	98%	See FC Nos. 982 & 1002, Pepco's Quarterly EQSS filings dated April 30, 2020; July 30, 2020; October 30, 2020; and February 1, 2021.		
3601.14/ 3601.16	At a minimum: each written report on non-major service outages and/or manhole incidents shall state, a) description, b) location, c) Wards, d) time of the outage, e) repair and restoration times, f) duration of outage(s) in hrs/min., g) total # of customers, h) total # of manholes, i) classification of the manhole incident(s); each written report on loss of human life and/or personal injury shall state, a) description, b) location, c) Ward, d) exact time, e) total # of customers, f) assistance steps, g) time it took assistance to arrive, h) steps to prevent reoccurrence.	Each 3601.14 report must contain **(a) - (i)**, each 3601.16 report must contain **(a) - (h)**.	247	100%			
3601.17	Provide a detailed report on non-major service outages, manhole incidents, and/or incidents that result in the loss of human life or personal injury to the Productivity Improvement Working Group (PIWG) every quarter.	Submit all applicable reports to the PIWG **every quarter**.	0	100%			

3601	**Reporting Requirements for Service Outages, Incidents and Power Quality Complaints**						
Standards			**2020 Aggregate Totals**				
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3601.18	File a written report concerning major service outages within 3 weeks following the end of the outage.	File the required written report **to each office within three (3) weeks** of the end of a major service outage.	0	NA			
3601.19	Specifies minimum requirements for the contents of the written report for major service outages. ***Please refer to the EQSS for (a)-(o) as they are very detailed and are not listed here.***	Each written report must **contain** information **from (a) - (o).**	NA	NA			
3601.2	Submit a written report on the Outage Management System's (OMS) actual performance during the major service outage within 30 days after restoration efforts are completed.	Submit written report **within 30 days** after restoration.	NA	NA			
3601.21/ 3601.23	Record and report the number of power quality complaints received, types of complaints received, results of subsequent investigations, corrective actions taken, and the time it took to resolve the customer's problem.	Submit the report **45** days after each **six (6) month** reporting period.	2 See reports filed May 15, 2020 and Nov. 15 2020 in FC Nos. 982 & 1002	NA			

3602	Customer Service Standards						
Standards			2020 Aggregate Totals				
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3602.1	Maintain a customer service (walk-in) office located in the District of Columbia.	Notify location of **one (1)** office.	701 9th St NW, Washington, DC 20068	100%			
3602.2	Answer at least seventy (70) percent of all customers' phone calls received within thirty (30) seconds and maintain records delineating customer phone calls answered by a utility representative or an automated operator system. Utility shall measure and report on the average customer wait time for a customer transferred from an automated operator system to a utility representative.	70% of received calls answered within **30** seconds	720,979 (Total calls) Call answering rate = 95%	100%			
3602.4/ 3602.6/ 3602.7	Develop a corrective action plan if 3602.2 standard is not met. Report on the progress of current corrective action plans and actual call center performance in the annual Consolidated Report.	Written corrective action plan in CR	NA	NA			
3602.8	Call abandonment rate must be maintained below ten (10) percent.	Call abandonment rate **below 10%**	3,401 (Calls abandoned) Call abandonment rate = 1%	100%			
3602.10/ 3602.12/ 3602.13	Develop a corrective action plan if 3602.8 standard is not met. Report on the progress of current corrective action plans and actual call center performance in the annual Consolidated Report.	Written corrective action plan in CR	NA	NA			

3602	Customer Service Standards (cont'd.)						
Standards			2020 Aggregate Totals				
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3602.14	Complete installation of new residential service requests within ten (10) business days of the start date for the new installation.	Service requests installed within **10** days of start.	NA	NA			
3602.16	Submit a written report on its performance in 3602.14 every six (6) months.	One report every six **(6)** months.	2 See reports filed May 15, 2020 and Nov. 15 2020 in FC Nos. 982 & 1002	NA			
3602.19/ 3602.21/ 3602.22	Develop a corrective action plan if 3602.14 standard is not met. Report on the progress of current corrective action plans and actual performance in the annual Consolidated Report.	Written corrective action plan in CR		NA			

3603	Reliability Standards						
Standards			2020 Aggregate Totals				
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3603.1	Implement a plan to improve the performance of the two (2) percent least performing feeders.	Written plan identifying the 2% LP feeders targeted.	See Consolidated Report Filed 4/11/2020	100%			
3603.3/ 3603.5	If the utility fails to comply with 3603.1, a corrective action plan is required. Report on the progress of the corrective action in the Consolidated Report.	Written corrective action plan in CR	See Consolidated Report Filed 4/1/2020	100%			
3603.7/ 3603.8	Complete service restoration within 24 hours following a non-major service outage. Report on the number and percentages of outages that extend beyond the 24 hour standard and the causes for the extended outages.	Restoration within **24** hrs. Written report on 24 hr exceedance in CR	5	96%	See FC Nos. 982 & 1002, Pepco's Quarterly EQSS filings dated April 30, 2020; July 30, 2020; October 30, 2020; and February 1, 2021.		
3603.10/ 3603.11/ 3603.12/ 3603.13	Utility shall not exceed the benchmark levels established for the System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), and the Customer Average Interruption Duration Index (CAIDI).	Refer to Order No. 16700.	NA (Refer to Order No. 18148)	NA			
3603.14/ 3603.16/ 3603.17	Develop a corrective action plan if 3603.10 standard is not met. Report on the progress of current corrective action plans and actual performance in the annual Consolidated Report.	Document Corrective action plan in CR	NA	NA			

3604	Billing Error Notification							
Standards			2020 Aggregate Totals					
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3604.1	Inform Commission and OPC of a billing error when it affects 100 or more customers or the number of affected customers is equal to or more than two (2) percent of the utility's or service provider's customer base (whichever is less). If the customer base is less than 100, report errors when two (2) or more customers are affected.	Notices when 100, or 2%, or 2 or more customers are affected.	2	100%			
3604.2/ 3604.3	Submit an initial billing error notification (by e-mail) within one (1) business day of discovering or being notified of the error, submit a written report within 14 calendar days and a final written report within 60 calendar days.	Initial notification within one **(1)** b/day, 1st written report within **14** c/days, final written report within 60 c/days.	2	100%			
3604.4	Initial billing error notification shall contain: a) type of billing error, b) when discovered, c) how discovered, and d) # of customers affected.	Notification must contain **(a)** - **(d)**.	NA	NA			
3604.5	Follow-up written report shall contain: a) type of billing error, b) when it occurred, c) # of customers affected, d) the cause of the error and correction status, and, e) timeline for completing correction plan.	Report must contain **(a) - (e)**, and show closeout of **(d) within 60 days.**	NA	NA			

3604	Billing Error Notification (cont'd.)						
Standards			2020 Aggregate Totals				
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3604.6/ 3604.7	Final written report shall contain: a) type of billing error, b) when it occurred, c) # of customers affected, d) duration of the billing error(s), e) corrective and preventive measures taken, and, f) lessons learned, if any. Commission shall determine whether further investigation is necessary.	Report must contain **(a) - (f).**	2	100%			

Non-Major Outages, Restoration Completion Within 24 Hours

In accordance with Section 3603.8 in the EQSS, Pepco is to include in the Consolidated Report the number and percentage of non-major customer outages that extend beyond the 24-hour standard and the causes for these extended service outages. A Major Service Outage in the District of Columbia, as defined in Section 3699.1, Definitions, of the EQSS states, *"customer interruption occurrences and durations during time periods when 10,000 or more of the electric utility's District of Columbia customers are without service and the restoration effort due to this major service outage takes more than 24 hours."*

Table 2.4-I provide the required information.

For 2020, there was 1 (of 247) non-major outages that extended beyond 24 hours.

Percentage of Non-Major Outages that Extended Beyond 24 Hours

Table 2.4-L

Total number of Non-Major Outages extending beyond 24 hours	5
Total number of Non-Major Outages: January 1 - December 31, 2020	247
Percentage of Non-Major Outages extending beyond 24 hours	2%

Table 2.4-M: 2020 Non-Major Outages Extending Beyond 24 Hours

2020 Non-Major Outage Reporting to the Public Service Commission of the District of Columbia - Outages Exceeding 24 Hours

Report Sequence Number	Outage Sequence Number	Manhole Sequence Number*	Month	Day of Outage	OH or UG	Outage Cause/ Incident Description	Location	Quadrant	Ward	Time of Outage/ Incident	Actual Restoration Time	Duration of Outage Hours / min		Max No. of Cust. Affected	Reason for Outage Exeeding 24 Hours to Restore	Feeder No.
52	77	DC20-07	JUNE	9	UG	Manhole fire was reported by DC Fire Dept. A solid primary manhole cover was found displaced, no smoke and no fire. The crew found a failed 500 3/C PILC in duct line. Crew replaced cable. Event #2688783	3220 Connecticut Ave & Macomb St, NW	NW	3	1149	2325 (6/11)	59	30	5	This event occurred due to circuit failure. Feeder tripped and fire was reported. Feeder had to be cleared and station tagged. Repairs required the replacement of 670 feet of PILC and EPR cable.	14148R
61	101		JUNE	21	OH	Manhole Network Cable Failure/ feeder tripped; services dropped (15378) – Permanent repairs, services restored. Event# 2694797	1025 Connecticut Ave NW	NW	2	1365 (6/19)	701	41	6	1	This was a significant event that impacted multiple circuits. Repairs required replacing several stretches of cable in multiple locations.	15378
77	126		JULY	21	UG	Cable failure/services dropped (00063) - Temporary repairs, restored services. Event# 2710830	Vicinity of 34th St NW & Massachusetts Ave	NW	3	1656 (7/20)	2239	29	43	6	This event was an outage on 4KV circuit. This outage had a long duration due to repairs that had to be made to another 4KV circuit that was also damaged. Work was also required by overhead crews in order to isolate and ground circuit which took substantial time. Portable generation was provided to several customers in an effort to minimize disruption.	63
80	144		JULY	24	UG	Cable failure/service dropped (15204) Event# 2713987- Permanent repairs, services restored.	421 Q St NW	NW	2	1411 (7/23)	2126	31	14	1	This event was on a 13kV distribution feeder. Load was tied off after the fault was isolated. Permanent repairs were delayed due to resources needing to be called in off shift.	15204
85	154		AUGUST	2	UG	Cable failure/service dropped (15706) -Repaired, permanent repairs Event# 2718986	320 40th St NE	NE	7	1046 (8/1)	1157	25	11	1	This event was a B & C phase fault to a customer's switch gear. Customer coordination delayed the repairs, and assistance from overhead crews was also required. Customer also wanted repairs to be completed off shift since they still had partial power and were able to operate at limited capacity.	15706

PART 3: 2020 MANHOLE EVENT REPORT

PART 3: 2020 MANHOLE EVENT REPORT[69]

Part 3 of the Consolidated Report includes manhole event information, underground failure analysis results, detailed tracking trends in reportable events based on manhole cover type, and Pepco's cable splice records for 2020. The appendices provide detail regarding manhole events, and Pepco's manhole inspection program.

SECTION 3.1 – 2020 MANHOLE EVENT INTRODUCTION

Pepco herein submits its annual Manhole Event Report for 2020 in accordance with Order Nos. 11716, 13812, 15620 and 16091.

[69] In Order No. 16091 issued on December 10, 2010, the Commission stated at paragraphs 56, 59, 65, and 66 the following:
56. Decision. Pepco has agreed to make the recommended changes in the 2011 Consolidated Report with the exception of data on failure rates. We require that the members of the PIWG discuss the need for and feasibility of providing data on failure rates in future Consolidated Reports and include in the 2011 Consolidated Report the PIWG conclusions and recommendations, if any.
59. Decision. We adopt the Staff's recommendation and require Pepco to: (1) combine the Manhole Events portion of the failure analysis report with Part 3 of the Consolidated Report; (2) include data in the 2011 Consolidated Report that separates 4 kV primary failures from 13 kV primary failures;
(3) include data in the 2011 Consolidated Report that separates 4 kV from 13 kV manhole events; (4) include trend analyses for "Use of Slotted Manhole Covers;" and (5) include in the Cable Splice or Joint Database section of the Consolidated Report, cable type, age, type of splice and other pertinent information, except that cable type and age can be excluded if unavailable. If data on failure rates for all variables is available for manhole events, Pepco shall include such information in its 2011 Consolidated Report. If such data is unavailable, we require the members of PIWG to discuss the need for and the availability of such data include in the 2011 Consolidated Report the PIWG conclusions and recommendations, if any.
65. Pepco IS DIRECTED to include a discussion of failure data rates in the agenda for the Productivity Improvement Working Group, consistent with Paragraphs 56 and 59 of this Order; and
66. Pepco IS DIRECTED to include additional Manhole Event data in the 2011 Consolidated Report, consistent with Paragraph 59 of this Order.

In Order No. 15152 paragraphs 76 and 66, the Commission ordered the following:
76. PEPCO is DIRECTED to include as part of the 2009 Consolidated Report a proposed plan for significantly reducing manhole events consistent with paragraph 66 of this Order…

Summary of 2020 Manhole Events

During 2020, there were a total of 22 reportable manhole events in the District of Columbia. Of these 22 manhole events, 13 were classified as Smoking Manholes (S), 5 were classified as Manhole Explosions (E), and 4 were classified as Manhole Fires (F). 13 out of the 22 events occurred on the 13 kV system. Of these, 7 were classified as Smoking Manholes (S), 4 were classified as Manhole Explosions (E) and 4 were classified as Fires (F). The 2 events occurring on the 4 kV system were classified as Smoking Manhole (S). Appendix 3A is a list of the 2020 manhole events, categorized and described as directed in Order Nos. 11716, 13812, 15620 and 16091.

SECTION 3.2 – UNDERGROUND FAILURE ANALYSIS

Order No. 17074 Requirement

38. *The Order further noted OPC's statement that according to Pepco, its replacement program would screen all feeders by collecting the number of underground faults experienced by each feeder in the last ten years and feeders with five or more faults ("5-in1-10") would be further analyzed for replacement. [Footnote: See F.C. 766-ACR-12, Order No. 16975, paragraph 75.] ...Thus, we direct Pepco to report on the results of its screening program along with Pepco's recommendations for further analysis and replacement in the ACR starting with 2013.*

40. *... Some progress should have been made in the development of a tracking mechanism for PILC actual replacement and Pepco should be able to report on the actualization of its strategy with data that will help the Commission to better understand Pepco's future plans for PILC replacement and examine the results of its PILC Replacement Strategy. Thus, the Company is required to report on the actualization of its PILC Replacement Strategy in the ACR and to include in the report the information identified in Recommendations 8(c), (d) and (e). If the requested information is not available, Pepco shall provide a reasonable substitute that will allow the Commission to assess the progress that Pepco has made and intends to make in the implementation of its PILC Replacement Strategy for the ten-year period from 2012 to 2021.*

Pepco Response – Corrective Actions

Pepco is currently in the process of analyzing available data of the underground electric system faults in the District of Columbia. Feeders with at least five faults within ten years were identified for further analysis. From that list of feeders, those that are already being addressed as part of Pepco's Reliability program and/or other strategies—or programs that would address these issues on the feeders—were removed to avoid duplication of efforts.

In 2020, targeted PILC replacement was performed on eight feeders, shown below in Table 3.1.

Table 3.1: PILC Replacement Status

Year	Feeder ID	PILC Replaced (ft)
2020	15307	4629
2020	15308	7717
2020	15309	7081
2020	15310	7434
2020	15311	5056
2020	15312	5733
2020	14531	2490
2020	14537	1149

In Pepco's 2001 "Alternative Design Proposal to Pepco's 15kV Paper Insulated Lead Covered Power Cables (PILC)" study, Pepco estimated there were 1,109 miles of primary lead cables on the Pepco system in the District of Columbia. Given the current configuration of the District of Columbia underground system, which includes varied duct and manhole sizes, it is not possible to know how many of those miles are non-replaceable. Reconfiguring the manholes and ducts would allow most of Pepco's PILC cable to be replaceable, albeit at significant cost and time. As stated in Pepco's PILC Replacement Strategy, in line with most other electric utilities and with industry best practice, Pepco has not committed to replacing a fixed number of miles of PILC each year and has not identified a year by which full replacement of primary PILC would be expected. Instead, Pepco is seeking opportunistic replacement based on conditions, which it expects to be a more cost-effective replacement strategy.

Consequently, Pepco cannot provide an estimate of the number of miles of PILC that will be replaced by EPR for the 10-year period from 2012 through 2021. Since 2001, Pepco has replaced 83 miles of PILC in the District of Columbia both through the opportunistic replacement approach, and planned jobs. This data is reflected in Table 3.2 below.

Table 3.2: PILC Replacement: 2001-Present

Years	*PILC Replaced Footage*	*PILC Replaced Mileage*
2001	0	0
2002	0	0
2003	0	0
2004	7,733	1
2005	27,981	5
2006	14,322	3
2007	26,341	5
2008	26,217	5
2009	28,217	5
2010	25,593	5
2011	17,824	3
2012	35,571	7
2013	17,037	3
2014	25,882	5
2015	23,414	4.4
2016	14,158	2.7
2017	27,936	5.3
2018	50,123	9.5
2019	30,712	5.8
2020	41,289	7.82
Total	***440,350***	***82.52***

Underground (UG) Failure Analysis

The results of Pepco's annual UG failure analyses are presented below, in compliance with Order No. 12735 paragraph 138.[70]

In analyzing the performance of the Pepco UG system, it is necessary to distinguish three different measures of system performance:

- Equipment Failures
- Outages
- Reportable Events (RE)

An RE is a reported explosion, fire, or smoke in a manhole. Some Pepco equipment failures may result in customer outages, REs or both. However, not all Pepco equipment failures result in an outage and/or an RE. This is due to the redundancy of some components of the system, especially on secondary networks. In fact, for the underground secondary networks, most equipment failures do not result in customer outages because each network is fed by multiple primary feeders, and each customer can be fed from multiple transformers and secondary mains, making them less susceptible to outages. Further, some underground outages or events are not initiated by equipment failures, but are in fact caused by accidents, such as dig-ins by excavation contractors, failures of non-Pepco equipment, such as District of Columbia owned streetlight cables or gas company equipment.

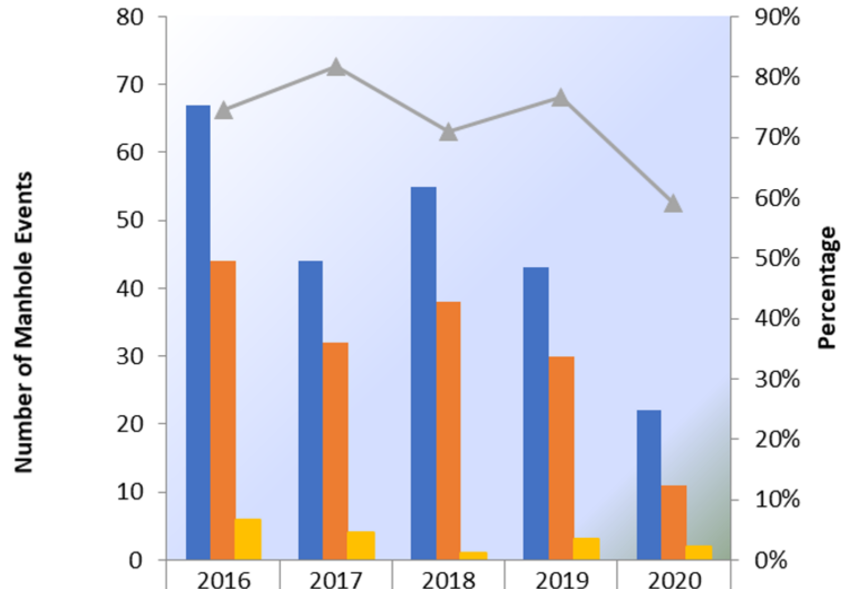
There are three types of manhole reportable events:

- Explosions
- Fires
- Smoking

Of these three types, from 2016 – 2020 smoking manhole events account for most of all manhole events experienced in the District. See Figure 3.3.

[70] In Order No. 12735, paragraph 138, the Commission ordered the following:
138.Pepco shall file a report that summarizes the results of the failure analyses conducted for the calendar year 2002, 30 days from the issuance date of this Report and Order, and subsequently, to file an annual report on the results of the failure analysis group to the PIWG;

Figure 3.3: Manhole Events - Smoking (2016-2020)

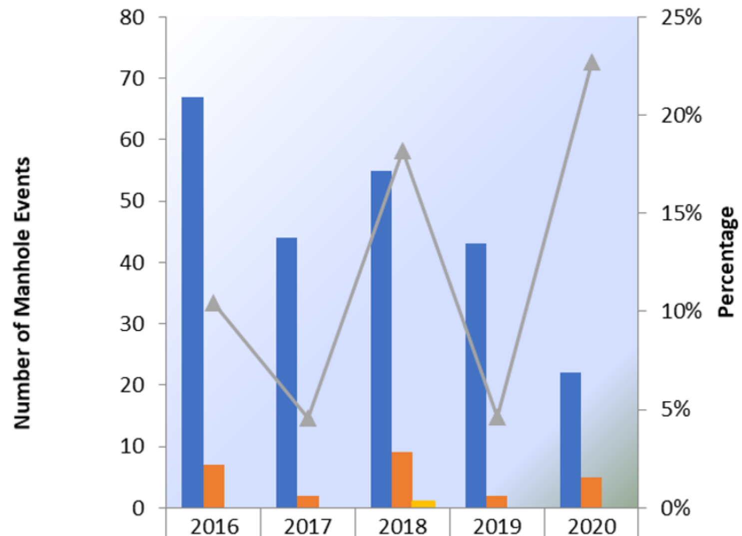


	2016	2017	2018	2019	2020
All Events	67	44	55	43	22
13kV Smoke	44	32	38	30	11
4kV Smoke	6	4	1	3	2
% Smoking	75%	82%	71%	77%	59%

Year

Figure 3.7 breakdown the number of manhole fires and manhole explosions as compared to the total number of events. As reflected below, explosions and fires occur less frequently than smoking manholes.

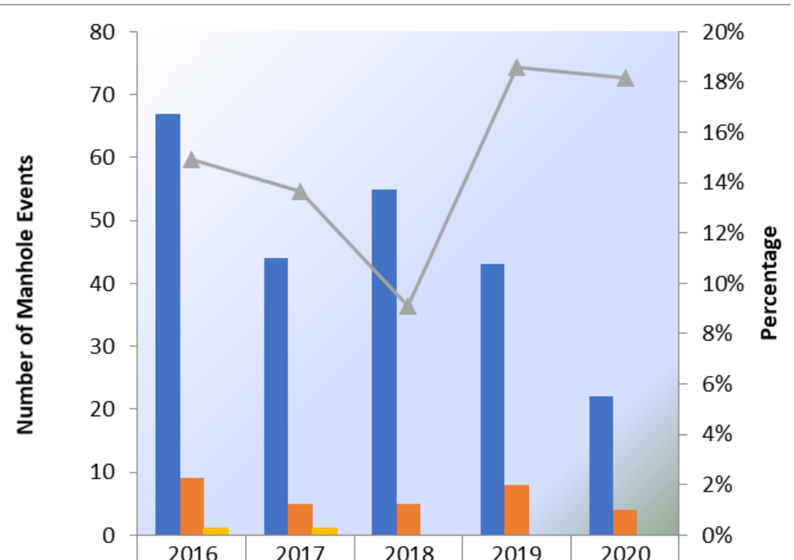
Figure 3.4: Manhole Events - Explosions (2016-2020)



	2016	2017	2018	2019	2020
All Events	67	44	55	43	22
13kV Explosions	7	2	9	2	5
4kV Explosions	0	0	1	0	0
% Explosions	10%	5%	18%	5%	23%

Year

Figure 3.5: Manhole Events - Fires (2016-2020)

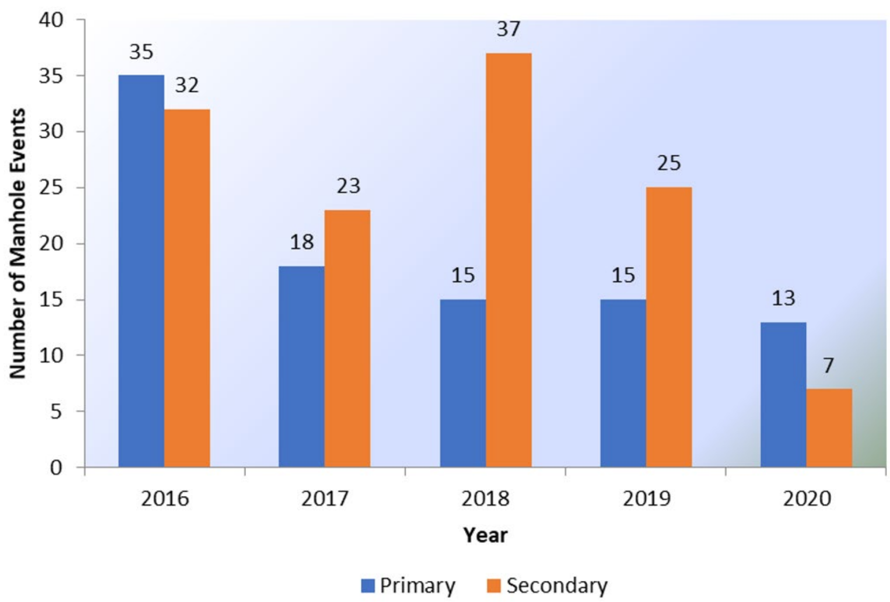


	2016	2017	2018	2019	2020
All Events	67	44	55	43	22
13kV Fires	9	5	5	8	4
4kV Fires	1	1	0	0	0
% Fires	15%	14%	9%	19%	18%

Year

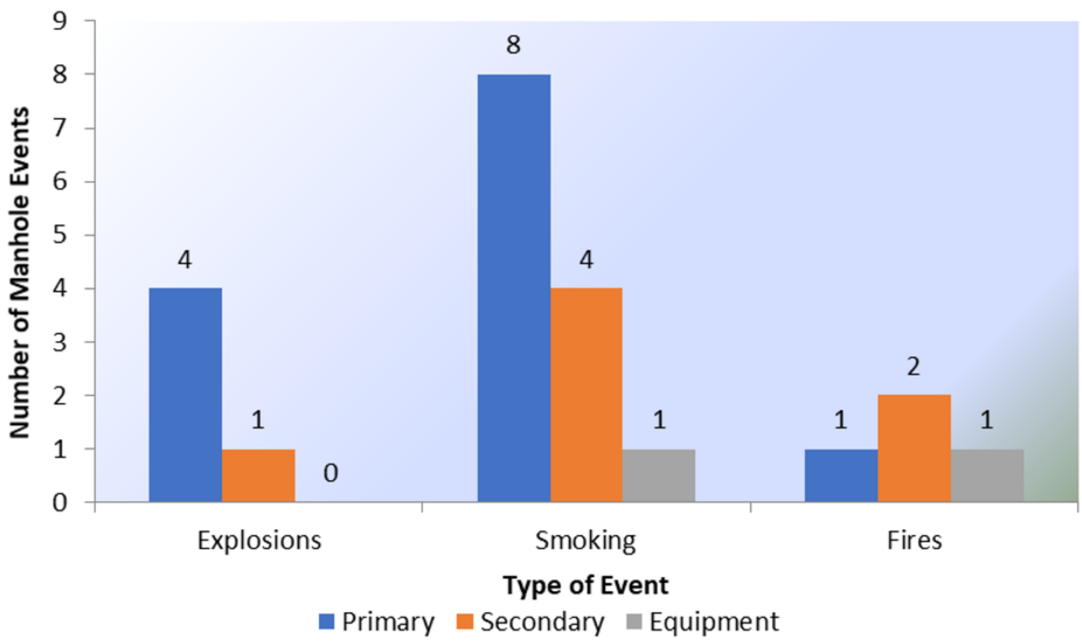
Since 2016, on average most of the manhole events experienced in the District have occurred on Pepco's secondary equipment. See Figure 3.6.

Figure 3.6: Manhole Events by Type of Equipment (2016-2020)



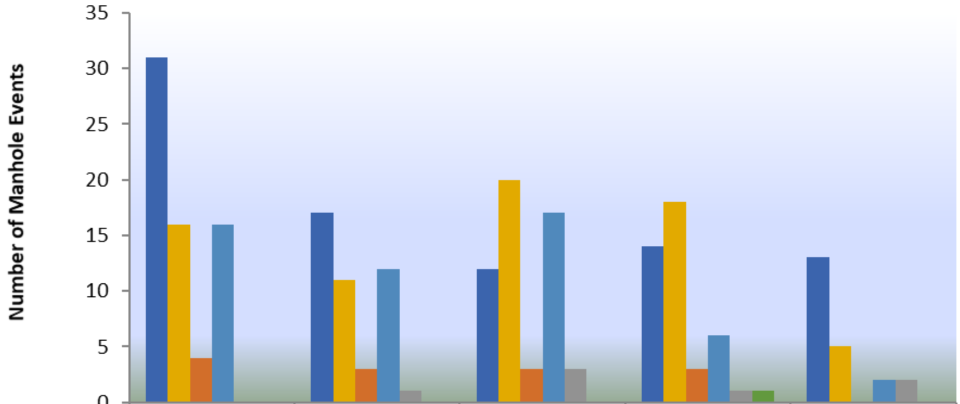
In 2020, two manhole fires occurred on the secondary systems. Smoking manholes occurred more on the primary system, and manhole explosions occurred more on the primary system. Figure 3.7 below depicts this breakdown.

Figure 3.7: Manhole Events by Type and Equipment (2020)



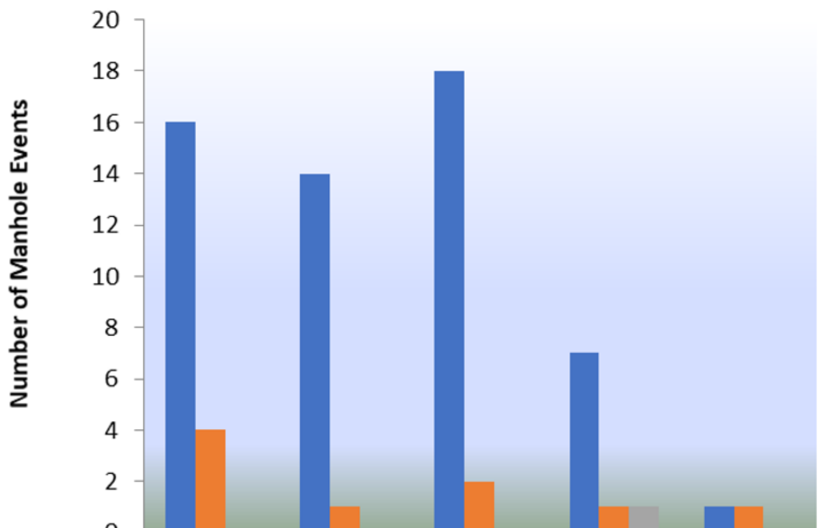
Slotted manhole covers are designed to minimize the frequency and impact of manhole events by allowing gas and smoke to vent from manholes in the event of an underground failure. This provides an early warning and prevents build-up of gases to potentially explosive proportions; thereby allowing energy to disperse more easily should an event occur. The tradeoff when installing slotted covers is that they allow more water and street run-off contaminants to enter the manhole than solid covers. More analysis on the effects of slotted covers and manhole events is presented in the slotted MH cover section of this report. See Figure 3-8 and Figure 3-7 for a breakdown of manhole event by event type, voltage class, and cover type.

Figure 3.8: Manhole Events by Type, Equipment, and Manhole Cover (2016-2020)



	2016	2017	2018	2019	2020
Solid Primary	31	17	12	14	13
Solid Secondary	16	11	20	18	5
Slotted Primary	4	3	3	3	0
Slotted Secondary	16	12	17	6	2
Grated Primary	0	1	3	1	2
Grated Secondary	0	0	0	1	0

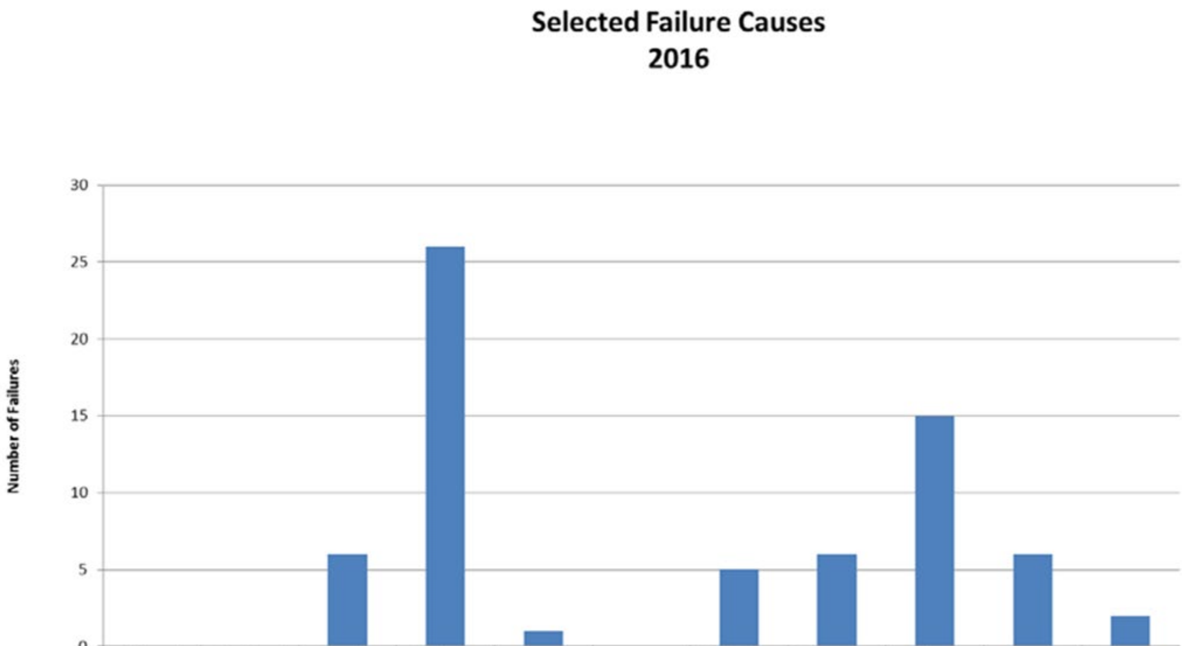
Figure 3.9: Slotted Manhole Events by Type (2015-2020)



	2016	2017	2018	2019	2020
Slotted Smoking	16	14	18	7	1
Slotted Fire	4	1	2	1	1
Slotted Explosions	0	0	0	1	0

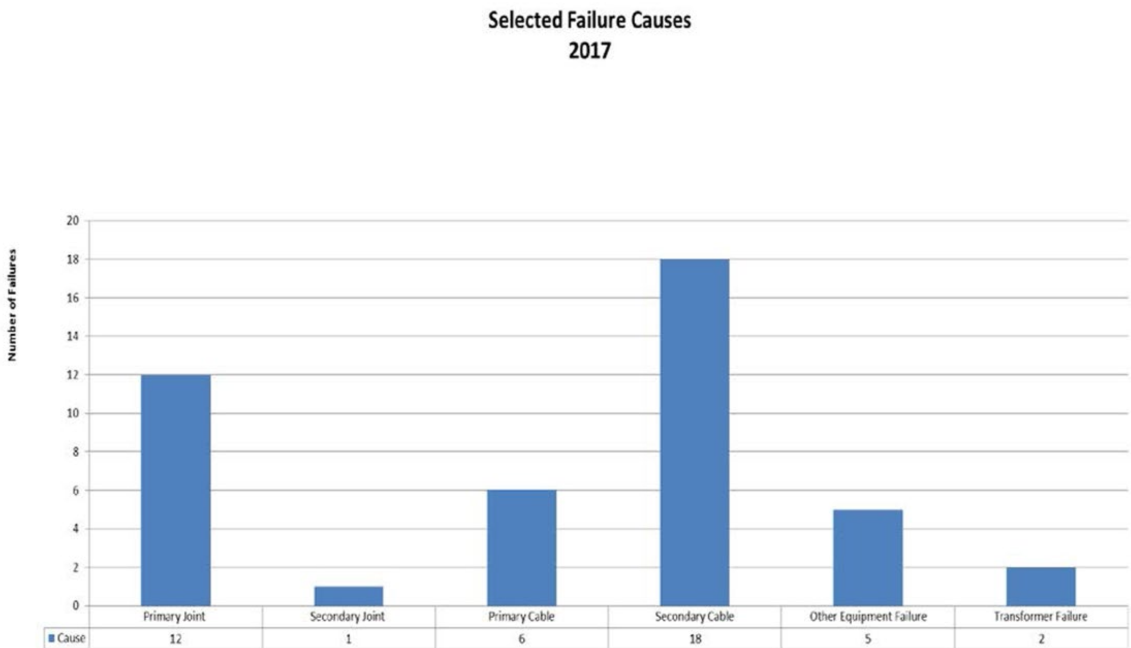
By design, primary cable is more insulated than secondary cable. Whereas primary cable and its accessories are designed to their voltage rating and are shielded, secondary cable and its accessories are not shielded. As a result of less physical protection, secondary cable and its accessories are more likely to fail due to a breach in the insulation. Since 2016, the leading cause of manhole reportable events in the District is insulation-related, such as insulation deterioration. See Figures 3.10 through 3.14.

Figure 3.10: Selected Failure Causes (2016)



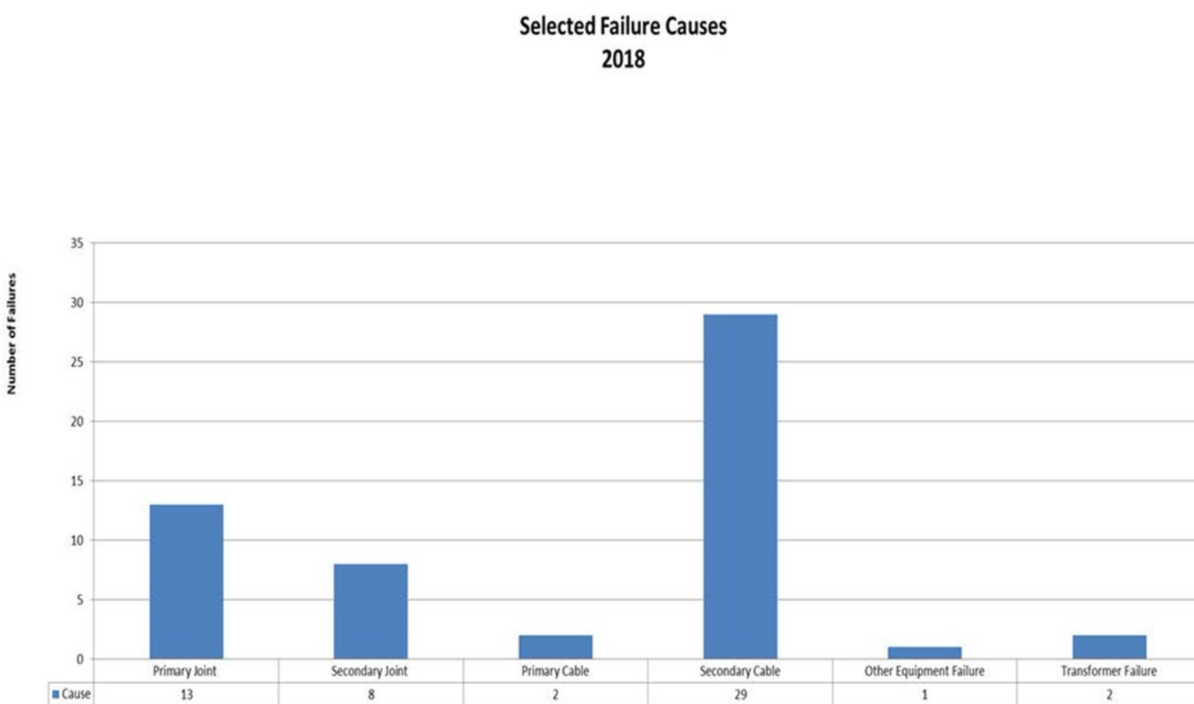
	Collapsed Duct	Misaligned Duct	Corrosion related	Insulation related	Leak	Overload	Third Party Damage	Transformer Failure	Primary Joint related	Unknown	Other
Cause	0	0	6	26	1	0	5	6	15	6	2

Figure 3.11: Selected Failure Causes (2017)



	Primary Joint	Secondary Joint	Primary Cable	Secondary Cable	Other Equipment Failure	Transformer Failure
Cause	12	1	6	18	5	2

Figure 3.12 Selected Failure Causes (2018)



	Primary Joint	Secondary Joint	Primary Cable	Secondary Cable	Other Equipment Failure	Transformer Failure
Cause	13	8	2	29	1	2

Figure 3.13 Selected Failure Causes (2019)

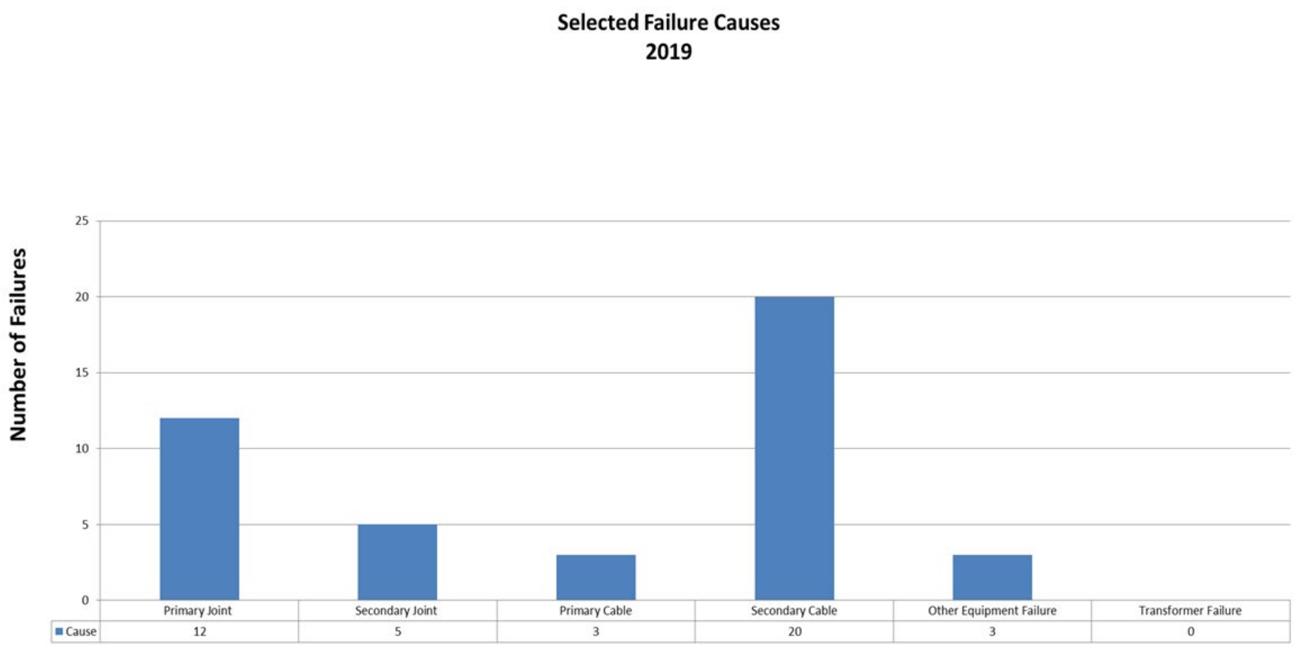
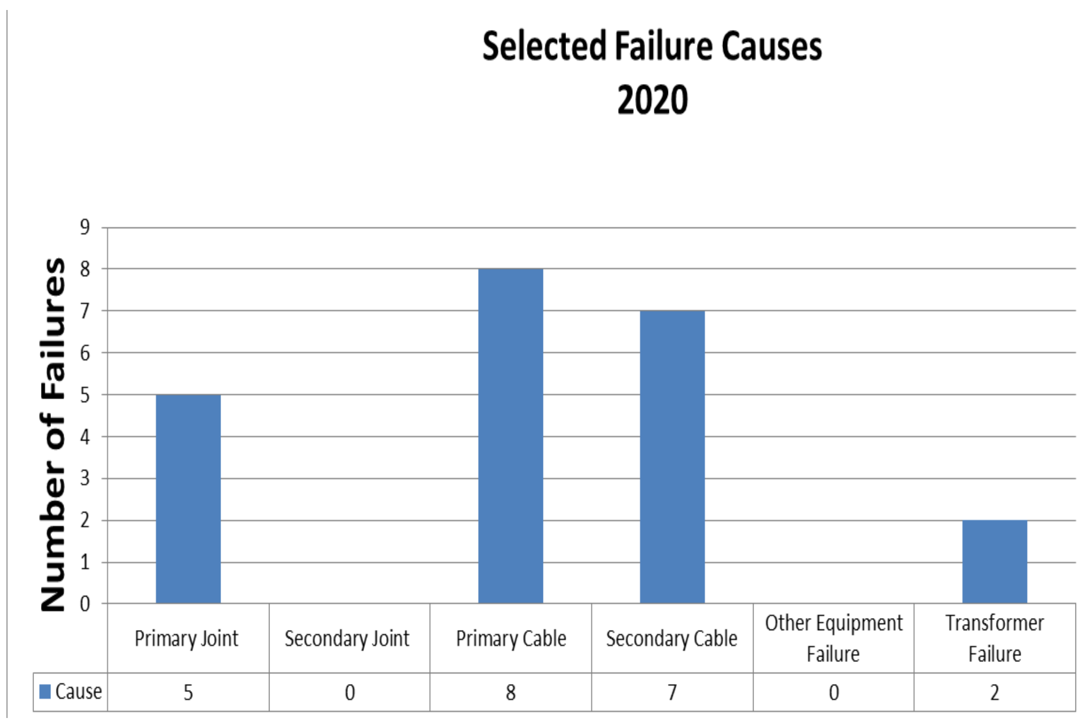


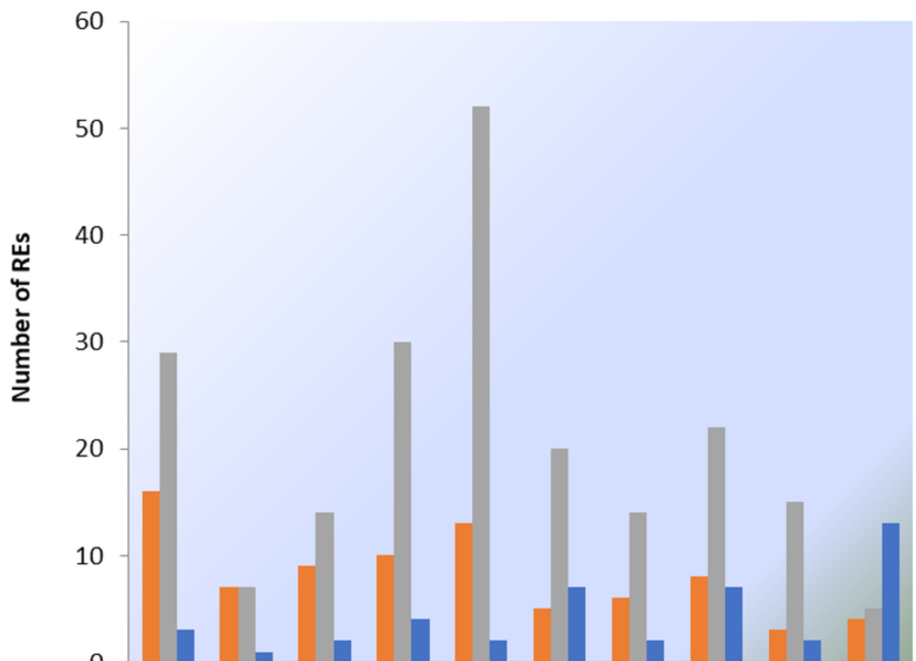
Figure 3.14 Selected Failure Causes (2020)



Selected Failure Causes (2020)

The type of insulation related to cable and joint failures resulting in a reportable event for secondary equipment does not provide a discernible trend in reportable events caused by Rubber Lead (RL), Rubber Neoprene (RN), or other insulation types (Figure 3.13). RL secondary cable is an outdated technology and has not been installed on the system for more than twenty years. It is not possible to trend future reportable events associated with this cable type.

Figure 3.15: Insulation Type of Secondary REs (2011-2020)

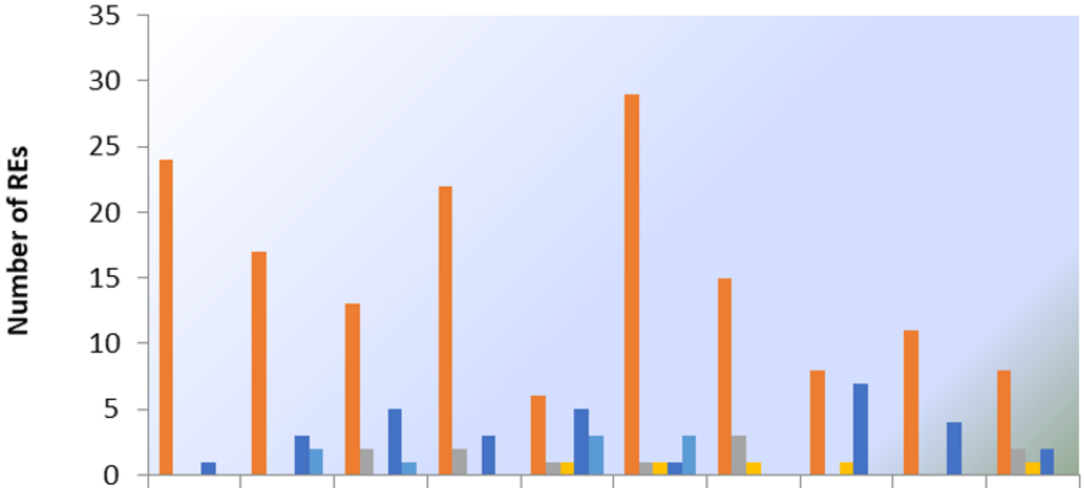


	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
RL	16	7	9	10	13	5	6	8	3	4
RN	29	7	14	30	52	20	14	22	15	5
Other	3	1	2	4	2	7	2	7	2	13

Year

PILC is the predominant primary cable on the Pepco underground system. Consequently, most primary cable reportable events involve PILC cable (Figure 3.16).

Figure 3.16: Insulation Type of Primary REs (2011-2020)

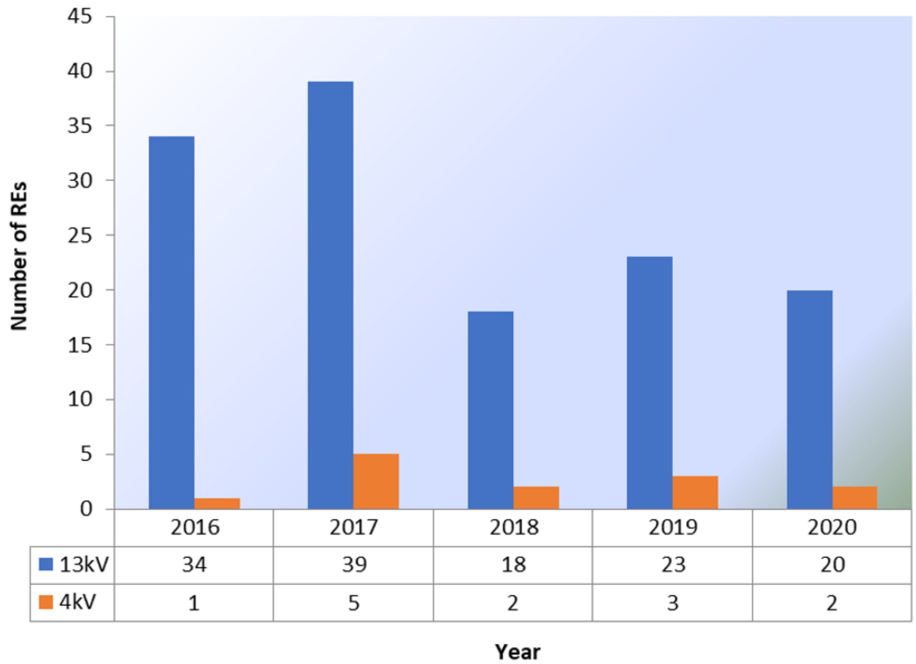


	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
PILC	24	17	13	22	6	29	15	8	11	8
RL	0	0	2	2	1	1	3	0	0	2
RN	0	0	0	0	1	1	1	1	0	1
EPR	1	3	5	3	5	1	0	7	4	2
Other	0	2	1	0	3	3	0	0	0	0

Year

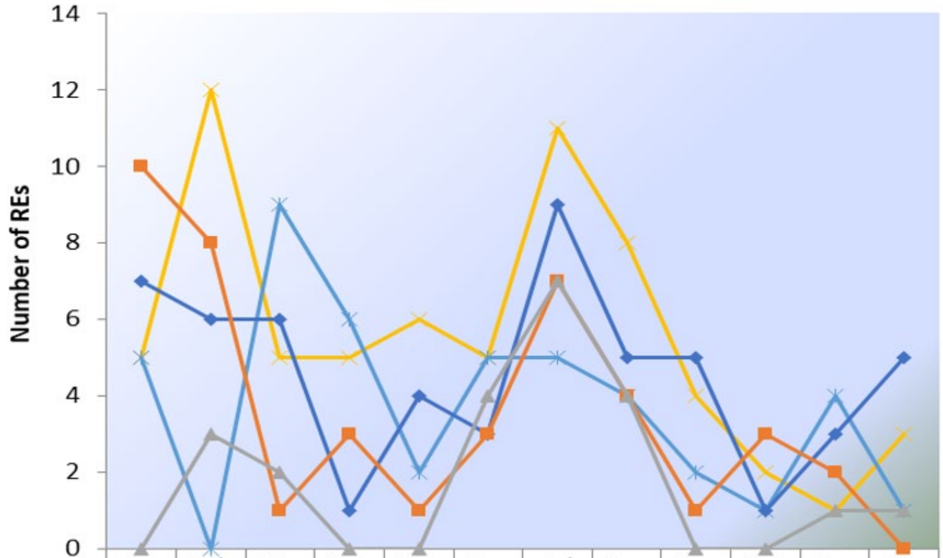
The majority of reportable events involving primary equipment occur on 13 kV feeders (Figure 3.17). 4 kV is a vintage technology and the majority of Pepco's underground system is 13 kV.

Figure 3.17: Voltage Class of Primary REs (2016-2020)



In addition, moisture plays a major role in the deterioration of both primary and secondary cable insulation. When a significant amount of precipitation occurs in the District, moisture and contaminants from the street, such as motor oil, lawn chemicals, etc., enter into the manholes and affect cable insulation. Additionally, snow/ice melt chemicals ingress after a storm can also penetrate cable insulation and lead to failure. While moisture affects all cable insulation, since secondary cable is not as robust or of the same design as primary cable, secondary cable is inherently more likely to fail under adverse weather conditions. A comparison of Figures 3.18 and 3.19 suggests that total moisture accumulation affects the number of reportable events.

Figure 3.18: Reportable Events by Month (2015-2020)



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	5	12	5	5	6	5	11	8	4	2	1	3
2017	5	0	9	6	2	5	5	4	2	1	4	1
2018	7	6	6	1	4	3	9	5	5	1	3	5
2019	10	8	1	3	1	3	7	4	1	3	2	0
2020	0	3	2	0	0	4	7	4	0	0	1	1

Year

Figure 3.19: Total Precipitation in Inches by Month (2016-2020)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	2.67	3.79	1.16	2.05	5.65	3.68	3.13	2.79	2.5	0.9	0.76	2.61
2017	2.61	0.68	3.32	2.62	5.55	1.13	9.15	4.53	1.43	2.02	2	0.5
2018	0.94	4.79	1.92	3.59	8.73	5.21	9.73	5.19	9.73	3.06	7.56	5.82
2019	3.78	3.52	3.97	2.27	4.97	4.26	6.48	2	0	5.8	2.37	3.28
2020	2.78	3.22	2.19	5.33	2.60	3.51	6.47	8.37	5.93	4.86	4.31	6.79
Normal	3.21	2.63	3.6	2.77	3.82	3.13	3.66	3.44	3.79	3.22	3.03	3.05

Month

The Failure Analysis Section will show failure analysis for all manhole incidents in the District in order to determine trends and remediation activities.

Slotted Manhole Covers [71]

New Slotted Manhole Cover Program Locations

In its 2013 Consolidated Report, Pepco discussed its criteria for selecting areas for installation of slotted manhole covers. This included areas with high load growth and potential business development. There were no slotted covers installed in 2020.

Historical Slotted Manhole Cover Program[72]

Pepco installed grated manhole covers over single and three-phase transformer installations, and network transformer installations in roadways and sidewalks. Their purpose is to assist in the dissipation of heat from the transformers. To explore the potential of an expanded application of vented manhole covers to non-transformer locations, Pepco contracted the Electric Power Research Institute (EPRI) to simulate manhole explosions. The simulations were specifically designed to test the effectiveness of solid, slotted and grated manhole covers in minimizing displacement of covers under fault conditions. The test data showed that the installation of slotted covers minimizes the frequency and impact of manhole events in three main ways:

- Energy released may escape through the slotted cover without lifting or displacing it;
- Smoke can provide an early warning of cable faults, thus preventing more serious events from occurring; or
- Explosions or fires may be avoided by the dissipation of combustible gases.

Based on these findings, Pepco installed custom-designed, slotted manhole covers in high volume pedestrian traffic areas of the District of Columbia where the low voltage alternating current network exists. The installation of slotted manhole covers has enhanced public safety while minimizing potential damage to underground electric facilities. The installation program was concluded in 2004 with an overall total of 7,880 slotted manhole covers having been installed.

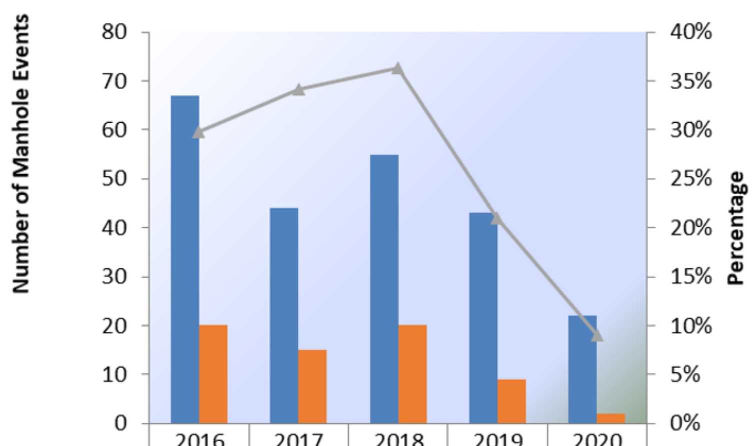
[71] Order No. 16975 states the following at paragraphs 74 and 111:
85. Decision: …We agree with the Staff that a manhole replacement program that concluded in 2004 may no longer be appropriate, given business development in new areas of the District. We therefore require Pepco to reexamine the criteria used to select locations for the installation of slotted manhole covers and to report on this reexamination in the 2013 Consolidated Report.
114.Pepco is DIRECTED to revisit criteria used to select locations for installing slotted manhole covers consistent with paragraph 74 herein;
[72] In Order No. 16091 issued on December 10, 2010, the Commission stated among other things, at paragraph 59, the following:
59. … (4) include trend analysis for "Use of Slotted Manhole Covers;"

In Order No. 14093, the Commission approved Pepco's proposal to suspend further slotted manhole installations provided the Company submit an analysis of manhole events and failure rates associated with slotted covers, including recommended actions for 2008 by October 27, 2007, and continue to monitor debris accumulation in manholes with slotted covers. Pepco filed its analysis on August 21, 2007.

Pepco realizes that the openings in the covers, while allowing gases to vent, also allow rain, snow, dirt, debris and chemicals into manholes. As a result, Pepco continues to monitor debris accumulation in manholes with slotted covers. Of the 22 reportable manhole events that occurred in the District of Columbia in 2020, 2 involved manholes fitted with slotted covers.

Over the five-year period from 2016 through 2020, there were 231 reportable manhole events. Of these, 66 (29%) occurred in manholes with slotted covers. See Figure 3.20.

Figure 3.20: Manhole Events Involving Slotted Covers



	2016	2017	2018	2019	2020
All Events	67	44	55	43	22
# Events Slotted Covers	20	15	20	9	2
% Slotted	30%	34%	36%	21%	9%

Year

The rate of manhole events on these slotted covers is disproportional to the total population of these covers on the system. Currently there are slotted covers deployed on about 13% of manholes within the Pepco system yet we are consistently seeing slotted covers account for upwards of 29% of the total manhole events each year. This coupled with the fact that the current Pepco designed slotted covers are not 100% ADA compliant has led Pepco to reconsider the design for vented manhole covers.

With the support of EPRI, an Exelon utility peer group was formed to research manhole events and mitigation techniques. As a result of this research group, all Exelon utilities have aligned on a new design for vented manhole covers. These new manhole covers use a 3% vented design as compared to the current 23% slotted cover. Additionally, the new manhole cover design is fully ADA compliant.

Cable Splice or Joint Records[73]

Quality of workmanship is also being monitored as part of Pepco's program to reduce underground failures. Pepco repair crews complete a "Splice Manifest" report which records, among other things, the location, date, type of splice, the splicer's name and the foreman's name. Table 3.6 contains information from the "Splice Manifest" report for 2020 maintenance work performed. The splicer and foreman names have been redacted from the table.

Table 3.3: 2020 Splice Data (District of Columbia)

Date	Location	Type of Splice
1/23/2020	SW Corner 11th & H St., NW	Test Cap 350 3/c and below
3/19/2020	11th & H St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
3/19/2020	11th & H St., NW	3-1C, #2 Loadbreak Elbows
3/23/2020	2501 Calvert St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
3/23/2020	2501 Calvert St., NW	200 AMP Elbows
3/31/2020	4340 Conn. Ave., NW	200 AMP Elbows
3/31/2020	4340 Conn. Ave., NW	3-1/C PILC to #2 URD Tape Jt.
4/2/2020	2800 Quebec, NW	200 AMP Elbows
4/2/2020	2800 Quebec St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
4/12/2020	800 N. Capitol St., NW	200 AMP Elbows
4/12/2020	800 N. Capitol St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
4/15/2020	2501 Calvert St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
4/15/2020	2501 Calvert St., NW	200 AMP Elbows
4/26/2020	20th & S St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0

[73] In Order No. 16091, the Commission stated among other things, at paragraph 59, the following:
59. …(5) include in the Cable Splice or Joint Database section of the Consolidated Report, cable type, age, type of splice and other pertinent information, except that cable type and age can be excluded if unavailable.

Date	Location	Type of Splice
4/26/2020	20th & S St., NW	200 AMP and 600 AMP Deadbreaks
4/28/2020	2446 Wisc. Ave., NW	3-1/c Cold Shrink Potheads 350 to 600
4/28/2020	2446 Wisc. Ave., NW	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
5/1/2020	Arlington Memorial Bridge	200 AMP Elbows
5/1/2020	5900 Blair Rd., NW	3-1/c Cold Shrink Potheads 350 to 600
5/1/2020	5900 Blair Rd., NW	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
5/4/2020	16th & Mass. Ave., NW	3-1/C PILC to #2 URD Tape Jt.
5/4/2020	16th & Mass. Ave., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
5/7/2020	E St. b/w 6th & 7th St., NE	3-1/C URD Slip on Splices
5/7/2020	E St. b/w 6th & 7th St., NE	3-1/C URD Slip on Splices
5/7/2020	4th & M St., SE	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
5/7/2020	4th & M St., SE	3-1/c 500 or 600 Straight Heat Shrink Splices
5/7/2020	4th & M St., SE	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
5/8/2020	N. Brook Lane	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
5/8/2020	N. Brook Lane	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
5/11/2020	10th & NY Ave., NW	Heat Shrink Test Cap
5/12/2020	1st & Michigan, NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
5/12/2020	1st & Michigan, NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
5/13/2020	15th & Vermont St., NW	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
5/14/2020	15th & Vermont St., NW	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
5/20/2020	K St., NW	Heat Shrink Test Caps
6/17/2020	13th & Irving, NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
6/17/2020	13th & Irving, NW	200 AMP Elbows
6/22/2020	Conn. & L St., NW	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
6/22/2020	Conn. & L St., NW	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
6/23/2020	Conn. & L St., NW	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
6/23/2020	Conn. & L St., NW	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
6/23/2020	Conn. & L St., NW	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
6/23/2020	Conn. & L St., NW	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
6/23/2020	Conn. & L St., NW	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
6/26/2020	14th & Indep. Ave., SW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
6/26/2020	14th & Indep. Ave., SW	200 AMP Elbows
7/7/2020	1st & Indiana, NW	Heat Shrink Test Caps
7/23/2020	Potomac & M St., NW	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
7/23/2020	Potomac & M St., NW	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
7/23/2020	Potomac & M St., NW	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
7/24/2020	34th & Mass. Ave., NW	Tape Joint 2/0 to #2 URD
7/24/2020	34th & Mass. Ave., NW	Tape Joint #2 RL #2 URD
7/24/2020	Potomac & M St., NW	Cold Shrink Y
7/25/2020	19th & T St., NW	200 AMP Elbows
7/29/2020	17th & WV Ave., NE	3-1/c Cold Shrink Potheads #2 to 4/0
7/29/2020	17th & WV Ave., NE	3-1/c Cold Shrink Potheads #2 to 4/0
7/30/2020	1501 Eckington Pl., NE	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0

Date	Location	Type of Splice
7/31/2020	9th & G St., NW	Single Branch Joint 350 3/c to 600 3/c
8/3/2020	4th & E St., SW	3-1/C URD Slip on Splices
8/13/2020	1255 23rd St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
8/13/2020	1255 23rd St., NW	200 AMP Elbows
8/13/2020	4th & G St., SW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
8/14/2020	918 P St., NW	3-1/C URD Slip on Splices
8/14/2020	918 P St., NW	3-1/C URD Slip on Splices
8/17/2020	11th & O St., NW	200 AMP Elbows
8/17/2020	10th & O St., NW	3-1/C URD Slip on Splices
8/25/2020	24th & Mass. Ave., NW	3-1/C URD Slip on Splices
8/25/2020	24th & Mass. Ave., NW	3-1/C URD Slip on Splices
8/26/2020	Constitution Ave., NW	200 AMP Elbows
8/26/2020	Constitution Ave., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
8/27/2020	12th & D St., SW	200 AMP Elbows
8/27/2020	12th & D St., SW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
8/27/2020	6th & L St., SE	3-1/C URD Slip on Splices
8/27/2020	5th & L St., SE	3-1/C URD Slip on Splices
8/31/2020	2nd & D St., SE	3-1/C URD Slip on Splices
8/31/2020	2nd & D St., SE	3-1/C URD Slip on Splices
9/2/2020	Half & L St., SE	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
9/2/2020	Half & K St, SE	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
9/3/2020	14th & K St., NW	3-1C, #2 Loadbreak Elbows
9/10/2020	2116 F St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
9/10/2020	2116 F St., NW	200 AMP Elbows
9/13/2020	4th & G St., SW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
9/13/2020	4th & G St., SW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
9/14/2020	SWC Montello Ave. & Quen St., NE	3-1/C URD Slip on Splices
9/14/2020	SWC Montello Ave. & Quen St., NE	3-1/C URD Slip on Splices
9/15/2020	Trinidad & Florida Ave., NE	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
9/15/2020	Trinidad & Morris St., NE	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
9/16/2020	9th & French, NW	3-1/C URD Slip on Splices
9/16/2020	9th & French, NW	3-1/C URD Slip on Splices
9/17/2020	14th & Indep. Ave., SW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
9/17/2020	14th & Indep. Ave., SW	3-1/C URD Slip on Splices
9/21/2020	16th & Pine St., NW	3-1/C URD Slip on Splices
9/21/2020	16th & Lamont St., NW	3-1/C URD Slip on Splices
9/21/2020	Raoul Wallenberg & Indep. Ave., SW	200 AMP Elbows
9/21/2020	Indep. Ave., f/o Wallenberg, SW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
9/22/2020	39th & Rodman, NW	200 AMP Elbows

Date	Location	Type of Splice
9/22/2020	39th & Rodman, NW	200 AMP Elbows
9/23/2020	10th & H St, NW	3-1/C URD Slip on Splices
9/23/2020	10th & H St, NW	3-1C, #2 Loadbreak Elbows
9/24/2020	65 K St., NE	200 AMP Elbows
9/24/2020	65 K St., NE	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
9/27/2020	1012 14th St., NW	200 AMP Elbows
9/27/2020	1 Thomas Circle, NW	Test Cap 350 3/c and below
9/30/2020	15th & M St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
9/30/2020	15th & M St., NW	200 AMP Elbows
10/1/2020	1369 Savannah Pl, SE	3-1/C URD Slip on Splices
10/1/2020	1369 Savannah Pl, SE	200 AMP Elbows
10/1/2020	8 Eckington, NE	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
10/1/2020	8 Eckington, NE	200 AMP Elbows
10/2/2020	23rd & Conn. Ave., NW	Double Branch Joint 4/0 3/c and below
10/3/2020	23rd & Conn. Ave., NW	Double Branch Joint 4/0 3/c and below
10/4/2020	N. Cap. & O St., NW	3-1/C 4/0 or 350 Straight Heat Shrink Splices
10/4/2020	N. Cap. & O St., NW	3-1/C 4/0 or 350 Straight Heat Shrink Splices
10/6/2020	10th & G St., NW	3-1/C #2 PILC Test Caps
10/8/2020	14th & Penn. Ave., NW	200 AMP Elbows
10/8/2020	14th & Penn. Ave., NW	200 AMP Elbows
10/20/2020	Potomac Ave., & Grace St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
10/20/2020	3230 Grace St., NW	3-1C, #2 Loadbreak Elbows
10/21/2020	38th & Porter, NW	200 AMP and 600 AMP Deadbreaks
10/21/2020	38th & Porter, NW	200 AMP Elbows
10/21/2020	38th & Porter, NW	3-1/C URD Slip on Splices
10/25/2020	1012 14th St., NW	200 AMP Elbows
10/25/2020	1 Thomas Circle, NW	3-1/C 4/0 or 350 Straight Heat Shrink Splices
10/25/2020	1 Thomas Circle, NW	3-1C, #2 Loadbreak Elbows
10/27/2020	2022 H St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
10/30/2020	N/E/C 6th & Howard St., NW	3-1/C URD Slip on Splices
11/3/2020	North Cap. & Mass. Ave., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/3/2020	North Cap. & Mass. Ave., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/4/2020	3rd & M St., SE	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
11/4/2020	3rd & M St., SE	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
11/5/2020	Mass Ave. & N. Capitol, NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/5/2020	Mass Ave. & N. Capitol, NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/9/2020	635 Mass. Ave., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/9/2020	635 Mass. Ave., NW	200 AMP Elbows
11/11/2020	101 Indep. Ave., NW	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
11/11/2020	Gallatin & S. Dakota, NE	3/c P.L. to 3 1/c EPR or XLP Trif. Joint 500 to 600
11/11/2020	Hamilton & S. Dakota, NE	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600

Date	Location	Type of Splice
11/12/2020	Vermont & L St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/12/2020	Vermont & L St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/13/2020	S. Dakota & Galloway St., NE	3-1C, #2 Loadbreak Elbows
11/13/2020	S. Dakota & Galloway St., NE	3-1C, #2 Loadbreak Elbows
11/13/2020	S. Dakota & Galloway St., NE	3-1C, #2 Loadbreak Elbows
11/13/2020	S. Dakota & Galloway St., NE	200 AMP and 600 AMP Deadbreaks
11/13/2020	S. Dakota & Galloway St., NE	3-1/C URD Slip on Splices
11/13/2020	S. Dakota & Galloway St., NE	3-1C, #2 Loadbreak Elbows
11/16/2020	Vermont & L St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/16/2020	Vermont & L St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/18/2020	Potomac Ave. & S. Capitol, SE	3-1/C URD Slip on Splices
11/18/2020	Potomac Ave. & S. Capitol, SE	3-1/C URD Slip on Splices
11/19/2020	L St. & Vermont Ave., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/19/2020	Vermont & L St., NW	3-1/C URD Slip on Splices
11/23/2020	Vermont & L St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/23/2020	Vermont & L St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
11/25/2020	10th & G St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
12/1/2020	New Jersey & D St., SE	3-1/C URD Slip on Splices
12/1/2020	New Jersey & D St., SE	3-1/C URD Slip on Splices
12/3/2020	10th & G St., NW	200 AMP Elbows
12/3/2020	10th & G St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
12/4/2020	400 Virginia Ave., SW	3-1C, #2 Loadbreak Elbows
12/4/2020	400 Virginia Ave., SW	3-1/C URD Slip on Splices
12/4/2020	Florida Ave., & 11th St., NW	200 AMP Elbows
12/4/2020	Florida Ave., & 11th St., NW	200 AMP Elbows
12/4/2020	Florida Ave., & 11th St., NW	200 AMP Elbows
12/6/2020	2119 Champlain St., NW	3-1/c Cold Shrink Potheads 350 to 600
12/7/2020	325 P St., SW	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
12/8/2020	2616 Conn. Ave., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
12/8/2020	2616 Conn. Ave., NW	200 AMP Elbows
12/9/2020	1458 Columbia Rd., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
12/9/2020	1458 Columbia Rd., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
12/16/2020	4th & J St., NW	3-1/c #2 URD Test Caps
12/17/2020	450 K St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
12/17/2020	12th & Penn Ave., SE	200 AMP and 600 AMP Deadbreaks
12/17/2020	12th & Penn Ave., SE	200 AMP and 600 AMP Deadbreaks
12/18/2020	SEC 4th & I St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
12/18/2020	300 Blk I St., NW	200 AMP Elbows
12/18/2020	4th & I St., NW	3-1/C URD Slip on Splices

Date	Location	Type of Splice
12/18/2020	5th & G St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
12/18/2020	5th & G St., NW	3-1/C URD Slip on Splices
12/18/2020	4th & I St., NW	200 AMP Elbows
12/21/2020	3rd & R St., NE	Separable 3 Way Cable Joint
12/22/2020	44th & Reservoir Rd., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
12/22/2020	44th & Reservoir Rd., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
12/22/2020	44th & Reservoir Rd., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
12/24/2020	Florida Ave., & T St., NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
12/24/2020	Florida Ave., & T St., NW	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
12/24/2020	Florida Ave., & T St., NW	3-1/c 500 or 600 Straight Heat Shrink Splices
12/24/2020	Florida Ave., & T St., NW	Separable 3 Way Cable Joint
12/25/2020	Champlain Sub	3-1/c Cold Shrink Potheads 350 to 600
12/25/2020	Champlain Sub	3-1/c Cold Shrink Potheads 350 to 600
12/26/2020	4005 Van Ness, NW	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
12/26/2020	4005 Van Ness, NW	Cold Shrink Y
12/26/2020	4005 Van Ness, NW	3/c P.L. to 3 1/c EPR or XLP Trif. Joint #2 - 1/0 or 4/0
12/26/2020	4005 Van Ness, NW	3/C P.L.to 3-1/C EPR or XLP Trif. Jt. 350 to 600
12/26/2020	4005 Van Ness, NW	Cold Shrink Y
12/27/2020	3rd & R St., NE	3-1/c 500 or 600 Straight Heat Shrink Splices
12/27/2020	3rd & R St., NE	Cold Shrink Y

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Appendix 3A: 2020 Manhole Events[74]

New Manhole Event Information

At the December 13, 2011 and February 16, 2012 PIWG meetings, it was decided that the following types of additional information related to manhole events would be included in future Consolidated Reports. The following categories of information have been included in this year's Consolidated Report.

- Incident Date
- Work Order/Request #
- Address
- Grid Number

[74] In Order No. 11716 ordering paragraph 3, the Commission ordered the following:

3. *PEPCO shall file an annual report on the previous calendar year's manhole incidents;*

Order No. 16975 states the following at paragraphs 72 and 110:

72. Decision: We accept the Staff's recommendation and require Pepco to include grid numbers and Siemens' inspection dates on manhole event reports. Each year over 200 manholes are selected through stratified sampling criteria and inspected by Siemens. Including grid numbers and inspection dates will help to identify manhole events traced to the manholes recently inspected, manholes located along Pepco's Priority Feeders, and manholes with and adjacent to recent manhole events. This will enhance independent/third party validation and quality assurance of the manhole inspection program.

110.Pepco is DIRECTED to provide grid numbers consistent with paragraph 72 herein;

- Feeder Number
- Manhole cover type (solid, slotted, roadway, round, sidewalk)
- Manhole Condition (clean, water below cable, water above cable, debris above cable)
- Voltage class (600V, 4kV, 13kV, 34kV, 69kV)
- Type of equipment (transformer, protector, cable, switch, straight joint, branch joint, trifurcating joint, transition joint, other)
- Equipment description: details specifics of the equipment such as size, insulation, phases, type of joint
- Repair description: details repair work
- A description of the failure mode (not previously recorded)
- A determination if the failure is a repeating event at this location (not previously recorded)

Pepco undertook a substantial database conversion during 2012 to make these additions to enhance summary reporting and analysis. The duration of the repair effort, which was outstanding in the database conversion effort as of the 2013 Consolidated Report, is now included within the database.

The listing of 2020 Manhole Events is provided in the following table:

Table 3A-1

2020 MANHOLE EVENT REPORT - DISTRICT OF COLUMBIA

As of : 4/5/21

EVENT No.	DATE	LOCATION	WARD	Quad	FDR	EVENT TYPE	Failure Type	Prim/Sec	Cable Size	Insulation	MANHOLE COVER	MH Size	DESCRIPTION/CAUSE	ACTION
DC20-01	2/6/2020	22nd & L St, NW	2	NW	14422	Smoke	Secondary Cable	Secondary	250 KCM	RN	Slotted	28'x28'	Burning 250 secondaries in duct line	cut cables in hole before and after to isolate. Pulled in new cable to make permanent repairs
DC20-02	2/18/2020	1200 Independence Ave, SW	2	SW	15309	Smoke	Primary Joint	Primary	4/0 AWG	PILC	Solid	6'x12'	Blown Branch Joint	Made permanent repairs
DC20-03	2/27/2020	2305 New York Ave, NE	5	NE	14016	Explosion	Primary Joint	Primary	500 KCM	PILC	Solid	4'x6'	Blown straight joint	Made permanent repairs
DC20-04	3/19/2020	1220 12th St, SE	6	SE	228	Smoke	Primary Joint	Primary	#2 AWG	RN	Solid	4'x4'	Blown single phase branch joint	Remade blown single phase branch joint
DC20-05	3/28/2020	Connecticut Ave & Woodley Rd, NW	3	NW	15338	Smoke	Primary Cable	Primary	350 KCM	RL	Solid	6'x7'	Faulted primary lead cable	Replaced 330ft of 350kcm lead cable on Woodley Rd @ 784397-724742
DC20-06	6/7/2020	19th & Constitution Ave, NE	6	NE	229	Smoke	Secondary Cable	Secondary	250 KCM	RL	Solid	3'x3'	Burned secondary mains	Made repairs replacing 2 stretches orf R/L 250 mains w/ R/N 250 from 806385-365704 to 806385-418487
DC20-07	6/9/2020	3220 Connecticut Ave & Macomb St, NW	3	NW	14148R	Explosion	Primary Cable	Primary	500 KCM	PILC	Solid	6'x12'	Failed 500 3/C PILC in duct line S/O 783400-628536	Replaced 670 feet of 500 3/C PILC with 600 flat strap 3-1/C RN.
DC20-08	6/19/2020	Connecticut Ave & L St, NW	2	NW	Multiple	Fire	Secondary Cable	Secondary	N/A	PILC	Solid	5'x12'	Secondary buss ties burnt into primary causing multiple feeder failures	Pulled 3 ways to repairs feeders 15376, 15377, 15378, 15379, 15380, 15381, 14616, 14617. Removed PILC cable, Installed RN
DC20-09	6/28/2020	Wisconsin Avenue & N Street, N.W.	2	NW	14559	Smoke	Secondary Cable	Secondary	250 KCM	RL	Solid	6'x18'	Secondary mains in 2 M/Hs from xfmr #781390-765887	Made permanent repairs
DC20-10	7/1/2020	3504 International Dr	3	NW	15867	Fire	Equipment	Equipment	500 KCM	RN	Grated	6'x18'	Bank 333 burnt up primary and secondary cables	Replaced bank 333kva w/ 1000kva subsrface, replace 3 phase primary to TH 357538, replace 3 sets of service secondary
DC20-11	7/3/2020	9th St & Jefferson St NW	4	NW	15197	Smoke	Primary Cable	Primary	500 KCM	PILC	Solid	6'x10'	Failed 500 3/C PILC joint	Replaced 420' of 500 3/c PILC with 50 flat strap RN
DC20-12	7/4/2020	3031 Cathedral Ave, NW	3	NW	14146	Fire	Primary Cable	Primary	250 KCM	PILC	Solid	3X3	Burned secondary mains	Made permanent repairs
DC20-13	7/5/2020	3240 Grace St NW	2	NW	4556&1455	Smoke	Primary Cable	Primary	#2 AWG	EPR	Solid	6'X10'	#2PILC 3/C to #2 3-1/C # 2 URD Trificating Joint	Feeder Test capped out to network transformer 781389-640866
DC20-14	7/6/2020	320 1st Street, N.W.	6	NW	14631	Smoke	Primary Joint	Primary	#2 AWG	PILC	Solid	6'X10'	Blown joint on Feeder 14631	Made permanent repairs
DC20-15	7/20/2020	North Capitol & H St. NE	5	NE	15467	Smoke	Primary Cable	Primary	#2 AWG	PILC	Solid	5'x10'	feeder # 15467 Joint falt in M H #797388-319646 replaced 110 feet of #2 URD to MH #797388-279625 Per repairs	Made permanent repairs
DC20-16	7/27/2020	1500 Eckington Pl. NE	5	NE	15457	Fire	Secondary Cable	Secondary	250 KCM	EPR	Slotted	5'x10'	Manhole fire due to secondary insulation failure. Multiple feeders in the hole tripped.	Test cap feeders and replaced cable.
DC20-17	8/13/2020	1255 23rd St. NW	2	NW	14543	Smoke	Equipment	Equipment	N/A	N/A	Grated	6'X18'	Failed network transformer# 785390-691691 primary door was blown off and oil in the mahole	Replaced Faulted Network Transformer W/New Transformer 1500KVA 120/208 sec Voltage
DC20-18	8/13/2020	49th St. & Hillbrook Ln.	3	NW	75	Smoke	Primary Cable	Primary	#2 AWG	RL	Solid	4'X6'	RL cable faulted at the edge of Duct line	Installed 60' of #2 URD R/S/C Made perm. Repairs
DC20-19	8/17/2020	4th & Constitution Ave NE	6	NE	15875	Smoke	Secondary Cable	Secondary	500 KCM	RN	Solid	4'X6'	Failed secondary cable straight joint	De-Energize secondary cable to remake secondary straight joints
DC20-20	8/21/2020	307 T St NE.	5	NE	15457	Explosion	Primary Cable	Primary	350 KCM	PILC	Solid	6'X10'	Failure in the cable 40' away from the MH in the duct line.	Cable was replaced with RN and two heat shrink transition splices. There was another fault after repairs were completed on 15458 at same location due to colateral damage from the first event. UG crews had to replace the cable the second time. One heat shrink transition splice and a set of straight joints.
DC20-21	11/30/2020	402 New Jersey Ave, SE	6	SE	16002	Explosion	Secondary Cable	Secondary	#2 AWG	RN	Solid	3'x3'	Burned secondary mains	Replaced secondary mains back to transformer 797382-955750
DC20-22	12/25/2020	3rd St, NE & R St, NE	5	NE	15459	Explosion	Primary Joint	Primary	500 KCM	EPR	Solid	6'x15'	BØ of Y-splice in 4/0 3-1/c cable	Replaced 600 flat strap cable, made new Y-splice & three 600 straight splices

Table 3A-2

2020 MANHOLE EVENT REPORT - DISTRICT OF COLUMBIA

As of : 4/7/21

EVENT No.	DATE	Work Order	LOCATION	Event Voltage	FAILURE MODE	REPEAT EVENT	4kV / 13kV	Manhole Condition	NO. OF CUST.	Outage (hr/min)	Repair Duration	DATE INSPECTED BY SIEMENS	LAST INSPECTION	Facility ID	Personal injury or property damage
DC20-01	2/6/2020		22nd & L St, NW	120/208V	Secondary Cable	No	13kV	Water below cable	0				6/3/2011	785389-997745	No
DC20-02	2/18/2020		1200 Independence Ave, SW	13kV	Primary Joint	No	13kV	Water below cable	0				N/A	792383-236918	No
DC20-03	2/27/2020		2305 New York Ave, NE	13kV	Primary Joint	No	13kV	Water above cable	114	7693	67		4/18/2018	807394-994708	No
DC20-04	3/19/2020		1220 12th St, SE	4kV	Primary Joint	No	4kV	Water below cable	111	529	633		3/15/2017	803379-232814	No
DC20-05	3/28/2020		Connecticut Ave & Woodley Rd, NW	13kV	Primary Cable	No	13kV	Water below cable/debris	0				2/27/2019	784397-892692	No
DC20-06	6/7/2020		19th & Constitution Ave, NE	120/240V	Secondary Cable	No	13kV	Water above cable	0				7/23/2018	806385-365704	No
DC20-07	6/9/2020		3220 Connecticut Ave & Macomb St, NW	13kV	Primary Cable	No	13kV	Debris/Water below cable	5				9/9/2019	783400-628536	No
DC20-08	6/19/2020		Connecticut Ave & L St, NW	13kV	Secondary Cable	No	13kV	Debris	103				7/26/2010	788389-463770	No
DC20-09	6/28/2020		Wisconsin Avenue & N Street, N.W.	13kV	Secondary Cable	No	13kV	Water below cable					3/21/2019	781390-765887	No
DC20-10	7/1/2020		3504 International Dr	13kV	Equipment	No	13kV	Clean	0				6/18/2015	781403-365533	No
DC20-11	7/3/2020		9th St & Jefferson St NW	13kV	Primary Cable	No	13kV	Debris	1446	1549	97		1/25/2013	792408-622556	No
DC20-12	7/4/2020		3031 Cathedral Ave, NW	13kV	Primary Cable	No	13kV	Debris					N/A	782399-665005	No
DC20-13	7/5/2020		3240 Grace St NW	13kV	Primary Cable	No	13kV	Debris					N/A	781389-599866	No
DC20-14	7/6/2020		320 1st Street, N.W.	13kV	Primary Joint	No	13kV	Mud below cable					N/A	796386-300357	No
DC20-15	7/20/2020		North Capitol & H St. NE	13kV	Primary Cable	No	13kV	Water below cable					5/23/2013	797388-319646	No
DC20-16	7/27/2020		1500 Eckington Pl. NE	13kV	Secondary Cable	No	13kV	Debris					N/A	798391-403960	No
DC20-17	8/13/2020		1255 23rd St. NW	13kV	Equipment	No	13kV	Oil in the manhole	0				7/2/2014	785390-691691	No
DC20-18	8/13/2020		49th St. & Hillbrook Ln.	4kV	Primary Cable	No	4kV	Clean	315	1			5/4/2017	772401-481891	No
DC20-19	8/17/2020		4th & Constitution Ave NE	120/240V	Secondary Cable	No	13kV	Clean	48	50	50		N/A	799385-742519	No
DC20-20	8/21/2020		307 T St NE.	13kV	Primary Cable	No	13kV	Clean					11/16/2017	799394-334073	No
DC20-21	11/30/2020		402 New Jersey Ave, SE	120/208V	Secondary Cable	No	13kV	Clean	56	151			N/A	797382-914887	No
DC20-22	12/25/2020		3rd St, NE & R St, NE	13kV	Primary Joint	No	13kV	Water above cable					7/8/1905	799393-338019	No

Table 3A-3

Notes:
22 events :13 primary (8 S, 1 F, 4 E), 7 secondary (4 S, 2 F, 1 E), 2 Equipment (1 S, 1 F, 0 E)
2 events involved slotted manhole covers (1 S, 1 F,0 E),
18 events involved solid manhole covers (11 S, 2 F, 5 E)
2 events involved grated manhole covers (1 S, 1 F, 0 E)

Event category breakdown:			
Smoking manholes	13		
Manhole fires	4		
Manhole explosions	5		
Total:	22		
Northwest	12	Georgetown:	2
Northeast	7		
Southwest	1		
Southeast	2		
Total:	22		

Events Summary 13kV
20 events : 11 primary (6 S, 1 F, 4 E), 7 secondary (4 S, 2 F, 1 E) , 2 Equipment (1 S, 1 F, 0 E)

Event category breakdown:			
Smoking manholes	11		
Manhole fires	4		
Manhole explosions	5		
Total:	20	Georgetown:	2

Events Summary 4kV
2 events : 2 primary (2 S, 0 F, 0 E), 0 secondary (0 S, 0 F, 0 E),

Event category breakdown:			
Smoking manholes	2		
Manhole fires	0		
Manhole explosions	0		
Total:	2	Georgetown:	0

Events Summary 69kV
0 events :0 primary (0 S, 0 F, 0 E)

Event category breakdown:			
Smoking manholes	0		
Manhole fires	0		
Manhole explosions	0		
Total:	0		
		Georgetown:	0

First Quarter 2020 - Summary		**Third Quarter 2020 - Summary**	
Insulation Deterioration by Cable Type:		Insulation Deterioration by Cable Type:	
Paper Insulated Lead Cable (PILC)	2	Paper Insulated Lead Cable (PILC)	5
Rubber Lead (RL)	1	Rubber Lead (RL)	1
Rubber Neoprene (RN)	2	Rubber Neoprene (RN)	2
Ethylene Propylene Rubber (EPR)	0	Ethylene Propylene Rubber (EPR)	2
Cross Link Polyethylene (XLP)	0	Cross Link Polyethylene (XLP)	0
Other (Braided)	0	Other (Braided)	0
Other	0	Other (URD)	0
Non-Pepco	0	Non-Pepco	0
Non-Cable related	0 a/	Non-Cable related	1 b/
TOTAL	5	TOTAL	11

Second Quarter 2020 - Summary		**Fourth Quarter 2020 - Summary**	
Insulation Deterioration by Cable Type:		Insulation Deterioration by Cable Type:	
Paper Insulated Lead Cable (PILC)	2	Paper Insulated Lead Cable (PILC)	0
Rubber Lead (RL)	2	Rubber Lead (RL)	0
Rubber Neoprene (RN)	0	Rubber Neoprene (RN)	1
Ethylene Propylene Rubber (EPR)	0	Ethylene Propylene Rubber (EPR)	1
Cross Link Polyethylene (XLP)	0	Cross Link Polyethylene (XLP)	0
Other (Braided)	0	Other (Braided)	0
Other (URD)	0	Other	0
Non-Pepco	0	Non-Pepco	0
Non-Cable related	0 a/	Non-Cable related	0
TOTAL	4	TOTAL	2

a/ Transformer
b/ Network Transformer

Appendix 3B: 2020 Manhole Inspection Program[75]

[75] In Order No. 11716, the Commission stated the following:

PEPCO is hereby directed to include the following information in its [manhole inspection] reports beginning in July 2000:

1. *The general location of the manholes inspected, including the street or streets where the manholes are located and the blocks bounding the street, e.g., M Street, NW, between 23rd and 28th streets;*
2. *The number of manholes inspected in the month, broken down as to the number of manholes containing primary cables only, both primary and secondary cables, and secondary cables only;*
3. *The number of primary cable problems found;*
4. *The number of secondary cable problems found;*
5. *The type of cable problems found in each manhole, categorized as to the physical degradation or damage of the cable, overheating, overloading, damaged splice and deteriorated cable or splice due to age;*
6. *The number of manholes with problems;*
7. *The corrective actions taken for each cable and manhole problem found; and*
8. *Other general condition of the manhole such as whether it contained water, oil, grease, debris, and whether the manhole cover and the manhole are in good mechanical condition.*

APPENDIX 3B - MANHOLE INSPECTION PROGRAM (MIP)

Pepco began development of its manhole inspection program in 1999. By the end of 2006, Pepco had performed a total of 79,295 inspections, completing Phase I. Phase II of the Company's Manhole Inspection Program began in 2007 and was completed in the first quarter of 2013 with a total of 69,670 inspections. Phase III of the Company's Manhole Inspection Program began in 2013 and was completed in 2018 with a total of 66,836 inspections. Phase IV of the manhole inspection program is currently underway. A total of 10,614 manholes were inspected in 2020

Manhole inspections represent a significant undertaking that involve the visual assessment of the underground manholes and vaults and the equipment contained in them, taking load readings of low voltage cables and reviewing the integrity of cable splices. Supervisory personnel review records and corrective actions are identified and tracked. Data obtained during the inspections can be used to ascertain whether the secondary cables are overloaded or are likely to be overloaded under peak load conditions using appropriate de-rating factors and factors to simulate peak conditions. Inspections are also designed to identify load variations between phases which could indicate possible imbalanced conditions. By identifying such instances and taking appropriate actions, Pepco will continue to improve and maintain the reliability of its system.

Inspection Priority Definitions

As a result of the merger, new procedures and processes are in place across the Pepco region for planning and prioritizing corrective maintenance activities. Beginning in 2019, Pepco has adopted the Exelon work screening and prioritization practices in the manhole inspection program. All corrective maintenance reportable conditions (CMs) are classified into one of four categories under the Exelon model: P10, P20, P30, or P40. A description of each deficiency is shown below:

<u>P10:</u> Immediate response required; work item until complete or until corrective actions allow the downgrading of the priority. Priority 10 CMs should not exceed 3 days. These items have a direct and immediate impact to safety, SAIFI, or SAIDI.

P20: Priority 20 CMs are usually completed within 14 days and should not exceed 30 days. corrective plans shall be created for Priority 20 CMs that exceed 30 days. These items have a high probability of affecting SAIFI, SAIDI, or safety.

P30: Priority 30 CMs are typically completed within 9 months and should absolutely not exceed 1 year. A corrective plan shall be created for priority 30 CMs that exceed 1 year. These items have a moderate probability of affecting SAIFI or CAIDI if not addressed within a year's timeframe. For priority 30 CMs that require completion before the 9-month target, an agreed upon need date shall be established through the work screening process. All changes in proposed need date require approval.

P40: Work not meeting the criteria for a P10, P20, or P30 shall be considered a P40 and completed not to exceed the predominant maintenance cycle interval. Impact on SAIFI or CAIDI would only result if the condition rapidly degrades. A priority 40 CM shall not exceed 1 year past the determined preventative maintenance cycle for the associated equipment class.

Current Program Status

During 2020, the MIP has identified the following remediation Priorities:

	Priorities Count	Percentage of CY 2020 Priorities
Priority Code 10	88	3%
Priority Code 20	16	1%
Priority Code 30	18	1%
Priority Code 40	3157	96%

Inspectors are conducting more comprehensive and thorough inspections which have resulted in a substantial increase in Priorities found. In 2020, approximately 31% of the manholes inspected revealed potential areas of concern that have been or are in the process of being addressed. Figure

3.2-B1 provides a graphical representation of the number of manholes and the percentage of overall inspections with priority conditions.

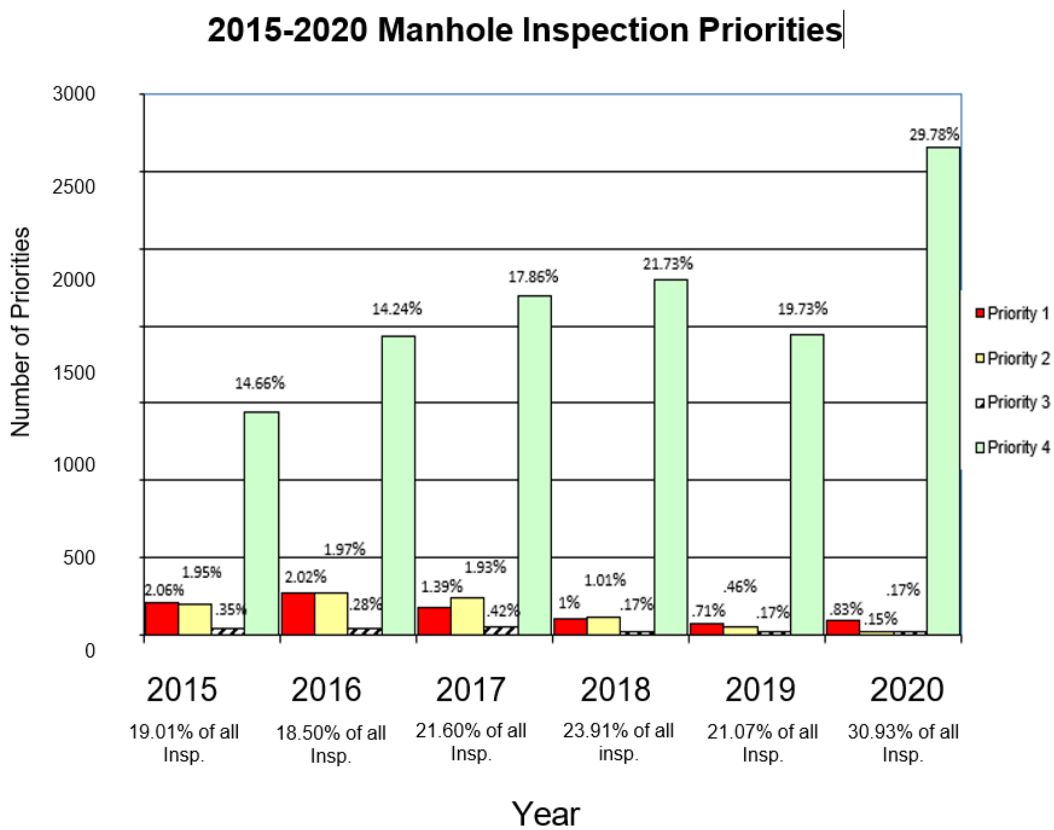
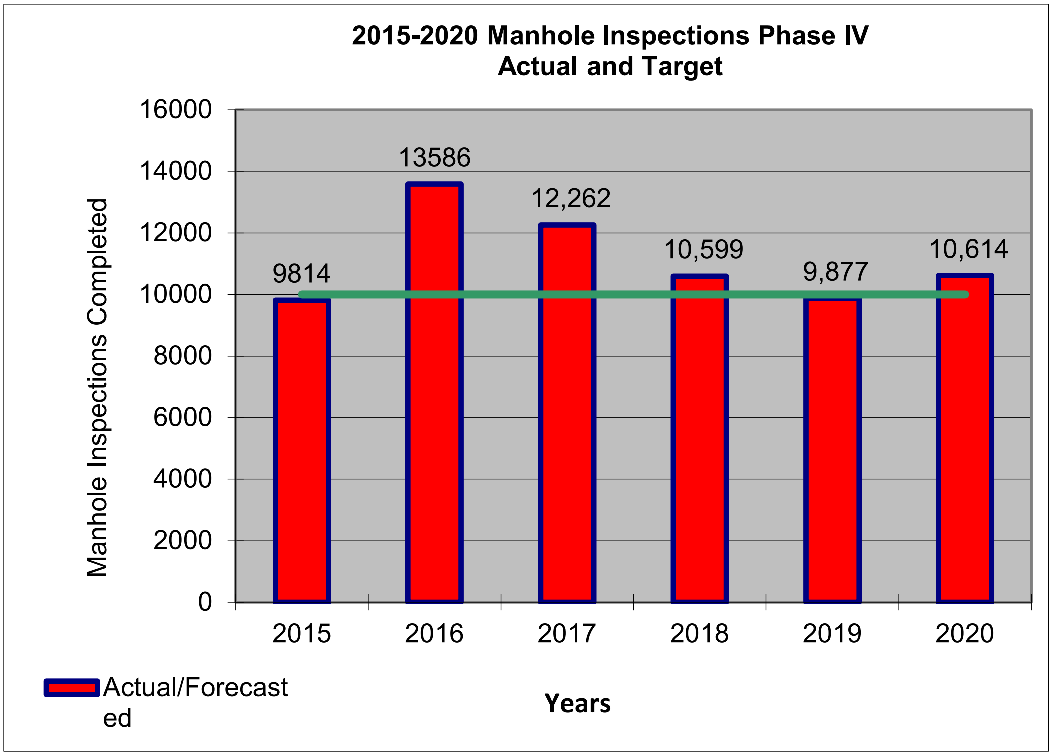


Figure 3.2-B1: Manhole Inspection Priorities – Phase IV

With the implementation of the Manhole Inspection Quality Control (QC) Program, inspection Priorities have increased from 1,866 in 2015 to 3,279 Priorities in 2020. The majority of the increase is related to Priority 40 conditions, which are not considered an imminent risk and must be remediated within 12 months and the increase can be attributed at least in part to more rigorous inspections.

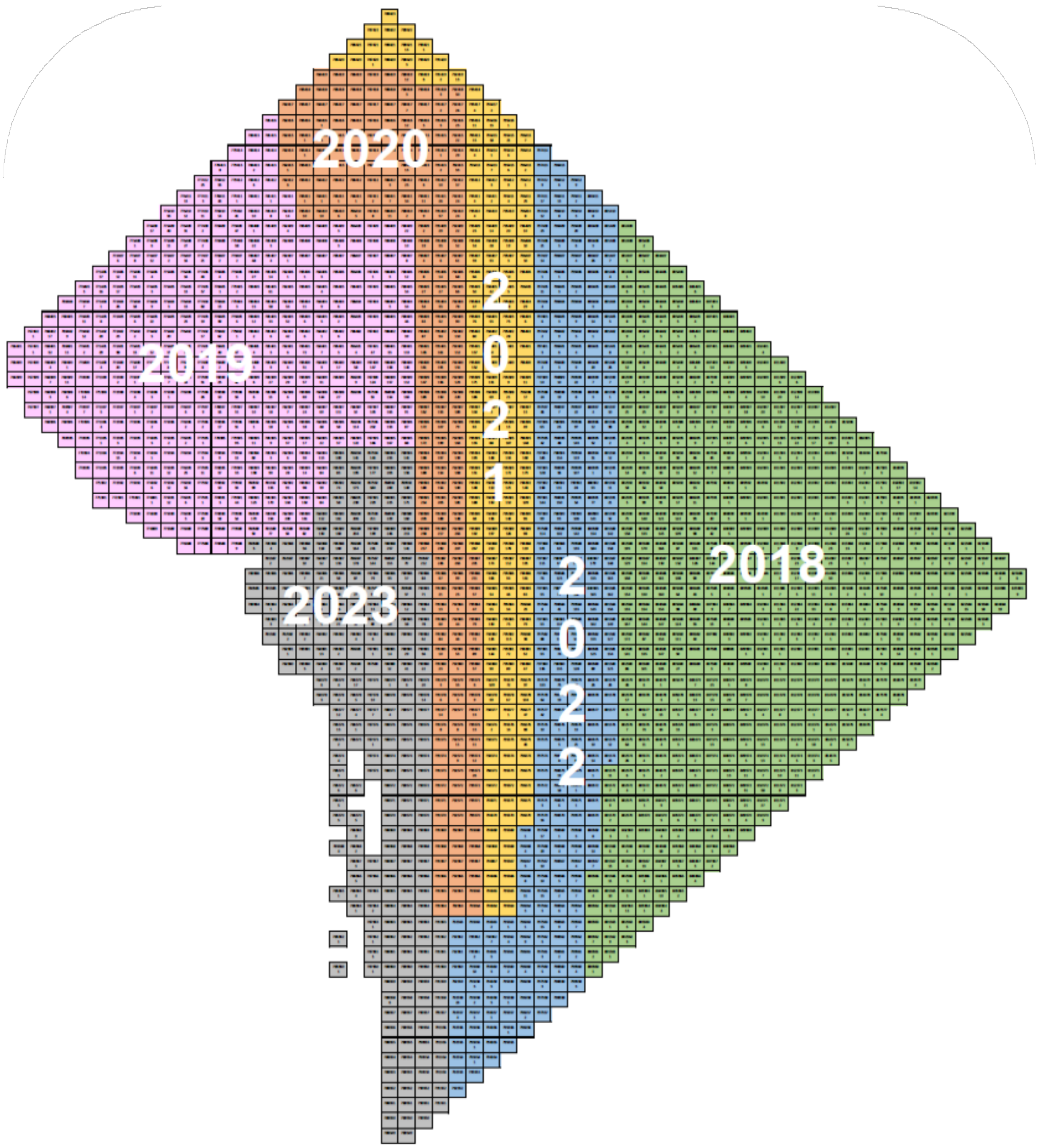
Figure 3.2-B2: Manhole Inspections Completed – Phase IV



In 2017, a comprehensive analysis on the manhole population in the District was performed using GIS extracts. Using these records, a more efficient inspection plan was created for the next complete cycle in the District. Additionally, the tracking mechanism for manhole inspections was changed for inspections occurring in 2018 and forward. Previously, inspections were assigned on a 1,000' x 1,000' "plat" basis rather than by individual manholes. This left room for gaps and a small number of missing inspections. Moving forward, all manhole inspections will be tracked on an individual manhole level, leaving no room for errors or missing inspections.

With the new GIS extract that was performed, a grouping of manholes based on geographic location was performed in order to solidify the inspection plan for the next 6 years. Figure 3.3 below shows the manhole inspection map of the District for years 2018-2023. Each colored region has an equivalent number of manholes within it, equally divided between 6 inspection years. This plan will improve the crew efficiency and future corrective maintenance work planning as crews won't be moving all across the city for one year.

Figure 3.2- B3: 2018-2023 Manhole Inspection Plan



Quality Control Program

The manhole inspection program QA/QC process is broken into three parts that is to be followed by Aldridge Electric:

- Office Review: A minimum of 15% of the inspected locations are to be reviewed in office after the inspections are complete and the information is uploaded into the manhole inspection database. This review process consists of the following:
  - Review photos to ensure quality of 360 and Still shots labeled accurately
  - Verify if manhole cleaning is required based off photos
  - Verify Output of assessment pdf is accurately filled out
  - Verify CM work
  - Verify all manhole locations deemed out of scope or missing.
- Field Inspection Review: A minimum of 8% of the inspected location are reviewed which include a review of inspectors' work (setup, assessment, safety, etc.) on site at the time of inspection, by the field leadership team.
  - 2 AE Foreman training and performing quality inspections full time
  - 1 AE General Foreman providing oversite and quality inspections when available
  - 1 AE Construction Manager overseeing subcontractor full time
- Field CM Review Process: A minimum of 7% of the inspected locations are reviewed by Foreman and PM daily with 360 completion photos to verify accuracy of work performed. A completion log is filled out by crew leader for every manhole worked.
  - 1 AE Foreman performing quality inspections full time
  - 1 AE General Foreman providing oversite and quality inspections when available
  - Verify installed items vs. called out items in assessment
  - Field Lead identifies all CM work is complete
  - Verify 360 photo taken upon completion
  - Crew leader reviewing original assessment to verify accuracy at every location visited

2020 Quality Control Metrics

OFFICE REVIEW (15% Min)			
Month	Locations Visited	QA/QC Performed	%
JANUARY	342	342	100.00%
FEBRUARY	717	717	100.00%
MARCH	960	960	100.00%
APRIL	790	790	100.00%
MAY	1240	1240	100.00%
JUNE	1715	1715	100.00%
JULY	1531	1531	100.00%
AUGUST	1612	1612	100.00%
SEPTEMBER	1368	1368	100.00%
OCTOBER	1661	1661	100.00%
NOVEMBER	1087	1087	100.00%
DECEMBER	752	752	100.00%

FIELD ASSESSMENTS (8% Min)			
Month	Assessments Completed	QA/QC Performed	%
JANUARY	322	30	9.30%
FEBRUARY	641	58	9.00%
MARCH	890	72	8.10%
APRIL	717	65	9.10%
MAY	1067	90	8.40%
JUNE	1422	136	9.60%
JULY	1180	102	8.60%
AUGUST	1256	125	10.00%
SEPTEMBER	1083	93	8.60%
OCTOBER	1309	118	9.00%
NOVEMBER	923	85	9.20%
DECEMBER	715	60	8.40%

FIELD CMs PERFORMED (7% Min)			
Month	CMs Completed	QA/QC Performed	%
JANUARY	0	0	0%
FEBRUARY	0	0	0%
MARCH	0	0	0%
APRIL	0	0	0%
MAY	0	0	0%
JUNE	0	0	0%
JULY	48	48	100%
AUGUST	61	30	49%
SEPTEMBER	106	42	40%
OCTOBER	152	68	45%
NOVEMBER	231	96	42%
DECEMBER	169	52	31%

Appendix 3C: Network Accuracy Procedure Report[76]

[76] In Order No. 16709 paragraphs 9 and 10, the Commission ordered the following:

9. *The Commission is satisfied that Pepco has developed a reasonable plan to ensure that its underground cables are adequately sized for existing and future loads. However, we do want to monitor Pepco's diligence in performance and the results of implementation of its network modeling, GIS updates, and timely network technology improvements going forward. We, therefore, direct the Company to file periodic reports to keep the Commission and interested parties apprised of the status of several ongoing projects as follows:*
   a. *Pepco is directed to provide a detailed status report on those eight networks that are currently undergoing analysis under the Company's Network Accuracy Procedure including the corrective actions that were identified by December 2011. This report on the eight networks should be added to the Company's 2012 Consolidated Report or filed as a Supplement to the 2012 Consolidated Report if the 2012 Report has already been filed or it is too late to include it for publication in the 2012 Report; and*
   b. *Pepco is directed to file a detailed status report on the results of its modeling and analysis and the implementation of its remedial actions on all of its remaining networks under its Network Accuracy Procedure. This report on the remaining networks should also be added to the 2012 Consolidated Report (or filed as a Supplement to the 2012 report if the 2012 Report has already been filed or it is too late to include it for publication in the 2012 Report) with updates in each subsequent year's report. The status report on those remaining networks shall include corrective actions that have been scheduled and those that have been completed.*

THEREFORE, IT IS ORDERED THAT:

10. *Pepco shall comply with the directives set forth in paragraph 9 herein.*

Network Accuracy Procedure Report

Status Report of the Analysis of the Remaining District of Columbia Networks, in Accordance with the Network Accuracy Procedure.

As reported in 2020, all investigations of Pepco's LVAC networks in the District of Columbia have been completed. Pepco has adopted the network accuracy procedure and intends to continue reviewing the accuracy of the LVAC networks; however, Pepco will not report further on this procedure's results in the ACR.

PART 4: REFERENCES

SECTION 4.1 – ABBREVIATIONS AND ACRONYMS

2005 Plan - Vegetation Management Plan for Utility Tree Pruning – D.C.
A&G - Administrative & General
AC - Alternating Current
ACR - Automatic Circuit Reclosers
AFP - Assist Fire/Police
AMI - Advanced Metering Infrastructure
ANSI - American National Standards Institute
AQL - Acceptable Quality Level
ASR - Automatic Sectionalizing and Restoration
CAD - Computer Aided Design
CAIDI - Customer Average Interruption Duration Index
CBM - Condition Based Maintenance
CIC - Crisis Information Center
CIS - Customer Information System
CMT - Crisis Management Team
COG - Council of Governments
COOP - Continuity of Operations
CPI - Composite Performance Index
CRP - Comprehensive Reliability Plan
DA - Distribution Automation
D.C. - District of Columbia
DDOT - District of Columbia Department of Transportation
DGA - Dissolved Gas in oil Analysis
DOE - Department of Energy
DOT - Department of Transportation
DPWT - Department of Public Works and Transportation
DRTU - Digital Remote Terminal Unit
E - Manhole Explosion
ECA - Equipment Condition Assessment EMA
- Emergency Management Agency EMF -
Electromagnetic Field
EMS - Energy Management System
EOC - Emergency Operations Center
EOP - Emergency Operations Plan
EPR - Ethylene Propylene Rubber cable
EPRI - Electric Power Research Institute
EQSS - Electricity Quality of Service Standards
ERIP - Emergency Restoration Improvement Project
ETR - Estimated Time of Restoration
F - Manhole Fire
FAA - Federal Aviation Administration
FEMA - Federal Emergency Management Agency

FERC	-	Federal Energy Regulatory Commission
FTE	-	Full Time Equivalent
GIS	-	Geographic Information System
GWD	-	Graphical Work Design
GWh	-	Gigawatt-hour
HMPE	-	High Molecular weight Polyethylene
HSEMA	-	Homeland Security and Emergency Management Agency
HVCA	-	High-Volume Call Answering
IEEE	-	Institute of Electrical and Electronics Engineers
ICS	-	Incident Command System
IMT	-	Incident Management Team
ISA	-	International Society of Arboriculture
IST	-	Incident Support Team
kV	-	Kilovolt
LTC	-	Load Tap Changer
LVAC	-	Low Voltage Alternating Current (Network)
MDS	-	Mobile Dispatch System
MDT	-	Mobile Data Terminal
MED	-	Major Event Day
MIP	-	Manhole Inspection Program
MOV	-	Metal Oxide Varistor
MVA	-	Megavolt Ampere
MVAR	-	Megavolt Ampere Reactive
MWh	-	Megawatt-hour
NERC	-	North American Electric Reliability Corporation
NIMS	-	National Incident Management System
NOC	-	Network Operating Center
NOFR	-	Notice of Final Rulemaking
OCB	-	Oil Circuit Breaker
OH	-	Overhead
O&M	-	Operations and Maintenance
OMS	-	Outage Management System
OPC	-	Office of the People's Counsel
OTR	-	Office of Tax and Revenue
P&A	-	Planning & Analysis
PAC	-	Phase Angle Control or Pre-assembled Arial Cable
PCA	-	Palisades Citizens Association
PCB	-	Polychlorinated Biphenyls
PDM	-	Predictive Maintenance
Pepco	-	Potomac Electric Power Company
PH	-	Pepco Holdings LLC
PIP	-	Productivity Improvement Plan
PIWG	-	Productivity Improvement Working Group
PILC	-	Paper Insulated Lead Cable
PJM	-	PJM Interconnection
PLC	-	Power Line Carrier
PNB	-	Prospective New Business report
QC	-	Quality Control

RCM	-	Reliability Centered Maintenance
RE	-	Reportable Event
RFC	-	Reliability First Corporation
RL	-	Rubber Lead
RN	-	Rubber Neoprene
ROW	-	Right of Way
RPTA	-	Real Property Tax Administration
RTO	-	Regional Transmission Organization
RTU	-	Remote Terminal Unit
S	-	Smoking Manhole
SAIDI	-	System Average Interruption Duration Index
SAIFI	-	System Average Interruption Frequency Index
SCADA	-	Supervisory Control and Data Acquisition
SEC	-	Security Exchange Commission
SGIG	-	Smart Grid Investment Grant
SMECO	-	Southern Maryland Electric Cooperative
SOS	-	Standard Offer Service
StormMan	-	Oracle Storm Management module/function
T&D	-	Transmission and Distribution
TGR	-	Tree Growth Regulator
TOA	-	Transformer Oil Analyst
UFA	-	Urban Forestry Administration
UG	-	Underground
URD	-	Underground Residential Distribution
VAR	-	Volt-ampere Reactive
VLF	-	Very Low Frequency
VM	-	Vegetation Management
WMIS	-	Work Management Information System
XLPE	-	Cross Link Polyethylene

SECTION 4.2 – TECHNICAL TERMS AND DIAGRAMS

This section contains definitions, explanations and diagrams used in discussing electric system operations, design characteristics, and performance.

Alternating Current (AC)

A current, which reverses at regularly recurring intervals of time and that has alternately positive and negative values.

Ampere

The "ampere" is the basic unit of current equal to the flow of one coulomb of charge passing a point in one second. It is also the amount of current that is allowed to flow when a difference of potential of one volt is applied to a resistance of one ohm.

Ampere-hour

The flow of current per hour. Ten ampere-hours is equal to the flow of 10 amperes for a period of one hour or the flow of one ampere for ten hours.

Arrester

A device that provides an alternate path for surge currents caused by over-voltage resulting from lightning or switching surges.

Battery

Two or more cells electrically connected for producing electric energy. A device that transforms chemical energy into electric energy.

Cable Joint

A connection between two or more separate lengths of cable with the conductors in one length connected individually to conductors in other lengths and with the protecting sheaths so connected as to extend protection over the joint.

Cable Rack

A device usually secured to the wall of a manhole, cable raceway, or building to provide support for cables.

Cable Splice

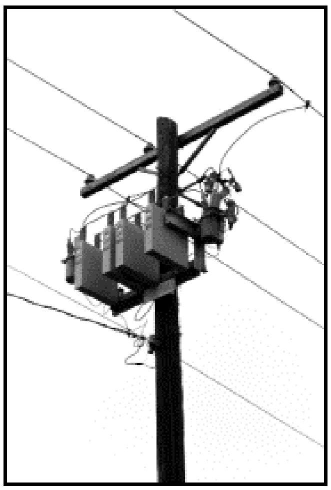
See Cable Joint

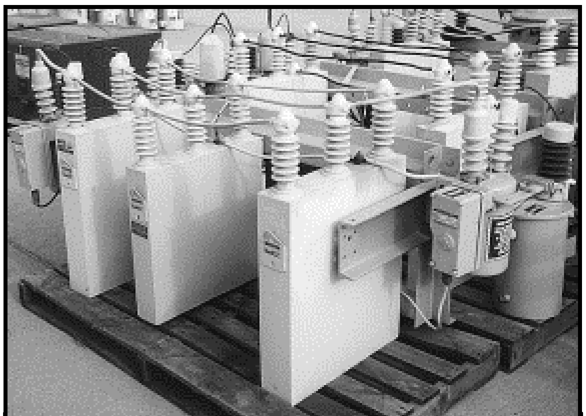
CAIDI (Customer Average Interruption Duration Index)

Represents the average time required to restore service to the average customer per sustained interruption. Mathematically equal to SAIDI divided by SAIFI.

Capacitor

An electrical device for storing a charge of electricity and returning it to the line. It is used to balance the inductance of a circuit, since its action is opposite in phase to that of inductive apparatus; it throws the current ahead of the electromotive force in phase. It is made of alternate plates of tinfoil and insulating material. The size of plates and the thickness of insulating material determine the capacity for holding electric charge. Capacity is measured, practically, in micro-farads, millionths of a farad.





Capacitors

Circuit

A conductor or system of conductors through which an electric current is intended to flow.

Circuit Breaker

A device designed to open and close a circuit by non-automatic overload of current without damage to itself when properly applied within its rating.

Conductor

A material that allows the flow of electricity; a metal wire, in the center of an electrical cable, through which current flows.

Conduit

A pipe, most often made of polyvinyl chloride, used for the installation of cables underground.

CPI (Composite Performance Index)

A distribution feeder performance measuring index created by combining 4 industry standard reliability indicators. The indicators used in CPI are Number of Interruptions (NI), Number of Customer Hours of Interruption (CHI), System Average Interruption Frequency (SAIF) and System Average Interruption Duration (SAID).

Cycle

One complete set of positive and negative values of an alternating current.

Duct

A single enclosed runway for conductors or cables.

Duct Bank

An arrangement of conduit providing one or more continuous ducts between two points.

Efficiency

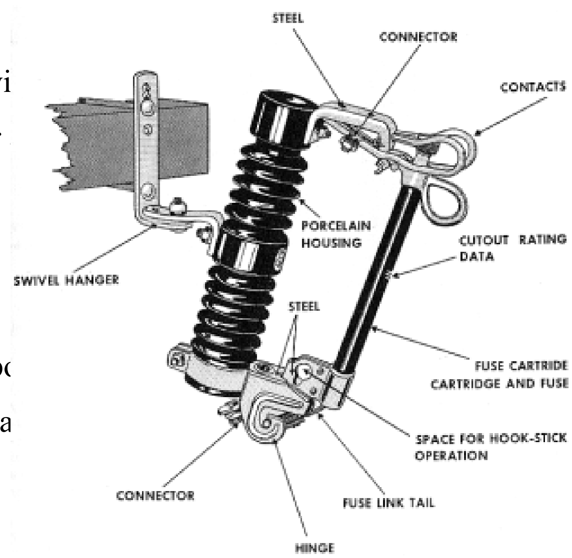
The ratio of the useful output to the input of energy, power, quantity of electricity, etc.

Fault Current

A current that flows from one conductor to ground or to another conductor owing to an abnormal connection (including an arc) between the two. Note: A fault current flowing to ground may be called a ground fault current.

Fuse

An electrical safety device consisting of, or including, a wi
interrupts the circuit when the current exceeds a particular



Fuse Cutout

A device that is used to de-energize and re- energize compo
protects the line and components from the effect of overloa

Fuse Element

The part of a fuse that melts and interrupts the circuit when excessive current flow occurs.

Ground

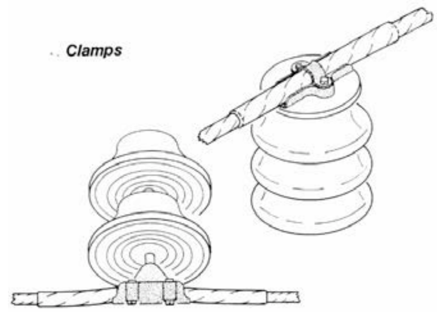
A conducting connection, whether intentional or accidental, by which an electric circuit or equipment is connected to the earth or to some conducting body that serves in place of the earth.

Inductance

The process that produces a voltage due to interaction of a conductor, a magnetic field, and relative motion between them.

Insulator

A material that offers a great deal of resistance to electron flow.



Kilowatt-Ampere (kVA)

The unit of apparent power in alternating current circuits as distinguished from kilowatts which represent true power.

Kilowatt (kW)

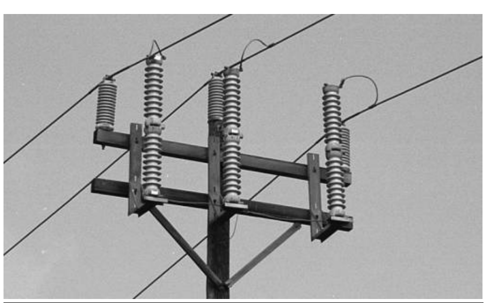
A unit of electric power equal to one thousand watts.

Kilowatt-hour (kWh)

The work performed by one kilowatt of electric power during one hour.

Lightning Arrester

A device that has the property of reducing the voltage of a surge applied to its terminals by the surge current to ground. It is capable of interrupting follow current if present and restores itself to original operating conditions.



Load Factor

The ratio of the average load over a designated period of time to the peak load occurring in that period.

Low Voltage (LV)

600 volts and lower.

Manhole

A subsurface chamber, large enough for a man to enter, in the route of one or more conduit runs and affording facilities for placing and maintaining in the runs, conductors, cables, and any associated apparatus.

Megawatt (MW)

One million watts.

Network

An aggregation of interconnected conductors consisting of feeders, mains, and services.

Overload

A load greater than the rated load of an electrical device.

Paper-Insulated Lead Cable (PILC)

A primary cable designed with paper insulation wrapped around a shielded conductor and covered with a flexible lead covering.

Phase

The relative time of change in values of current or electromotive force. Values that change exactly together are in phase. Difference in phases is expressed in degrees, a complete cycle or double reversal being taken as 360 deg. A 180-deg phase difference is complete opposition in phase.

Polychlorinated Biphenyls (PCB)

A toxic environmental contaminant requiring special handling and disposal in accordance with US Environmental Protection Agency Regulations. No longer used in transformers.

Pothead

A device used to protect the connection between a URD and an overhead system. A pothead also provides a termination for the URD cable insulation.

Power

The rate of doing work or the rate of expending energy. The unit of electrical power is the watt. Power is calculated by multiplying current time voltage.

Power Factor (pf)

The ratio of the actual power of an alternating current as measured by a wattmeter, to the apparent power, as indicated by ammeter and voltmeter reading. The power factor of an inductor, capacitor or insulator is an expression of their losses. The ratio of total watts to the total root-mean-square (RMS) volt-amperes. It is a mathematical term whose value is less than or equal to unity, or one. This term is used to show the relationship between volt-amperes (which is the basis for rating transformers, generators, etc.) and watts which is the measure of usable power delivered. A low power factor results in a lower usable power delivery or consumption for a given value of electric current than would result with a high power factor. The result of a low power factor is higher losses through the wires, cables, and other electrical apparatus.

$$pf = \frac{\sum Watts}{\sum RMS\ VoltsxAmperes}$$

Preassembled Aerial Cable (PAC)

Preassembled Aerial Cable (PAC) is an installation of three single underground cables triplexed together and installed on the overhead distribution system in heavily wooded areas. Each of the three conductors is a fully insulated cable grouped together in a package that is supported by a metallic messenger. The installation is more robust than tree wire and has the ability to withstand falling tree limbs.

Primary Circuit

The higher voltage circuit in a URD system that carries power to the transformers.

Protective Relay

A relay whose function is to detect conditions of an abnormal or dangerous nature and to initiate appropriate control circuit action.

Reactive Power

The product of voltage and the out-of-phase component of alternating current generally measured in kilovars (kVAR). Reactive power decreases the substation's ability to deliver real power and increases system losses.

Reactor

A device, the primary purpose of which is to introduce reactance into a circuit.

230 kV Reactor

Real Power

The rate, generally measured in kilowatts (kW), of generating, transferring, or using energy. The power which serves the customers' end-use electrical devices and the power for which the customer is metered.

Relay

An electric device that is designed to interpret input conditions in a prescribed manner and, after specified conditions are met, to respond to cause contact operation or similar abrupt change in associated electric control circuits.

Remote Terminal Unit (RTU)

A device that controls substation equipment.

SAIDI (System Average Interruption Duration Index)

Average time customers are interrupted. Mathematically equal to the sum of Customer Interruption Hours divided by Total Number of Customers Served.

SAIFI (System Average Interruption Frequency Index)

Average frequency of sustained interruptions per customer. Mathematically equal to the sum of Number of Customer Interruptions divided by Total Number of Customers Served.

SCADA (Supervisory Control and Data Acquisition) System

A system that allows dispatchers to monitor and control substation equipment from a central location; also provides documentation for record keeping.

Secondary

Referring to the energy output side of transformers or the conditions (voltages) usually encountered at this location.

Short-Circuit

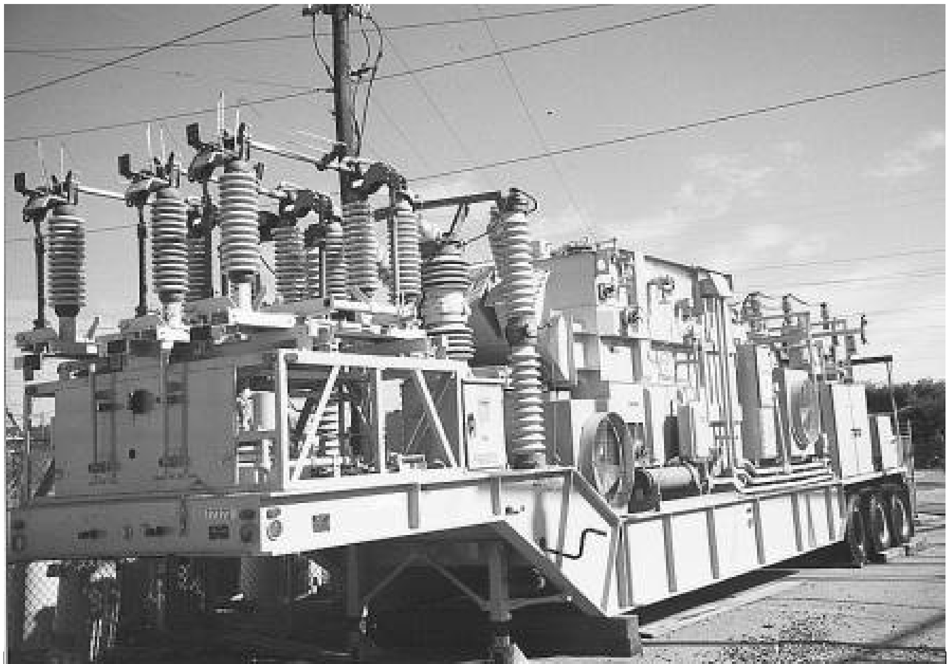
An abnormal connection of relatively low resistance, whether made accidentally or intentionally, between two points of different potential in a circuit.

Splice

A joint used for connecting in series, two lengths of conductor or cable.

Substation

An assemblage of equipment for purposes other than generation or utilization, through which electric energy in bulk is passed for the purpose of switching or modifying its characteristics. Note: A substation is of such size or complexity that it incorporates one or more buses, a multiplicity of circuit breakers, and usually is either the sole receiving point of commonly more than one supply circuit, or it sectionalizes the transmission circuits passing through it by means of circuit breakers.



Mobile Substation

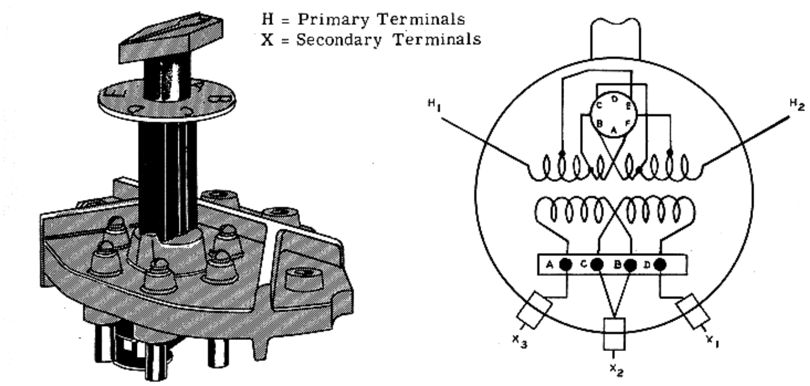
Switchgear

A general term covering switching and interrupting devices and their combination with associated control, metering, protective, and regulating devices, also assemblies of these devices with associated interconnections, accessories, enclosures, and supporting structures, used primarily in connection with the generating, transmission, distribution and conversion of electric power.

Tap

Connections that allow a transformer's turns ratio to be adjusted by adding turns to or subtracting turns from the transformer's primary or secondary winding. A connection brought out of a winding at some point between its extremities to permit changing the voltage or current ratio (general). An intermediate point in an electric circuit where a connection may be made.

A Tap Changer is Used to Adjust the Turns Ratio of a Transformer



No Load Tap Changer

Typical Internal Wiring of Transformer with Tap Changer

Tap Changer

A device for changing the turns ratio of a transformer.

Telemetering

Transmission of intelligence such as meter readings over a long distance, usually from stations to the dispatcher's office, by direct wire or carrier current.

Three-Phase Circuit

A combination of circuits energized by alternating voltages that differ in phase by one-third, that is, 120 degrees.

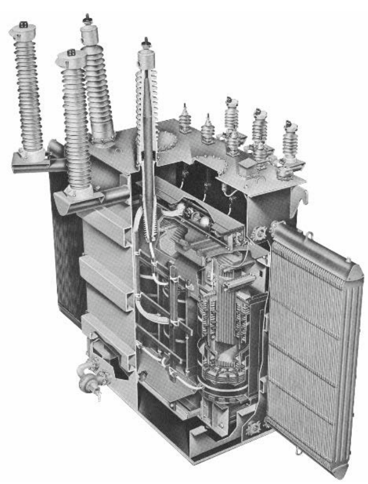
Three-Wire System

A system of electric supply comprising three conductors, one of which, known as the neutral wire, is maintained at a potential midway between the potential of the other two, referred to as the outer conductors. There are two distinct voltages of supply, one being twice the other.

Transformer

A component used to change AC voltage to meet specific requirements. A device consisting of a winding with tap or taps, or two or

more coupled windings, with or without a magnetic core, for introducing mutual coupling between electric circuits.



Transmission Line

A line used for electric-power transmission.

URD System

A local distribution system designed primarily to be buried in the ground and to serve residential customers.

VAR

Reactive volt-amperes.

Volt

Unit of measure for voltage. One volt is defined as the voltage necessary to drive a current of one ampere through a resistance of one ohm.

Voltage

Electric potential or potential difference expressed in volts.

Watt

Unit of measure for electric power, equal to the amount of power produced when one volt causes one ampere of current to flow.

Watt-hour

Basic unit used to measure electrical energy. Watt-hours are determined by multiplying power by time. One watt-hour is the amount of energy used when one watt of power is delivered to an electrical device for one hour.

SECTION 4.3 – SELECTED COMMISSION ORDERS

COMPREHENSIVE PLAN

System Planning

The initial requirements for the Comprehensive Plan section of the Consolidated Report were delineated in hearings taking place from November 5-7, 2001. The Commission requested that the Company provide a Comprehensive Plan detailing proposed changes to the electric system for the purposes of meeting load growth or maintaining system reliability. On pages 143-144 of the hearing transcript, Pepco's witness Mr. Gausman explained the nature of the Company's existing plans for the distribution and transmission systems:

We have plans for each of our substations in D.C., and in each of those plans we address the needs for that location, what the growth forecast is, what type of construction is going to be needed for expansion in the distribution system in each of those locations… Now when you go up to the transmission level or the substation supply level, there you have a plan that is addressing a larger area of the town because you're looking at the whole capacity of the system.

The Company expanded its responses to the Commission's requests in the first filed Comprehensive Plan. Since that date, the Company's Comprehensive Plans have been expanded based on several Commission directives. The report that follows either expands upon the discussion in the initial hearings requesting the Consolidated Report or responds to subsequent Commission directives as cited below.

The following section of the report addresses system plans based on forecasted load growth.

In Order No. 12804 paragraph 53 B, the Commission stated the following:

53. The 2003 PIP is hereby APPROVED, provided that PEPCO:

(b) Submit quarterly reports to the PIWG as well as a report in the 2004 and subsequent PIPs on its plans for implementing the recommendations for alleviating the anticipated transmission constraints identified in the RTEP report;

Load Forecasting

In the initial November 5-7, 2001 hearings requiring the production of the Comprehensive Plan, the following topics were discussed, as cited on pages 141-144 of the hearing transcript:

Comprehensive long-term planning on the underground system

Pepco's 10-year construction plans

Distribution load growth forecasts by substation

Transmission/substation supply load growth forecasts

In order No. 12735 issued on May 16, 2003 the Commission stated at paragraph 139, the following:

PEPCO shall file the additional information not included in its expurgated comprehensive plan as outlined below, within three months of the issuance date of this Report and Order:

Customer growth projections by District of Columbia wards (including historical comparisons);

Load growth projections encompassing commercial and residential development by District of Columbia wards (including historical comparisons);

The summary should cover a 10-year planning horizon while historical comparisons should provide at least five years of history.

In Order No. 12804 paragraph 53, the Commission stated the following:

The 2003 PIP is hereby APPROVED, provided that PEPCO:

Provide the projected zonal and projected default (i.e., SOS) load data for the District of Columbia to the PIWG on a quarterly basis as well as in the 2004 and subsequent PIPs;…

Power Factors

In Order No. 10133, the Commission directed Pepco to include performance factors relating to the transmission and distribution (T&D) system in future PIPs.

"PEPCO…was directed to…provide in future PIP reports forecasts of plant performance factors which are based on analyses of both the projected performance and the prior year's actual performance"(page 10, Section B).

"…the Commission finds it entirely appropriate to include performance measures for PEPCO's transmission and distribution in the mix of issues examined by the PIWG and reported in the PIP"(page 12, third paragraph).

By way of compliance with the above requirements, in the September 1993 PIWG Meeting, Pepco proposed reporting performance data on its 13 kV distribution substation power factors.

Substation

In the initial November 5-7, 2001 hearings requiring the production of the Comprehensive Plan, Commissioner Meyers stated the following (page 266 of the hearing transcript):

But what we were talking about here yesterday was that the comprehensive plan would include… any rebuilt substations you might have; any new substations you might have…

Distribution

In the initial November 5-7, 2001 hearings requiring the production of the Comprehensive Plan, Commissioner Meyers stated the following (pages 266-267 of the hearing transcript):

But what we were talking about here yesterday was that the comprehensive plan would include… anything that you might envision to account for distribution load growth…

In Order No. 12735 issued on May 16, 2003, the Commission stated the following at paragraphs 74 and 135:

74. During the November 2001 hearings the Commission requested that PEPCO submit a comprehensive plan to include a current assessment of, and future plans for, its underground distribution and network facilities.[179] *The Commission requested the plan as a tool to evaluate PEPCO's planning methodology and to assess PEPCO's ability to anticipate and respond to changing conditions in its underground distribution system…*

135. PEPCO shall file the additional information not included in its expurgated comprehensive plan as outlined below, within three months of the issuance date of this Report and Order:

(c) Listing of underground distribution projects, such as the Adams-Morgan neighborhood project (including budgets, time schedules, and expected benefits) by secondary vs. primary system by District of Columbia wards affected, but not specific locations;

The summary should cover a 10-year planning horizon while historical comparisons should provide at least five years of history.

Technology

In Order No. 12804 paragraph 53 E, the Commission stated the following:

53. The 2003 PIP is hereby APPROVED, provided that PEPCO:

(e) Provide to the PIWG, quarterly status reports on the new Technology Initiatives being undertaken by Pepco. An annual status report should be included in the 2004 and future PIPs. The status reports should include current accomplishments, plans for the future, and anticipated completion dates.

SCADA

The initial requirements for the Comprehensive Plan section of the Consolidated Report were delineated in hearings taking place from November 5-7, 2001. On page 313 of the hearing transcript, Commissioner Meyers stated the following:

We're going to ask Pepco to please include a section on reporting and monitoring in the comprehensive plan… And just as a quick for instance of this real-time systems control and data acquisition system, SCADA, what could it do? Give me a for instance there.

DA

In Order No. 12804 paragraph 53 E, the Commission stated the following:

53. The 2003 PIP is hereby APPROVED, provided that PEPCO:

(e) Provide to the PIWG, quarterly status reports on the new Technology Initiatives being undertaken by Pepco. An annual status report should be included in the 2004 and future PIPs. The status reports should include current accomplishments, plans for the future, and anticipated completion dates.

OMS

In Order No. 13422 on the 2004 Consolidated Report, paragraph 66, the Commission stated the following:

The 2004 Consolidated Report: Productivity Improvement Plan and Comprehensive Plan is hereby APPROVED, provided that PEPCO:

Report in the 2005 Consolidated Report, due February 15, 2005, on the corrective actions taken to fix the OMS;…

CIS

The initial requirements for the Comprehensive Plan section of the Consolidated Report were delineated in hearings taking place from November 5-7, 2001. On page 503 of the hearing transcript, Commissioner Meyers stated the following:

You've been a leader in CADS all along, computer assisted data systems. There's some discussion here about various other types of reporting and monitoring systems…

Power Delivery Information Systems Projects

In Order No. 12735, paragraph 139, the Commission stated the following:

PEPCO shall file the additional information not included in its expurgated comprehensive plan as outlined below, within three months of the issuance date of this Report and Order:…

Listing of power delivery information system projects with implementation schedules, annual costs, and milestones;

Listing of new technology investigations with decisions, annual costs, and implementation schedules;

…The summary should cover a 10-year planning horizon while historical comparisons should provide at least five years of history.

Equipment Standards

The initial requirements for the Comprehensive Plan section of the Consolidated Report were delineated in hearings taking place from November 5-7, 2001. On page 149 of the hearing transcript, Commissioner Meyers stated that the Comprehensive Plan should include:

…not only [the 10-year underground construction budget and 4 kV to 13 kV conversion], but… incorporating standards of what you want this to look like…

Equipment Inspections

In Order No. 16091, paragraphs 46 and 63, the Commission stated the following:

46. Decision. ... we shall require that Pepco provide a list of the types of equipment for which a "run to failure" method applies and those for which a preventive method applies. (Footnote: If other maintenance methods are used, Pepco shall describe them as well.) The Commission requires that Pepco provide an explanation of why different maintenance methods apply to *different types of equipment. We also require a description of the "test procedures" that Pepco uses to assess the performance and remaining life of the equipment. (Footnote: See Pepco comments at 7.) Further, Pepco shall provide an estimate of the current book value of equipment maintained under each method used by Pepco. The 2011 Consolidated Report shall include this description of maintenance policies and methods.*

63. Pepco IS DIRECTED to provide a description of its maintenance policies and methodologies, consistent with paragraph 46 of this Order;

Storm Readiness / ERIP

In Order No. 15152 at paragraph 71, the Commission ordered the following:

71. PEPCO is DIRECTED to prepare an action plan to reduce service restoration times and improve SAIDI and CAIDI performance, consistent with Order No. 14643 issued November 30, 2007 and herein, to be included in the 2009 Consolidated Report;

Order No. 15568 followed, requiring the following:

32. The Commission directs Pepco to report to each meeting of the PIWG on its Action Plan. That report should include a written description of the steps taken pursuant to the Plan. For example, in connection with the item that includes "Develop a process design and implement training," Pepco should describe the design and the training given to crews, including the number of employees who have availed themselves of the training. In addition, Pepco should be prepared to answer questions about the progress of the Action Plan from other members of the PIWG.

52. Pepco IS DIRECTED to report to each meeting of the PIWG on its Action Plan, consistent with Paragraph 32 of this Order;

Electricity Quality of Service Standards

Specific Consolidated Report requirements from the EQSS portion of the D.C.M.R. are listed below.

Progress on current corrective action plans [on customer calls answered] shall be included in the utility's annual Consolidated Report.

The utility shall report the actual call center performance during the reporting period in the annual Consolidated Report of the following year.

Progress on any current corrective action plans [on call abandonment rates] will be included in the utility's annual Consolidated Report.

The utility shall report the actual performance obtained during the reporting period in the annual Consolidated Report of the following year.

The utility shall complete installation of new residential service requests within ten (10) business days of the start date for the new installation.

Progress on any current corrective action plans [on new residential service installation requests] will be included in the utility's annual Consolidated Report.

The utility shall report the actual performance obtained during the reporting period in the annual Consolidated Report of the following year.

3603.5 The utility shall report on the progress of the corrective action plan [on repeat least performing feeders] in the Annual Consolidated Report submitted to the Commission.

The utility shall report on the number and percentage of non-major service outages that extend beyond the twenty-four (24) hour standard and the reasons each such outage extended beyond the twenty-four (24) hour standard.

The report drafted pursuant to Section 3603.8 shall be included in the annual Consolidated Report on reliability data.

The utility shall report on the progress of the corrective action plan [on SAIFI, SAIDI and CAIDI benchmarks] in the annual Consolidated Report submitted to the Commission.

The utility shall also, per the orders of the Commission, continue current requirements of reporting annual reliability indices of SAIFI, SAIDI and CAIDI (with and without major events) in the annual Consolidated Report of the following year.

Industry Comparisons

In Order No. 15568 paragraph 57, the Commission ordered the following:

57. Pepco IS DIRECTED to provide a report on the Electric Utilities Best Practices, consistent with Paragraph 50 of this Order. This report shall be included in that 2010 Consolidated Report; and shall include the best practices of the electric utility industry on improving reliability and outage restoration (from the Benchmarking Studies). Pepco shall submit a continuous improvement plan, including resourcing, specific performance targets, and milestone dates to achieve the reliability and outage restoration performance of the best (quartile) performing (comparable) utilities in the Benchmarking Studies.

Implementation of Twenty Best Practices

In Order No. 16091 paragraph 61, the Commission stated the following:

61. Pepco IS DIRECTED to include a "2011 Best Practices Report" in its 2011 Consolidated Report describing its on-going implementation of no fewer than twenty of the best practices identified in the 2009 Polaris Program, consistent with Paragraph 22 of this Order;

22. Decision. First, we conclude that Pepco has complied with the requirements of Paragraphs 32 and 52 of Order No. 15568. Second, as to the Staff's Recommendation that Pepco file a "Best Practices Report" from the PA Consulting's 2009 Polaris Transmission and Distribution Benchmarking Program, we agree that a report may be helpful in assuring that best practices continue to be implemented. Therefore, the

Commission shall require that Pepco include in its 2011 Consolidated Report a section entitled "2011 Best Practices Report" in which Pepco shall describe its on-going implementation of no fewer than twenty of the best practices identified in the 2009 Polaris Program included in the 2010 Consolidated Report as Appendix 2D. The twenty best practices selected by Pepco should be those judged to have the most impact on reliability and outage restoration performance. Pepco shall report on all its activities during 2010 to implement these best practices, including data on staffing levels, expenses and results. This requirement is separate from the requirement to produce a "Continuous Improvement Plan," as is described more fully in Section IV.A.1.f.

PA Consulting Recommendations

In Order No. 15632 issued in these proceedings, the Commission states at paragraph 5 the following:

5. Pepco shall file with the Company's annual Consolidated Reports to the Commission data on the Company's measures to continue to address each of the recommendations made by PA Consulting and the effectiveness of the Company's approaches to improve CAIDI and SAIDI to at least the average of PA Consulting benchmarks. This obligation shall begin with the 2010 Consolidated Report.

In Order No. 15568 issued October 7, 2009 in these proceedings, the Commission states at paragraph 52 the following:

*52. Pepco IS **DIRECTED** to report to each meeting of the PIWG on its Action Plan, consistent with Paragraph 32 of this Order;*

32. The Commission directs Pepco to report to each meeting of the PIWG on its Action Plan. That report should include a written description of steps taken pursuant to the Plan. For example, in *connection with the item that includes "Develop a process design and implement training." Pepco should describe the design and the training given to the crews, including the number of employees who have availed themselves of the training. In addition, Pepco should be prepared to answer questions about the progress of the Action Plan from other members of the PIWG.*

In Order No. 16091 issued in these proceedings, the Commission states at paragraph 22 the following:

22. *Decision. First, we conclude that Pepco has complied with the requirements of Paragraphs 32 and 52 of Order No. 15568.*

PRODUCTIVITY IMPROVEMENT PLAN

Productivity Improvement Plan

In Order No. 15152 on the 2008 Consolidated Report, paragraph 68, the Commission ordered the following:

The Productivity Improvement Working Group, which includes OPC, provided a reasonable definition of a productivity improvement project in 2006. Specifically, the PIWG states:

T&D productivity improvement projects were considered those projects that will increase T&D system efficiency by reducing losses and improve[ing] system reliability, and which may defer more costly additions to the electric system. (Footnote: F.C. No. 766, Decision on Consideration of OPC's T&D Productivity Improvement Working Group in Response to Commission Order No. 13754, filed July 6, 2006 ("2006 PIWG Report"), at 2.)

The power serving the District's Standard Offer Service customers is now procured through a wholesale procurement process by PEPCO and, as such, productivity improvement is applicable only to transmission and distribution issues. We find the PIWG's definition of a productivity improvement project workable and adopt it here.

The PIWG also provided a reasonable definition of comparative cost analysis for reliability projects. The PIWG suggested that the comparative cost analysis used for reliability projects should "consist *of a comparison of the cost of alternative reliability improvement solutions as well as any differences in relative reliability improvement." (Footnote: 2006 PIWG Report at 2.) …*

Reliability Statistics

Page 190 of the transcript for the November 5-7, 2001 hearings documents Commissioner Cartagena as stating the following:

You testified earlier that you have a 10-year plan for updating the system or addressing whatever changes are required with regards to that. Does that 10-year plan contain reliability goals or other measurable performance objectives? In other words, are there some kinds of standards that we can look at and will give us an idea of whether the company is hitting or missing those standards and objectives with regards to its plan?

This section of the Consolidated Report addresses the Company's performance with respect to reliability standards and Electricity Quality of Service Standards.

Targeted Reliability Indices

In Order No. 12735, paragraph 139, the Commission ordered the following:

PEPCO shall file the additional information not included in its expurgated comprehensive plan as outlined below, within three months of the issuance date of this Report and Order:

Targeted reliability indices (including historical comparisons); and

The summary should cover a 10-year planning horizon while historical comparisons should provide at least five years of history.

Also, in paragraph 142, the Commission directed the Company to file performance indices for the District of Columbia only.

PEPCO is DIRECTED to work with the PIWG to develop target system reliability indices for the District of Columbia, only.

Vegetation Management

In Order No. 15621 at paragraph 5, the Commission ordered the following:

5. Pepco shall file within the Company's annual Consolidated Reports to the Commission, yearly data on tree trimming by feeder and wards (or multiple wards) compared to the Company's *tree down and tree limb outage causes listed in its monthly power outage reports beginning with the Company's 2010 Consolidated Report.*

Priority Feeders & Aggressive Initiatives

The Electricity Quality of Service Standard D.C.M.R. 3603.6 states the following:

3603.6 The utility shall continue the current reporting of the worst performing (lowest two (2) percent) feeders (utility methodology) and corresponding corrective action plans, with the action taken in year 1 and the subsequent performance in year 2 in the annual Consolidated Report.

In Order No. 15152 paragraph 73, the Commission ordered the following:

73. Pepco is DIRECTED to investigate the viability of the "aggressive" initiatives for all least performing feeders, to file a progress report regarding the implementation of these initiatives where viable as part of the 2009 Consolidated Report, and to file quarterly progress reports thereafter, consistent with paragraph 62 of this Order;

In Order No. 15809 paragraph 11, the Commission ordered the following:

11. Pepco IS DIRECTED to include in its 2011 Consolidated Report a plan for development and application of "aggressive initiatives" to its underground distribution feeders;

Repeat Priority Feeders

In Order No. 15152 issued on Pepco's 2008 Consolidated Report, the Commission stated (at paragraph 72),

*72. PEPCO is **DIRECTED**, beginning with the 2009 Consolidated Report, to identify the feeders that are part of the separate annual program of corrective actions for reappearing least reliable feeders, describe the corrective actions planned for each feeder and the projected dates for completion of the corrective actions and explain whether the corrective actions improved the performance of these feeders consistent with paragraph 59 of this Order;*

In Order No. 15941 issued on August 18, 2010, the Commission stated at paragraphs 13 and 16, the following:

13. Beginning with the 2011 Consolidated Report, Pepco shall identify any feeders that have appeared more than once on the Priority Feeder List, by year from the first Priority Feeder List in 2002, so that it shall be apparent how many times each feeder has appeared on the Priority Feeder List…

16. Pepco IS DIRECTED to identify in its 2011 and successive Consolidated Reports, each feeder that has appeared more than once on the Priority Feeder List.

4 to 13 kV Conversions

These projects are a continuation of the 2011 Reliability Projects, as required by Order No. 16091 at paragraph 64 and referenced paragraphs 50 and 53:

*64. Pepco IS **DIRECTED** to provide detailed schedules and budgets for conversion projects, as well as justification for any non-minor deviations from these , consistent with Paragraphs 50 and 53 of this Order;*

50. Decision. We agree with the Staff recommendation and require Pepco to provide justification for any deviations from the plan schedules and annual budgets for 4 kV to 13 kV conversion projects in its Consolidated

Reports, excluding minor deviations of less than 5%. This information may be provided in the discussion of "Reliability Projects."

53. Decision. …we have not adopted the Staff's "replace or rebuild" recommendation. However, we agree that future Consolidated Reports should contain detailed schedules and budgets for Reliability Projects, as well as justification for deviations from those schedules and budgets. We shall require Pepco to submit such schedules in future Consolidated Reports.

Manhole Event Report

In Order No. 16091 issued on December 10, 2010, the Commission stated at paragraphs 56, 59, 65, and 66 the following:

56. Decision. Pepco has agreed to make the recommended changes in the 2011 Consolidated Report with the exception of data on failure rates. We require that the members of the PIWG discuss the need for and feasibility of providing data on failure rates in future Consolidated Reports and include in the 2011 Consolidated Report the PIWG conclusions and recommendations, if any.

59. Decision. We adopt the Staff's recommendation and require Pepco to: (1) combine the Manhole Events portion of the failure analysis report with Part 3 of the Consolidated Report; (2) include data in the 2011 Consolidated Report that separates 4 kV primary failures from 13 kV primary failures; (3) include data in the 2011 Consolidated Report that separates 4 kV from 13 kV manhole events; (4) include trend analyses for "Use of Slotted Manhole Covers;" and (5) include in the Cable Splice or Joint Database section of the Consolidated Report, cable type, age, type of splice and other pertinent information, except that cable type and age can be excluded if unavailable. If data on failure rates for all variables is available for manhole events, Pepco shall include such information in its 2011 Consolidated Report. If such data is unavailable, we require *the members of PIWG to discuss the need for and the availability of such data include in the 2011 Consolidated Report the PIWG conclusions and recommendations, if any.*

Pepco IS DIRECTED to include a discussion of failure data rates in the agenda for the Productivity Improvement Working Group, consistent with Paragraphs 56 and 59 of this Order; and

Pepco IS DIRECTED to include additional Manhole Event data in the 2011 Consolidated Report, consistent with Paragraph 59 of this Order.

In Order No. 15152 paragraphs 76 and 66, the Commission ordered the following:

76. PEPCO is DIRECTED to include as part of the 2009 Consolidated Report a proposed plan for significantly reducing manhole events consistent with paragraph 66 of this Order…

In Order No. 12735, paragraph 138, the Commission ordered the following:

Pepco shall file a report that summarizes the results of the failure analyses conducted for the calendar year 2002, 30 days from the issuance date of this Report and Order, and subsequently, to file an annual report on the results of the failure analysis group to the PIWG;

Slotted Manhole Covers

In Order No. 16091 issued on December 10, 2010, the Commission stated among other things, at paragraph 59, the following:

59. …(4) include trend analyses for "Use of Slotted Manhole Covers;" 60.

Cable Splice or Joint Database

In Order No. 16091, the Commission stated among other things, at paragraph 59, the following:

59. *...(5) include in the Cable Splice or Joint Database section of the Consolidated Report, cable type, age, type of splice and other pertinent information, except that cable type and age can be excluded if unavailable.*

Failure Rates

In Order No. 16091, the Commission stated among other things, at paragraph 59, the following:

59. ...(5)...If data on failure rates for all variables is available for manhole events, Pepco shall include such information in its 2011 Consolidated Report. If such data is unavailable, we require the members of PIWG to discuss the need for and the availability of such data include in the

2011 Consolidated Report the PIWG conclusions and recommendations, if any.

Appendix 3A –Manhole Events and Summary of Selected Failures

In Order No. 11716 ordering paragraph 3, the Commission ordered the following:

PEPCO shall file an annual report on the previous calendar year's manhole incidents;

Appendix 3B – Manhole Inspection Program

In Order No. 11716, the Commission stated the following:

PEPCO is hereby directed to include the following information in its [manhole inspection] reports beginning in July 2000:

The general location of the manholes inspected, including the street or streets where the manholes are located and the blocks bounding the street, e.g., M Street, NW, between 23rd and 28th streets;

The number of manholes inspected in the month, broken down as to the number of manholes containing primary cables only, both primary and secondary cables, and secondary cables only;

The number of primary cable problems found;

The number of secondary cable problems found;

The type of cable problems found in each manhole, categorized as to the physical degradation or damage of the cable, overheating, overloading, damaged splice and deteriorated cable or splice due to age;

The number of manholes with problems;

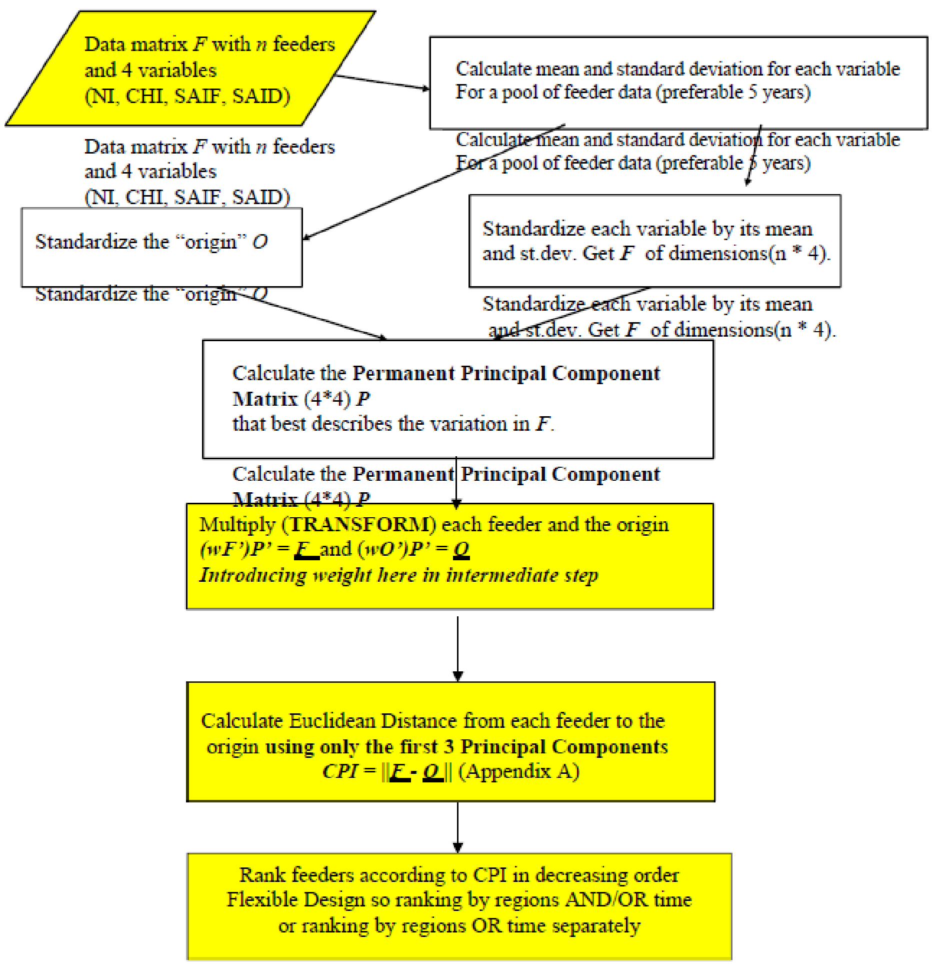
The corrective actions taken for each cable and manhole problem found; and

8. *Other general condition of the manhole such as whether it contained water, oil, grease, debris, and whether the manhole cover and the manhole are in good mechanical condition.*

Description of Calculation Process

The following flow chart (Figure 4.4-B) illustrates the process for calculating the Composite Performance Index for a feeder.

Figure 4.4-B -- Illustration of CPI Concep



Description of Euclidean Distance to Derive CPI

Definitions

Principal Component Matrix (each row is Principal Component vector)

$$P = \begin{bmatrix} PC_1 \\ PC_2 \\ PC_3 \\ PC_4 \end{bmatrix} = \begin{bmatrix} pc_{1,NI} & pc_{1,CHI} & pc_{1,SAIF} & pc_{1,SAID} \\ pc_{2,NI} & pc_{2,CHI} & pc_{2,SAIF} & pc_{2,SAID} \\ pc_{3,NI} & pc_{3,CHI} & pc_{3,SAIF} & pc_{3,SAID} \\ pc_{4,NI} & pc_{4,CHI} & pc_{4,SAIF} & pc_{4,SAID} \end{bmatrix}$$

Original Feeder Data

$$originalFeeders = F = \begin{bmatrix} f_{1,NI} & f_{1,CHI} & f_{1,SAIF} & f_{1,SAID} \\ f_{2,NI} & . & . & . \\ . & . & . & . \\ f_{n,NI} & . & . & f_{n,SAID} \end{bmatrix}$$

Weight

$$W = \begin{bmatrix} w_{NI} & 0 & 0 & 0 \\ 0 & w_{CHI} & 0 & 0 \\ 0 & 0 & w_{SAIF} & 0 \\ 0 & 0 & 0 & w_{SAID} \end{bmatrix}$$

Standard Deviation

$$\Sigma = \begin{bmatrix} \sigma_{NI} & 0 & 0 & 0 \\ 0 & \sigma_{CHI} & 0 & 0 \\ 0 & 0 & \sigma_{SAIF} & 0 \\ 0 & 0 & 0 & \sigma_{SAID} \end{bmatrix}$$

Intermediate Calculations

$$M = \Sigma * W = \begin{bmatrix} \sigma_{NI} & 0 & 0 & 0 \\ 0 & \frac{w_{CHI}}{\sigma_{CHI}} & 0 & 0 \\ 0 & 0 & \frac{w_{SAIF}}{\sigma_{SAIF}} & 0 \\ 0 & 0 & 0 & \frac{w_{SAID}}{\sigma_{SAID}} \end{bmatrix}$$

Transformation

$$\hat{F} = F * M * P'$$

$$\hat{F} = \begin{bmatrix} f_{1a} & f_{1b} & f_{1c} & f_{1d} \\ f_{2a} & . & . & . \\ . & . & . & . \\ f_{na} & . & . & f_{nd} \end{bmatrix}$$

Where

F is the original feeder data matrix (size n*4)

M is the intermediate calculation matrix (size 4*4)

P' is the (transposed) principal component matrix (size 4*4)

Finalization of CPI – Euclidean Distance Method

For each feeder i take the values for the 3 first components of row i in the last matrix above.

$$CPI_{f_i} = \sqrt{f_{ia}^2 + f_{ib}^2 + f_{ic}^2}$$

FACT SHEET

PHI

ENVIRONMENTAL STEWARDSHIP & SUSTAINABILITY:

VEGETATION MANAGEMENT ON RIGHTS-OF-WAY

A reliable supply of electricity is essential to the safety, security, economy and welfare of our nation and the communities where we live and work. To ensure the safe and reliable delivery of electricity to our customers, PHI must manage vegetation near its transmission and distribution lines and other facilities to prevent interruptions, blackouts and wildfires. PHI's regulated power delivery operations are required to maintain transmission and distribution rights-of-way so that trees, shrubs and other vegetation do not pose preventable hazards to power lines, poles or other facilities. PHI uses "best practices" to manage vegetation around electricity infrastructure, selecting among mechanical, chemical (herbicides), cultural, and biological control methods for the most suitable approach to meeting safety and reliability needs while maintaining or improving habitats for the region's indigenous flora and fauna. PHI employs professional, certified foresters and arborists to administer their vegetation management program.

VEGETATION MANAGEMENT: THE BASICS

- Utilities maintain right-of-way lands on a regular basis in order to provide for the safe transmission and distribution of electricity.
- Utilities must identify and utilize the most direct, least intrusive route possible when constructing power lines, in order to minimize both the amount of land used and any environmental impact.
- Trees and other vegetation beneath power lines must be properly maintained to avoid causing interruptions of electric service by growing into, falling through or knocking down power lines.
- In cooperation with federal, state, and local authorities, PHI, like most utilities, implements integrated vegetation management strategies to minimize overall risk to people and the environment while providing safe and reliable electric service.

HOW DOES PHI MANAGE VEGETATION NEAR ITS POWER LINES?

- PHI carefully selects vegetation management practices that balance environmental concerns, public needs, safety and cost-effectiveness.
- PHI partners with state, regional and local groups to create and maintain numerous natural habitats on its rights-of-way.
- PHI minimizes the use of EPA-approved herbicides through the selection and use of proper application methods, equipment and technology.

- PHI promotes native flora and fauna through intergrated vegetation management of our rights-of-way;
- PHI enhances vegetation management projects through cultivation or planting of compatible native vegetation;
- PHI protects native rare species populations that could otherwise be impacted by rights-of-way establishment, construction or maintenance;
- PHI manages rights-of-way areas to maintain wildlife habitat and protect threatened and endangered species habitat; and
- PHI reduces the introduction and control the spread of nonnative invasive species or noxious weeds in rights-of-way and adjacent lands.

Recognized Excellence

- All PHI utilities (Atlantic City Electric, Delmarva Power and Pepco) are active in community outreach and educational efforts to promote its **Right Tree, Right Place** initiative. **Right Tree, Right Place** advocates planting each tree species where it will thrive and not planting large species where they will interfere with power lines once they reach mature height.
- All PHI utilities have been named **Tree Line USA** Utilities by the Arbor Day Foundation. The Tree Line program is sponsored by the foundation in cooperation with the National Association of State Foresters. It recognizes utilities that demonstrate a program of quality tree care, annual tree worker training, public education, tree planting, and energy conservation through tree planting.

TREE LINE USA.

- PHI has longstanding commitments to vegetation management and green infrastructure efforts to help promote the sequestration of carbon dioxide by trees and other vegetation to stabilize and gradually reduce greenhouse gas emissions.

Proj - Project Group	Prod - Descr	ITN Name	2020 CapEx Actuals 1/1/ - 12/31
74083	Distribution - DC	74083: Waterfront Sub - Establish Waterfront North LVAC Network Group	466,548
75093	Distribution - DC	75093: NB Commercial Pepco DC	219,804
75095	Distribution - DC	75095: PEPCO DC NB Network Commercial	32,509
62161	Distribution - DC	62161: New Jersey Ave Reliability Initiative - Pepco DC	242,669
62215	Distribution - DC	62215: Pepco DC DC PLUG FEEDER 00308	4,850,617
62219	Distribution - DC	62219: Pepco DC DC PLUG FEEDER 14900	673,564
62221	Distribution - DC	62221: Pepco DC PLUG FEEDER 00368	1,351,501
62222	Distribution - DC	62222: Pepco DC DC PLUG FEEDER 14758	1,027,078
70031	Distribution - DC	70031: 1005 1ST ST NE- NBC (DLPCS1W029)	(5,021)
70060	Distribution - DC	70060: 13.8kV Swgr Replacement - Pepco DC (UDSPRD8KD)	1,583,980
70096	Distribution - DC	70096: 13kV Distribution Cutovers "F" St to "L" St (UDLPLM7W27)	2,916,439
70117	Distribution - DC	70117: 1550 1ST ST SW- NBC (DLPCS6W036)	(22,449)
70177	Distribution - DC	70177: 301/331 N St NE- NBC (DLPCS6W044)	1,240,804
70187	Distribution - DC	70187: 4kv Substation Automation - DC (UDSPRD8H)	572,351
70433	Distribution - DC	70433: Alabama Ave Sub 136: Extend 7 Fdrs to Retire Anacostia (UDLPLWF1)	771,991
70439	Distribution - DC	70439: Anacostia Sub : Convert 4 to 13kv & Retire Sub (UDLPLWF3)	10,844
70442	Distribution - DC	70442: Animal Guards in Dist Subs: Pepco DC (UDSPRD8JD)	225,683
70554	Distribution - DC	70554: BBNL 808 Bladensburg Road NE-NBC (DLPCS6W023)	703,265
70602	Distribution - DC	70602: Batt & Chgr Replacement Distri. Subs. - DC (UDSPRD8ED)	264,011
70762	Distribution - DC	70762: Pepco DC - ACR/SF6 Control Install/Replace	238,674
70897	Distribution - DC	70897: Cable Pepco DC (UDLPRM4BCX)	1,059,191
71011	Distribution - DC	71011: Champlain - New 34kV Sub (UDSPRD8AD8)	682,173
71012	Distribution - DC	71012: Champlain - New 69kV Sub (DSPRD8AD17)	706,268
71015	Distribution - DC	71015: Champlain to L Street 34kV (UDLPRM4WA8)	406,311
71119	Distribution - DC	71119: Comprehensive Feeder Improvements - Pepco DC (UDLPRM63D)	1,500,696
71138	Distribution - DC	71138: Convert Alabama Ave. Sub 136 Feeder 15178 and 15165 from a 3-wire to a 4-	236,158
71214	Distribution - DC	71214: DC Highway Relocations (UDLPCH0W)	1,605,873
71222	Distribution - DC	71222: DC- Ground Test Device Installation Program (UDSPRD8GTD)	292,002
71231	Distribution - DC	71231: DDOT DC South Capital Street Relocation 34kV UG (UDLPCSCAP2)	237,835
71411	Distribution - DC	71411: Dist Feeder Load Relief - DC (UDLPLM7W)	189,088
71426	Distribution - DC	71426: Pepco DC CM Distribution Substation Capital	2,667,978
71448	Distribution - DC	71448: Distribution Pole Replacements - Pepco DC (UDLPRM4BE)	337,437
71605	Distribution - DC	71605: Emergency Restoration OH PEP DC (DLPRM32DXX)	2,723,367
71612	Distribution - DC	71612: Emergency Restoration UG PEP DC (UDLPRM32DX)	15,807,335
71615	Distribution - DC	71615: Emergency Restoration: Network Transfs & Protectors (UDLPRM3K1)	1,398,283
71630	Distribution - DC	71630: F St Sub Rebuild (69kV) (UDSPLM718A)	59,810
71631	Distribution - DC	71631: F St Sub Rebuild (UDSPLM717A)	119,317
71721	Distribution - DC	71721: Ft Lincoln Reliability Initiative - Pepco DC (UDLPRM4LRD)	60,132
71731	Distribution - DC	71731: G St 4kV Conversion (UDLPRGST1)	1,551,803
71855	Distribution - DC	71855: Harrison Sub: Construct New Sub (UDSPLNW2)	2,676,848
71859	Distribution - DC	71859: Harrison Sub: Extend New Dist Fdrs to 38 (UDLPLNW3)	1,746,452
71864	Distribution - DC	71864: Harvard Rebuild - Distribution Upgrade to 230/13kV, 210 MVA (UDSPRD8AD2)	11,206,186
71867	Distribution - DC	71867: Harvard Rebuild - 13 kV Harvard Load Transfers (UDLPRM4WA6)	9,489,907
72137	Distribution - DC	72137: L St Sub Capacity Expansion Work (UDSPLM722A)	177,783
72268	Distribution - DC	72268: Misc. Reliability Improvements - Pepco DC (UDLPRM4BA)	3,120,663
72355	Distribution - DC	72355: Meter Equipment DC (DLPCMR2DXX)	1,909,709
72359	Distribution - DC	72359: Meter Install DC (UDLPCMR2DX)	1,927,659
72525	Distribution - DC	72525: Mt Vernon Sq Sub: Construct 230/13kv Sub (UDSPLMV3)	9,570,716
72529	Distribution - DC	72529: Mt Vernon Sq Sub: Extend LVAC (UDLPLMV1)	90,236
72733	Distribution - DC	72733: Navy Yard: Transfer to Waterfront Sub. 223 (UDLPLWF7)	1,421
72746	Distribution - DC	72746: Pepco DC - Network RMS - Line	191,336
72750	Distribution - DC	72750: Network Xfmr&Prot Repl Planned: Benni (UDLPRM4BN)	9,418,951
72810	Distribution - DC	72810: North Capitol 4kV Conversion - Pepco DC (UDLPRM8BC)	647,550
72840	Distribution - DC	72840: Northeast Sub. 212 East Network Group (NEW) (UDLPLM7W14)	121,133
72978	Distribution - DC	72978: PILC REPLACEMENT PLANNED (UDLPRPLIC)	9,780,558
72997	Distribution - DC	72997: Padmount Transformer Replacements - Pepco DC (UDLPRM4BO)	18,815
73032	Distribution - DC	73032: Pep-DC Damage Equipment Replacements (UDLPOEMGD)	4,410,900
73042	Distribution - DC	73042: Pumping Plant Upgrades - Pepco DC (UDLPRM9PD)	76,599

Proj - Project Group	Prod - Descr	ITN Name	2020 CapEx Actuals 1/1/ - 12/31
73052	Distribution - DC	73052: Pepco DC: Substation Ventilation (UDSPRD8LD)	2,130,488
73054	Distribution - DC	73054: Pepco DC: Add Sub Condition Monitoring Points (UDSPRD9D5)	1,565,395
73055	Distribution - DC	73055: Benning Area Plan - Pepco DC (UDLPRM4WA2)	1,539,957
73179	Distribution - DC	73179: Planned Rubber/Lead Secondary Replacement (UDLPRM4WA9)	5,784,581
73250	Distribution - DC	73250: Priority Feeder Improvements - Pepco DC (UDLPRM4BF)	1,452,683
73332	Distribution - DC	73332: Recloser Installations (ACR) - Pepco DC (UDLPRM4DJ)	2,063,576
73368	Distribution - DC	73368: Repl 69kV SCFF UG Supl-Georgetown, F St, 22nd St (UDLPRM5SG)	845,065
73371	Distribution - DC	73371: Repl Eng Generators Dist Sub: Pepco DC (UDSPRD8UD)	287,586
73696	Distribution - DC	73696: NRL- Blue Plains DC Water Redundant 69kV Supply	1,113,256
73734	Distribution - DC	73734: Sub 150 Twining City T2 - B-0551 (ECA) (UDSPRD8TC1)	639,534
73762	Distribution - DC	73762: Sub.168 Naval Research-Replace T1 & T2 Transformer (DSPRD8AD11)	4,184,640
73781	Distribution - DC	73781: Substation Improvements and Additions - DC (UDSPRD8AD)	4,546,874
73787	Distribution - DC	73787: Substation Retirements-DC. (UDSPRD8RN)	51,246
73839	Distribution - DC	73839: Takoma to Sligo 69kV Line: Install Three 69kV Feeders (UDLPLM72	6,271,884
73902	Distribution - DC	73902: Transformer Load Management (TLM) Pep - DC (UDLPLM7W21)	338,881
73918	Distribution - DC	73918: Trinidad Sub 106 - Retire (UDSPRD8RO)	11,875
73932	Distribution - DC	73932: 12th St 4kV Conversion - Pepco DC (UDLPRM8BU)	639,254
74033	Distribution - DC	74033: Van Ness SWGR Replacement (Dist Line) - Pepco DC (UDLPRM4WA1)	107,825
74082	Distribution - DC	74082: Waterfront Half-loop Extensions - Pepco DC (UDLPRM4BP1)	665,178
74083	Distribution - DC	74083: Waterfront Sub - Establish Waterfront North LVAC Network Group	1,654,792
74084	Distribution - DC	74084: Waterfront Sub - Install 4th Transformer (UDSPLM7WF4)	1,878,232
74087	Distribution - DC	74087: Waterfront Sub-Extend Fdrs: Transfer HV, Metro, Distrib frm Sta	559,628
74093	Distribution - DC	74093: Waterfront Sub: Construct Third LVAC Group (UDLPLWF6)	938,312
74349	Distribution - DC	74349: Benning 4kV Area-Phase Balancing to Fix Voltage Drop Issues (UD	228,691
74350	Distribution - DC	74350: Pepco DC Fire Protection Distribution (UDSPRD8DC1)	10,960,089
74352	Distribution - DC	74352: FEP Physical Security - Pepco (DC): 22nd Street Sub 124 (UDSPRD	193,601
74353	Distribution - DC	74353: FEP Physical Security - Pepco (DC): 9th Street Sub 117 (UDSPRD8	232,409
74383	Distribution - DC	74383: FEP Physical Security - Pepco (DC): 12th & Irving Sub 133 (	352,632
74590	Distribution - DC	74590: DDOT DC South Capitol Street Bridge Conduit (UDLPLM7001)	11,512,172
75092	Distribution - DC	75092: NB Residential Pepco DC	20,035,713
75092	Distribution - DC	75093: NB Commercial Pepco DC	21,931,333
75093	Distribution - DC	75095: PEPCO DC NB Network Commercial	4,371,365
94237	Distribution - DC	94237: PEPCO Misc ACCTG Projects	(2,274,245)
62223	Pepco General	62223: Pepco DC DC PLUG FEEDER 14007	154,703
62224	Pepco General	62224: Pepco DC DC PLUG FEEDER 15009	177,971
62269	Pepco General	62269: FEP Physical Security - Pepco (DC): New Jersey Ave Sub 161	662,591
62504	Pepco General	62504: Pepco DC Alabama Ave Breakers Installation	2,462,806
62900	Pepco General	62900: Pepco DC Alabama Ave. Sub 136 Feeder 15166 Battery Substation	46,618
62935	Pepco General	62935: Pepco DC Alabama Ave. Sub 136 Feeder 15166 Battery Distribution	22,563
63429	Pepco General	63429: Pepco DC - ITE Air Circuit Breakers	1,122,059
63506	Pepco General	63506:PEPCO(DC) FEP Physical Security-Little Falls	745,704
63507	Pepco General	63507:PEPCO(DC) FEP Physical Security-Florida Ave	357,327
63509	Pepco General	63509:PEPCO(DC):FEP- Physical Security-Georgetown	5,663
63510	Pepco General	63510:PEPCO(DC): FEP- Physical Security-Northeast	4,590
63511	Pepco General	63511: PEPCO DC Dist FEP Physical Security: Southwest	4,484
63556	Pepco General	63556:Pepco DC DC Plug Feeder 00308 - Removal	256,320
63628	Pepco General	63628 Pepco DC Dist: Substation Infrastructure - DC	216,013
63632	Pepco General	63632: Pepco: DC- Storm Water Retention Credit	466,281
63635	Pepco General	63635: Pepco DC- Yards ML 1A & Parcel G	1,113,793
63661	Pepco General	63661: Pepco DC- Yards ML 1B	460,648
63677	Pepco General	63677: Pepco DC: Dist- Spare Transformer Florida T3	1,389,976
63680	Pepco General	63680: Pepco DC Dist: Buzzard 230/34kV Substation	2,350,821
63697	Pepco General	63697: Pepco DC- 1615 Eckington Place, NE	1,086,966
63698	Pepco General	63698: PEPCO DC Parks at Walter Reed	2,233,195
63700	Pepco General	63700: Pepco DC- 1501 Harry Thomas Way, NE	607,350
63702	Pepco General	63702: Pepco DC- 680 Rhode Island Avenue, NE (Blocks 1A, 1B, 2B)	819,287
63704	Pepco General	63704: Pepco DC- 600 Rhode Island Avenue, NE	415,056
63710	Pepco General	63710: Pepco DC- 2607 Reed Street, NE	58,160

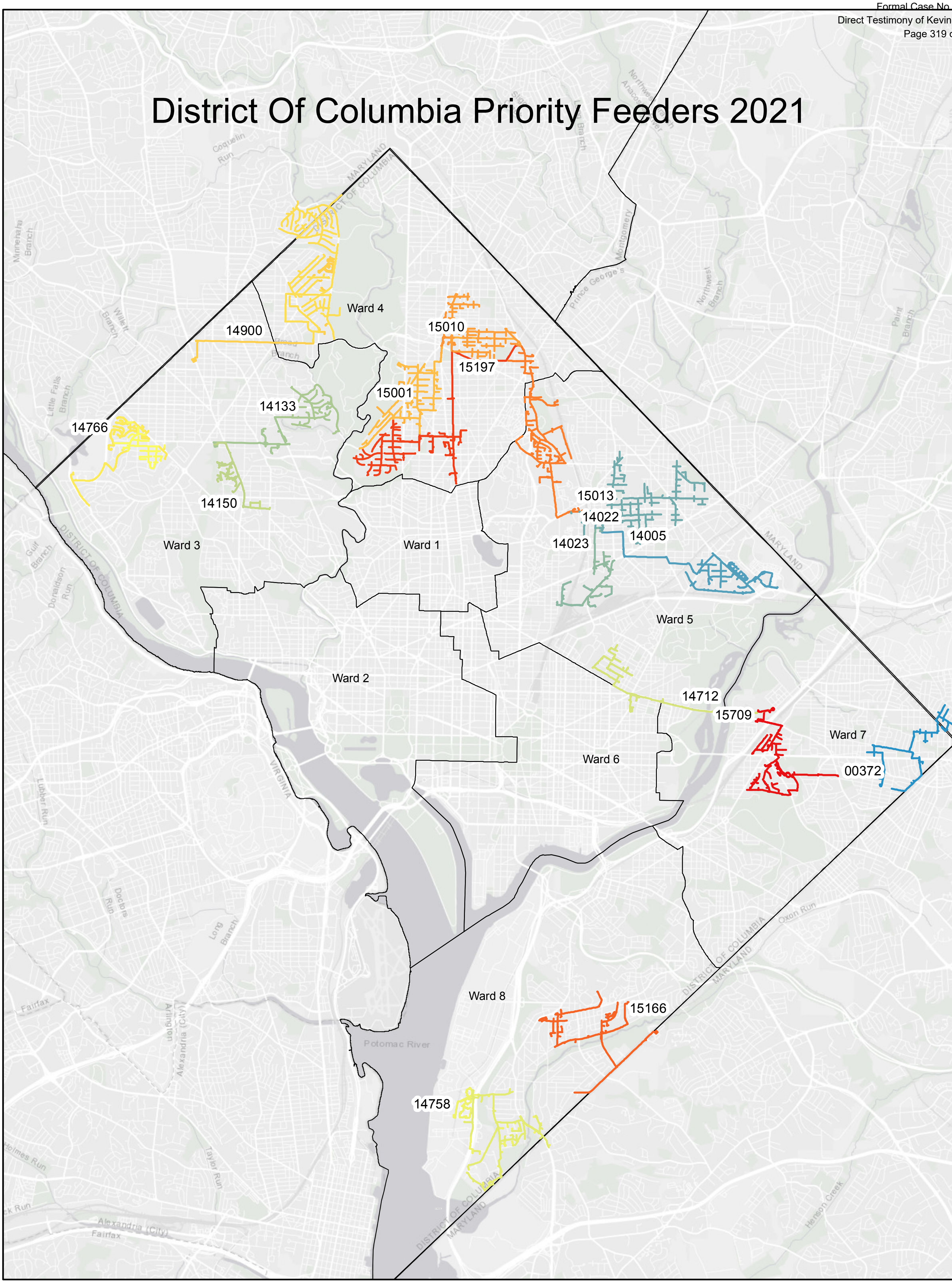
Proj - Project Group	Prod - Descr	ITN Name	2020 CapEx Actuals 1/1/ - 12/31
63718	Pepco General	63718: Pepco DC- 1676 Maryland Ave NE	5,203,827
63725	Pepco General	63725: Pepco DC- 500 Penn Ave NE	7,096
63727	Pepco General	63727: Pepco DC- 1500 Harry Thomas WY NE	410,091
63736	Pepco General	63736: PEPCO DC 300 MORSE ST NE 2 SPOT NTWK 208V	714,814
63923	Pepco General	63923: Pepco DC DC Plug Second Biennial Install	(199,145)
64102	Pepco General	64102: PEPCO DC CM Georgetown Sub 12 Pumps, Bushing & Gasket Replacements	649,934
64396	Pepco General	64396: PEPCO DC: Dist- Three 42MVA Spare Transformers	483,836
64407	Pepco General	64407: PEPCO DC DIST-33MVA Spare Transformer	434,865
64724	Pepco General	64724: PEPCO DC: Mobile Distribution Transformer for Urban Area	166,571
64794	Pepco General	64794: PEPCO DC 4669 South Capitol St SW Distribution	80,880
64796	Pepco General	64796: PEPCO DC 4669 South Capitol St SW Telecom	3,842
64922	Pepco General	64922 PEPCO DC: DIST-Two 56 MVA Spare Transformers	1,235,042
64993	Pepco General	64993: PEPCO DC Dist Florida Ave 4T LTC & Bushing	123,746
65194	Pepco General	65194: Harvard Rebuild - 13 kV Harvard Re-Load	133,813
65551	Pepco General	65551 Pepco DC- DIST:Benning Sub. 41 69kV T8 Replacement	1,511,157
65553	Pepco General	65553: PEPCO DC: DIst- Benning Sub. 41 69kV GIS	187,108
65555	Pepco General	65555: PEPCO:DC-DIST:22nd Street, Sub. 124.T4	7,303
65583	Pepco General	65583: Pepco DC 1300 4th ST NE	1,084,046
70190	Pepco General	70190: 500 Morse Street NE- NBC (DLPCS6W045)	616,811
72752	Pepco IT Projects	72752: New Business DC (UDLPCS6WX)	31,854
		Sub Total:	**252,532,281**

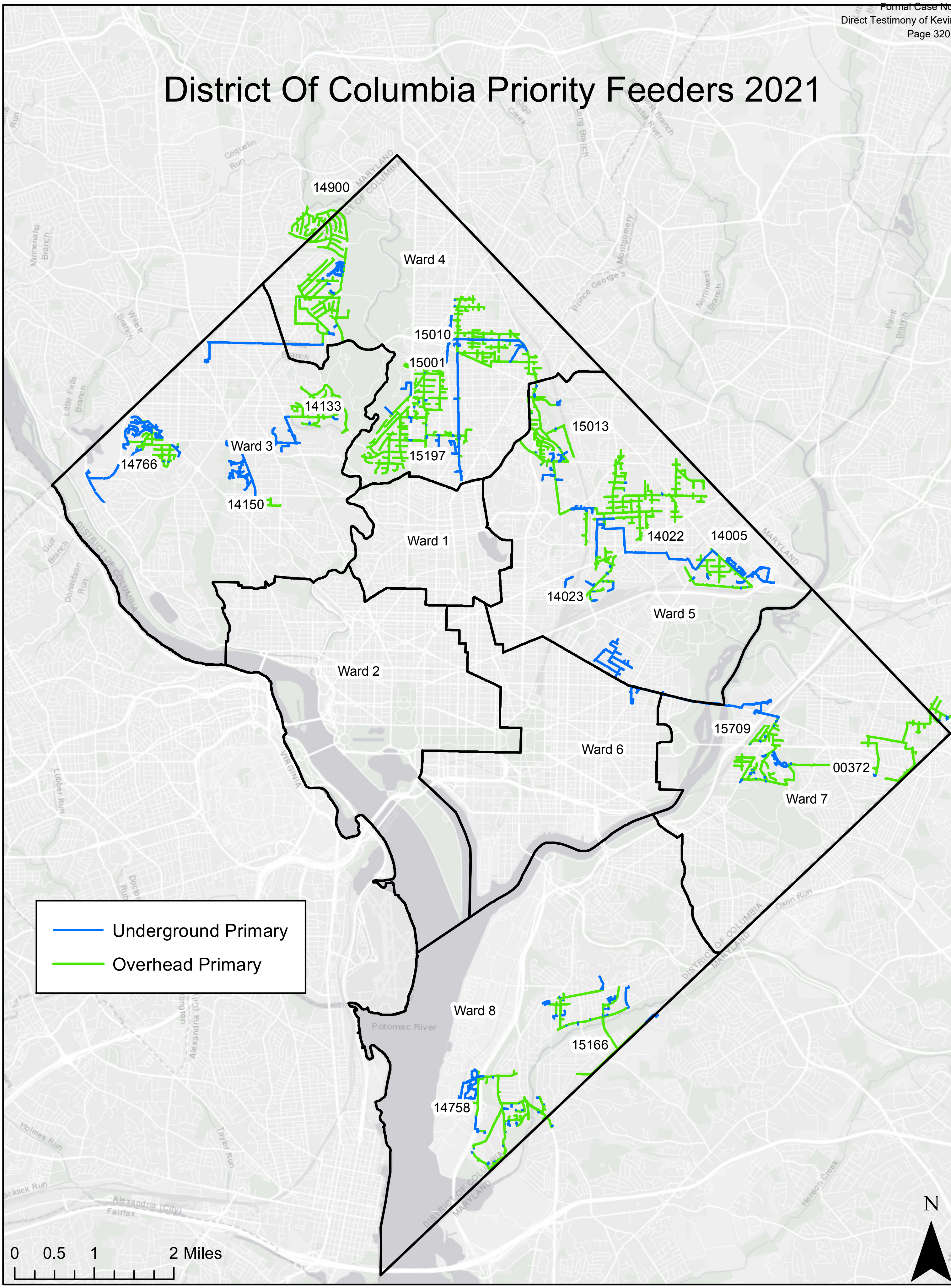
Proj - Project Group	Prod - Descr	ITN Name	2021 CapEx Adj Budget 1/1 - 12/31
62161	Pepco Distribution - DC	62161: New Jersey Ave Reliability Initiative - Pepco DC	5,256,981
62215	Pepco Distribution - DC	62215: Pepco DC DC PLUG FEEDER 00308	74,444
62219	Pepco Distribution - DC	62219: Pepco DC DC PLUG FEEDER 14900	959,901
62221	Pepco Distribution - DC	62221: Pepco DC PLUG FEEDER 00368	1,170,181
62222	Pepco Distribution - DC	62222: Pepco DC DC PLUG FEEDER 14758	1,439,659
70060	Pepco Distribution - DC	70060: 13.8kV Swgr Replacement - Pepco DC (UDSPRD8KD)	3,025,251
70096	Pepco Distribution - DC	70096: 13kV Distribution Cutovers "F" St to "L" St (UDLPLM7W27)	8,180,934
70187	Pepco Distribution - DC	70187: 4kv Substation Automation - DC (UDSPRD8H)	507,740
70439	Pepco Distribution - DC	70439: Anacostia Sub : Convert 4 to 13kv & Retire Sub (UDLPLWF3)	700,420
70442	Pepco Distribution - DC	70442: Animal Guards in Dist Subs: Pepco DC (UDSPRD8JD)	553,793
70602	Pepco Distribution - DC	70602: Batt & Chgr Replacement Distri. Subs. - DC (UDSPRD8ED)	514,159
70897	Pepco Distribution - DC	70897: Cable Pepco DC (UDLPRM4BCX)	4,601,458
71011	Pepco Distribution - DC	71011: Champlain - New 34kV Sub (UDSPRD8AD8)	875,499
71012	Pepco Distribution - DC	71012: Champlain - New 69kV Sub (DSPRD8AD17)	358,468
71015	Pepco Distribution - DC	71015: Champlain to L Street 34kV (UDLPRM4WA8)	3,616,828
71119	Pepco Distribution - DC	71119: Comprehensive Feeder Improvements - Pepco DC (UDLPRM63D)	4,184,665
71204	Pepco Distribution - DC	71204: Pepco DC - Distribution Smart Sensors	329,313
71214	Pepco Distribution - DC	71214: DC Highway Relocations (UDLPCH0W)	2,623,114
71222	Pepco Distribution - DC	71222: DC- Ground Test Device Installation Program (UDSPRD8GTD)	41,946
71231	Pepco Distribution - DC	71231: DDOT DC South Capital Street Relocation 34kV UG (UDLPCSCAP2)	930,210
71411	Pepco Distribution - DC	71411: Dist Feeder Load Relief - DC (UDLPLM7W)	2,834,362
71417	Pepco Distribution - DC	71417: Dist Sub Bushing Replacement: Pepco DC (UDSPRD8FD)	35,943
71418	Pepco Distribution - DC	71418: Dist Sub Bushing Replacement: Pepco DC (UDSPRD8FV)	50,170
71438	Pepco Distribution - DC	71438: Distribution Automation Place Holder - Pepco DC (UDLPRDA1D)	1,348
71440	Pepco Distribution - DC	71440: Distribution DC - HPFF System Cathodic Protection Program (UDLP	859,565
71441	Pepco Distribution - DC	71441: Distribution Feeder Load Relief DC (UDSPLM7W)	1,155,107
71448	Pepco Distribution - DC	71448: Distribution Pole Replacements - Pepco DC (UDLPRM4BE)	1,930,834
71605	Pepco Distribution - DC	71605: Emergency Restoration OH PEP DC (DLPRM32DXX)	2,938,154
71612	Pepco Distribution - DC	71612: Emergency Restoration UG PEP DC (UDLPRM32DX)	15,214,827
71615	Pepco Distribution - DC	71615: Emergency Restoration: Network Transfs & Protectors (UDLPRM3K1)	668,210
71630	Pepco Distribution - DC	71630: F St Sub Rebuild (69kV) (UDSPLM718A)	1,113,001
71631	Pepco Distribution - DC	71631: F St Sub Rebuild (UDSPLM717A)	3,015,517
71721	Pepco Distribution - DC	71721: Ft Lincoln Reliability Initiative - Pepco DC (UDLPRM4LRD)	3,353,648
71731	Pepco Distribution - DC	71731: G St 4kV Conversion (UDLPRGST1)	9,976,881
71855	Pepco Distribution - DC	71855: Harrison Sub: Construct New Sub (UDSPLNW2)	219,522
71864	Pepco Distribution - DC	71864: Harvard Rebuild - Distribution Upgrade to 230/13kV, 210 MVA (UDSPRD8AD2)	18,839,695
71987	Pepco Distribution - DC	71987: Improve/Add Substation Enclosures (UDSPRD8D2)	2
72004	Pepco Distribution - DC	72004: Install 4th 230/69kV 224MVA transformer #12 at Benning (UDSPLM7	656
72064	Pepco Distribution - DC	72064: Install Smart Relays & Replace RTU's -DC (UDSPRD8SD)	116,252
72137	Pepco Distribution - DC	72137: L St Sub Capacity Expansion Work (UDSPLM722A)	1,127,276
72268	Pepco Distribution - DC	72268: Misc. Reliability Improvements - Pepco DC (UDLPRM4BA)	3,148,049
72355	Pepco Distribution - DC	72355: Meter Equipment DC (DLPCMR2DXX)	1,948,929
72359	Pepco Distribution - DC	72359: Meter Install DC (UDLPCMR2DX)	2,030,824
72525	Pepco Distribution - DC	72525: Mt Vernon Sq Sub: Construct 230/13kv Sub (UDSPLMV3)	8,043,449
72529	Pepco Distribution - DC	72529: Mt Vernon Sq Sub: Extend LVAC (UDLPLMV1)	1,963,234
72685	Pepco Distribution - DC	72685: NERC Physical Security Pepco Dist Sub.- DC (UDSPRD8VD)	7,032
72733	Pepco Distribution - DC	72733: Navy Yard: Transfer to Waterfront Sub. 223 (UDLPLWF7)	6
72746	Pepco Distribution - DC	72746: Pepco DC - Network RMS - Line	1,982,037
72750	Pepco Distribution - DC	72750: Network Xfmr&Prot Repl Planned: Benni (UDLPRM4BN)	5,005,769
72810	Pepco Distribution - DC	72810: North Capitol 4kV Conversion - Pepco DC (UDLPRM8BC)	697,250
72978	Pepco Distribution - DC	72978: PILC REPLACEMENT PLANNED (UDLPRPLIC)	12,439,857
72997	Pepco Distribution - DC	72997: Padmount Transformer Replacements - Pepco DC (UDLPRM4BO)	393,361
73032	Pepco Distribution - DC	73032: Pep-DC Damage Equipment Replacements (UDLPOEMGD)	161,434
73042	Pepco Distribution - DC	73042: Pumping Plant Upgrades - Pepco DC (UDLPRM9PD)	210,733
73045	Pepco Distribution - DC	73045: Pepco DC Reg: Salvage Scrap Wire/Cable (UDLPOSV5D)	(999,990)
73052	Pepco Distribution - DC	73052: Pepco DC: Substation Ventilation (UDSPRD8LD)	5
73054	Pepco Distribution - DC	73054: Pepco DC: Add Sub Condition Monitoring Points (UDSPRD9D5)	50,908
73179	Pepco Distribution - DC	73179: Planned Rubber/Lead Secondary Replacement (UDLPRM4WA9)	10,921,867
73250	Pepco Distribution - DC	73250: Priority Feeder Improvements - Pepco DC (UDLPRM4BF)	1,832,735
73332	Pepco Distribution - DC	73332: Recloser Installations (ACR) - Pepco DC (UDLPRM4DJ)	551,237
73348	Pepco Distribution - DC	73348: Pepco DC - Regulator Control Install/Replace	399,974

Proj - Project Group	Prod - Descr	ITN Name	2021 CapEx Adj Budget 1/1 - 12/31
73368	Pepco Distribution - DC	73368: Repl 69kV SCFF UG Supl-Georgetown, F St, 22nd St (UDLPRM5SG)	3,396,917
73371	Pepco Distribution - DC	73371: Repl Eng Generators Dist Sub: Pepco DC (UDSPRD8UD)	69,952
73399	Pepco Distribution - DC	73399: Replace Deteriorated Dist Transformers DC (UDSPRD9GD)	27,481
73452	Pepco Distribution - DC	73452: Retire Anacostia 4kV and 13kV Substations (UDSPRD8RW1)	895,321
73651	Pepco Distribution - DC	73651: TripSaver Installations - Pepco DC (UDLPRM4WJ)	234,475
73696	Pepco Distribution - DC	73696: NRL- Blue Plains DC Water Redundant 69kV Supply	202,543
73698	Pepco Distribution - DC	73698: Sta. C Replace RTU, breakers & Station Service (UDSPRD8SB)	573,736
73762	Pepco Distribution - DC	73762: Sub.168 Naval Research-Replace T1 & T2 Transformer (DSPRD8AD11)	8,931
73787	Pepco Distribution - DC	73787: Substation Retirements-DC. (UDSPRD8RN)	216,477
73839	Pepco Distribution - DC	73839: Takoma to Sligo 69kV Line: Install Three 69kV Feeders (UDLPLM72	4,234,182
73902	Pepco Distribution - DC	73902: Transformer Load Management (TLM) Pep - DC (UDLPLM7W21)	708,359
73918	Pepco Distribution - DC	73918: Trinidad Sub 106 - Retire (UDSPRD8RO)	2,470
73932	Pepco Distribution - DC	73932: 12th St 4kV Conversion - Pepco DC (UDLPRM8BU)	3,091,579
74033	Pepco Distribution - DC	74033: Van Ness SWGR Replacement (Dist Line) - Pepco DC (UDLPRM4WA1)	2,387,350
74083	Pepco Distribution - DC	74083: Waterfront Sub - Establish Waterfront North LVAC Network Group	57,502
74085	Pepco Distribution - DC	74085: Waterfront Sub - Install 5th Transformer (UDSPLM7WF3)	16,616
74087	Pepco Distribution - DC	74087: Waterfront Sub-Extend Fdrs: Transfer HV, Metro, Distrib frm Sta	1,878,502
74093	Pepco Distribution - DC	74093: Waterfront Sub: Construct Third LVAC Group (UDLPLWF6)	1,751
74354	Pepco Distribution - DC	74354: PEP - Wedge for DC Dist Sub (UDSPSPDACR)	(21,522,420)
74590	Pepco Distribution - DC	74590: DDOT DC South Capitol Street Bridge Conduit (UDLPLM7001)	22,048,462
75093	Pepco Distribution - DC	75093: NB Commercial Pepco DC	32,770,932
75095	Pepco Distribution - DC	75095: PEPCO DC NB Network Commercial	1,346,344
62223	Pepco General	62223: Pepco DC DC PLUG FEEDER 14007	857,914
62224	Pepco General	62224: Pepco DC DC PLUG FEEDER 15009	848,182
62504	Pepco General	62504: Pepco DC Alabama Ave Breakers Installation	1,655,559
62900	Pepco General	62900: Pepco DC Alabama Ave. Sub 136 Feeder 15166 Battery Substation	2,214,221
62935	Pepco General	62935: Pepco DC Alabama Ave. Sub 136 Feeder 15166 Battery Distribution	65,009
63208	Pepco General	63208: Pepco DC Alabama Ave. Sub 136 Feeder 15166 Battery Fiber/Telecom	130,835
63344	Pepco General	63344: PEPCO DC Feeder 15165 Extension	578,084
63429	Pepco General	63429: Pepco DC - ITE Air Circuit Breakers	178,013
63509	Pepco General	63509:PEPCO(DC):FEP- Physical Security-Georgetown	206,621
63510	Pepco General	63510:PEPCO(DC): FEP- Physical Security-Northeast	207,720
63511	Pepco General	63511: PEPCO DC Dist FEP Physical Security: Southwest	410,256
63514	Pepco General	63514:PEPCO(DC): FEP-Physical Security-Van Ness	11,604
63556	Pepco General	63556:Pepco DC DC Plug Feeder 00308 - Removal	36,025
63628	Pepco General	63628 Pepco DC Dist: Substation Infrastructure - DC	516,518
63632	Pepco General	63632: Pepco: DC- Storm Water Retention Credit	200,600
63635	Pepco General	63635: Pepco DC- Yards ML 1A & Parcel G	57,462
63643	Pepco General	63643: Pepco DC Dist: Drainage and Driveway Remediation	150,844
63661	Pepco General	63661: Pepco DC- Yards ML 1B	230,256
63666	Pepco General	63666: Pepco DC 1000 South Capitol St SE	802,815
63679	Pepco General	63679: Pepco DC: Dist-Mobile Transformer	50
63680	Pepco General	63680: Pepco DC Dist: Buzzard 230/34kV Substation	4,226,541
63698	Pepco General	63698: PEPCO DC Parks at Walter Reed	6,544,217
63725	Pepco General	63725: Pepco DC- 500 Penn Ave NE	176,926
64120	Pepco General	64120:PEPCO(DC):Dist-Station Service Transformer Replacement Buckets	115,552
65194	Pepco General	65194: Harvard Rebuild - 13 kV Harvard Re-Load	2,026,244
65534	Pepco General	65534: PEPCO DC Replace Three (3) I Street Transformers	1,120
65537	Pepco General	65537: PEPCO DC O Street Sub 2, Transformer # 2 Spare	157
65551	Pepco General	65551 Pepco DC- DIST:Benning Sub. 41 69kV T8 Replacement	82,119
65553	Pepco General	65553: PEPCO DC: DIst- Benning Sub. 41 69kV GIS	5,352,951
65554	Pepco General	65554 Pepco DC - Dist: Little Falls T4 Install	193,223
65555	Pepco General	65555: PEPCO:DC-DIST:22nd Street, Sub. 124.T4	1,105,029
65559	Pepco General	65559: Pepco DC - Dist Replace L St Switchgear	(49,497)
74082	Pepco General	74082: Waterfront Half-loop Extensions - Pepco DC (UDLPRM4BP1)	1,109,128
74350	Pepco General	74350: Pepco DC Fire Protection Distribution (UDSPRD8DC1)	2,533,158
63056	Pepco IT Projects	63056: Pepco DC CM Non-emergency Dist Sub Cap	80,882
63645	Pepco IT Projects	63645: Pepco DC - UG SCADA Interrupter Install/Replace	1,816,862
63647	Pepco IT Projects	63647: Pepco DC - UG SCADA Interrupter Control Install/Replace	479,942
64355	Pepco IT Projects	64355: Pepco DC: Roof Replacements Distribution	343,974
64357	Pepco IT Projects	64357: Pepco DC: Sub Ventilation Distribution	77,846

Proj - Project Group	Prod - Descr	ITN Name	2021 CapEx Adj Budget 1/1 - 12/31
64365	Pepco IT Projects	64365: Pepco DC: Sub Imprv. & add. Distribution	904,399
75092	Pepco IT Projects	75092: NB Residential Pepco DC	24,963,576
		Sub Total:	**268,275,037**

District Of Columbia Priority Feeders 2021




District Of Columbia Priority Feeders 2021
Ward 1
Ward 2
Ward 3
Ward 4
Ward 5
Ward 6
Ward 7
Ward 8
14900
15010
15001
14133
14766
14150
15197
15013
14022
14005
14023
15709
00372
15166
14758
Underground Primary
Overhead Primary
0 0.5 1 2 Miles
N

Pepco 2020 Safety Merger Commitments

The following attachments reflect the Company's compliance with the merger commitment described in Order No. 18148 Attachment B at P 60, Safety:[1]

Exelon is committed to having all its utilities achieve and maintain first quartile performance in safety. Consistent therewith, Pepco will file annual reports on its safety performance and safety initiatives with the Commission as part of its Annual Consolidated Report and will also present this information to the PIWG. Pepco's reporting will include a report by Exelon on its existing safety and cybersecurity policies.

- Exelon Corporate Safety Policy
- Exelon Safety Update
- Pepco Transmission and Distribution Safety Incident rate, Including Edison Electric Institute (EEI) 2012-2020 Rankings
- Exelon Cyber-Security Statement

[1] In the Matter of the Joint Application of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC and New Special Purpose Entity, LLC for Authorization and Approval of Proposed Merger Transaction, Formal Case No. 1119, Order No. 18148, March 23, 2016, Attachment B at P 60

Exelon®

Dedicated to Safety

Corporate Policy: Safety

Policy Statement

Exelon Corporation will operate all aspects of its businesses in a manner that protects the safety and health of its employees, contractors, customers and the general public. We will foster a safety culture in which everyone believes and demonstrates that accidents, injuries and occupational illnesses are preventable and all employees understand their responsibility for maintaining a safe and healthful workplace. Further, each employee recognizes and accepts his/her right and obligation to question, stop and correct any unsafe conditions or behaviors.

Policy Intent

Exelon shall:

- Create a safety culture to achieve an accident, injury and occupational illness-free workplace;
- Comply with all applicable health and safety laws and regulations, industry and internal company standards, at a minimum;
- Integrate safety risk analysis into business planning, engineering design, and operating decisions, to develop and implement effective hazard control measures and safety performance improvement, engineering out hazards where feasible;
- Promote the value of employee empowerment in the prevention of injuries and illnesses, and maintain an open and honest dialogue with our employees on health and safety issues and performance; and
- Continually improve safety performance to become the safest electric and gas utility in the United States.

Implementation

This policy shall be implemented by establishing and maintaining:

- A corporate-wide safety program that will be integral to the Exelon Management Model based on external standards and best practices;
- Safety councils and committees, including the Exelon Operations Council, to encourage management sponsorship and employee involvement in injury and illness prevention;
- Annual objectives and targets for measuring and continually improving safety performance and recognition of top performing departments and individuals for safety is routine;
- An independent, corporate audit program and business unit self-assessments;
- Safety and health hazard evaluation programs including documented methods for controlling known safety and health hazards;
- Communications and Corrective Action Programs that facilitate the identification and resolution of safety related concerns;
- Training programs for employees and education programs for contractors on safety expectations and responsibilities;
- Employee and management personal accountability for following health and safety fundamentals and procedures; and
- Promote electricity and gas hazard awareness and accident prevention through public safety programs.

To anonymously report any safety concerns, employees or others working on behalf of Exelon can call the Exelon Helpline at 800.233.8442.

Exelon Safety Update

Exelon is committed to having all its utilities achieve and maintain first quartile performance in safety. As of the end of 2020, PHI has had a 21% reduction in OSHA recordable injuries, 29% reduction in Days Away Restricted Time Cases. This was PHI's best safety performance since 2014 (a 43% improvement from 2016 merger performance).

PHI initiated the following safety programs in 2020:

- Focused observation initiative implemented by leadership to ensure employee adherence to required COVID-19 PPE behaviors within field teams and crews.
- Alignment with other Exelon Utilities on screening strategy for employees working in high-density, critical infrastructure workspaces
- Developed shift work strategies that promote less employee interaction while maintaining necessary support levels.
- Participated with the other Exelon Utilities to continue to align safety best practices that were researched and benchmarked against Edison Electric Institute and American Gas Association utilities.
- Sustained Performance Assessment Programs by sharing incidents, lessons learned, and best practices across Exelon utilities through common communication channels.
- Continued the Ergonomic Coach program to provide Triage Support as needed in PHI overhead line school and field crews.
- PHI expanded driver training technologies and continues to leverage driver monitoring system.

Exelon has an established management model that governs key operational areas throughout the enterprise, including the safety function. The corporate Safety Policy, applicable to all Exelon operations, including Pepco Holdings and Pepco, establishes the framework for defining Exelon's industrial safety culture and sets expectations for continuously improving safety performance. It clearly sets expectations for each employee to take personal responsibility for his or her safety.

Underpinning the Safety Policy is the Corporate Industrial Safety Program, which delineates Exelon's requirements for the management of safety for the enterprise and which is based on recognized industry standards including BSI-OHSAS 18001, OSHA Voluntary Protection Program and ANSI Z10.

Detailed procedures (*e.g.*, Hazards Assessments) are maintained to affect the Safety Policy and programs, and they are routinely evaluated to ensure that best practices are utilized.

To ensure alignment and to facilitate learning, a Corporate Safety Council comprised of safety officers from each business addresses strategic safety issues, and a Corporate Safety Peer Group comprised of safety professionals and managers focuses on operational experience and use of best practices. Pepco is represented on both of these functions. In addition, the Exelon Utilities have a Safety Peer Group, with representation from each utility, including Pepco Holdings, who concentrate on improving safety performance in their specific operations.

As part of the safety performance oversight function, Exelon's enterprise-wide safety

performance is reviewed at Quarterly Management Meetings (QMM) and a comprehensive review of the effectiveness of the safety policy and program is reviewed with the senior leadership team annually.

Further, the Exelon Environmental, Health & Safety Audit Program conducts independent assessments of the effectiveness of Exelon's compliance programs at a select number of locations annually. The results of the audits are reported to senior leadership, who have responsibility for affecting any corrective actions required.

Pepco Transmission and Distribution Incident Rate, Including Edison Electric Institute (EEI) 2019 Rankings

Year	Incident Rate	EEI Quartile Ranking
2012	1.89	Third Quartile
2013	1.79	Third Quartile
2014	1.52	Third Quartile
2015	1.68	Fourth Quartile
2016	2.16	Fourth Quartile
2017	1.51	Third Quartile
2018	1.20	Third Quartile
2019	1.05	Second Quartile
2020	0.94	Second Quartile

Exelon Cyber-Security Statement

As one of the nation's major critical infrastructure providers, Exelon recognizes that the safety, reliability and security of our systems and facilities are a top priority. The company utilizes a risk- based, intelligence-driven security approach to implementing a comprehensive set of cyber and physical security controls, in line with the National Institute of Standards and Technology's (NIST) Cybersecurity Framework to effectively identify, protect, detect, respond to and recover from a spectrum of threats, mitigating the likelihood of successful attacks and their potential impacts. In addition, Exelon has implemented the mandatory regulatory requirements defined within the NERC CIP and NRC standards, ensuring further protection of cyber assets critical to the safe and reliable operation of the BES and Nuclear from cyber threats. Regulated critical cyber assets are isolated within restricted networks, segmented from the enterprise IT environment and the Internet, continuously monitored for malicious activity, and routinely evaluated for vulnerabilities.

pepco
An Exelon Company

Bill Sullivan
Vice President
Technical Services

EP8603
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8th Floor
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202-872-2942

April 1, 2020

Ms. Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 G Street, N.W.
Suite 800
Washington, DC 20005

Re: <u>Pepco-DC Vegetation Management</u>

Dear Ms. Westbrook-Sedgwick:

In accordance with Order No. 19119, and Pepco's December 20, 2017 letter electing to adopt performance-based vegetation management reporting, I, Bill Sullivan, hereby verify that Pepco has in place a comprehensive vegetation management plan, which is fully implemented and was in place in 2017, and that its practices during 2020 conformed to the plan.

Sincerely,

Will Sull

Bill Sullivan
Vice President
Technical Services

Annual Consolidated Report

Downtown Resupply Description (updated, if appropriate):

The Downtown Resupply project will replace aging 34 kV and 69 kV supply feeders to the L Street, F Street, Georgetown, and 22nd Street Substations. This work along with upgrades to the F Street Substation and extension of new 13 kV feeders will accommodate load transfers from I Street Substation as well as increasing sub-transmission supply capacity and providing reliability benefits to the District of Columbia.

Explanation of Significant changes to Project:

As discussed above, Pepco is retiring the 34 kV Transformer sources at L Street Substation and replacing them with 69kV transformer sources. As a result of this change, some of the construction dates have changed below.

Cost Estimate (provided in Formal Case No. 1144):

Items	Estimate Net (Lifecycle) ($)
Downtown Resupply	494,028,210
13kV Distribution Cutovers "F" St to "L" St (UDLPLM7W27)	39,849,304
13kV Distribution Cutovers from "I" St to "F" St & "L" St (UDLPLM7W28)	32,434,952
Champlain to L Street 34kV (UDLPRM4WA8)	102,319,736
F St Sub Rebuild (69kV) (UDSPLM718A)	50,372,188
F St Sub Rebuild (UDSPLM717A)	33,581,458
L St Sub Capacity Expansion Work (UDSPLM722A)	4,011,558
Repl 69kV Self-Containd UG Supl-Georgetown,"F" St, 22nd St Subs (UDLPRM5SG)	177,223,136
Retire "I" St Sub (UDSPRD27RD)	2,081,496
Retirements for Downtown Resupply 34kV and 69kV for DC (UDLPRM4RDR)	35,522,470
Retirements for Downtown Resupply 34kV and 69kV for MD (UDLPRM4DRM)	1,309,199
Retirements for Downtown Resupply 34kV and 69kV for VA (UDLPRM4DRV)	13,322,712
Telecom - 22nd Street Sub (UDFPO22SS)	500,000

Telecom - Fiber for 34-69kV Resupply Champlain, L Street, F Street (UDFPOCL01)	500,000
Telecom - Georgetown Sub (UDFPOGS01)	500,000
Telecom - L Street Sub (UDFPOLS01)	500,000

Current Cost Estimate:

There are no changes to the cost estimate for the Downtown Resupply Project cost estimates as of March 31, 2020.

Updated Construction Schedule:

L Street Substation: 2023-2025
F Street Substation: 2025-2028
I Street Substation: 2029-2030
69kV Supplies: 2022-2028
34kV Supplies: 2019-2025
13kV Supplies: 2019-2029

Updated Construction Schedule:

Please see above updated construction scheduled as of April 15, 2021

CERTIFICATE OF SERVICE

I hereby certify that a copy of Potomac Electric Power Company's Annual Consolidated Report was served this April 15, 2021 on all parties in PEPACR 2021-01 and Formal Case No. 1119 by electronic mail.

Ms. Brinda Westbrook-Sedgwick
Commission Secretary
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April 15, 2022

Ms. Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 G Street N.W., Suite 800
Washington, DC 20005

Re: PEPACR-2022-01 and Formal Case No. 1119

Dear Ms. Westbrook-Sedgwick:

Attached please find Potomac Electric Power Company's ("Pepco") 2022 Annual Consolidated Report. Please note that a revised EQSS section 3602 new residential service data table and Table 13, "Historical Information System Projects" will be filed when completed.

Please feel free to contact me if you have any questions regarding this matter.

Sincerely,

/s/ *Dennis P. Jamouneau*

Dennis P. Jamouneau

Enclosures

cc: All Parties of Record

2022 CONSOLIDATED REPORT

- Comprehensive Plan
- Productivity Improvement Plan
- Manhole Event Report

Filed By

POTOMAC ELECTRIC POWER COMPANY

In accordance with

D.C. Formal Case No. 991, Order No. 12735 (Comprehensive Plan)

D.C. Formal Case No. 766, Order No. 7668 (Productivity Improvement Plan)

D.C. Formal Case No. 991, Order No. 13812 (Manhole Event Report)

D.C. Formal Case No. 766, Order No. 16975 (Consolidated Report)

D.C. Formal Case No. 991, Order No. 17074 (Consolidated Report)

D.C. Formal Case No. RM5-2014-01-E, Order No. 17684 (Consolidated Report)

D.C. Formal Case No. PEPACR-2014-01, Order No. 17816 (Consolidated Report)

D.C. Formal Case No. 1119, Order No. 18148 (Merger Order) and

D.C. Formal Case No. PEPACR-2015-01, Order No. 19119 (Consolidated Report)

D.C. Formal Case No. PEPACR-2016-01, Order No. 20776

pepco SM
AN EXELON COMPANY

Contents

INTRODUCTION

Potomac Electric Power Company (Pepco or the Company) herein presents its 2022 Consolidated Report (Report) combining three reporting requirements directed by the District of Columbia Public Service Commission (Commission) in Formal Case Nos. 766 and 991. The three reports comprising the Consolidated Report are:

1) the Comprehensive Plan for the Planning, Design, and Operation of the Distribution System within the District of Columbia (Comprehensive Plan),
2) the Productivity Improvement Plan (PIP), and,
3) the annual Manhole Event Report. Additionally, a section of References has been included at the end of the report.

The following is a brief description of the four parts of this Report:

Part 1: Comprehensive Plan

During Commission hearings on November 5-7, 2001, addressing Formal Case No. 991, the Commission issued directives, followed by Order No. 12293, requiring the Company to produce and submit its first Comprehensive Plan on February 8, 2002. Pepco's filed report presented a compilation of major elements of its underground distribution construction and plans as well as supporting technologies and conversion programs to improve system reliability. Over the years, the Comprehensive Plan's content evolved with Commission Orders. The 2022 Comprehensive Plan's content is similar to the 2021 Comprehensive plan, however in contains additional detail that complies with the Commission's July 23, 2021, Order No. 20776 [1]

Part 2: PIP

On November 1, 1982, in Order No. 7668, the Commission adopted final rules regarding the submission of an annual PIP in Formal Case No. 766. These rules are codified in Title 15 of the District of Columbia Municipal Regulations, Chapter 5, Rules 502.1 and 502.2. Because of the divestiture or transfer to an affiliate of all of Pepco's generating stations, most of these rules are no longer applicable to Pepco's operations. Instead, this PIP was compiled pursuant to the latest requirements for Pepco to report on its transmission and distribution system operating performance and measures to improve service reliability.

[1] .C. Formal Case No. PEPACR-2016-01, Order No. 20776

Part 3: Manhole Event Report

In 2000 in Formal Case No. 991, the Commission issued Order No. 11716 requiring Pepco to file an annual Manhole Event Report on the previous year's manhole incidents. The Manhole Event Report includes statistics regarding reportable events, a trend analysis for slotted manhole covers, and a listing of splice data. Appendix 3A contains a listing of 2021 Manhole Events. Appendix 3B includes a discussion of the 2021 Manhole Inspection Program including annual program results. Appendix 3C contains Pepco's update on the implementation of its Network Accuracy Procedure.

Part 4: References

Part 4 of the filing contains a compilation of abbreviations, acronyms, and technical terms and diagrams; and a section providing Commission Order references delineating the history of the Consolidated Report requirements.

Attachments:

A. Vegetation Management Communications

B. Work Plan

C. Priority Feeder Maps

D. Cyber and Safety Statement

E. Vegetation Management Attestation

F. Downtown Resupply Description

G. ECA Summary Table

PART 1: 2022 COMPREHENSIVE PLAN

Section 1 – SYSTEM PLANNING[2]

The mission of System Planning is to develop a rational and orderly plan for Pepco's existing and future electric system needs that will provide reliable electric service to customers and support load growth in a cost-effective manner. In order to accomplish this mission, the North American Electric Reliability Corporation (NERC) / Reliability First Corporation (RFC) Standards and Pepco's Planning Criteria for the transmission, subtransmission, and distribution systems govern the design of the electric system.

Pepco continuously analyzes the adequacy of its electric system to meet demand for energy on its system and to plan for future growth. The Company maintains engineering and operating criteria for use in the design of new and modified portions of the system. To provide for rational and orderly changes to the electric system, Pepco has developed engineering and operating criteria that it applies to the design of

[2] The initial requirements for the Comprehensive Plan section of the Consolidated Report were delineated in hearings taking place from November 5-7, 2001. The Commission requested that the Company provide a Comprehensive Plan detailing proposed changes to the electric system for the purposes of meeting load growth or maintaining system reliability. On pages 143-144 of the hearing transcript, Pepco's Witness Gausman explained the nature of the Company's existing plans for the distribution and transmission systems. The Company expanded its responses to the Commission's requests in the first filed Comprehensive Plan. Since that date, the Company's Comprehensive Plans have been expanded based on several Commission directives. The report that follows either expands upon the discussion in the initial hearings requesting the Consolidated Report or responds to subsequent Commission directives as cited below.

The following section of the report addresses system plans based on forecasted load growth. In Order No. 12804 paragraph 53 B, the Commission stated the following:

> *53. The 2003 PIP is hereby APPROVED, provided that PEPCO: (b) Submit quarterly reports to the PIWG as well as a report in the 2004 and subsequent PIPs on its plans for implementing the recommendations for alleviating the anticipated transmission constraints identified in the RTEP report.*

> *53. The 2003 PIP is hereby APPROVED, provided that PEPCO:*
>
> *(b) Submit quarterly reports to the PIWG as well as a report in the 2004 and subsequent PIPs on its plans for implementing the recommendations for alleviating the anticipated transmission constraints identified in the RTEP report.*

new and modified systems. The three major components of system planning criteria are (1) voltage and reactive support, (2) ratings of facilities, and (3) reliability. For example, voltage on a nominal 120-volt system must be maintained between 114 and 126 volts under normal conditions and between 105 and 126

volts under contingency conditions. Ratings of facilities include normal, emergency, and short-term emergency ratings on all facilities including feeders, power transformers, circuit breakers, for both summer and winter periods. In terms of reliability, the data that are reviewed and tracked include historical and forecasted load compared to capacity of the feeders, feeder groups, and substations.

1.1 The Current Load Forecasting Process

Planning for future load growth starts with the development of load growth projections. A forward- looking 10-year peak load forecast is developed and maintained for each distribution system component such as feeders, substation transformers, and substations to plan for longer duration projects. Short-term, summer-peak forecasts are developed for three years to address the more frequent changes from new building construction and customer load growth that occurs across the distribution system. Long range forecasting (four to ten years) is used to develop advance plans for longer duration projects or construction projects that require more than two or three years to complete, and to identify future capital projects in the Construction Budget Forecast process.

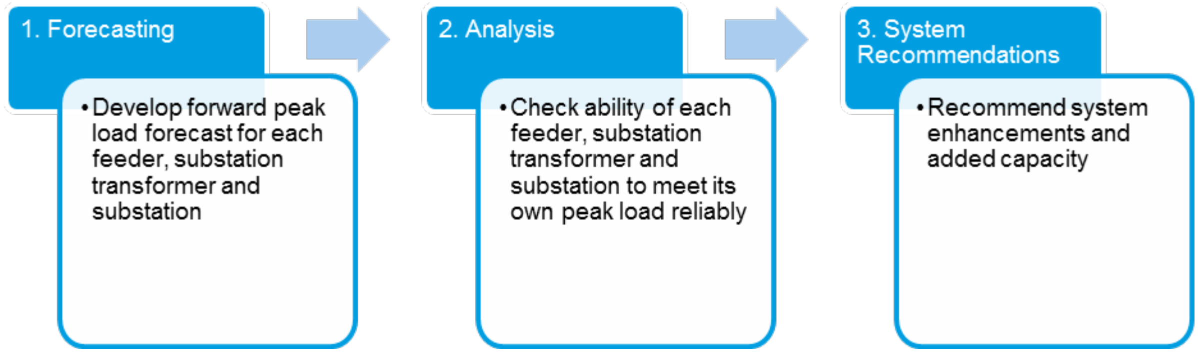
Forecasting begins with the examination of the summer historical loads for each feeder and substation on a two-year cycle. Further, actual new customer loads from submitted class of service forms and other available development reports, planned changes in feeder configuration and emergency transfers, and reductions due to distributed energy resources (DER) are also analyzed. The individual feeder and feeder group loads for each year are calculated and adjusted to produce the substation load predictions for each year of the plan.

Over the past year, Pepco has implemented a new planning tool, the Distribution System Planning Load Forecasting (DSP-LF) program. This program compares the historical weather patterns for the previous year against a thirty-year record of weather patterns. Feeder and Substation loads during the summer and winter periods are adjusted to match the values expected during temperature extremes projected to occur once in a ten-year period. These historical values are projected by the program into the upcoming ten-year period by adding new customer load requests submitted by the developers and anticipated area growth trends beyond the submitted requests, including anticipated electric vehicle charging loads and fossil fuel heating system conversions. The program also incorporates the anticipated load reductions anticipated from DER submittals, DER predicted installations, and general demand response commands. The planners review these before case load projections for predicted overloads of the feeders and substations and use the program to identify likely corrective actions, including non-wire alternatives, that can be used to relieve the facility overload for several years. One of the strengths of this program is to assist in review of corrective measures that adjust the energy use over the day, such as Battery Energy Storage Solutions (BESS) and Targeted Demand Response (TDR). These types of measures can reduce the peak power demand but will increase energy use on the feeder or substation during off peak periods, which must be analyzed to assure proper operation of the distribution system throughout the following day.

A challenge in using this tool has been anticipating the future load response to the COVID protocols put into place by the communities that Pepco serves. The weather-load patterns for the previous two years are significantly reduced from the pre-COVID patterns. Pepco anticipates the system load patterns will return to similar patterns from pre-COVID periods; however, as COVID protocols are being removed, planners will review the system load response and will adjust load projections to match their findings.

1.2 Peak Load Forecasting Process

Figure 1 General Planning Process for Distribution Feeders, Substation Transformers, and Substations



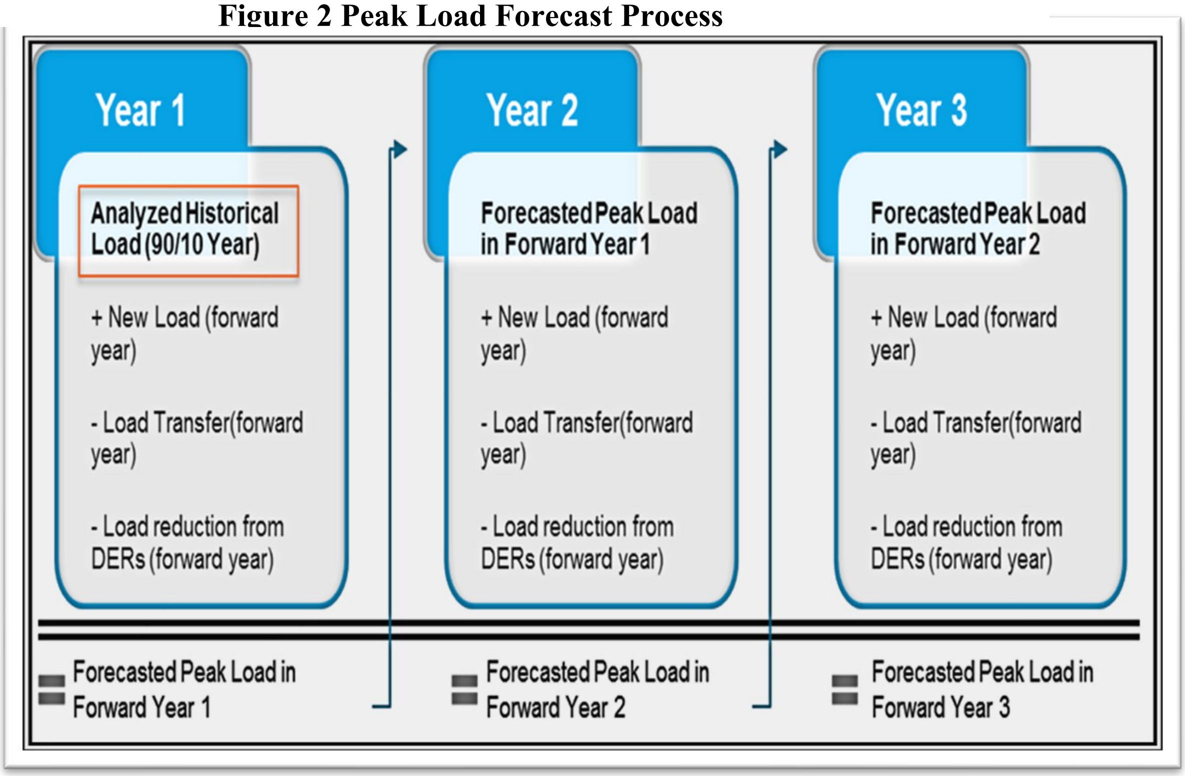
As described in Figure 1, the development of the peak load forecast is the first step in Pepco's distribution system planning process. The development of the forecast is a critical step because it has an impact on the outcomes of each subsequent step in the process and, ultimately, the timing and magnitude of the investments in the distribution system made by Pepco.[3] This section provides additional details on the analytical processes Pepco employs to develop its peak load forecast and the way in which DERs are incorporated into these processes.

It is important to note that Pepco must create more than just one peak load forecast. In fact, it creates many – one for each distribution feeder, individual substation transformer, and substation on its system. The creation of peak load forecasts for each distribution system component is needed to ensure that both individual system components are sized appropriately, and that the system as a whole will perform as it should.

This peak load planning process is depicted in the following figure:

[3] Consistent with PHI's regulatory obligations to provide safe, reliable electric service to its customers.

Figure 2 Peak Load Forecast Process



1.3 Short-Range and Long-Range Peak Load Forecasts

The peak load forecast is comprised of a short-range forecast for future years 1-3 and a long-range forecast for future years 4-10. This short-term forecast also serves as the basis for the development of the longer term 10-year plan. The former is a detailed, "bottom-up" analysis of historical peak load data, projected new load growth and energy reduction initiatives. The latter is a higher-level and "top- down" trending effort based on the PJM (the regional transmission operator or "RTO" responsible for maintaining the stability of the transmission system in Pepco's region) system peak load forecast. The short-range forecast is generally formulated in accordance with the calculation detailed in Figure 2.[4] For the purposes of this report, terms are defined as follows:

- **Analyzed Historical Peak Load** – This value serves as the base value from which future projections are calculated. This value is most often derived for each distribution system component by taking its actual historical peak load[5] in the hottest year within the last ten years,[6]

[4] Specific circumstances may merit variations in this calculation process.

[5] As recorded within the SCADA and AMI systems.

[6] Pepco plans to the hottest year in the last 10-years to develop its peak loads for each distribution system component in the short-term load forecast. Pepco uses the 90/10 forecast produced by PJM as the basis

and adding to it the incremental load changes (i.e., new loads, load transfers and load reductions from DERs) that have occurred between that hottest year and the year prior to the current year.[7]

- **New Load** – This represents additional new load that is anticipated to come online as a result of new building or development activities. At times and in some areas of Pepco's service territories, this value may be negative such as when an existing customer facility closes. New loads are added at the anticipated level of load that Pepco expects a building of the same size and energy use would add to the distribution system.
- **Load Transfers** – These are projects that Pepco conducts to utilize available capacity in one portion of its distribution system to help meet a projected capacity shortfall in another part of the system. Such projects may include re-routing feeders from one substation to another or transferring a portion of one feeder to another feeder. These types of projects occur seasonally on the distribution system and are a way of managing load without undertaking more expensive upgrades or construction. Such projects are planned ahead of time and have an impact on the forecast in future years. As a result, these projects are accounted for in the process. These are permanent redistributions of load that must not cause a total projected load to exceed the normal rating of the component, as opposed to the contingency load transfers which occur during outages to help sectionalize and restore customers' service and can result in a component operating up to its emergency rating.
- **Load Reductions from DERs** – Distributed Energy Resources may, depending on their

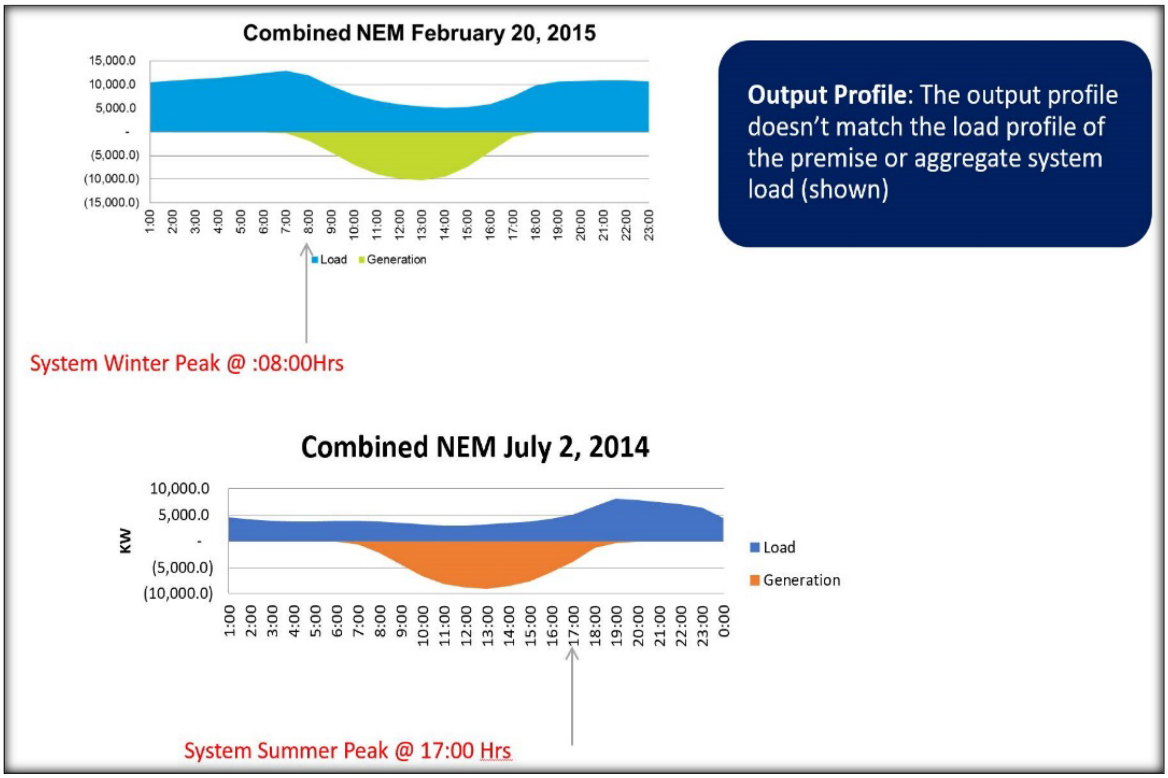
of its long-range growth forecast in order to ensure that each utility has adequate system capacity to meet area load needs during seasons with extremely hot weather. The 90/10 forecast is produced by PJM to depict peak loading that has a 10 percent probability of occurring in any given year. For capturing peak historical loadings, Pepco's methodology uses actual load readings for each component during years of extreme (one in ten year) weather. For years when less than extreme weather occurs, Pepco uses the load of the latest extreme summer, making adjustments to the load to account for prospective new businesses (PNBs), load transfers, DERs and other factors. By employing this historical loading methodology, Pepco can seamlessly transition from the historical loads used to develop its short-term plan to the long-term forecast using the PJM 90/10 loads as the basis for the trend in growth. This process also assures that no peak load used for future planning is more than 10 years old.

[7] On occasion, this method will result in a value that is less than the peak load encountered in the year prior to the current. This may occur because actual load growth on a feeder is greater than what Pepco would arrive at through its calculation (i.e., the addition of new load only from new build). In such cases, Pepco will use the actual peak load (i.e., via SCADA and AMI readings) from prior years as the Analyzed Historical Peak Load, to ensure that it is planning the distribution system to meet its maximum load requirement.

operation, reduce peak load. Whether or not these resources reduce peak load depends on the coincidence of the resource with the time of peak load on a particular distribution system component. The degree to which a DER contributes to a reduction in peak load depends on its output (which may be variable) and its contribution to total load at the time of peak load.

In addition, energy efficiency measures that are known are reflected in the historical loads that are being measured for each facility. Figure 3 is an example of a chart that shows the effects of Net Energy Metering (NEM) facilities on feeder peak loading.

Figure 3: Example of Impacts of PV on Feeder Peak Loading



1.4 Long-Range Forecast

Upon completion of the short-range forecast, Pepco then completes the long-range forecast for years 4-10. Pepco's process for completing the long-range forecast generally occurs via the following steps:

1) Pepco first conducts a trending of the short-range forecast beyond its duration (within years 1-3) and into the window of the long-range forecast (years 4-10).

2) Pepco then adjusts this trending of peak load for each feeder, substation transformer, and substation for larger-scale system changes and factors that are known to be planned within the

long-range forecast window. These changes may include considerations such as major long-term redevelopment initiatives within a geographical area.

3) Finally, Pepco adjusts the projected year-by-year long-range peak load growth on each distribution system component such that the growth rate of the system-level peak load of Pepco's long-range forecast is reconciled with the rate of growth within the corresponding PJM long-range load forecast. Pepco reconciles the growth rate of its long-range forecast with PJM's 90/10 long-range forecast to ensure consistency across the planning process of the entirety of the power delivery system, inclusive of the distribution system under Pepco's purview and the transmission and generation systems under PJM's purview.

Pepco must plan for the reliable operation of each feeder, substation transformer, and substation at its individual peak load (MVA). These individual equipment peak loads generally do not coincide with one another and are thus generally referred to as being "non-coincident" peaks. Moreover, the sum of individual non-coincident equipment peaks generally exceeds the peak load demanded of the collective whole at any given time. In other words, Pepco must plan for its "non-coincident" peaks for each component of the distribution system while PJM must plan for the coincident peak that the transmission system is required to serve.

1.5 Feeder, Substation Transformer, and Substation Analysis Process

Once the peak load forecast is completed, Pepco analyzes the capabilities of each distribution system component to ensure that it can reliably meet its forecasted peak loads. Planners use the Prospective New Businesses (PNB) and DER information gathered in the load forecasting process along with historical Advanced Metering infrastructure (AMI) customer load data, System Control and Data Acquisition (SCADA) and electrical configuration information from Pepco's Geographic Information System (GIS) to model each feeder in its power flow analysis software. From this analysis, predicted system violations such as low voltage and thermal overloads are identified and resolved through the system recommendations process.

1.5 System Recommendations Process

Upon completing its analysis process, Pepco considers the specific predicted system violations to develop recommended actions, which may consist of:

- Operational measures – Resetting relay limits, conducting phase balancing, or other measures;
- Load transfers – Conducting field switching to transfer load from a higher loaded feeder to a lower loaded feeder;

- Short-range construction projects – Feeder extensions, installation of capacitors or voltage regulators, reconductoring, NWA solutions; and
- Long-range construction projects – New feeder extensions, new substation transformers or entirely new substations, and NWA solutions.

Once the recommended actions are identified, an area plan containing construction recommendations is issued.

1.6 Factors Guiding the Consideration of DERs in Pepco's Peak Load Forecast

DERs are considered in the peak load forecast and, therefore, are reflected in the entirety of the distribution planning process that follows. How or whether a DER is counted as providing a peak load reduction depends on the availability of that resource during the peak load time for the component of the distribution system being assessed. The magnitude of impact of a DER to be counted toward reducing load depends on the level to which that resource can be relied upon to provide a load reduction at that specific point in time when the peak load will occur on the component being assessed.

1.7 Availability of a DER at the time of Peak Load

A DER may or may not be available or in operation at the time of distribution feeder, substation transformer, or substation peak load. This is an important factor that has an impact on how the resource is considered in the peak load forecast, and ultimately the entirety of the planning process. The examples below illustrate some of the potential scenarios to be contemplated when incorporating DERs in the planning process:

- A customer completes an energy efficiency upgrade consisting of the installation of a new energy efficient air conditioning unit in place of an old unit – this would result in a permanent load reduction, and thus this DER (the EE upgrade)—if known to Pepco—would be fully available at the time of peak load on the distribution feeder, substation transformer, and substation from which this customer is provided service, and would thus be considered a resource that reduces peak load on these components.
- A commercial customer installs a large diesel generator that is run on occasion to supplement the customer's energy usage at the time of the customer's maximum energy demand, which occurs seasonally in mid-spring and not in the summer when the local distribution system experiences

a peak load. Therefore, the diesel generator would not be a resource toward reducing peak load on the distribution feeder, transformer, and substation from which this customer is provided service.

- Several customers install small-scale residential solar systems on their roofs. In a given area, these DERs would be considered available at the time of peak load on the distribution feeder, substation transformer, and substation from which these customers are provided service. The total percentage of nameplate capacity considered to be available can be determined using a back casting analysis that relates the hourly capacity factor[8] of the DERs, the hour of the peak load on the component, and the total nameplate capacity on the component. Therefore, this would not be considered a firm resource counted toward reducing peak load on the distribution feeder, substation transformer, and substation from which this customer is provided service.
- A commercial developer installs a utility-scale battery system on a distribution feeder that is discharged during peak load periods on the transmission system. Therefore, most likely this would not be a resource counted toward reducing peak load on the distribution feeder, substation transformer, and substation from which this customer is provided service, because distribution system peaks do not necessarily coincide with the peak load on the transmission system.

In order to be considered as a planning resource, a DER must be "firm." In other words, it must be available at the time of peak load. Pepco's system planning criteria dictate that a DER is considered firm and is thus a dependable resource for peak planning purposes, if it is available (or coincides) 95% of the time with the peak on whichever component of the distribution system is being evaluated (feeder, substation transformer, or substation).

Planners, however, must also consider the consequences to the system when the DER is not available such as after restoration from a momentary or sustained power outage. For example, current industry standards and local electric codes mandate that all inverter-based systems (e.g., solar PV) automatically disconnect from the utility feeder upon loss of power.[9] When the feeder is reenergized, loading observed on that feeder is now the full load without the reduction from the solar generation until the inverters reconnect the customer PV back to the distribution system, which generally occurs after a minimum of five minutes. For planning purposes, the reduction from solar PV is added back into the loads of each distribution system component and those loads are compared to the emergency capacity ratings of the feeders and substation transformers and to the firm capacity rating of the substation. This Capacity Factor is defined as the average

[8] Capacity Factor is defined as the average power generated for a specified period of time divided by the rated nameplate power of the generating asset.

[9] IEEE 1547.

power generated for a specified period of time divided by the rated nameplate power of the generating asset.

This ensures that Pepco maintains adequate capacity during times when customer generation is unavailable, consistent with its regulatory obligation to provide safe, reliable electric service. Actions to be taken by the planners as a result of this analysis will depend on which component is overloaded and what actions that can be taken to mitigate the overload until the solar PV systems begin to generate and reduce customer net loads. For example, if the only overload that exists is at the substation level, then restoration can be performed in stages to mitigate the risk of an overload and no further system enhancements would be needed.

Planners also consider the effects of distributed generation being offline during an outage event when Automatic Sectionalizing and Restoration (ASR) schemes are operated through automated inline and tie switching devices. These ASR schemes are designed to automatically operate in order to isolate a fault during a feeder outage event and restore as many customers as possible. During the outage event, it is anticipated that all distributed generation on the affected feeder will have tripped off due to loss of utility power. Planners must analyze the potential transfers[10] to examine if the receiving feeder/substation transformer/substation can handle the extra load being transferred to it through automated switching. Planners design ASR schemes to maximize the amount of time during the year that there is adequate capacity to back-up an adjacent feeder.

1.8 Magnitude of Impact (kW) of a DER at the time of Peak Load

While some resources which meet the firm criteria are considered permanent load reductions (e.g., Conservation Voltage Reduction (CVR), Energy Management Tools (EMTs) and other programmatic energy efficiency) additional analysis is required for other types of DERs to calculate the magnitude of the impact of the resource. This is particularly evident for variable generation sources such as solar PV. Over the course of a 24-hour period, hourly production of solar PV can range from 0% to 100% of nameplate capacity. Therefore, calculating the magnitude of the impacts requires considering several pieces of related information:

[10] The total load to be transferred would be equal to the load that existed just prior to the outage plus the total available PV generation on the circuit. Once all load is transferred and customers are restored to service, the solar PV systems will be restored, and load will be reduced to pre-outage levels.

- Actual or simulated production of the resource (in the case of distributed generation without dedicated metering and telemetry, a back casting process is used to simulate production based upon conditions in a representative area);
- The amount of nameplate capacity of the DER interconnected to a distribution system component; and,
- The hour and magnitude (MVA) of the peak for the distribution system component being evaluated.

1.9 Customer Growth Projections and Historical Comparisons[11]

Pepco's System Planning group forecasts electric load growth to plan for future additions to the electric system. Changes in the number of customers do not necessarily correspond to a similar change in load since neighborhoods containing specific types of customers may be redeveloped into ones containing different types of customers with different load characteristics. For example, former industrial zoned districts can be re-zoned to permit mixed use development. In addition, existing customers may increase their load, which has no effect on the customer count. Both new customer additions and increases in existing customer load are factors used in forecasting load growth. The increase or decrease in the number of customers can have an impact on system load. However, the more critical information is the amount of load that a customer uses. Thus, Pepco focuses on forecasting system load growth with future development and associated customer counts as an input.

District of Columbia customer counts for six years (2016-2021) are provided on a substation basis in Table 1. Substations have been assigned to District of Columbia wards based on their location rather than the area they serve.

Load Growth Projections and Historical Comparisons

Pepco's load growth projections and historical comparison data are shown in the following tables: Table 2 provides six years of historical loads, and Table 3 provides Pepco's projections for electric load growth in the District of Columbia for 2022 to 2031. The 33 substations listed in Table 1 represent all the 13 kV distribution substations as well as the 4 kV substations not supplied by a listed 13 kV substation within the District of Columbia. Pepco tracks and projects load by substation. Substations have been assigned to one

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[11] In Order No. 12735 issued on May 16, 2003, the Commission directed (paragraph 139) the following:

> *139. PEPCO shall file the additional information not included in its expurgated comprehensive plan as outlined below, within three months of the issuance date of this Report and Order:*
> *(a) Customer growth projections by District of Columbia wards (including historical comparisons);*
> *(b) Load growth projections encompassing commercial and residential development by District of Columbia wards (including historical comparisons);*
> *The summary should cover a 10-year planning horizon while historical comparisons should provide at least five years of history.* In Order No. 12804 (paragraph 53) the Commission directed the following:

> *53. The 2003 PIP is hereby APPROVED, provided that PEPCO:*
> *(a) Provide the projected zonal and projected default (i.e., SOS) load data for the District of Columbia to the PIWG on a quarterly basis as well as in the 2004 and subsequent PIPs;…*

of the eight District wards based on the substations' locations rather than the area where they serve. Because feeders may cross ward boundaries, all feeders emanating from a substation will be assumed to supply load in the ward to which that substation is assigned.

Table 1 D.C. Historical Customer Counts per Substation

			2016			2017			2018			2019			2020			2021			2016 - 2021 Avg. Trend		
Ward 1	Substation Number	KVLEV	Res.	Comm.	Total	Res.	Comm.	Total	Res.	Comm.	Total	Res.	Comm.	Total	Res.	Comm.	Total	Res.	Comm.	Total	Res.	Comm.	Total
	10	13.8	21159	1546	22705	20386	1441	21827	21026	1461	22487	21337	1461	22798	27218	1905	29123	27092	1924	29016			
	13 (4kV)	4.33	2799	254	3053	750	74	824	670	76	746	654	69	723	0	0	0	0	0	0			
	13 (13kV)	13.8	7899	658	8557	8499	698	9197	8648	712	9360	8734	723	9457	0	0	0	0	0	0			
	25	13.8	10494	1114	11608	12506	1213	13719	12911	1210	14121	13101	1221	14322	13041	1221	14262	12926	1220	14146			
	Subtotal - Ward 1		**42351**	**3572**	**45923**	**42141**	**3426**	**45567**	**43255**	**3459**	**46714**	**43826**	**3474**	**47300**	**40259**	**3126**	**43385**	**40018**	**3144**	**43162**	**-1.13%**	**-2.52%**	**-1.23%**
Ward 2	Substation Number	KVLEV																					
	2	13.8	9936	1908	11844	10256	1895	12151	10486	1915	12401	10558	1912	12470	10486	1877	12363	10569	1905	12474			
	12	13.8	6337	1467	7804	6340	1454	7794	6315	1466	7781	6688	1474	8162	6789	1441	8230	6833	1438	8271			
	18	13.8	3270	577	3847	3318	534	3852	3351	540	3891	3494	550	4044	3695	550	4245	3668	546	4214			
	21	13.8	44	222	266	43	238	281	57	248	305	56	238	294	55	239	294	56	241	297			
	52	13.8	8697	1500	10197	9399	1336	10735	9417	1350	10767	9528	1358	10886	9566	1345	10911	9767	1360	11127			
	74	13.8	4	19	23	4	19	23	4	19	23	4	22	26	4	22	26	4	23	27			
	124	13.8	3036	1073	4109	3108	1042	4150	3408	1049	4457	3257	1040	4297	3209	1035	4244	3246	1029	4275			
	197	13.8	510	697	1207	510	705	1215	514	730	1244	513	715	1228	501	692	1193	667	690	1357			
	Subtotal - Ward 2		**31834**	**7463**	**39297**	**32978**	**7223**	**40201**	**33552**	**7317**	**40869**	**34098**	**7309**	**41407**	**34305**	**7201**	**41506**	**34810**	**7232**	**42042**	**1.80%**	**-0.63%**	**1.36%**
Ward 3	Substation Number	KVLEV																					
	38 (13kV)	13.8	4861	288	5149	3420	268	3688	3410	270	3680	3425	253	3678	3443	257	3700	4342	274	4616			
	77	13.8	6242	619	6861	6068	616	6684	6081	617	6698	6079	616	6695	6066	616	6682	6037	602	6639			
	93	4.33	711	17	728	715	15	730	716	14	730	711	15	726	721	16	737	681	16	697			
	129	13.8	18065	1351	19416	19071	1355	20426	19181	1333	20514	19022	1337	20359	19110	1338	20448	18461	1291	19752			
	145	4.33	362	34	396	362	35	397	363	35	398	365	35	400	235	32	267	349	36	385			
	146	4.33	1147	60	1207	1129	59	1188	1132	63	1195	1127	61	1188	1131	60	1191	1129	61	1190			
	Subtotal - Ward 3		**31388**	**2369**	**33757**	**30765**	**2348**	**33113**	**30883**	**2332**	**33215**	**30729**	**2317**	**33046**	**30706**	**2319**	**33025**	**30999**	**2280**	**33279**	**-0.25%**	**-0.76%**	**-0.28%**
Ward 4	Substation Number	KVLEV																					
	27	13.8	8128	633	8761	7565	564	8129	7161	513	7674	7192	522	7714	7190	526	7716	6341	451	6792			
	190	13.8	22013	1558	23571	23098	1621	24719	23497	1612	25109	23435	1584	25019	28546	1987	30533	29568	2052	31620			
	Subtotal - Ward 4		**30141**	**2191**	**32332**	**30663**	**2185**	**32848**	**30658**	**2125**	**32783**	**30627**	**2106**	**32733**	**35736**	**2513**	**38249**	**35909**	**2503**	**38412**	**3.56%**	**2.70%**	**3.51%**
Ward 5	Substation Number	KVLEV																					
	133	13.8	16768	1761	18529	17385	1756	19141	17807	1797	19604	18124	1785	19909	17945	1785	19730	19005	1793	20798			
	212	13.8	9475	454	9929	11065	718	11783	12226	789	13015	12625	812	13437	13771	831	14602	14553	835	15388			
	Subtotal - Ward 5		**26243**	**2215**	**28458**	**28450**	**2474**	**30924**	**30033**	**2586**	**32619**	**30749**	**2597**	**33346**	**31716**	**2616**	**34332**	**33558**	**2628**	**36186**	**5.04%**	**3.48%**	**4.92%**
Ward 6	Substation Number	KVLEV																					
	Sta. 'B'	13.8	15191	1356	16547	15848	1226	17074	4075	187	4262	4068	188	4256	0	16	16	0	16	16			
	33	13.8	0	2	2	0	2	2	0	2	2	0	2	2	0	0	0	0	0	0			
	117	13.8	1266	428	1694	1275	376	1651	1270	396	1666	1275	383	1658	1274	383	1657	1273	381	1654			
	161	13.8	3319	724	4043	3319	640	3959	3339	627	3966	3336	625	3961	3393	610	4003	3439	610	4049			
	223	13.8	0	0	0	1482	160	1642	14876	1219	16095	16866	1237	18103	24209	1450	25659	24913	1482	26395			
	Subtotal - Ward 6		**19776**	**2510**	**22286**	**21924**	**2404**	**24328**	**23560**	**2431**	**25991**	**25545**	**2435**	**27980**	**28876**	**2459**	**31335**	**29625**	**2489**	**32114**	**8.42%**	**-0.17%**	**7.58%**
Ward 7	Substation Number	KVLEV																					
	7	13.8	42594	3444	46038	43314	3439	46753	43022	3403	46425	43645	3398	47043	43619	3318	46937	44263	3321	47584			
	Subtotal - Ward 7		**42594**	**3444**	**46038**	**43314**	**3439**	**46753**	**43022**	**3403**	**46425**	**43645**	**3398**	**47043**	**43619**	**3318**	**46937**	**44263**	**3321**	**47584**	**0.77%**	**-0.72%**	**0.66%**
Ward 8	Substation Number	KVLEV																					
	8 (4kV)	4.33	358	97	455	371	93	464	9	55	64	12	51	63	12	48	60	10	50	60			
	8 (13kV)	13.8	7503	733	8236	5268	467	5735	5315	485	5800	5352	484	5836	5367	480	5847	4951	458	5409			
	136	13.8	15324	1248	16572	17618	1515	19133	17934	1518	19452	17607	1466	19073	18336	1468	19804	18840	1494	20334			
	168	13.8	5466	575	6041	5500	576	6076	5473	570	6043	5507	577	6084	5613	683	6296	5764	588	6352			
	Subtotal - Ward 8		**28651**	**2653**	**31304**	**28757**	**2651**	**31408**	**28731**	**2628**	**31359**	**28478**	**2578**	**31056**	**29328**	**2679**	**32007**	**29565**	**2590**	**32155**	**0.63%**	**-0.48%**	**0.54%**
	DC TOTAL		**252978**	**26417**	**279395**	**258992**	**26150**	**285142**	**263694**	**26281**	**289975**	**267697**	**26214**	**293911**	**274545**	**26231**	**300776**	**278747**	**26187**	**304934**	**1.96%**	**-0.17%**	**1.76%**

Table 2 Historical District of Columbia Load

Historical District of Columbia Loads

Loads in Mega-Volt-Amperes (MVA)

		2016	2017	2018	2019	2020	2021		
Ward 1	**Sub. Number**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**		
	10	143.0	125.6	127.1	127.5	140.1	134.2		
	13 (4.33kV)	9.9	3.1	2.5	2.2	0.0	0.0		
	13	33.0	31.9	34.3	33.6	7.6	0.0		
	25	44.0	50.2	51.0	56.0	46.4	46.5		
	Subtotal - Ward 1	**229.9**	**210.8**	**214.9**	**219.3**	**194.1**	**180.7**	Avg. Trend =	-4.70%
Ward 2	**Sub. Number**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**		
	2	154.1	147.6	146.9	143.1	115.9	125.3		
	12	106.6	104.2	102.5	100.8	90.3	95.5		
	18	134.3	128.3	126.0	127.7	104.2	103.0		
	21	36.3	37.1	39.9	33.7	25.1	28.9		
	52	175.8	157.0	154.7	159.7	129.5	138.0		
	74	43.3	41.0	41.8	42.3	28.4	41.3		
	124	101.5	98.5	96.2	93.4	78.0	87.3		
	197	117.5	112.4	107.2	104.1	82.6	87.0		
	Subtotal - Ward 2	**869.4**	**826.1**	**815.2**	**804.8**	**654.0**	**706.3**	Avg. Trend =	-4.07%
Ward 3	**Sub. Number**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**		
	38	47.3	37.5	36.7	38.7	38.3	41.2		
	38 (4.33kV)	0.0	0.0	0.0	0.0	0.0	0.0		
	77	68.7	64.3	64.9	66.9	65.8	61.7		
	93 (4.33kV)	5.4	3.0	3.4	4.4	3.2	3.4		
	129	162.1	159.3	162.7	153.5	144.6	143.1		
	145 (4.33kV)	3.1	2.4	2.6	2.5	3.3	4.1		
	146 (4.33kV)	5.8	5.4	4.8	5.4	5.4	4.9		
	Subtotal - Ward 3	**292.4**	**271.9**	**275.1**	**271.4**	**260.6**	**258.4**	Avg. Trend =	-2.44%
Ward 4	**Sub. Number**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**		
	27	34.1	34.1	36.4	35.6	29.7	27.5		
	190	88.9	89.0	87.3	90.5	94.9	99.5		
	Subtotal - Ward 4	**123.0**	**123.1**	**123.7**	**126.1**	**124.6**	**127.0**	Avg. Trend =	0.64%

Table 2 Continued- Historical District of Columbia Load

Historical District of Columbia Loads								
Loads in Mega-Volt-Amperes (MVA)								
Ward 5	**Sub. Number**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	
	133	108.2	101.8	106.2	103.4	95.3	101.9	
	212	83.9	106.9	116.2	122.1	107.0	113.1	
	Subtotal - Ward 5	**192.1**	**208.7**	**222.4**	**225.5**	**202.3**	**215.0**	Avg. Trend = 2.28%
Ward 6	**Sub. Number**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	
	Sta. 'B'	119.3	123.1	56.5	55.7	23.6	26.8	
	33	17.1	16.4	16.1	15.8	0.0	0.0	
	117	112.7	104.5	101.4	105.7	82.3	81.7	
	161	112.3	108.5	107.1	103.1	86.1	87.9	
	223	0.0	0.0	78.0	77.5	117.2	121.5	
	Subtotal - Ward 6	**361.4**	**352.5**	**359.1**	**357.8**	**309.2**	**317.9**	Avg. Trend = -2.53%
Ward 7	**Sub. Number**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	
	7	158.5	159.7	162.3	159.1	150.3	154.7	
	Subtotal - Ward 7	**158.5**	**159.7**	**162.3**	**159.1**	**150.3**	**154.7**	Avg. Trend = -0.48%
Ward 8	**Sub. Number**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	
	8 (4.33kV)	1.6	1.2	0.9	0.8	0.7	1.5	
	8	27.6	17.5	22.5	24.4	25.7	18.3	
	136	89.5	91.2	93.4	93.9	93.2	93.1	
	168	20.7	20.6	20.5	22.7	18.1	19.6	
	Subtotal - Ward 8	**139.4**	**130.5**	**137.3**	**141.8**	**137.7**	**132.5**	Avg. Trend = -1.01%
	DC TOTAL	**2366.1**	**2283.3**	**2310.0**	**2305.8**	**2032.8**	**2092.5**	Avg. Trend = -2.43%

Notes: All substations supply 13.8kV of primary power unless otherwise noted.
Loads shown are actual readings taken during peak summer conditions.
Totals shown are the sum of undiversified peak loads and are not meant to be used as official Pepco system peak loads.
Trends shown are based on the straight line regression of the loads and include transfers amongst the substations.

Table 3 - Forecasted District of Columbia Load

Forecasted District of Columbia Loads

Loads in Mega-Volt-Amperes (MVA)

Ward 1	**Sub. Number**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
	10	147.2	147.4	125.5	128.1	128.1	127.9	127.8	127.7	127.8	127.9	
	13 (4.33kV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	13	0.0	4.3	42.0	99.3	100.9	103.3	103.4	103.3	103.3	103.3	
	25	54.3	54.0	54.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	Subtotal - Ward 1	**201.5**	**205.8**	**221.5**	**227.4**	**229.0**	**231.2**	**231.2**	**231.0**	**231.1**	**231.2**	
											Avg. Trend =	1.54%
Ward 2	**Sub. Number**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
	2	148.7	148.8	148.9	148.8	148.8	148.9	148.9	148.7	148.8	149.0	
	12	91.6	91.6	91.8	91.8	91.8	91.8	91.8	91.8	91.7	91.5	
	18	100.0	100.0	103.1	108.1	112.4	112.0	112.2	112.1	112.1	112.0	
	21	34.7	34.6	34.8	34.7	72.3	72.2	72.5	72.3	35.8	35.9	
	52	161.4	146.6	146.7	146.6	146.7	146.7	146.5	146.7	146.7	146.5	
	74	39.9	39.6	39.9	39.7	0.0	0.0	0.0	0.0	38.5	38.6	
	124	88.4	88.4	88.5	88.3	88.2	88.3	88.4	88.4	88.5	88.5	
	197	118.3	118.2	118.0	117.9	118.2	118.0	117.9	118.1	118.0	118.0	
	Subtotal - Ward 2	**783.1**	**767.7**	**771.8**	**775.7**	**778.3**	**777.8**	**778.1**	**778.2**	**780.2**	**780.1**	
											Avg. Trend =	-0.04%
Ward 3	**Sub. Number**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
	38	43.0	42.7	42.8	42.6	42.9	42.8	42.6	42.5	42.6	42.5	
	38 (4.33kV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	77	73.2	73.9	73.8	73.7	73.7	73.9	73.9	74.0	73.9	73.9	
	93 (4.33kV)	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	
	129	162.3	164.5	168.7	173.0	172.4	171.8	172.1	172.2	168.7	162.6	
	145 (4.33kV)	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	
	146 (4.33kV)	5.4	5.3	5.3	5.3	5.2	5.2	5.2	5.2	5.1	5.1	
	Subtotal - Ward 3	**290.4**	**292.9**	**297.1**	**301.2**	**300.7**	**300.2**	**300.3**	**300.4**	**296.9**	**290.6**	
											Avg. Trend =	0.01%
Ward 4	**Sub. Number**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
	27	31.0	31.2	31.3	31.3	31.3	31.3	31.3	31.3	31.4	31.5	
	190	122.3	125.3	116.0	118.0	126.4	127.2	127.6	127.9	128.1	128.4	
	Subtotal - Ward 4	**153.3**	**156.5**	**147.3**	**149.3**	**157.7**	**158.4**	**158.8**	**159.2**	**159.5**	**159.9**	
											Avg. Trend =	0.47%
Ward 5	**Sub. Number**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
	133	103.5	106.3	108.1	110.0	116.6	116.6	116.6	116.8	116.7	116.6	
	212	159.1	131.4	142.0	124.6	126.3	128.2	129.9	131.8	133.4	135.3	
	Subtotal - Ward 5	**262.6**	**237.7**	**250.1**	**234.6**	**242.9**	**244.8**	**246.5**	**248.6**	**250.1**	**251.9**	
											Avg. Trend =	-0.46%
Ward 6	**Sub. Number**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
	Sta. 'B'	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	33	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	117	112.0	112.4	112.4	112.3	112.0	111.9	112.3	112.0	112.2	112.4	
	161	109.8	109.5	109.5	105.8	91.1	75.3	75.3	75.1	74.9	75.0	
	223	180.3	191.2	189.6	188.7	185.3	186.4	186.6	186.9	186.8	186.8	
	230	0.0	56.6	56.6	94.3	114.3	132.3	132.3	132.3	132.3	132.3	
	Subtotal - Ward 6	**402.0**	**469.7**	**468.1**	**501.0**	**502.7**	**505.8**	**506.5**	**506.3**	**506.3**	**506.5**	
											Avg. Trend =	2.60%
Ward 7	**Sub. Number**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
	7	165.4	166.8	169.6	173.0	174.5	175.4	175.7	176.7	177.4	178.1	
	Subtotal - Ward 7	**165.4**	**166.8**	**169.6**	**173.0**	**174.5**	**175.4**	**175.7**	**176.7**	**177.4**	**178.1**	
											Avg. Trend =	0.82%
Ward 8	**Sub. Number**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	
	8 (4.33 kV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	8 (13.8 kV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	136	128.9	149.9	155.7	161.4	160.9	164.3	153.2	153.4	153.9	154.3	
	168	23.0	24.1	25.8	29.1	31.2	33.3	33.4	33.5	33.4	33.9	
	Subtotal - Ward 8	**151.9**	**174.0**	**181.5**	**190.5**	**192.1**	**197.6**	**186.6**	**186.9**	**187.3**	**188.2**	
											Avg. Trend =	2.41%
	DC TOTAL	**2410.2**	**2471.2**	**2507.0**	**2552.8**	**2577.8**	**2591.2**	**2583.8**	**2587.3**	**2588.7**	**2586.5**	
											Avg. Trend =	0.79%

Notes: All substations supply 13.8kV of primary power unless otherwise noted.

Totals shown are the sum of undiversified peak loads and are not meant to be used as official Pepco system peak loads.

Totals shown include planned transfers, DERs, NWAs and known new business loads.

The District of Columbia has experienced uneven overall load growth from 2016 to 2021, as there are certain neighborhoods that have been growing relatively rapidly and other neighborhoods that have reduced load. Pepco attributes the reduction in loads to a marked increase in the number of customer owned Photo Voltaic (PV) solar generation connections and energy efficiency measures. Pepco's planning process examines historical load data on its substations and feeders, then examines PNB report data and internal and external reports regarding the load reductions due to DERs to develop a short-term forecast for each feeder and substation. Pepco uses trends developed in the short-term forecasting process combined with information about long-term neighborhood development projects and DERs to determine the long-term forecast for each feeder and substation. The trend analysis also takes into consideration energy efficiency activities that customers have supported during the past years and further uses AMI data from recently constructed buildings to refine expected loadings for new buildings. Developing energy usage trends will reflect these reductions in aggregate and are included in the decision-making process to determine when and where increased capacity is needed.

1.10 Incorporation of Field Information into the Planning Process[12]

Pepco's planning process incorporates Equipment Condition Assessments (ECA) and other field information into its short-term and long-range plans, when applicable. The planning group creates long-range plans to upgrade or replace utility infrastructure evaluated to be approaching end-of-life.

The capacity planning group is an active participant in ECA meetings and is the sponsor of substation transformer and switchgear replacement projects. The planning group participates in decision making regarding actions to take when equipment is evaluated to be near end-of-life, including whether to replace the equipment in kind or through a new capital project. The decision depends upon how close to failure a

[12] Order No. 16975 states the following at paragraphs 89 and 116:

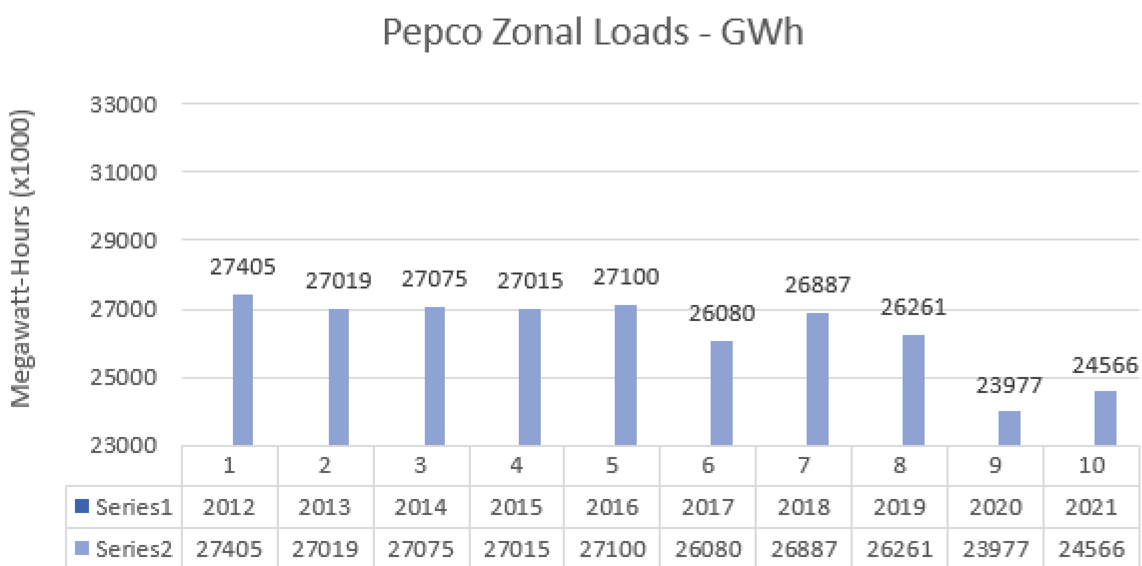
89. Decision: The Commission believes that OPC's recommendation has merit. However, we understand that equipment condition assessments may be included within the distribution system planning process, as shown in the description of the Pepco Planning Process provided by OPC at "Existing System Analysis." We direct Pepco to explain in the 2013 Consolidated Report the extent to which field information is considered within "Existing System Analysis."

116. Pepco is DIRECTED to provide field information consistent with paragraph 89 herein;

piece of equipment is evaluated to be, what other load-driven or reliability-driven capital projects are in the area, and the age and condition of other equipment in the substation.

On a system basis, Pepco's control area loads over the ten-year period between 2012 and 2021 are provided in the table below.

Table 4: Pepco Zonal Load



Note: Zonal Load excluding SMECO.

Pepco's projected monthly and annual zonal loads for 2022 are provided in Table 5. Pepco's zonal loads are for the Pepco distribution system (Maryland and District of Columbia), excluding the Southern Maryland Electric Cooperative (SMECO) and include demands for Pepco distribution customers.

Table 5: Pepco Zonal Load 2022 Forecast

2022 Forecast -- Pepco Zonal Load* (x 1,000)													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
MWh	2,243	1,926	1,953	1,606	1,724	2,051	2,387	2,311	1,870	1,720	1,703	1,983	23,476
*Excludes SMECO load													

1.11 Power Factors and Energy Loses[13]

Power Factors

The power factor provides one measure of how efficiently Pepco's electric system is being used. Substation load has two components: real power (kilowatts) and reactive power (kilovars). Real power is the power that serves the customers' end-use electrical devices. Reactive power does not serve customer requirements but decreases the substation's ability to deliver real power and increases system losses. This reduced ability to deliver real power is based on a substation's power delivery limitations. The power delivered is a combination of reactive and real power, so the greater the reactive power, the lower the real power that can be delivered. As the system power factor approaches unity, real power delivered is greater and system losses due to reactive power are reduced. By making appropriate use of capacitors, the reactive power flow on the electric system can be reduced such that it approaches zero. (When the reactive power flow is zero, the power factor is unity (*i.e.*, 1.0) A unity power factor would be ideal and would result in the maximum usable power being delivered to the customers. However, a unity power factor is not technically or economically practical to maintain because of changing loads and system conditions.

Pepco plans for a 98% (.98) power factor or higher on its 4 kV and 13 kV distribution substations at

[13] n Order No. 10133 (at 10 and 12), the Commission directed Pepco to include performance factors relating to the transmission and distribution (T&D) system in future PIPs.By way of compliance with the above requirements, in the September 1993 PIWG Meeting, Pepco proposed reporting performance data on its 13 kV distribution substation power factors.

the summer peak. Table 6 below provides the percent of all Pepco's 4 kV and 13 kV distribution substations that had power factors ≥ 98% at the summer peak hour for the years 2012 - 2021. In 2021, 96% of the 4 kV and 13 kV substations had a power factor of ≥ 0.98 at the summer peak hour.

Table 6 Power Factor - % of Pepco Substations with Power Factors Greater than 98% on Peak Summer Days (System-wide)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
% of 4 kV and 13 kV Substations with Power Factor ≥ 0.98	96%	97%	97%	97%	97%	96%	92%	89%	91%	96%
Total Number of 4 kV and 13 kV Distribution Substations (Pepco system-wide)	116	115	115	113	112	112	113	113	112	111

Annual System Energy Losses[14]

Table 7 shows a ten-year comparison of annual system energy losses for PJM and adjacent utilities. 2011 through 2020 were obtained from the Federal Energy Regulatory Commission (FERC) web site. All data are from FERC Form 1. A comparison of annual system energy losses over the past ten years is provided for PJM utilities and utilities adjacent to the Pepco service territory. Pepco's system energy losses for 2020 are 4.15% or approximately 15% lower than the group average of 4.89%.

% Annual System Energy Losses:

$$\text{\% Annual System Energy Losses} = \left(\frac{\text{Total Energy Losses (FERC Form 1, Line 27, page 401a)}}{\text{Total Energy (FERC Form 1, Line 28, page 401a)}} \right) \text{X } 100$$

[14] Industry comparison of annual system energy losses is presented in Table 7

Table 7 Annual System Energy Losses for PJM Adjacent Utilities

UTILITY	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Atlantic City Electric Company	5.61%	5.52%	5.15%	5.74%	5.78%	5.06%	6.27%	4.46%	5.88%	5.84%
Baltimore Gas & Electric Co. #	6.41%	6.17%	6.51%	6.24%	7.54%	6.36%	6.48%	6.67%	6.99%	6.99%
Delmarva Power & Light Co.	5.54%	4.52%	7.26%	5.39%	5.72%	7.92%	4.90%	4.77%	5.14%	5.49%
Jersey Central Power & Light Co.	6.35%	5.71%	8.39%	8.32%	8.60%	7.97%	7.99%	7.24%	6.27%	7.15%
Metropolitan Edison Company	4.71%	6.21%	5.30%	5.35%	7.41%	9.93%	7.95%	8.43%	7.32%	6.25%
Pennsylvania Electric Company	5.90%	6.08%	7.12%	8.23%	7.57%	6.35%	3.92%	6.67%	7.23%	6.58%
PPL Electric Utilities Corp.	6.55%	6.58%	6.66%	6.41%	6.07%	6.12%	6.12%	5.72%	5.93%	5.90%
PECO Energy Company	4.23%	5.67%	5.81%	5.69%	5.63%	5.69%	5.17%	5.13%	5.35%	5.02%
Potomac Edison Company #	2.07%	4.79%	5.12%	0.96%	1.96%	2.54%	3.09%	2.96%	2.42%	1.80%
Potomac Electric Power Co.	4.14%	4.12%	3.59%	4.01%	3.19%	2.90%	3.46%	3.79%	4.52%	4.15%
Public Service Electric & Gas	4.86%	3.99%	5.32%	4.25%	4.62%	4.58%	4.34%	3.78%	3.97%	3.76%
Virginia Electric & Power Co. #	3.12%	1.65%	2.07%	-0.79%	0.89%	-0.35%	1.20%	2.11%	2.29%	-0.28%
ANNUAL AVG.	**4.96%**	**5.09%**	**5.69%**	**4.98%**	**5.42%**	**5.42%**	**5.07%**	**5.14%**	**5.28%**	**4.89%**

Adjacent Utility

1.12 Substation Additions and Enhancements[15]

The discussion below updates the information provided in the 2021 Consolidated Report. All planning data is based on current information and may be revised as the Company completes final designs, fully evaluates site conditions, receives permitting and zoning requirements and receives final contract and equipment bids. This information could impact both the costs and timing of a project. Costs presented reflect forecasts based on approved budgets and include related transmission, distribution, real estate, and permitting costs. Plans associated with the L Street Substation have been removed from this list as they are being rolled into the long-term Downtown Resupply plan.

Table 8 reflects Pepco's planned substation additions and enhancements for the District of Columbia with their anticipated in-service dates based on current data and analysis as well as approved budgets. In-service dates are, therefore, tentative and are adjusted as in-service dates become nearer.

Table 8: Substation Additions and Enhancements

#	Project Cost	Project Description	Projected In-Service Date	Areas Served
1	**$138.6 million**	**Mt. Vernon Square Sub. –** Build new substation to relieve predicted network overloads.	June 2023	NoMa, Mt. Vernon Triangle, Shaw
2	**$191.7 million**	**Harvard Sub. –** Upgrade Harvard as a new 230/13 kV substation to retire existing Harvard and Champlain substations.	June 2024	Columbia Heights, Adams Morgan
3	**$234.82 million**	**Champlain Sub. –** Upgrade Champlain as a new 230/69 kV substation to resupply downtown distribution substations.	June 2029	Downtown

[15] In the 2001 hearings requiring the production of the Comprehensive Plan, Commissioner Meyers stated the following (page 266 of the hearing transcript):
But what we were talking about here yesterday was that the comprehensive plan would include… any rebuilt substations you might have; any new substations you might have…
Moreover, Order No. 16975 states the following at paragraphs 50 and 101:
50. Decision: …Consequently, we require Pepco to include a report on substation additions and enhancements in future Consolidated Reports. In addition to the information provided in the 2012 Consolidated Report, the Commission requires that Pepco provide details concerning the justification for these projects, including, as applicable, load growth projections and equipment age and condition in future Consolidated Reports.
101. Pepco is DIRECTED to provide a report on substation additions and enhancements consistent with paragraph 50 herein;

Construct New Mt. Vernon Square Area Substation (2023 Load Relief Project)

Overview: This project consists of constructing a new 230/13 kV substation with an ultimate capacity of 210 MVA near Mt. Vernon Square. It is currently planned to initially have three 230/13 kV transformers for a firm capacity of 140 MVA. This substation will provide distribution capacity to the rapidly redeveloping area in and around the Mt. Vernon Triangle. Initially, approximately 57.0 MVA of load would be transferred from the Northeast Sub. 212 Southwest LVAC Network Group and Tenth Street Sub. 52 radial distribution in 2023.

Justification of Substation Additions and Enhancements

The new substation at Mt. Vernon Square is needed to provide capacity to the redeveloping Mt. Vernon Triangle and Shaw areas. The capacity improvements at the Harvard Substation are needed to replace aging infrastructure at the Harvard and Champlain Substations and to create capacity to serve the growing Columbia Heights area. The new upgraded substation at Champlain will be used to re-supply existing L Street, F Street, and Georgetown substations with new solid dielectric feeders. Pepco has also projected capacity constraints and, thus, a potential need for a load-driven substation in the 2029-2031 timeframe in the St. Elizabeth's and Columbian Quarter area of Ward 8. Future ACRs will discuss this project in more detail and as its load continues to develop.

Load Projections:

Facility: Northeast Sub. 212 Southwest LVAC Group

Summer Summer Rating = 50.0 MVA

	2021 History	2022 Anticipated	2023 Anticipated	2024 Anticipated	2025 Anticipated	2026 Anticipated	2027 Anticipated	2028 Anticipated	2029 Anticipated	2030 Anticipated	2031 Anticipated
Net Load Forecast (MVA)	37.6	43.1	44.7	45.5	48.1	50.0	51.9	53.8	55.7	57.6	59.5

Facility: Northeast Sub. 212

Summer Summer Rating = 214.0 MVA

	2021 History	2022 Anticipated	2023 Anticipated	2024 Anticipated	2025 Anticipated	2026 Anticipated	2027 Anticipated	2028 Anticipated	2029 Anticipated	2030 Anticipated	2031 Anticipated
Net Load Forecast (MVA)	153.6	159.1	169.5	180.0	191.2	192.9	194.8	196.5	198.4	200.0	201.9

Magnitude of Load: Initially, approximately 57.0 MVA of load would be transferred from the

Northeast Sub. 212 Southwest LVAC Network Group and Tenth Street Sub. 52 radial distribution in 2023.

Justification:_The new Mt. Vernon Substation will provide relief to the Northeast Sub. 212 Southwest LVAC Network Group, which is expected to reach 90% of its firm capacity in 2023 and reach 100% of its firm capacity in 2026. Northeast Sub. 212 is expected to be at 90% of its firm capacity by 2025. Two Sub. 212 Southwest LVAC Network feeders will experience an average overload of about 5% in 2023, 7% in 2024 and over 10% in 2025. Due to space limitations in the streets around the Northeast substation, no new feeder groups can be extended to relieve these overloads.

Long-term growth exceeding 140 MVA is expected to come into service in the Mt. Vernon Triangle, NoMa, and Capitol Crossing areas over the next 8 years. This currently includes over 15,000 apartment type residential units, 1,300 hotel rooms, 2.5 million square feet of retail space and 6.5 million square feet of office space.

Total Planned Capital Investment (Includes A & G): $138.6 million

Current Status: In Construction.

In-service Date: June 2023

Alternative: There were several alternatives provided by Pepco in Formal Case No. 1144, including to delay the construction of the facility until 2024. To facilitate this specific alternative, a series of cascading load transfers are required to relieve Northeast Sub. 212 using Florida Avenue Sub. 10. This alternative is not practical due to load proximity. The feeders being extended from Florida Avenue Sub. 10 will be less reliable due to length and would reduce area operating flexibility as Florida Avenue Sub. 10 and the other area substations will all be loaded near their full capacity.

Multiple sites were evaluated for locating the proposed Mt. Vernon Square Sub. An alternative substation location was investigated along New York Avenue in Northeast DC. It was determined that the primary amount of development and load center of the new substation was in the Mt. Vernon Triangle area. Several sites were investigated in the Mt. Vernon Triangle area, but alternatives were rejected as too expensive or not offering required access to the nearby streets.

Upgrade Harvard Sub. 13 (2024 Aging Infrastructure Project)

Overview: This project consists of removing the current 34kV/13kV substation at Harvard Sub. 13 and upgrading to a new 230/13kV substation with an ultimate Firm Capacity of 210 MVA. It will initially have three 230/13kV transformers resulting in a Firm Capacity of 140 MVA. The upgraded Harvard Sub. 13 will serve all 13kV load supplied from the existing Harvard Sub. 13 and will provide capacity to enable the transfer of load from Florida Avenue Sub. 10 and partial load from Champlain Sub. 25. The remaining load of Champlain Sub. 25 will be transferred to Florida Avenue Sub. 10, allowing for the transition of that facility from a distribution substation to a re-built sub transmission substation. The upgraded Harvard Sub. 13 will also provide capacity for future load growth in the Columbia Heights and Adams Morgan areas.

NOTE: Changes to the original plan for transferring all load of Champlain Sub. 25 to new Harvard Sub. 13 are due to feeder routing limitations discovered during field investigations.

Load Growth Projections:

Facility: Harvard Sub. 13

Summer Rating = 140.0 MVA

	2021 History	2022 Anticipated	2023 Anticipated	2024 Anticipated	2025 Anticipated	2026 Anticipated	2027 Anticipated	2028 Anticipated	2029 Anticipated	2030 Anticipated	2031 Anticipated
Net Load Forecast (MVA)	0.0	0.0	4.3	42.0	99.3	100.9	103.3	103.4	103.3	103.3	103.3

Magnitude of Load: All load supplied from the existing Harvard Sub. 13 was transferred temporarily to nearby substations in 2020. After the upgraded Harvard Sub. 13 is placed in service, partial load from Florida Avenue Sub. 10 and Champlain Sub. 25 will be transferred to it. The remaining load supplied from Champlain Sub. 25 will be transferred to Florida Avenue Sub. 10, allowing for the transition of Champlain from a distribution substation to a new subtransmission substation.

Identified Need: This project is needed to retire aging infrastructure including the Harvard Sub. 13 - 13 kV substation originally constructed in 1907, the 34 kV supplies to Harvard Sub. 13 from Buzzard Point Sta. “B”, constructed around 1960, and Champlain Sub. 25 13 kV substation, constructed around 1954. This upgraded substation will also supply capacity to the growing Columbia Heights and Adams Morgan areas.

Justification: Harvard Substation 13 was initially built in 1907 with the substation having undergone several refurbishments with the latest taking place in the mid-1960s. The 34kV supplies to Harvard Substation 13 were constructed in the 1940s. The last incarnation of Champlain Substation 25 was put into service in the mid-1950s although some portions of the site are likely older. The substation does not meet Pepco’s current standard for fault current withstand and are configured in a non-standard way that could lead to longer restoration times for failures experienced inside the substation. In addition, completion of this project along with the project to resupply “L” Street Sub. 21 (Downtown 34-69kV Resupply) and the retirements of Anacostia Sub. 8 and Navy Yard Sub. 33 will enable the retirement of Buzzard Point Sta. "B" 13/34 kV substation. The upgraded Harvard substation will provide capacity to accommodate projected load growth in the Columbia Heights area.

Total Planned Capital Investment (Includes A & G): $191.7 million (overall estimated cost of project increased due to inclusion of historic landmark nomination, demolition, and civil engineering costs).

Current Status: In design and construction stages

In-service Date: June 2024

Alternative: The alternative to rebuilding the Harvard Substation would require construction of a new 210 MVA, 138/34 kV substation near Buzzard Point, from which three (3) new 34 kV "radial" underground circuits would be extended approximately 5.3 miles to the Harvard Substation. All existing equipment would be upgraded at the Harvard Substation; however, the capacity of the substation would remain at 80 MVA. Upgrading the Harvard Substation would require replacement of individual transformers and switchgear. This alternative would cost more overall than the selected alternative and would not increase overall substation capacity as much as the selected alternative. Pepco currently does not have adequate substation capacity in the area to transfer the entire load from the Harvard and Champlain Substations to other substations.

Upgrade Champlain Sub. 25 to 230/69 kV substation (2027 Aging Infrastructure Project)

Overview: This project consists of removing the current 69kV/13kV substation at Champlain Sub. 25 and upgrading to a new 230kV/69kV substation with an ultimate capacity of approximately 570 MVA. It will have three 230kV/69kV transformers with room for a fourth 230kV/69kV transformer. From the upgraded Champlain Sub. 25, four new 69 kV supplies will be extended to serve "F" Street Sub. 74 and Georgetown Sub. 12. The supply feeder replacements for "F" Street Sub. 74 and Georgetown Sub. 12 are recommended so the existing, aged, fluid self-contained 69 kV supplies from Potomac River Sta. "C" can be retired. These feeders have had increasing maintenance issues over the past several years. The new 69kV supply feeders to "L" Street Sub. 21 from Champlain are recommended to retire the existing 34kV feeders from Buzzard Point which restrict the Firm Capacity at "L" Street Sub. 21.

Load Growth Projections:

Facility: F St. Sub. 74

Summer Rating = 82.0 MVA (old)/210.0 MVA (new)

	2021 History	2022 Anticipated	2023 Anticipated	2024 Anticipated	2025 Anticipated	2026 Anticipated	2027 Anticipated	2028 Anticipated	2029 Anticipated	2030 Anticipated	2031 Anticipated
Net Load Forecast (MVA)	45.7	39.9	39.6	39.9	39.7	0.0	0.0	0.0	0.0	38.5	38.6

Facility: Georgetown Sub. 12

Summer Rating = 132.0 MVA

	2021 History	2022 Anticipated	2023 Anticipated	2024 Anticipated	2025 Anticipated	2026 Anticipated	2027 Anticipated	2028 Anticipated	2029 Anticipated	2030 Anticipated	2031 Anticipated
Net Load Forecast (MVA)	122.2	91.6	91.6	91.8	91.8	91.8	91.8	91.8	91.8	91.7	91.5

Facility: L St. Sub. 21

Summer Rating = 62.0 MVA (old)/100.0 MVA (new)

	2021 History	2022 Anticipated	2023 Anticipated	2024 Anticipated	2025 Anticipated	2026 Anticipated	2027 Anticipated	2028 Anticipated	2029 Anticipated	2030 Anticipated	2031 Anticipated
Net Load Forecast (MVA)	40.3	34.7	34.6	34.8	34.7	72.3	72.2	72.5	72.3	35.8	35.9

Magnitude of Load:_Approximately 166 MVA of load will be served from the upgraded Champlain Sub. 25 as the existing "F" Street Sub. 74, Georgetown Sub. 12 and "L" Street Sub. 21 will all be supplied from new 69 kV feeders extended from Champlain.

Identified Need:_This project is needed to retire aging 69 kV supply feeders to Georgetown Sub. 12 and " F" Street Sub. 74 and the aging 34 kV supply feeders to "L" Street Sub. 21.

Justification: The last incarnation of the Champlain Substation was put into service in the mid-1950's, although some portions of the site are older. Further, many of the Champlain Substation's air circuit breakers were installed in 1960 and 1976. While Pepco's inspections have found that this equipment is in good condition due to Pepco's ongoing maintenance programs, it is all operating well beyond its recommended lifespans. In addition, the feeders are all over thirty years old. The 69 kV supply feeders are "self-contained" type cables, meaning that there is fluid contained inside the cable jacket for cooling purposes. There have been an increasing number of maintenance problems with this cable which require extended time and resources to resolve due to limited material availability and few contractors with expertise repairing this type of cable system. This increases customer outage risk as the feeder needs to be taken out of service for extended periods of time while repairs are made.

The new 69 kV supplies to "L" Street Sub. 21 will replace the solid dielectric and gas filled cables that are at least 30 years old. In addition, resupplying "L" Street Sub. 21will allow for the retirement of the Buzzard Point Sta. "B" 13kV and 34kV substations, the former of which was originally built in the 1930's as a generating station. Another benefit of replacing the feeders is that the firm capacity at "L" Street Sub. 21 will significantly increase.

Total Planned Capital Investment (Includes A & G):_$234.81 million. The increase in cost is due to the inclusion of costs associated with Takoma Sub. 500 MVA phase shifters.

Current Status: In the early design stages.

In-service Date: June 2029.

Alternative: The alternative to rebuilding the Champlain Substation would require replacing the three existing 69 kV supply feeders from the Takoma Substation (5.4 miles) to Champlain Substation. The Champlain Substation would still need to be rebuilt, and, in addition, Pepco would need to build a new downtown substation. The new downtown substation would require the purchase of additional land. A new downtown substation would require extending three 230 kV "radial" underground circuits a total of approximately 5.0 miles from the Takoma Substation to the new downtown substation.

1.13 Distribution Projects[16][17]

Overhead and Underground Distribution Projects[18]

Pepco's overhead and underground distribution project budgets over the past eight years are provided in Table 9.

Table 9: Historical Routine Overhead and Underground Projects

Pepco DC 2014 - 2021 Capital Budgets (Dollars in Millions)								
Distribution	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Customer Driven	53.0	55.4	67.2	68.7	71.3	85.4	89.3	80.7
Reliability	133.7	127.5	121.2	114.8	157.6	176.0	197.8	212.1
Load	36.4	51.8	45.0	20.4	71.9	62.9	71.9	60.3
TOTAL	223.1	234.7	233.4	203.9	300.8	324.3	359.0	353.1

Pepco's overhead and underground distribution project budgets for the next five years are provided in Table 10. In developing forecasts, system planners review each component of the existing electric system, along with requirements for new service hook-ups, to develop the costs and schedules for changes to the

[16] In the initial November 5-7, 2001 hearings requiring the production of the Comprehensive Plan, Commissioner Meyers stated the following (pages 266-267 of the hearing transcript):
But what we were talking about here yesterday was that the comprehensive plan would include… anything that you might envision to account for distribution load growth…
[17] Order No. 16975 states the following at paragraphs 51, 52 and 102:
51. Staff Recommendation #7: Continue to provide annual updates of on-going and planned OH and UG distribution projects driven by customer, reliability, and load considerations in future Consolidated Reports. Include budget as well as actual spending for each of the three categories and explanation of significant differences in actual versus budgeted amounts…
85. Decision: The Commission adopts recommendation #7, noting that Section 1.2.4 of the Consolidated Report does not contain a comparison of actual vs. budgeted spending, nor does it include an explanation of any variances. Pepco is therefore directed to include this information in future Consolidated Reports. 102.Pepco is DIRECTED to continue providing updates of on-going and planned overhead and underground distribution projects consistent with paragraph 52 herein;
[18] In Order No. 12735 issued on May 16, 2003, the Commission stated the following at paragraphs 74 and 135:
74. During the November 2001 hearings the Commission requested that PEPCO submit a comprehensive plan to include a current assessment of, and future plans for, its underground distribution and network facilities.179 The Commission requested the plan as a tool to evaluate PEPCO's planning methodology and to assess PEPCO's ability to anticipate and respond to changing conditions in its underground distribution system…

135.PEPCO shall file the additional information not included in its expurgated comprehensive plan as outlined below, within three months of the issuance date of this Report and Order:
(c) Listing of underground distribution projects, such as the Adams-Morgan neighborhood project (including budgets, time schedules, and expected benefits) by secondary vs. primary system by District of Columbia wards affected, but not specific locations;
The summary should cover a 10-year planning horizon while historical comparisons should provide at least five years of history.

electric system. Results are then proposed as candidates for inclusion in the construction budget process, which takes place during the second half of each year. The construction budget process culminates with the approval of the following year's budget and the selection of projects to be included in the budget and four-year forecast of electric system additions. Projects may be added or deleted from the budget and four-year forecast from year to year as required. The summary budget and four-year forecast for overhead and underground distribution projects, which identifies types of projects and their respective budgets and forecasts for the years 2022 through 2026 is provided as Table 10.

Table 10: Planned Overhead and Underground Distribution Projects

Pepco DC 2022 - 2026 Capital Budgets (Dollars in Millions)					
Distribution Construction	**2022**	**2023**	**2024**	**2025**	**2026**
Customer Driven	76.8	87.3	83.0	82.5	72.1
Load	81.0	52.9	58.9	47.4	46.2
Reliability	199.9	209.0	248.4	241.4	266.7
Total	**357.7**	**349.2**	**390.3**	**371.3**	**385.0**

Note: Pepco prepares a five-year budget. Potential emergency restoration work is included in the Reliability budget and forecast. Prospective work for the DC PLUG initiative has been included in this plan.

Pepco's overhead and underground distribution project variances for 2021 are provided here in Table 11, in accordance with Order No. 18644.

Table 11 Routine Overhead and Underground Distribution Project Variances

Pepco DC 2021 Capital Budget Variances (Dollars in Millions)			
Distribution Construction	**2021 Budget**	**2021 Actual**	**Variance**
Customer Driven	80.7	78.6	(2.1)
Load	60.3	32.2	(28.1)
Reliability	212.1	204.9	(7.2)
TOTAL	353.1	315.6	(37.4)

MAINTAINING SYSTEM RELIABILITY

Pepco is committed to maintaining a safe and reliable electric distribution system and has programs in place that advance the operation of the electric distribution system by increasing the capabilities to monitor and analyze the performance of its system and enhance the ability to determine where to make modifications and additions to replace poorly performing equipment. Pepco monitors the performance of its distribution feeders system wide. This process is performed annually and enables Pepco to analyze and determine the relative ranking of each feeder's performance from the least to the most reliable.

This section of the Consolidated Report addresses:

- Technology: Monitoring, Automation, and Information Systems;
- Equipment Standards and Inspections;
- Vegetation Management (VM) Program Detail;
- Industry Comparisons;
- Best Practices; and
- Storm Readiness.

Systems and Technology: Monitoring, Automation, and Information Systems[19]

The discussion below addresses the Company's technology initiatives that contribute to improved reliability performance.

SCADA[20]

The System Control and Data Acquisition (SCADA) System is the primary tool used by the System Operators to monitor and operate the electric system. This system provides the System Operator at the Control Center the ability to remotely monitor and operate all major equipment at all substations and selected equipment outside of the substations. It is through this system that the System Operator learns what is happening across the electric system and can take appropriate actions to maintain a safe and reliable system and restore service during outages.

The Remote Terminal Unit (RTU) at each substation gathers data from all substation monitored equipment and provides an interface to pass the data to the central computer system, Energy Management System (EMS), and to the System Operator, who can then remotely control devices at each substation. Major equipment status (open or closed) and equipment metering (watt, var, voltage and ampere) is monitored by the Operator. Additionally, there are specific equipment alarms that indicate abnormal conditions like high temperature, low oil pressure or overloads on a particular device or feeder.

Pepco maintains its own extensive communication system that allows for direct communication between the RTUs at the substations and the computer system at the Control Center.

The computer system at the Control Center gathers the data from all the RTUs, analyzes the data, displays results to the System Operators, and provides the interface for the System Operator to

[19] In Order No. 12804 paragraph 53 E, the Commission ordered the following:
53. The 2003 PIP is hereby APPROVED, provided that PEPCO:
(e) Provide to the PIWG, quarterly status reports on the new Technology Initiatives being undertaken by Pepco. An annual status report should be included in the 2004 and future PIPs. The status reports should include current accomplishments, plans for the future, and anticipated completion dates.
[20] The initial requirements for the Comprehensive Plan section of the Consolidated Report were delineated in hearings taking place from November 5-7, 2001, at page 313.

remotely operate the system to protect equipment. Any change of electric system status at the substation is displayed to the System Operator within approximately 4 seconds. The system also provides various analyses. For example, it provides an indication if any substation equipment exceeds its capability limits. It does this by comparing the design limit of the equipment with the present loading. Through the SCADA system automatic switching activities can be performed or the System Operator can act manually to protect remote system equipment and relieve the condition that caused the equipment to be operating outside of its limits.

All raw data from the SCADA system (meter values and status changes) are retained and made available to those areas (System Planning, Distribution and Engineering, etc.) that need the data for analysis. The available data consists of meter values (watts, vars, volts and amps) and status (open and closed) of various facilities, equipment and feeders.

Substation Automation[21]

Although all 13 kV substations have full SCADA control, some 4 kV substations have only limited monitoring capability and do not have the full RTU capability that provides remote control and operation. At these substations all equipment status indications are grouped together on a substation basis and when there is a change of status, a single alarm point provides a single substation alarm indication. Personnel are dispatched to the substation to determine the specific problem. A project is underway to install full RTU capability in the Company's 4 kV substations that are not scheduled for conversion and retirement by installing smart relays on all critical equipment. This will provide for improved restoration capability and hourly data for analyses.

The following is the schedule for substation automation as currently planned:

- Macarthur Boulevard Sub. 152 (Q4 2022)
- Texas Ave Sub. 111 (Q2 2023)
- Fort Dupont Sub. 58 (Q2 2024)
- Fort Davis Sub. 100 (Q2 2025)

[21] Substation Automation and the following section, Distribution Automation, are also addressed in Sections 1.13, respectively, as PIP Projects.

In addition, conventional electro-mechanical relays are being replaced with new generation Smart Relays. Additional information provided by these relays is allowing for more effective and efficient operation. In certain applications, the smart relays can provide information with respect to the distance from the substation to the fault on the feeder. This will allow for faster troubleshooting of system problems, improved restoration capability and increased data for system analyses.

Distribution Automation (DA)

As part of the DA projects, eighteen 13 kV substations have been equipped with upgraded Smart Relays and enhanced RTUs for improved visibility and control at these locations. Additional information provided by these relays will allow for more effective and efficient operation and will support the operation of the Automatic Sectionalizing and Restoration (ASR) system being installed at each location. The following eighteen13kV substations, which supply load within the District of Columbia, have been equipped with enhanced RTUs and upgraded Smart Relays:

- 12th & Irving Substation
- Alabama Ave Substation
- Benning Substation
- Fort Slocum Substation
- Harrison Substation
- Little Falls Substation
- NRL Substation
- Van Ness Substation
- Beech Rd Substation (located in MD but serves some DC customers)
- Bladensburg Substation (located in MD but serves some DC customers)
- Grant Ave Substation (located in MD but serves some DC customers)
- Green Meadows Substation (located in MD but serves some DC customers)
- St. Barnabas Substation (located in MD but serves some DC customers)
- Takoma Substation (located in MD but serves some DC customers)
- Tuxedo Substation (located in MD but serves some DC customers)
- Walker Mill Substation (located in MD but serves some DC customers)
- Linden (located in MD but serves some DC customers)
- Wood Acres (located in MD but serves some DC customers)

Projects are underway to install additional 13 kV and 69 kV remotely operated switches on feeders in addition to the feeders associated with the ASR systems. The additional switches will allow more capability to isolate the faulted portion of the feeder and return more customers to service sooner. The remote-control capability of these switches allows the System Operator to perform switching without the need for field crews, thus reducing customer outage time.

Pepco has completed the installation, testing and integration of the network transformer remote monitoring system (RMS) in the following network groups. Buzzard SE, Buzzard W, Sub 161 South, Sub 18 Central, Sub 2 North, Sub 212 South, Sub 212 Southeast, Sub 25 Central, Sub 52 South, Sub 52 West, Sub 6 North, and Sub 7 Central.

These monitors will provide increased visibility and control capability for system operators to remotely open or close the network transformer protectors through two-way communications. Load, voltage, protector status, and equipment condition data are recorded for study and operating purposes, and for increased ability to schedule maintenance of this equipment. RMS will provide operational data to evaluate the performance of the transformer and protector, allowing Pepco to perform maintenance when needed and not just on an interval-based inspection schedule, and allow remote operation of the protector to disconnect network load from the transformer without the need to wait for a crew to manually operate the protector. This will provide great benefits during emergencies when there is a need to isolate a transformer very quickly from the network. The development of the RMS system and the initial installation at Buzzard Point were part of the Department of Energy Smart Grid Investment Grant (SGIG) that the Company received. The installations of RMS on these networks are part of the Company's long-term plan to install RMS in all its 49 networks, which contain approximately 4,000 transformers.

Outage Management System (OMS)[22]

The OMS is the primary tool used to receive customer trouble reports, analyze reports, and provide summary reports for crew dispatching. Typically, the process starts with the customer reporting an outage by calling the Pepco Call Center or from an Advanced Metering Infrastructure (AMI) meter reporting the loss of power. Information from that call or meter report is entered into the OMS system. The OMS database has the customer information, including customer phone number, address, and connected transformer. Additionally, the database contains the electrical network configuration of each feeder connecting each transformer to a feeder and the location of switches, fuses and taps. The system then analyzes all reported trouble by sorting the reports, prioritizing and grouping multiple problems to a

[22] In Order No. 13422 on the 2004 Consolidated Report, paragraph 66, the Commission ordered the following:
66. The 2004 Consolidated Report: Productivity Improvement Plan and Comprehensive Plan is hereby APPROVED, provided that PEPCO:
(a) Report in the 2005 Consolidated Report, due February 15, 2005, on the corrective actions taken to fix the OMS;

common source. The analyzed data are then displayed to the System Operator for dispatch of crews to investigate and resolve the problem.

The SCADA system also provides input to the OMS. When a feeder breaker at a substation opens and the entire feeder is out, all customers connected to that feeder are known to be out of service. Information obtained from customers (pole struck, line down, tree limb on wire, etc.) in the OMS is then used to determine the source of the problem and to dispatch crews. For trouble involving these pieces of equipment, the customer trouble calls provide the data necessary to determine the problem. The OMS analyzes all the customer calls as well as AMI meter statuses and then determines the common source of the problem. Information is also passed back through the OMS to the Call Center to provide that information to the customer when they call in or review their account online. This information includes knowledge of current trouble and estimated restoration time under non-major storm outage conditions. No significant changes or additions were made to Pepco's OMS system in 2021.

1.14 Information Systems

Asset Suite 8

AS8 is the system used for construction, engineering, scheduled preventative maintenance and corrective work management at Pepco. Asset data is also maintained in the system. It is closely integrated with the Graphical Work Design (GWD) system and two new scheduling systems, Primavera P6 and Syntempo. AS8 replaced Pepco legacy systems WMIS and SAP in early 2019. They are still available in read-only mode for reference.

Primavera P6

Primavera P6 is the primary tool for T-Week scheduling for construction, engineering, and plant maintenance (preventative and corrective) work at Pepco and is closely integrated with the Asset Suite 8 and Syntempo systems.

Syntempo

Syntempo is the primary tool for underground New Business work at Pepco and is closely integrated with the Asset Suite 8 and Primavera P6 systems.

GIS/GWD System

Pepco continues to deploy new functions offered by the GIS vendor for greater use of GIS data throughout the company, primarily in the area of data visualization and easier access to GIS data across the organization. The GIS/GWD system continues to be Pepco's official database of field assets. The Exelon utilities are discussing and evaluating the roadmap for GIS technologies among each company in the coming years.

1.15 Power Delivery Information System Projects[23]

Pepco's Power Delivery Information System Projects are provided in Table 12. Included in Table 12 are historical information system projects for the years 2016 - 2021. All costs are for those allocated to the District of Columbia.

Table 12 Historical Information System Projects

Rollup-1	Estimated DC Portion 2016	Estimated DC Portion 2017	Estimated DC Portion 2018	Estimated DC Portion 2019	Estimated DC Portion 2020	Estimated DC Portion 2021
ROLLUP ($000s)						
Customer Systems	782	2,295	10,634	4,544	5,734	
Smart Grid Systems	514	585	1,594	1,792	1,561	
Meter Systems	0	0	0	0	74	
Network Operating Center (NOC)	6	80	1	0	0	
Energy Supply Systems	35	0	0	0	0	
Operations Systems	102	1,176	1,147	143	765	
Energy Management System (EMS)	1,298	742	2,023	2,301	4,200	
Engineering Systems	260	33	38	422	680	
Field technologies	0	133	0	0	0	
Work Management	315	1,763	7,233	2,951	3,626	
Planning and Performance	0	80	255	548	1,214	
Subtotal IT Capital (DC Portion)	**3,312**	**6,886**	**22,925**	**12,701**	**17,855**	

Note: List does not include Smart Grid meters, Smart Grid communication network, distribution automation, or Telecom.

[23] In Order No. 12735, paragraph 139, the Commission ordered the following:
PEPCO shall file the additional information not included in its expurgated comprehensive plan as outlined below, within three months of the issuance date of this Report and Order:…
(d) Listing of power delivery information system projects with implementation schedules, annual costs, and milestones;
(e) Listing of new technology investigations with decisions, annual costs, and implementation schedules;
…The summary should cover a 10-year planning horizon while historical comparisons should provide at least five years of history.

1.16 Equipment Standards & Inspections

Equipment Inspections[24]

A proactive inspection and monitoring program reduces the possibility of unexpected failures and secondary damage to surrounding units and increases the opportunities that Pepco can plan for the replacement of impending problem equipment. The frequency of inspections and monitoring is based on Pepco's experience, manufacturers' recommendations, and/or industry practices. Inspections may lead to repair or replacement of transmission and distribution system components to maintain safety and reliability of the system.

Inspection and modeling activities identify equipment to be replaced due to loading or condition. Distribution line equipment such as transformers, cable, and other components are not subject to detailed electrical testing and are replaced only when physical inspection indicates a need for replacement. Other than those inspections, equipment is replaced when it is upgraded, relocated or fails.

As new technologies are installed, actual operational data will be available to better analyze the loading and performance of equipment. For example, load data from the AMI system can potentially identify overloaded transformers prior to failure.

Table 13 below provides a range of inspection or maintenance cycles for different classes of equipment. These were developed by weighing factors such as criticality, duty cycle, varying manufacturer's recommendations, and technological differences.

The equipment types and asset groups listed on Table 13 have been designated as either a "preventive" or a "predictive" maintenance. It should be noted that Pepco views its overall maintenance methodology to be defined by "reliability-centered" practices, with predictive and preventive methodologies to be subsets of this reliability-centered focus.

[24] In Order No. 16091, paragraphs 63 and 46, the Commission ordered the following:
63. Pepco is directed to provide a description of its maintenance policies and methodologies, consistent with paragraph 46 of this Order;
46. Decision. … we shall require that Pepco provide a list of the types of equipment for which a "run to failure" method applies and those for which a preventive method applies. (Footnote: If other maintenance methods are used, Pepco shall describe them as well.) The Commission requires that Pepco provide an explanation of why different maintenance methods apply to different types of equipment. We also require a description of the "test procedures" that Pepco uses to assess the performance and remaining life of the equipment. (Footnote: See Pepco comments at 7.) Further, Pepco shall provide an estimate of the current book value of equipment maintained under each method used by Pepco. The 2011 Consolidated Report shall include this description of maintenance policies and methods.\

Table 13: Equipment Inspections

Equipment	Inspection	Periodicity	Maintenance
Substation	**General Inspection**	**Every 2 months**	**Preventive**
Substation Power Transformers	Predictive Maintenance Routine	Annually	Predictive
	Oil Collection and Analysis of Transformer Main Tank and Load Tap Changer (LTC)	Once a year or more frequently if triggered by the Equipment Condition Assessment (ECA) Process, or criticality of transformer	Preventive
	Routine Inspection and Test	Every 4, 8, or 16 years based on criticality, or more frequently as recommended by Equipment Condition Assessment Process.	Preventive
	LTC Filter Change	Where applicable and condition- based maintenance on high filter differential pressure	Preventive
	Routine Cooler Inspection	Annually	Preventive
Substation Capacitor Banks - Metal Enclosed	Routine Inspection	Annually or more frequently as recommended by Equipment Condition Assessment Process	Preventive
Substation Capacitor Banks - Open Rack	Routine Inspection	Annually or more frequently as recommended by Equipment Condition Assessment Process.	Preventive
Substation Capacitor Banks - Open Rack with Circuit Switcher	Routine Inspection	Annually or more frequently as recommended by Equipment Condition Assessment Process.	Preventive
Substation Circuit Breakers – Air Magnetic	Predictive Maintenance (PDM) Tasks	Annually	Predictive
	Routine Test	6 Years or more frequently as recommended by Equipment Condition Assessment Process.	Preventive
	Oil Collection and Analysis Of OCB	Every 1, 2 or 3 years based on criticality, or more frequently as recommended by Equipment Condition Assessment	Predictive

Equipment	Inspection	Periodicity	Maintenance Methodology
Substation Circuit Breakers – Air Magnetic	Predictive Maintenance (PDM) Inspections	Annually	Predictive
	Internal Inspection and Test	3 – 4 Years, or more frequently as recommended by Equipment Condition Assessment Process	Preventative
	Diagnostic Testing	3 Years	Preventative
	Compressor Inspection/Pre-Charge	2 Years	Preventative

Equipment	Inspection	Periodicity	Maintenance Methodology
	Inspection (as applicable)		
Substation Circuit Breakers – SF6	Predictive Maintenance (PDM) Inspections – Non-Intrusive	Annually	Preventative
	Routine Inspection – Intrusive	Single Pressure: 8 Years, Dual Pressure: 4 Years, or more frequently as recommended by Equipment Condition Assessment	Preventative
	Diagnostic Testing	Single Pressure: 8 Years, Dual Pressure: 4 Years, or more frequently as recommended by Equipment Condition Assessment Process	Preventive
Substation Circuit Breakers – Vacuum	Predictive Maintenance (PDM)	Annually	Predictive
	Routine Inspection	6 Years or more frequently as recommended by Equipment Condition Assessment Process	Preventive
Substation – 69 to 230kV High-Pressure Pipe-Type Potheads	Periodic Inspections where sample ports are available.	Every 4 to 6 years (230kV),	Preventive
	Periodic Inspections where sample ports are available.	Every 6 to 8 years (115kV),	Preventive
	Periodic Inspections where sample ports are available.	Every 8 to 10 years (69kV)	Preventive
Substation – Battery & Charger Systems	Visual & On-line Test/Inspection	Annually or more frequent as recommended based on an ECA.	Preventive
Substation – Building Heating, Ventilation and Air Conditioning (HVAC) System	Annual Inspection	Annually	Preventative
Substation – Emergency Generators	Start and Run Test	Up to 4 times per year: Routine Inspections; Annually: Standby Generator Inspection and Maintenance and Black Start Generator Test Inspections as recommended based on equipment condition.	Preventative

Equipment	Inspection	Periodicity	Maintenance Methodology
Substation – Fire Protection Pump	Routine Inspection	Annually	Preventive
Right-of-Way Integrated VM (Transmission)	Routine Inspection	Interval based on Right-of-Way inspections and height of vegetation.	Preventive
Scheduled Tree Trimming - Overhead Distribution Feeders Not In Transmission Rights- of-Way	Routine and Condition-based Tree Inspection	2 Year trim cycle	Preventive
Protective Relays and Automatic Reclosing Relays	Preventive Maintenance	4 to 8 years based on system voltage class	Preventive
Under-Frequency Relays	Preventive Maintenance	8 years	Preventive
RTUs - SCADA	Predictive Maintenance	Failure to operate properly based on condition monitoring – self diagnostics, EMS trouble logs, real	Predictive
SCADA (Supervisory Control and Data Acquisition) Metering	Preventive Maintenance	Condition based maintenance	Preventive
Digital Fault Recorder	Preventive Maintenance	200kV and Above: 8 Years, Below 200kV: Failure to operate properly based on condition monitoring-self diagnostics, fault records, real time data analysis and remote communications.	Preventive
Power Line Carrier (PLC)	Preventive Maintenance	Every 24 Months	Preventive
Microwave Equipment	Preventive Maintenance	Every 24 Months	Preventive
Fiber Optic Equipment	Preventive Maintenance	Condition Based Maintenance	Preventive
Leased Line	Preventive Maintenance	Every 24 Months	Preventive
Pole-Type Recloser	Routine Inspection	Visual: 2 years Operational Test: Every 3 to 6 yrs.	Preventive
Pole-Type Regulators	Routine Inspection/Test	Every 24 months	Preventive
Critical (Hospital/Nursing Home) Network Transformers/Protectors	Routine Inspection	Every 3 years	Preventive
Distribution Manholes	Routine Inspection	Every 6 years	Preventive

Equipment	Inspection	Periodicity	Maintenance Methodology
Underground Network Transformers/Protectors	Routine Long Inspection	Every 5 years de-energized (Staggered w/Short Inspection so visits are 2.5 years apart). Inspection cycle for some locations may differ and be between 2 - 10 years based on: 1) criticality - hospital locations are inspected more frequently; 2) location type - sidewalk/roadway location or roof top/basement; and 3) installation type - junction	Preventive
Capacitor Banks – Pole Mounted	Routine Inspection	2 Years for Non-Distribution VAR Dispatch (DVD), DVD capacitors monitored near real-time.	Preventive
Distribution Pad mounted Transformers / Switchgear	Routine Inspection	5 Years	Preventive
Pipe-Type Cable Joint Sleeves in Manholes	Periodic Inspection	Every 5 to 10 years	Preventive
Wood Poles	Wood Pole Inspection, Remedial Treatment and Restoration	Every 10 years (starting in 2015)	Preventive
Power Line Over Navigable Waterway – Overhead Clearance	Routine Inspection	5 years	Preventive
High Voltage Transmission Structure Aviation Warning	Periodic Inspection	Annually	Preventive
High Voltage Transmission Structure Grounding	Periodic Inspection	Inspect Grounding System on a 5 – 10- y e a r interval	Preventive
Microwave Tower and Aviation Warning Lighting	Periodic Inspection	Annual or as per Federal Aviation Administration (FAA)	Preventive
High Voltage Transmission Line Comprehensive Inspection	Aerial Inspection	6 Years	Preventive
Cathodic Protection	Substation Inspection and Manhole Survey	Condition based – Various intervals (based upon type of work involved)	Preventive
Cable Oil and Gas Alarms	Annual Inspection	Annually	Preventive
Fluid Pressurizing Plants for High-Pressure Pipe-Type Cables	Operational Test and Inspection	Every 1 to 2 weeks (chart replacement), Every 1 to 2 years (operational test)	Preventive

Table 14 includes the book value of equipment as of December 31, 2021. Book values have been categorized by direct and allocable plant. The use of FERC Mass Asset Accounting does not allow any specific asset to be identified and linked to its accumulated depreciation and remaining useful life or to link it to the maintenance method applied to the equipment as assets are depreciated by account. Any specific asset to be identified and linked to its accumulated depreciation and remaining useful life or to link it to the maintenance method applied to the equipment as assets are depreciated by account.

Table 14 Distribution Equipment Net Book Value

Potomac Electric Power Company			
DC Distribution Plant, Reserve, Net Book Value - 2021			
DC DISTRIBUTION PLANT	**Book Cost**	**Reserve**	**Net Book Value**
E-3601-Land	70,669,569	-	70,669,569
E-3602-Land Rights	572,892	65,099	507,793
E-3610-Structures and Improvements	90,174,871	32,382,456	57,792,415
E-3620-Station Equipment	635,698,014	191,916,493	443,781,521
E-3640-Poles, Towers, and Fixtures	159,823,360	35,788,639	124,034,721
E-3650-O/H Conductors and Devices	181,987,188	54,308,413	127,678,775
E-3660-U/G Conduit	990,561,646	346,941,514	643,620,132
E-3670-U/G Conductors and Devices	1,050,731,895	273,874,663	776,857,232
E-3680-Line Transformers	658,133,178	198,000,267	460,132,911
E-3691-O/H Services	17,145,414	(1,662,021)	18,807,435
E-3692-U/G Services	124,765,449	77,566,190	47,199,259
E-3693-U/G Cable Services	184,644,393	71,997,811	112,646,582
E-3700-Meters	6,466,385	2,590,358	3,876,027
E-3701- AMI Meters	65,733,071	30,403,992	35,329,079
E-3711-Install on Customer Premises	1,367,203	1,250,798	116,405
E-3731-Overhead Street Lighting	193,105	(147,458)	340,563
E-3732-Underground Street Lighting	9,403,595	7,188,362	2,215,233
E-3734-Dusk to Dawn Street Lighting	50,315	33,617	16,698
Total DC Distribution Plant, Reserve, NBV	**4,248,121,543**	**1,322,499,193**	**2,925,622,350**

1.17 Overhead Feeder Inspection Program [25]

Pepco's Overhead Feeder Inspection Program was initiated in 2012 to improve overall system reliability and remediate potential safety issues. In the years since the initial inception, the Overhead Feeder Inspection Program has been refined to facilitate more aggressive inspection timelines and prioritization for remediation activities that addresses the criticality of infrastructure issues and is consistent with typical feeder improvement work.

Overhead Feeder Inspection Cycle

Pepco's Overhead Feeder Inspection Program ensures that all feeders with overhead exposure are inspected within a two-year period. Pepco currently has approximately 200 District of Columbia feeders with overhead exposure.

Overhead Feeder Inspection Components

The overhead feeder inspection consists of a mobile scan of all main line poles on a feeder, from ground line to the top of the pole, including the conductors from pole to pole, utilizing Ultrasonic and Infrared Non-Destructive Testing (NDT) methodology.

Visual inspection is performed on all feeder mainlines to determine feeder/equipment condition and identify immediate threats to reliability created on the following equipment:

- Cross-arms and braces
- Insulators
- Grounds
- Lightning arrestors
- Conductors
- Transformers
- Reclosers
- Capacitors
- Regulators
- Ancillary equipment
- Vegetation

[25] Order No. 16975 states the following at paragraphs 64 and 107:
64. Decision: Pepco is directed to report on the Overhead Feeder Inspection Program in future Consolidated Reports as recommended by OPC and the Staff, including results of the inspections, actual and incipient failures detected and remediation actions taken to correct the nonconformance items recorded. In particular, as requested by OPC, Pepco is directed to report on replacement of lightning arresters.
107.Pepco is DIRECTED to report on the Overhead Feeder Inspection Program consistent with paragraph 64 herein;

Overhead Feeder Inspection Results

Overhead feeder inspection results required remediation work and completion status are tracked. Prioritization of remedial work is based on both safety and reliability attributes. Immediate or near-term response is assigned to those conditions that must be addressed to mitigate imminent safety or reliability issues. Less emergent conditions are required to be remediated within the typical design and build cycle for distribution projects. Conditions that do not pose a reliability or safety threat in neither the near-term nor long-term, are identified for possible upgrade in conjunction with other planned work.

Repairs or upgrades to correct or eliminate conditions observed during inspections are scheduled under the following guidelines.[26]

- Priority 10: A condition where upon inspection, a Pepco facility is deemed to present an imminent safety hazard to utility personnel and/or the public. In this case, steps shall be taken to immediately eliminate the hazard. Inspectors are required to immediately notify Pepco and to stand by until relieved by Pepco personnel.
- Priority 20: A condition where upon inspection, a component of an overhead feeder is observed and confirmed to pose a threat to service reliability but does not pose a direct public safety threat. Conditions under this category should be remediated within 90 days.
- Priority 30: A condition where damage or degradation exists on a component of an overhead feeder line, does not pose a direct public safety threat, and if left uncorrected, has the potential to affect service reliability under adverse system conditions. Conditions under this category should be remediated within 18 months.
- Priority 40: A condition that poses no threat to safety or reliability but does not conform to current Pepco standards. Conditions under this category should be corrected when other work presents the opportunity to bring the condition to current standards.

[26] See APPENDIX 3B - MANHOLE INSPECTION PROGRAM (MIP) for a details of Exelon Utilities Corrective Maintenance Prioritization system.

Overhead Feeder Inspection Cycle:

Pepco inspects approximately half of its overhead feeders every other year resulting in a full inspection cycle being completed every two years.

Overhead Feeders Inspected in 2021

In 2021, 103 District of Columbia feeders were inspected, and there were 48 conditions identified (listed below).

Table 15: Feeders Inspected in 2021

Feeder	Condition
63	Broken Cross Arm Braces (x2)
63	Cracked Cross Arm
152	Broken Cross Arm Brace
152	Split/Decayed Pole Top
164	Cracked Cross Arm
164	Missing Pole Tag
165	Broken Cross Arm Brace (x4)
244	Floating Primary Wire
348	Cracked Cross Arm
494	Blown Arrestor (x2)
494	Damaged Fuse
496	Broken Fuse
14005	Broken Cross Arm
14005	Broken Cross Arm Brace
14005	Missing Pole Tag
14005	Missing Pole Tag
14008	Loose Insulator
14008	Split Cross Arm (Major)
14009	Broken Tie Wire
14014	Broken Cross Arm Braces (x2)

Feeder	Condition
14016	Split Cross Arm (Minor)
14017	Cracked Cross Arm
14017	Floating Primary Wire
14017	Split Cross Arm (Major)
14017	Wooden Dead-End Insulator x2
14020	Broken Cross Arm Braces (x2)
14020	Cracked Cross Arm
14020	Leaning/Bent Cross Arm
14021	Leaning Insulator
14021	Split Cross Arm - Minor
14022	Broken Tie Wire
14022	Loose Tie Wire
14767	Frayed Primary Wire (x2)
14767	Missing Pole Tag
14806	Broken Cross Arm Braces (x2)
14806	Floating Primary Wire
14809	Broken Cross Arm Brace
14891	Decayed Cross Arm
15018	Broken Cross Arm Braces (x2)
15018	Decayed Cross Arm
15018	Leaning/Bent Cross Arm
15018	Missing Pole Tag
15166	Broken Cross Arm Brace
15166	Leaning/Bent Cross Arm
15168	Insulator - Damaged/Flashed
15949	Split Cross Arm - Minor
15950	Broken Cross Arm Braces (x2)
15950	Leaning/Bent Cross Arm

All conditions summarized in the table above were referred to the appropriate engineering area for further evaluation and remediation and have been remediated.

1.18 Overhead Feeder Inspection Schedule

The following Overhead Feeder Inspection Schedule is projected for the District of Columbia to ensure that all feeders will be inspected over the next two years. Figures 4 and 5 below.

Figure 4: 2022 Overhead Feeder Inspection Schedule

56	309	479	14136	14752	15012	15198
97	324	481	14139	14753	15013	15199
99	333	482	14140	14755	15014	15457
119	345	485	14145	14756	15085	15458
120	347	489	14146	14758	15130	15459
128	366	495	14150	14811	15165	15632
132	367	14006	14158	14812	15169	15701
167	368	14035	14159	14900	15170	15705
177	369	14054	14200	15001	15171	15755
178	385	14055	14713	15006	15172	15756
181	386	14058	14715	15007	15173	15801
183	388	14132	14716	15008	15174	
227	394	14133	14717	15009	15175	
229	413	14134	14718	15010	15177	
308	476	14135	14719	15011	15197	**Total: 101**

Figure 5: 2023 Overhead Feeder Inspection Schedule

43	118	372	14007	14261	14987	15709
52	133	380	14008	14701	15003	15710
60	144	383	14009	14702	15015	15711
63	164	387	14010	14707	15016	15867
64	165	414	14014	14709	15018	15943
65	205	451	14015	14711	15021	15944
66	228	467	14016	14765	15094	15945
75	244	488	14017	14766	15166	15946

82	292	490	14019	14767	15167	15947
87	323	491	14020	14806	15168	15949
96	327	494	14021	14808	15176	15950
101	328	496	14022	14809	15631	15997
102	329	499	14023	14813	15702	14144R
104	348	14002	14031	14890	15706	
117	349	14005	14093	14891	15707	**Total: 103**

1.19 Vegetation Management Program Detail

Each year, Pepco's system reliability is impacted by trees and tree branches that have contacted, fallen on, or otherwise interfered with poles and wires, causing disruption of service. Due to the density of tree coverage in Pepco's District of Columbia service territory and public concerns relative to tree pruning, challenges exist when balancing the value of trees to customers and communities and the need for reliable electric service. The main objectives that the Vegetation Management (VM) program attempts to balance are safety, reliability, regulatory compliance, environmental stewardship, and customer satisfaction. Pepco's VM program includes tree pruning, tree removal, maintaining access and tree planting.

Pepco's VM priorities are:

- Achieving and maintaining a high degree of reliability across the entire electric system;
- Targeting areas of the electric system found to be most susceptible to outages and damage from trees;
- Performing cyclical pruning to maintain the stability of the system;

Working with local stakeholders and property owners in the removal of hazard trees in close proximity to Pepco's electric lines;

- Communicating with customers through various media;
- Performing emergency tree and limb removal from electric lines; and
- Assuring that the VM work is performed consistently with good environmental stewardship.

Pepco's VM program in the District of Columbia includes:

- Scheduled two-year cyclical maintenance or routine scheduled pruning and removals;
- Planting of trees to mitigate the impact of VM work;
- Unscheduled (non-cycle) maintenance operations; and
- Selective application of herbicide.

Pepco's VM process can be summarized in the following steps:

- Establish an annual VM plan strategy in accordance with regulatory requirements, International Society of Arboriculture (ISA) Best Management Practices and Pepco VM goals;
- Plan Work – Inspect the feeder to develop a VM work plan that defines the work to be performed;
- Prune/Remove/Clear Trees – VM personnel engage qualified contractors and perform project management and contract administration to complete feeder maintenance as planned;
- Validate completion of work plan – Certified Arborist inspects to validate that work performed is completed in accordance with plan and American National Standards Institute (ANSI) standards; and
- Document and report progress.

Scheduled Pruning

Pepco's scheduled cycle tree maintenance program in the District of Columbia includes a comprehensive inspection by an ISA Certified Arborist to develop a work plan for each feeder on a two-year cycle in accordance with guidelines established in conjunction with the District of Columbia's Urban Forestry Administration (UFA) and American National Standards Institute (ANSI) standards, and International Society of Arboriculture (ISA) Best Management Practices (BMPs).

Coordination with: DC Urban Forestry Administration (UFA) and others

The UFA is responsible for the management of most public space trees that grow in proximity to Pepco overhead facilities. UFA also administers the tree protection laws and is responsible for issuing permits for tree removal on private property. Arborists from Pepco and UFA work to identify and eliminate hazardous tree conditions during cycle and unscheduled maintenance operations. Pepco also coordinates with natural resource managers from the National Park Service, the District of Columbia Department of Parks and Recreation, and private property owners.

Despite the good working relationship between Pepco and UFA, challenges remain, especially with respect to VM work associated with "legacy" trees. District of Columbia statutes and regulations from decades ago resulted in "legacy trees" that impact operations today and have historically limited the degree and technique of vegetation cutback from Pepco power lines. This has resulted in large trees growing through and near conductors. Examples of the policies include the following:

1. Section 13 of "An Act for the Preservation of the Public Peace and the Protection of Property within the District of Columbia," approved July 29, 1892. (27 Stat. 324; District of Columbia Official Code § 22-3310) (Emphasis added.)

   1892: *"An act for the preservation of the public peace and the protection of property within the District of Columbia" …unlawful for any person willfully* ***top****, cut down, remove, girdle,* ***break, wound, destroy, or in any manner injure*** *….any tree not owned by that person…"*

2. Policy produced by District of Columbia, June 9, 1960, "Trees in Public Space: Washington, DC," at pg. 17.

   1960: *"Utility lines must be cleared by the use of directional clearance methods only…..the removal of internal branches to permit passage of utility lines through the trees where necessary"*

Many of the older trees conflict with the Pepco distribution system such that the issues with the various trees cannot be resolved without cutting entire "legacy" trees down. No standardized practice or agreement currently exists to resolve these conflicts. Pepco continues to work with UFA to resolve these issues on a case-by-case basis and in accordance with the Vegetation Management Plan for Utility Tree Pruning – District of Columbia (2005 Plan).[27]

In 2016, the Urban and Forestry Protection Act of 2002 was amended." The 2016 changes heightened the requirements to obtain permits to remove private trees. A "Special Tree Permit" is required to remove private trees as small as 13.9" diameter and the fee increased by 63%.

Mitigation and Tree Planting Programs

Pepco's tree planting funding mitigates removals and promotes "Right Tree Right Place" best management practices around utility space. In 2021 Pepco planted 351 trees in the District of Columbia and contributed $19,057 to the DC Tree Fund (in the form of special tree removal permits).

[27] The 2005 Plan was produced as a result of a tree-trimming working group including members from the District Department of Transportation's Urban Forestry Administration and Pepco's Vegetation Management team. Pepco filed the 2005 Plan on March 17, 2005 in Formal Case No. 982.

Selective Application of Herbicide and Tree Growth Regulators

Pepco's VM program includes the use of herbicide and tree growth regulators. An herbicide plan is developed each year to control brush and sprout growth where trees have been previously cleared. Herbicide applications are used selectively on rights-of-way, easements and, when granted permission, on private property, throughout the Pepco system in the District of Columbia. The use of herbicides follows a systematic approach with the aim of reducing woody stems from growing in the utility space. Herbicides and growth regulators used on Pepco's ROW are extremely low in toxicity and are biodegradable. Most herbicides affect treated plants by inhibiting the production of chemicals which plants need to produce chlorophyll, or by inhibiting the formation of leaf-buds. Without chlorophyll production, or functional leaves, the treated plant exhausts its stored food supply and dies. Tree growth regulators reduce the cell elongation of trees, which can help to extend the cycle time that we need to return to prune a tree again. Only herbicides and growth regulators registered by the U.S. Environmental Protection Agency (EPA) and D.C. Department of Environment are applied in strict accordance with the label and under the regulation of United States Department of Agriculture (USDA). Pepco contract applicators are supervised by certified commercial pesticide applicators.

Customer Communication Materials

- Provide consistent notification to customers regarding Pepco's VM activities on their property and in their community;
- Provide information to customers explaining the VM program along with a schedule of trim and contact information;
- Make available Pepco forestry representatives to respond to inquiries as work is being done and scheduled;
- Encourage customers to access the Pepco website for more detailed educational material including links to ANSI A330 standards, Utility Arborist Association, and the "Right Tree, Right Place" program under the Arbor Day Foundation;
- Enable the planners to meet with customers and local officials, or correspond through mail, e-mail, and phone as needed;
- Enable work permits to be obtained in advance of scheduled work to allow work to continue in a coordinated and planned manner;
- Participate in community meetings; and

- Coordinate public awareness of Pepco's VM activities and programs through the use of door hangers that are placed on customer's door prior to start of VM work.

Customer Communications: VM

See Attachment A for an example of the Company's 2021 customer communications, which is an example of pertinent information that is relayed to customers as bill inserts and other means of communication.

1.20 Industry Comparisons[28]

The Industry Comparisons section contains industry comparisons of transmission and distribution operations and performance. The comparisons of reliability indices are provided in Figures 6 through 8 in response to Commission directives in Formal Cases No. 766 and 982.

Institute of Electrical and Electronics Engineers (IEEE) Benchmarking Survey Results

Each year, Pepco participates in the annual Transmission and Distribution System Benchmarking Study conducted by IEEE. Although Pepco's District of Columbia service territory did not participate separately in the study, the Company has calculated separate values for Pepco's District of Columbia territory in both 2020 and 2021, using the MSO reporting criteria and has indicated both reliability results on the following charts. Note that Pepco's 2021 reliability results that are reported in the following graphs are not directly comparable to the data used in the 2021 study. See Figure 6 through Figure 8.

[28] In Order No. 15568 paragraph 57, the Commission ordered the following:
57. Pepco IS DIRECTED to provide a report on the Electric Utilities Best Practices, consistent with Paragraph 50 of this Order. This report shall be included in that 2010 Consolidated Report; and shall include the best practices of the electric utility industry on improving reliability and outage restoration (from the Benchmarking Studies). Pepco shall submit a continuous improvement plan, including resourcing, specific performance targets, and milestone dates to achieve the reliability and outage restoration performance of the best (quartile) performing (comparable) utilities in the Benchmarking Studies.

Figure 6 IEEE SAIFI Industry Comparison

Major Event Excluded (IEEE SAIFI 2021)

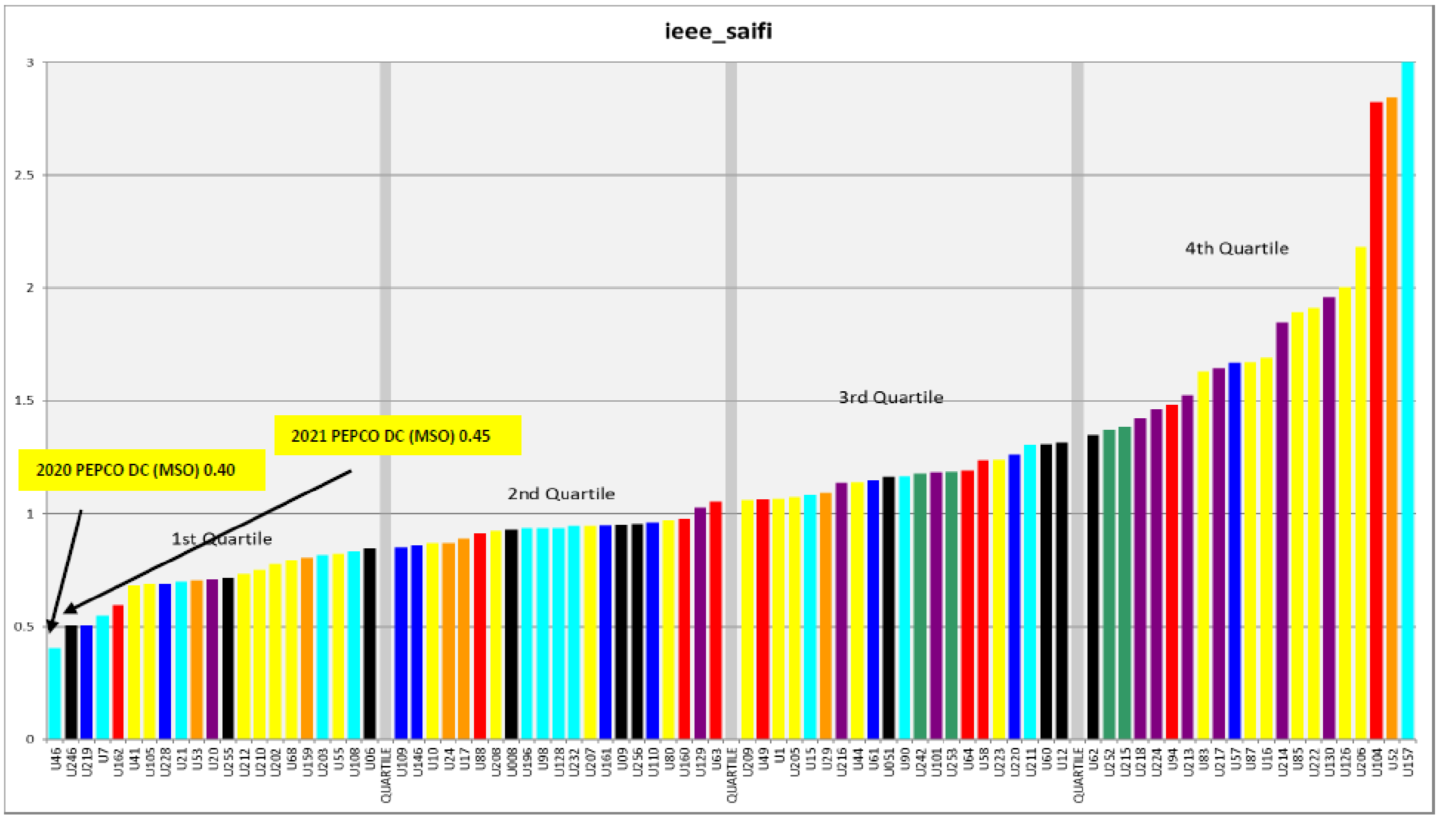


Figure 7 IEEE SAIDI Industry Comparison

Major Event Excluded (IEEE SAIDI 2021)

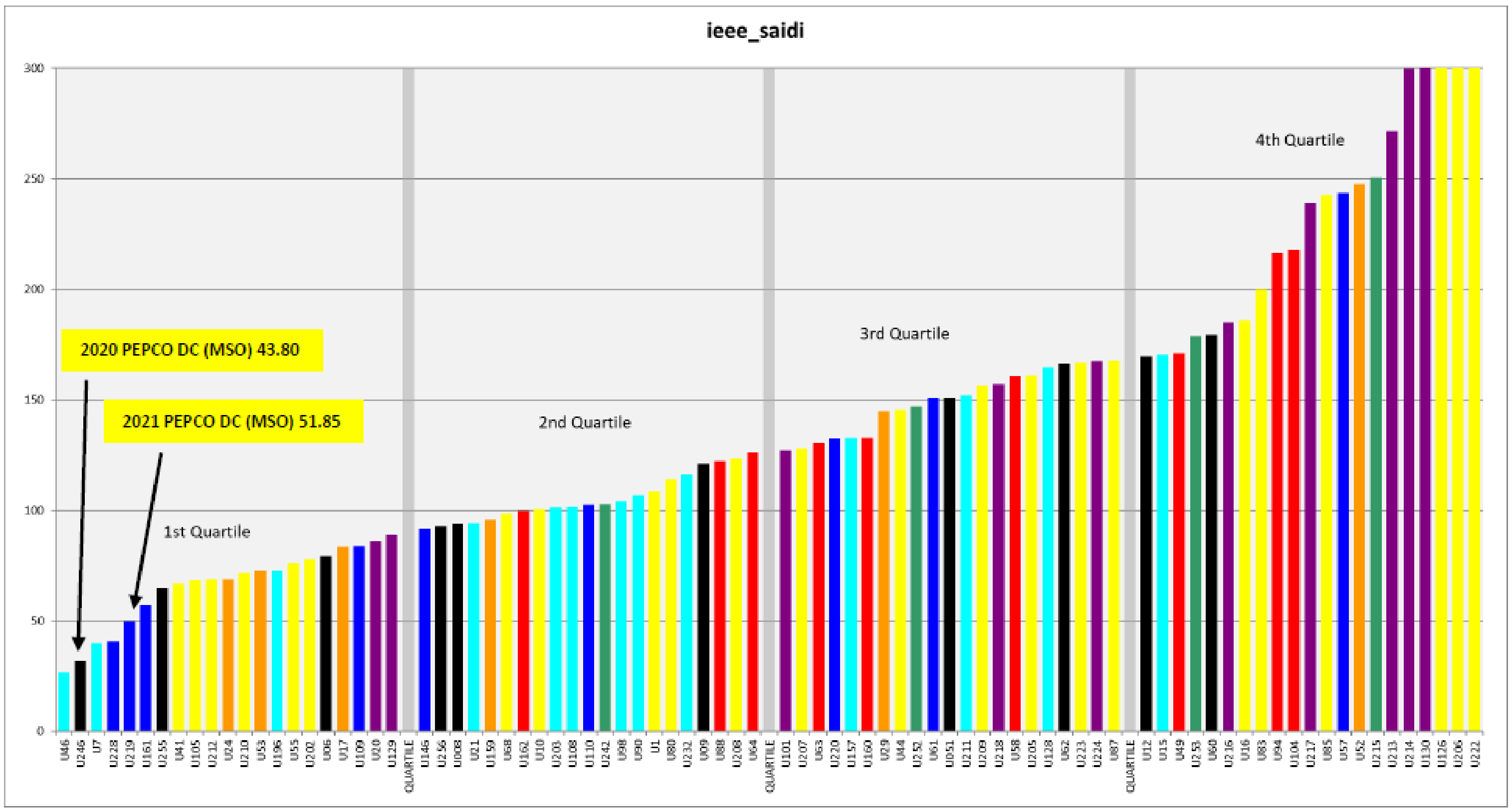
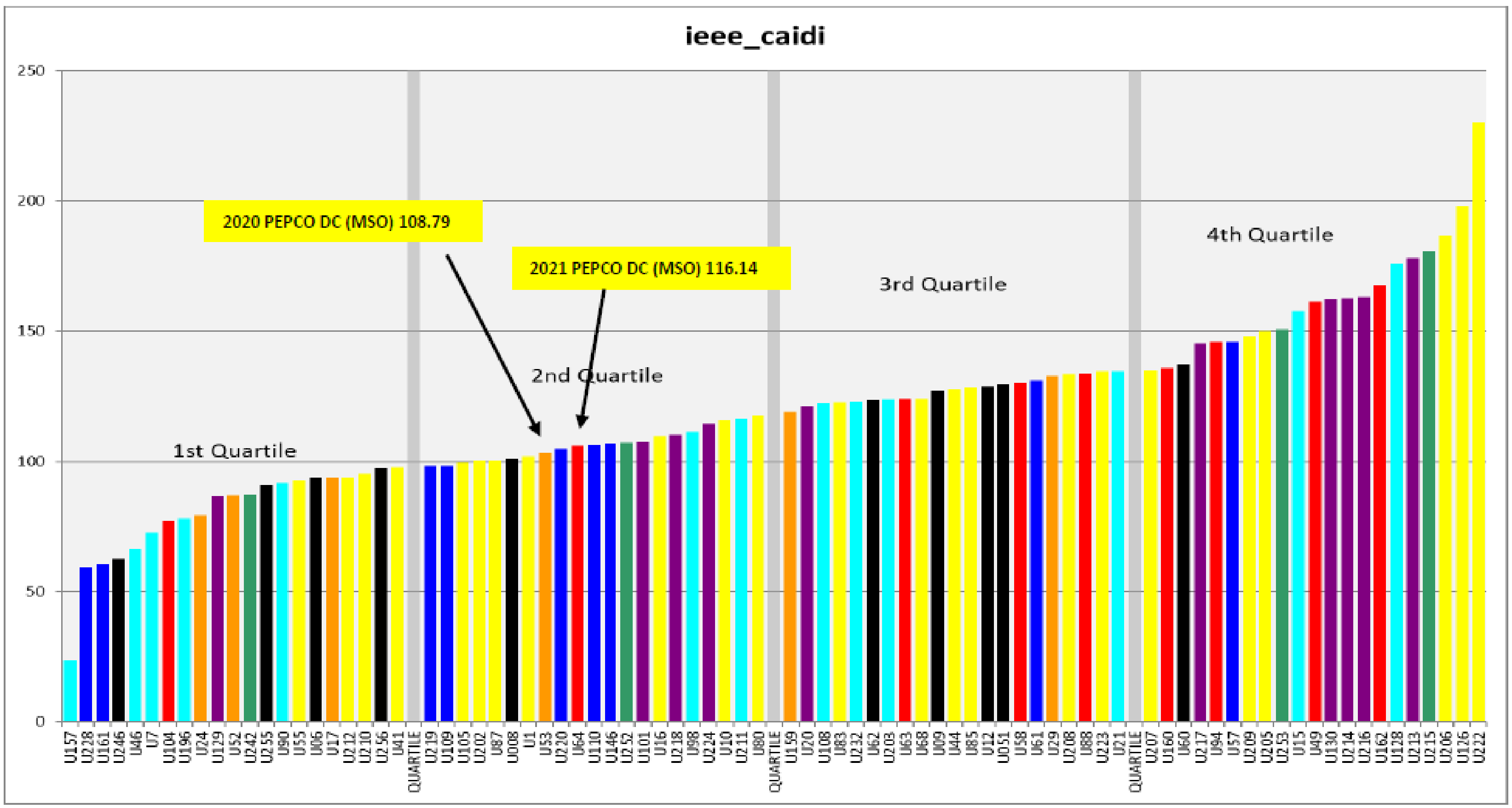


Figure 8 IEEE CAIDI Industry Comparison

Major Event Excluded (IEEE CAIDI 2021)



1.21 Best Practices

Implementation of Twenty Best Practices[29][30][31][32]

Regarding the best practices, Pepco must provide the following explanations:

1. **Cost allocation across companies and jurisdictions:** Many of the activities associated

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[29] In Order No. 16091 paragraph 61, the Commission stated the following:
61. Pepco IS DIRECTED to include a "2011 Best Practices Report" in its 2011 Consolidated Report describing its on-going implementation of no fewer than twenty of the best practices identified in the 2009 Polaris Program, consistent with Paragraph 22 of this Order;
22. Decision. First, we conclude that Pepco has complied with the requirements of Paragraphs 32 and 52 of Order No. 15568. Second, as to the Staff's Recommendation that Pepco file a "Best Practices Report" from the PA Consulting's 2009 Polaris Transmission and Distribution Benchmarking Program, we agree that a report may be helpful in assuring that best practices continue to be implemented. Therefore, the Commission shall require that Pepco include in its 2011 Consolidated Report a section entitled "2011 Best Practices Report" in which Pepco shall describe its on-going implementation of no fewer than twenty of the best practices identified in the 2009 Polaris Program included in the 2010 Consolidated Report as Appendix 2D. The twenty best practices selected by Pepco should be those judged to have the most impact on reliability and outage restoration performance. Pepco shall report on all its activities during 2010 to implement these best practices, including data on staffing levels, expenses and results. This requirement is separate from the requirement to produce a "Continuous Improvement Plan," as is described more fully in Section IV.A.1.f.
[30] In Order No. 15632 issued in these proceedings, the Commission states at paragraph 5 the following:
5. Pepco shall file with the Company's annual Consolidated Reports to the Commission data on the Company's measures to continue to address each of the recommendations made by PA Consulting and the effectiveness of the Company's approaches to improve CAIDI and SAIDI to at least the average of
[31] Order No. 16623 states the following at paragraphs 29 and 52:
29. Decision: The Commission agrees with the Staff that the information provided in the 2011 Consolidated Report does not allow a complete assessment of Pepco's progress in implementing the twenty "best practices." Therefore, we direct Pepco to provide further information for each "best practice," including staffing levels, expenses and schedules and percentage of completion. In those cases where no incremental expenses or staffing occurred, we require Pepco to identify the other activities with which these best practices were combined "for efficiency" and provide expenses and staffing levels associated with those activities. In order to provide a comparative analysis, we require Pepco to provide budget vs. actual expenses and staffing levels for the period 2007 to 2011. We also require Pepco to provide an assessment of the progress it has made in fully implementing each best practice. In addition we require Pepco to identify whether and how each best practice has been incorporated within its Comprehensive Reliability Plan.96 This information shall be included in the 2012 Consolidated Report.
52. Pepco is DIRECTED to prepare a report on best practices consistent with paragraph 29 herein;
[32] 35 Order No. 16975 states the following at paragraphs 85 and 114:
85. Decision: The Commission finds that Pepco has failed to comply completely and explicitly with the requirement that it identify "whether and how each best practice has been incorporated within its Comprehensive Reliability Plan." While Pepco includes some of its best practices as part of the REP, it does not discuss each best practice, as required by Order No. 16623. The Commission agrees with OPC that "including these practices within the REP would be an effective means for improving reliability." Pepco is required to fully address the role that each best practice has in the REP in its 2013 Consolidated Report and in future Consolidated Reports. If a best practice is not part of the REP, then Pepco shall explicitly state that fact.
114.Pepco is DIRECTED to address the role each best practice has in the Reliability Enhancement Plan consistent with paragraph 85 herein;

with the best practices described herein are performed by centralized teams supporting all PHI companies or teams supporting Pepco system-wide. Budgets and expenditures of departments that serve all of PHI are not directly attributable to one jurisdiction or another.

2. **Redirection of resources:** The implementation of some best practices by these teams did not necessarily require additional resources, but rather either required the allocation of additional duties or a shift in duties from previous practices to the newly identified best practices. Further, activities supporting the best practices are only a subset of all work done by these departments, and the activities of many of the primary personnel involved in executing and advancing these best practices are allocated to general overhead accounts.
3. **Reported best practices costs:** In past years, the Company has attempted to allocate estimated resource hours and associated activity-based costs in these centralized functions to the District of Columbia.

Given the passage of time since this directive was issued, and that this directive was linked to the REP, the practices themselves and associated directives can no longer be broken out as previously directed. While the Company certainly incorporates these and other best practices from its sister utilities and the industry at large, the information requested cannot be provided in the form requested.

1.22 ECA Teams[33][34][35]

A discussion of costs and benefits, as required by Order No. 16975, is provided below.

ECA driven projects generally consist of planned projects to replace large, high cost, long lead time primary components within substations. Targets for these projects are usually selected by condition-based criteria such as dissolved gas in oil analysis. However, due to certain external drivers (such as load, location, environment, and system criticality), these replacements may also be triggered by historic performance of a component. These projects are primarily driven by Pepco's need to manage contingency risk and do not result from cost / benefit analyses. Replacements are usually in-kind or upgrades and depend on component availability at the time. System emergencies can alter the prioritization of these projects.

The utility's obligation to serve requires substation design criteria which provides redundancy and risk management. Although substation component failures are rare in comparison to feeder components, the loss of a critical substation asset could result in long term outages affecting thousands of customers. The provision of redundant components, backup sources, and minimization of single points of failure in substation designs reduces this risk and generally allows Pepco to perform routine maintenance and upgrades without the need for planned outages. This redundancy also allows Pepco to manage contingencies and continue service despite the loss of a major substation component. As such, substation reliability is maintained by keeping both the primary and redundant assets in good working condition. Therefore, condition and criticality of assets predominantly drives substation reliability programs and many projects in the substation reliability category do not directly translate to improvements in outage frequency and duration. This concept is

[33] Order No. 16975 states the following at paragraphs 39 and 98:
39. Decision: …Specifically, the Commission directs Pepco to report on the recommendations and actions taken by the ECA team, including membership lists, meeting dates and minutes, analyses of impact of the ECA team on maintenance or replacement policies and asset management strategy and tactics. We also require Pepco, to the extent not already included, to report on costs for recommended equipment replacements and the projected benefits of those replacements, as OPC suggests. Further, the Commission directs Pepco to provide an explanation of how the work of the ECA team relates to other Pepco reliability initiatives and include a discussion of the equipment failure analysis as part of future years' Consolidated Reports.
98. Pepco is DIRECTED to include a report on the results of its Equipment Condition Assessment work consistent with paragraph 39 herein;

[34] The ECA minutes have been modified in response to the Commission's directive "to include a brief description of the project status *(i.e.*, whether it is deferred, completed or ongoing)," *In The Matter of the Annual Consolidated Report of the Potomac Electric Power Company*, Formal Case No. PEPACR-2014-01, Order No. 17816 at P 231 (February 27, 2015).

known as Reliability Centered Maintenance (RCM), the principles of which dictate that predictive maintenance activities serve to identify failing assets prior to catastrophic failure.

Substation assets are inspected under various inspection programs, including visual, infrared, and oil sampling where applicable. Based on observed condition and potential system risk, assets are cleared for normal duty, scheduled for closer monitoring, scheduled for maintenance, selected for immediate replacement, or added to prioritized programmatic replacement programs, as appropriate. Pepco's ECA process is the vehicle used to identify substation assets for condition-driven replacement in order to maintain the reliability of the substation. The ECA process cooperatively analyzes major equipment condition, makes major repair / replace decisions utilizing various subject matter experts and through consensus, prioritizes candidates for replacement on a quarterly basis.

Substation assets such as transformers, breakers, and larger components typically have long lead times and must be ordered well in advance (months to years) of anticipated need. For this reason, several replacement projects are kept in the project pipeline at any given time. This allows Pepco to substitute one project for another in situations where long lead times would subject the system and customers to significant reliability risk. Projects are engineered and built using standard designs and approved equipment.

Generally, substation reliability projects cannot be translated into measurable or forecasted SAIDI or SAIFI benefits. The presence of redundant systems within substations reduces or eliminates the direct threat to customer reliability from the loss of a single asset. However, the failure of such assets reduces the security of supply to feeders and elevates the risk of large-scale customer outages. Given the potential for customer impacts along with the long replacement cycle of major substation assets, Pepco replaces these assets proactively based on condition assessment and the desire to manage such contingency risk.

A summary of the four quarters of ECA meetings for 2021 are included below. The format has been changed to summarize the data while retaining requests for greater clarity regarding timing, costs, and completion of projects.

Pepco-DC Region Equipment Condition Assessment

BATTERIES:

Location	EPS	ITN	2021 Spend	Status
Sub 124 22nd Street	PC19QS096	70602	$168,691	Completed
Sub 181 Chesapeake Street	PC19QS097	70602	$21,330	Completed
Sub 111 Texas Avenue	PC20QS132	70602	$33,429	Completed
Sub 152 MacArthur Boulevard	PC21QS021	70602	$3,069	Completed
Sub 100 Fort Davis	PC21QS025	70602	$579	Completed

Meeting Attendees:

1st through 4th Qt. 2021

Title	Department
Manager Transmission & Substation Engineering	PSC Equipment Standards
Principal Engineer	PSC Equipment Standards
Senior Engineer Standards	PSC Equipment Standards
Senior Engineer Standards	PSC Equipment Standards
Senior Engineer Standards	PSC Equipment Standards
General Engineer	PSC Equipment Standards
Engineer	PSC Equipment Standards
Associate Engineer	PSC Equipment Standards
Manager Transmission & Substation Engineering	PEPCO Substation Engineering
Supervisor of Engineering	PEPCO Substation Engineering
Senior Engineer	PEPCO Substation Engineering
Senior Engineer	PEPCO Substation Engineering
Senior Engineer	PEPCO Substation Engineering
Senior Engineer	PEPCO Substation Engineering
Manager Regional Capacity Planning	PEPCO Distribution Planning
Principle Engineer	PEPCO Distribution Planning
Senior Engineer	PEPCO Distribution Planning
Sr. Engineering Tech Specialist	PEPCO Distribution Planning
Manager Regional Electrical Operations	PEPCO Sub Construction & Maintenance
Sr. Engineer	PEPCO Sub Construction & Maintenance
Engineering Tech Specialist	PEPCO Sub Construction & Maintenance
Principle Project Outage Coordinator	PEPCO System Operations

ECA Summary Table

To avoid outages similar to the Florida Avenue Substation outage that occurred in 2019 and to obtain a holistic view of the substation equipment in the District, the Commission directed Pepco to file an ECA summary table within 90 days of Order No. 20766 issued in July 23, 2021 including the following: (1) existing condition of various equipment within each of the distribution substations in the District; (2) date of the last performed maintenance; and (3) outstanding issues to be remediated. The Commission also directs Pepco to provide the above summary in future ACR filings. Pepco has complied with this order and filed an ECA summary table on October 18, 2021, and is including an ECA Summary as Attachment G. There were no updates to this table since the October 18, 2021, filing.

1.22 STORM READINESS

Pepco's mandate is to provide safe and reliable electric service. This is the basis for all Company contingency operations, including storm restoration, and is the foundation for the storm restoration objective of safely restoring electric service to the greatest number of customers in a minimum amount of time. The Pepco District of Columbia Major Service Outage Restoration Plan (MSO Plan) uses these principles to assess damage across the entire Pepco service area and to establish restoration guidelines for preparedness, pre-storm planning, storm response, communications, and post-storm evaluations.

The PHI Crisis Management Plan and the MSO Plan necessarily modify the normal corporate organization, in accordance with the National Incident Management System's (NIMS) Incident Command System structure and manages this amended structure to accomplish storm restoration and emergency response. The Pepco Regional Incident Management Team (IMT) assigns personnel to this temporary structure to efficiently restore customer service. The overall governing principle of the Pepco IMT is to match resources to restoration requirements. The Pepco IMT is flexible in order to adjust resources to the various types of restoration efforts that may be required and to enable restoration activities to be prioritized to restore the largest number of customers first across Pepco's service territory. All Company resources, including Operations, Logistics, Planning &Analysis, and Finance and Administration are dedicated to customer service and the storm restoration effort.

Each branch of the Pepco IMT can expand or contract staffing for the response effort as necessary. Storm positions are activated based on the support or response functions required for efficient restoration. Pre-established storm duties are maintained for each storm position. The Staging Area branch of the IMT is activated under unique circumstances.

The increased number of customer calls during storms requires additional staffing at the Customer Operations Call Center to answer customer inquiries and to supplement the automated entry of customer outage information. In the event of a major storm, Pepco's High-Volume Call Answering (HVCA) System can be activated to takes the high volume of outage calls Pepco expects in the immediate aftermath of a major storm. This HVCA system can answer more than 100,000 calls per hour to reduce the incidence of busy signals and hold times and is most efficient in the early stage of the restoration process. Once the initial outage reports are in, the Company can disable the automated call system and staffs the Pepco call center with additional employees who are trained to assist call center representatives in handling the increased volume of calls. All areas in the Customer Care Group, in performing their second roles, are required to provide support to the Call Center. Additional personnel across the Company provide assistance through their incident response role assignments and help to relay accurate information between customers and operations

Communication requirements for internal as well as external groups are identified in advance, planned for, and monitored for effectiveness during storm response. Accurate, timely and coordinated communications provide a vital link in the restoration response. Approximately 48 hours in advance of a significant major storm with predicted multi-day outages, Pepco notifies customers who are enrolled in Pepco's Emergency Medical Equipment Notification Program so they can prepare to implement their contingency plans in the event of power outages. Pepco also notifies regulatory and government officials and emergency management agencies of its storm preparations and to discuss any special concerns. Operational communications coordinate field restoration activities. Communication roles in the PHI Crisis Management Plan and the MSO Plan provide for a proactive and flexible communication strategy.

The Storm Restoration Objectives are to safely restore electric service to the largest number of customers in a minimum amount of time. This requires advance planning and pre-storm preparation. Advance planning during non-storm conditions enables operational readiness for restoration activities. In addition to drills and exercises designed to lead employees through a variety of emergency scenarios, Pepco also works with local emergency management agencies and a cross-section of community, government and business leaders in a collaborative effort to review restoration plans and practices to develop more effective ways to improve Pepco's response.

In addition, Pepco actively pursues a public education and awareness campaign that includes initiatives such as the "Weathering the Storm" brochure. These publications and additional brochures contain information about the Company's Emergency Medical Equipment Notification Program, tree trimming, and portable generator safety, all of which are available upon request as well as on Pepco's web site. These materials and information provided in Pepco's monthly newsletter that is mailed to customers with their bill provide information that help families and individuals prepare in advance for any emergency situation and are a significant component of Pepco's advance planning efforts. Additional preparedness information, as well as neighborhood outage maps, with information regarding each outage event, including the ETR, is also available on the Pepco web site.

Pre-storm preparation is the process of preparing for mobilization before a storm occurs. When a significant major storm threatens, Pepco begins preparations, when possible, by reviewing Pepco's inventory of storm repair materials and notifying vendors of the potential need for material procurement. To plan for sufficient staffing, Pepco informs employees of the pending storm and the potential for activation of their incident response second role assignments. The Company also alerts Pepco contractors and discuss plans for possible aid from the utilities within Pepco's participating mutual assistance groups. Both advance planning and pre-storm preparation activities enable a state of preparedness to transition smoothly to IMT operations and to minimize restoration time.

After a storm affects the electric system, assessment and restoration begins. Damage Assessment requires an on-going evaluation of the substations shut down, distribution feeders locked out, and feeders with damaged segments, as well as the areas and the number of customers affected. This continual process enables efficient and appropriate allocation of restoration resources. The IMT is activated to provide customer communications and to coordinate the mobilization of crews for system repairs. Since damage assessment is on-going and storm levels may change in intensity, the restoration strategy may be modified throughout the effort, and the level of mobilization may be adjusted to meet restoration requirements.

Adequate supplies of materials, tools, and equipment are necessary for restoration to proceed safely and efficiently. Logistics include procuring, maintaining, and transporting restoration resources, personnel and materials. Departments are responsible for determining logistics requirements on an on-going basis and maintaining procedures.

When major reconstruction work or significant outside resources are required for system restoration, a staging area may be established. Staging Areas are defined as sites where crews and materials are temporarily stationed in severely damaged areas of the service territory. Staging areas are set up to respond to specific restoration efforts with assigned crews and on-site materials. Sites are selected for their accessibility, parking, and space to store materials needed for reconstruction and restoration of customer service, and ability to house and feed crews.

During major outage events of extended duration Pepco can use resources from other PHI companies, if available, or request mutual assistance from one of several regional and national mutual assistance groups in which it participates. These groups meet periodically to review policies, procedures and work practices to ensure continued ability to provide mutual assistance between electric utility companies. Post-event evaluations following major service outages contribute to continuous improvements to the Pepco District of Columbia MSO Plan. Response activities are most likely to improve when recommendations are linked and incorporated into the plan and departmental support procedures. These links serve as the vehicle to enhance response plan capability. Trained personnel are essential for successful execution of storm response duties. Additional training requirements may be highlighted as a result of debriefings or drills.

Further, during major outage events, Pepco uses AMI to enhance storm restoration efforts. For example, during those major outage events, Pepco's AMI capability to "ping" meters help to determine whether a customer has electric service. This application of Pepco's AMI network contributes to reducing restoration times, and avoiding costs, without necessitating phone calls to customers thus minimizing unnecessary costs. It also materially reduces the number of truck rolls needed to verify customer restoration, helping ensure that crews are dispatched efficiently.

Drills and Functional Exercises

In 2021, Pepco held a combined Service Center Drill at the Forestville and Rockville Service Center on October 3. In addition, the Pepco IMT (Incident Management Team) held their annual Drill on June 3rd which satisfied their regional exercise requirements. In 2021, Pepco also participated in GridEx VI, exercise on November 16-17, 2021, to exercise our response and recovery plans in the face of simulated, coordinated cyber and physical attacks on the North American bulk power system and other critical infrastructure. GridEx is the largest grid security exercise in North America. Hosted every two years by NERC's Electricity Information Sharing and Analysis Center (E-ISAC).

In conjunction with the MSO Plan, Pepco may also activate PHI's Crisis Management Plan. PHI's Crisis Management Plan defines the management structure and outlines response activities for extensive emergencies, including unplanned events that can cause significant injuries to employees, customers or the public; cause physical, environmental or technological damage; or can shut down the business or disrupt operations. This plan also provides general guidelines allowing PHI and Pepco sufficient flexibility to respond to any emergency condition promptly and effectively.

PART 2: PIP

Section 2 <u>Requirements</u>

On November 1, 1982, in Order No. 7668, the Commission adopted final rules regarding the submission of an annual PIP in Formal Case No. 766. These rules are codified in Title 15 of the District of Columbia Municipal Regulations, Chapter 5, Rules 502.1 and 502.2. In 1982, the Commission also directed the Company to establish the Productivity Improvement Working Group (PIWG), consisting of representatives from the Commission Staff, the Office of the People's Counsel (OPC), and Pepco to provide a setting for communication among all parties and Commission Staff during the developmental stage of the first annual Productivity Improvement Plan (PIP) With the divestiture or transfer to an affiliate of all of Pepco's generating stations, the primary focus of the PIP and PIWG has shifted instead to transmission and distribution operations, performance, and reliability.[36] Later, Order No. 16623 emphasized a focus on reliability for the ACR.

[36] In Order No. 15152 on the 2008 Consolidated Report paragraphs 68 the Commission stated the following:
68. The Productivity Improvement Working Group, which includes OPC, provided a reasonable definition of a productivity improvement project in 2006. Specifically, the PIWG states:
T&D productivity improvement projects were considered those projects that will increase T&D system efficiency by reducing losses and improve[ing] system reliability, and which may defer more costly additions to the electric system. (Footnote: F.C. No. 766, Decision on Consideration of OPC's T&D Productivity Improvement Working Group in Response to Commission Order No. 13754, filed July 6, 2006 ("2006 PIWG Report"), at 2.)

2.1 PIWG

As discussed above, the PIWG has evolved over the years since its establishment but continues to serve as a standing committee for collaboration among the Commission Staff, the Office of the People's Counsel (OPC), and Pepco. The PIWG meetings address issues of interest to the Commission or PIWG members. Agendas and meeting frequency are determined according to issues of immediate concern to PIWG members and according to directives of the Commission. The PIWG generally meets no more frequently than monthly, but at least once per quarter. A discussion of the items on the next meeting's agenda usually occurs at the end of each PIWG.

2021 PIWG Activities

The PIWG met four times in 2021. The 2021 PIWG meeting dates and meeting minutes filing dates are shown in Table 16 as follows:

Table 16: 2021 PIWG Meeting Dates and Meeting Minutes Filing Dates

Meeting Date	Filing Date of the Meeting Minutes (See Formal Case No. 766 and PEPPIWG)
Mar. 23	Apr. 12
Jun. 30	Jul. 9
Dec. 7	Dec. 17
Dec. 20	Dec. 20

2.2 PIP

In Order No. 16623 on the 2011 Consolidated Report, the Commission stated the following in paragraph 8: "As a preliminary matter, we note our continuing concern with the reliability of the Pepco electrical distribution system… It is through the prism of these [reliability] efforts that we consider the Pepco Consolidated Report." In accordance with the Commission's focus in Order

The power serving the District's Standard Offer Service customers is now procured through a wholesale procurement process by PEPCO and, as such, productivity improvement is applicable only to transmission and distribution issues. We find the PIWG's definition of a productivity improvement project workable and adopt it here.

No. 16623 and the guidance of the PIWG, the Company presented its PIP projects, with a strong emphasis on reliability.

The 2021 PIP projects were as follows:

- 4 kV Distribution Substation Automation Projects
- 4 kV to 13 kV Conversion Projects
- DA Projects
- Priority Feeder Projects

PIP Project Status

The year-end 2021 status of the PIP Projects is included in Table 17.

Table 17 2021 PIP Projects

Item	Description	2021 Project Totals *(Dollars in Thousands)*		
		Actuals	Budget	Variance Over / (Under) Budget
1	4kV Distribution Substation Automation Projects	730.1	507.7	222.3
2	4kV to 13kV Conversion Projects	8,225.7	16,875.9	(8,650.2)
3	Distribution Automation Projects	7,252.3	4,766.0	2,486.3
4	Priority Feeder Projects	3,684.7	1,832.7	1,852.0

2.3 PIP Project Detail

Detail addressing each of the 2021 PIP projects – including work completed in 2021, work forthcoming in 2022, and longer-term plans – is provided below.

4 kV Distribution Substation Automation Projects

The substation automation work at Macarthur Boulevard Sub 152 and will be completed in Q4 of 2022. The construction at Texas Avenue Sub. 1 1 1 is expected to be completed in the summer of 2022.

4 kV to 13 kV Conversion Projects[37][38]

These projects are included in the Load Growth program.

Background: The 4 kV distribution system supplies load throughout various neighborhoods in the District of Columbia. The 4 kV system has provided an effective and reliable supply to Pepco customers for many years. However, the 13 kV system is capable of supplying a greater density of load and generally produces less electrical losses. Therefore, as load density increases locally, or the system requires more maintenance and replacement becomes the best economic alternative, the 4 kV system is gradually being replaced with a 13 kV distribution system.

Magnitude of the Conversion: There are presently 108.7 megawatts of 4 kV load on the Pepco system, mostly in the District of Columbia. Over the next ten years, approximately 37.0 megawatts (including growth) will be converted to 13 kV service. Allowing for load growth, approximately 72.0 megawatts are projected to remain on the 4 kV distribution system by 2031. This 4 kV load will be located primarily in Wards 3, 7 and 8 where the load is served by substations that have either multiple transformers or are networked together through the feeder primaries. These remaining 4 kV areas are considered reliable due to the shortness of the feeders and the availability of ready backup. Areas that are going to be maintained and not converted will involve upgrading of substantial transformer equipment and other supporting equipment.

Areas Scheduled for Conversion: Areas supplied by the following substations are scheduled to have conversion work performed in the next ten years:

[37] In Order No. 16091 at paragraphs 50, 53, and 64, the Commission stated the following:
50. Decision. We agree with the Staff recommendation and require Pepco to provide justification for any deviations from the plan schedules and annual budgets for 4 kV to 13 kV conversion projects in its Consolidated Reports, excluding minor deviations of less than 5%. This information may be provided in the discussion of "Reliability Projects."
53. Decision. …we have not adopted the Staff's "replace or rebuild" recommendation. However, we agree that future Consolidated Reports should contain detailed schedules and budgets for Reliability Projects, as well as justification for deviations from those schedules and budgets. We shall require Pepco to submit such schedules in future Consolidated Reports.
64. Pepco IS DIRECTED to provide detailed schedules and budgets for conversion projects, as well as justification for any non-minor deviations from these , consistent with Paragraphs 50 and 53 of this Order;
[38] Commission Order No. 16623 states the following:
32. Staff Recommendation: Require Pepco to provide and submit a report as to whether the budgets and schedules for each of the four 4 kV to 13 kV conversion projects have undergone non-minor deviations from previous plans. Include the justification for such deviations.
33. We accept the Staff's recommendation and direct Pepco to include a complete update in the 2012 Consolidated Report, including changes in budgets and schedules and justification for each non-minor deviation.
54. Pepco is DIRECTED to provide a report of conversion projects consistent with paragraph 33;

• Georgetown Sub. 12	NW	Underground conversion.
• North Capitol Sub. 40	NE	Overhead conversion
• Twelfth Street Sub. 126	SW	Underground conversion
• Anacostia Sub. 8	SE	Overhead conversion
• "G" Street Sub. 28	SE	Underground conversion

All of the projects described below are multi-year projects with multiple phases. Four of the five projects were initiated prior to 2015. "G" Street was accelerated to begin work in 2016 to build infrastructure to extend new 13 kV feeders. This was done because significant new loads are expected to materialize in the "G" Street area and the existing 4 kV infrastructure is inadequate to meet this expected new load. Dollars spent on these projects may fluctuate over the years to account for project phasing. The Anacostia conversion work is scheduled to be completed during 2022. The overall budget for the 4 kV conversion projects is still in line with the Company's long-term conversion plan.

Status: In 2021 Pepco spent $8,225,654 on its 4 to 13 kV conversion projects, listed above, $8,650,209 less than the budget of $16,875,863. The deviation between the 2021 budget and actual expenditures is due to a combination of work being delayed by re-design, permitting and work time.

Convert a part of the load at Georgetown Sub. 12 from 4 kV to 13 kV and retire 4 kV Substation

A modernization of this area infrastructure started in 2001. It includes the 4 kV to 13 kV conversions that will ultimately retire the 4 kV radial distribution system supplied from Georgetown Sub. 12. The 4 kV to 13 kV conversion has been completed for the area between M Street to the south, P Street to the north, Wisconsin Avenue to the west and 27th Street, NW to the east, by extending two 13 kV distribution feeders from Georgetown Sub.

In addition, conversions along M Street, Prospect Street, and N Street west of Wisconsin Avenue were completed in 2010 and 2011. Conversions along O and P Streets west of Wisconsin Avenue concluded in 2012.

Existing Configuration: The 4 kV underground radial distribution system serves mostly residential and some small commercial loads. Moderate load growth is anticipated for this isolated area but there are basically no external ties to deliver this power. The existing underground infrastructure, conduit and cable are in need of remediation with a history of extended outages due to limited transfer capability and circuit configuration and conduit construction that limits the size of cable that can be installed and provides limited physical protection to the cables.

The Georgetown 4 kV substation was rebuilt in the 1980s however the 4 kV underground infrastructure is the original construction and is nearing its full capacity.

Proposed Enhancement: Convert all 4 kV load to 13 kV with the exception of Francis Scott Key Bridge which feeds Roosevelt Island where step-down transformers are being considered due to access limitations and the retirement of all 4 kV substation equipment.

Status: With the exception of a few remaining transformers, conversions of the area north of M Street were completed in 2016. Due to the unanticipated non-constructability of the previous plans, all construction was placed on hold and Pepco revised the conversion work and released a new Construction Recommendation Plan in 2020.

The revised plan is a combination of traditional 4kV conversion work, load transfers to neighboring LVAC networks and possible consideration of other solutions. The new designs plan around the "K" Street bridge crossing and the re-supply of load from Feeders 29 and 91 to other substations. Under the current schedule, work to retire the remaining five feeders should be completed by 2024. However, Pepco continues to encounter delays due to the network conversion portion which requires checking customer premises. The 2021 budget was $2,409,734 and approximate spend for 2021 was $686,561.

Georgetown Sub. Conversion Budget:

2022 – 2026 Budget (Figures in Thousands of Dollars)

2022	2023	2024	2025	2026	Total
$3,624	$3,995	$0	$0	$0	$7,619

Convert load at North Capitol Sub. 40 from 4 kV to 13 kV and retire 4 kV Substation

This project related to the extension of existing and new 13 kV feeders to convert all 4 kV load served by North Capitol Street Sub. 40 to 13 kV. The North Capitol Street 4kV system served mostly residential and small commercial customers in the Manor Park, Fort Totten, and Petworth neighborhoods. The first phase of this project converted load from portions of North Capitol Sub. 40 Feeders 482 and 485 along 4th Street, NW between Buchanan and Hamilton Streets, NW to Fort Slocum Sub. 190 - 13kV Feeders 15006, 15012 and 15015 was completed in 2013. 2014 saw the completion of conversions along Hamilton Street, NW, Hawaii Avenue, NE and Fort Totten Drive, NE. In 2015, conversions were completed along North Capitol Street and Rock Creek Church Road.

Existing Configuration: The North Capitol Sub. 40 4 kV system was an isolated area on the Pepco distribution system that was not connected to any other 4kV substations or systems. Recent substation inspections revealed deteriorating circuit breakers. The Allis Chalmers switchgear necessitated the salvage of spare parts from like equipment because the original equipment manufacturer is no longer in business and other manufacturers no longer supply parts for this equipment.

Proposed Configuration: Convert all 4 kV loads to 13 kV distribution feeders and retire North Capitol Sub. 40 - 4 kV.

Status: As of the end of 2021, several 13 kV trunk extensions have been completed and approximately 11.0 MVA of the 4 kV load has been converted to 13 kV. In 2017, two new 13 kV feeders were extended from Fort Slocum Sub. 190 to facilitate conversions in the area bounded by Kansas Avenue, NW, New Hampshire Avenue, NW, 4th Street, NW, and Missouri Avenue, NW. The budget for 2021 was $697,250. Approximately $2,813,022 was spent in 2021.

North Capitol Sub. Conversion Budget:

2022 – 2026 Budget (Figures in Thousands of Dollars)

2022	2023	2024	2025	2026	Total
$0	$0	$0	$0	$0	$0

Convert load at 12th Street Sub. 126 from 4 kV to 13 kV and retire 4 kV Substation

This project will extend two 13 kV feeders in order to convert and/or transfer all 4 kV load supplied by 12th Street Sub. 126.

The 12th Street 4 kV system serves residential and small commercial customers in Southwest area and National Park Service buildings, streetlights and traffic signals in the National Mall area. The conversion and retirement of the 12th Street Sub. 126 will be done in two phases. Phase 1 will construct an 8-way conduit bank from 2nd and C street SW to the vicinity of 7th and Maryland Avenue SW. It will involve the construction of approximately 1 mile of 8-way conduit bank. Phase 2 will involve extending Feeders 15294 and 15295 to two new three-way switches. Loops will then be extended from the switches to supply load around the National Mall and Southwest Waterfront. The last phase will require extending Feeders 15294 and 15295 to two new 3-way switches and extending laterals to the area of Hains Point, the Tidal Basin, and the 14th Street Bridge.

Existing Configuration: The 12th Street Sub. 126 contains oil circuit breakers that will be removed based on the review of condition and reliability. One of the 13 kV/4 kV transformers is identified as in need of eventual replacement. These oil circuit breakers are no longer manufactured, and the manufacturer no longer provides spare parts. As part of the conversion process, this substation will be retired.

Proposed Configuration: Convert all 4 kV loads to 13 kV distribution feeders and retire Twelfth Street Sub. 126 – 4 kV including the transformers and oil circuit breakers.

These projects are included in the Load Growth program.

Status: Project completion date has moved from 2021 due to engineering & construction being on hold due to Project Management, Engineering and Design resource availability & turnover, rescoping & rebidding of remaining designs and permitting delays. Construction has resumed in February 2022. All remaining designs are to be completed in April 2022 and construction completed by the end of 2022. The budget for 2021 was $3,091,579. Approximately $872,010 was spent in 2021.

12th Street Sub. Conversion Budget:

2022 – 2026 Budget (Figures in Thousands of Dollars)

2022	2023	2024	2025	2026	Total
$2,166	$0	$0	$0	$0	$2,166

Convert Load at Anacostia Sub. 8 from 4 kV to 13 kV and Retire 4 kV Substation

The project relates to the extension of 13 kV feeders from Alabama Avenue Sub. 136 in order to convert all 4 kV load from Anacostia Sub. 8 4 kV and retire the Anacostia Sub. 8 – 4 kV substation.

The Anacostia Sub. 8 4 kV system supplies residential and small commercial load in the Anacostia area of Southeast Washington, D.C. New and existing 13 kV overhead feeders from Alabama Avenue Sub. 136 will be extended in order to convert all 4 kV load.

Existing Configuration: Anacostia Sub. 8 is supplied by two 34 kV feeders from Buzzard Point Station B. Converting 4 kV load from Anacostia Sub. 8 will also relieve load from Buzzard Point Station B 13 kV substation, which is approaching its firm capacity. Review of the equipment at Anacostia Substation and the 34 kV supplies indicated the need to replace all this equipment for long term reliability. Instead of rebuilding this station, conversion of the 4 kV load and transfer of the 13 kV load to Alabama Avenue Substation will allow the retirement of both the substation and supplies and improve the overall reliability of the distribution system in this area.

Proposed Configuration: Convert all 4 kV loads to 13 kV distribution feeders and retire Anacostia Sub. 8 – 4 kV.

Status: Much of the Anacostia Sub. 8 4 kV load has been converted over the past several years as part of the 23rd Street and Anacostia 4 kV conversion projects. Construction for the Anacostia 4 kV conversion project began in 2012 and about 2.4 MVA load has been converted to 13 kV. The 2021 budget for this project was $700,420 and $187,639 was spent in 2021. The work to convert the remaining 0.9 MVA to Feeders 15173 and 15178 is scheduled to be completed in 2022. Anacostia substation will be retired after all Alabama Avenue substation and distribution work has been completed. New feeders were recommended to transfer/covert all load currently supplied from the Anacostia substation to Alabama Avenue Sub. 136. All work is scheduled to be completed by the end of 2022.

Anacostia Sub. Conversion Budget:

2022 – 2026 Budget (Figures in Thousands of Dollars)

2022	2023	2024	2025	2026	Total
$248	$0	$0	$0	$0	$248

Convert load at “G” Street Sub. 28 from 4 kV to 13 kV and retire 4 kV Substation

This project relates to an extension of existing and new 13 kV feeders to convert all 4 kV load served by “G” Street Sub. 28 to 13 kV.

The “G” Street 4kV system serves mostly residential and small commercial customers in the Capitol Hill, Barney’s Circle and Navy Yard neighborhoods. The first phase of this project to convert load from portions of “G” Street Sub. 28 feeders 212, 223, 227 & 228 Street, supplying load east of 11th Street SE and south of Pennsylvania Avenue SE to new Southwest Sub. 18 – 13kV Feeders 15876 and 15877, which has been designed and released to construction and will be extended to make the first phase conversions. The next phases will consist of extending a third 13 kV feeder from Southwest Sub. 18 along with the initial two feeders to convert portion of “G” Street 4kV load north of Pennsylvania Avenue SE and South of Massachusetts Avenue SE. The remaining 4 kV load north of Massachusetts Avenue SE will be converted to Benning Sub. 7 feeders 14708 and 14152.

Existing Configuration: G Street Sub. 28, was built in 1965 and is an isolated 4kV system not connected to any other 4kV substation. The area is experiencing moderate load growth and the existing 4kV system cannot accommodate any large new business load. Furthermore, some of the 4kV Feeders have had voltage problems, and the existing conduit and cables are very old.

Therefore, an upgrade of this system is underway to eliminate potential reliability concerns proactively.

Status: Project scope and estimate was reassessed in early 2019. The project was handed over to Project Management for execution. It is currently in design. Construction anticipated to begin in late 2022. The 2021 budget for this project was $9,976,881 and approximately $2,197,379 was spent in 2021.

G Street Sub. Conversion Budget:

2022– 2026 Budget (Figures in Thousands of Dollars)

2022	2023	2024	2025	2026	Total
$12,362	$13,222	$13,214	$14,314	$17,599	$70,711

2.4 DA PROJECTS

Distribution Automation is the conversion of a manually operated distribution system with limited available status information and limited control to a system that not only is fully automated but also performs operations totally independent of any human intervention. Advancements in technologies have made these automation activities practical for the lower voltage systems and will significantly change the way the Company responds to outages and operates and restores the electric system.

Status: Refer to section 1.13 (Technology: Monitoring, Automation, and Information System) above for the status of the completed DA Projects. There were 36 feeders activated in ASR in 2021. The table below lists the feeders that were deployed in 2021. This set of feeders will primarily benefit customers in Ward 8.

Table 18: ASR Feeders Activated in 2021 with their Historical Lockout Statistics

#	Substation	Feeder Number
1	Alabama Ave	15166
2	Alabama Ave	15172
3	Alabama Ave	15174
4	Alabama Ave	15175
5	Alabama Ave	15176
6	Alabama Ave	15177
7	St Barnabas 59	15082
8	St Barnabas 59	15083
9	St Barnabas 59	15084
10	St Barnabas 59	15085
11	St Barnabas 59	15087
12	St Barnabas 59	15089
13	St Barnabas 59	15091
14	Beech road 159	14251
15	Beech road 159	14252
16	Beech road 159	14253
17	Beech road 159	14255
18	Beech road 159	14256
19	Beech road 159	14257
20	Beech road 159	14258
21	Beech road 159	14259
22	Beech road 159	14260
23	Beech road 159	14261
24	Green Meadows	14291
25	Green Meadows	14292
26	Green Meadows	14293
27	Green Meadows	14294
28	Green Meadows	14295
29	Green Meadows	14298
30	Bladensburg	15094
31	Bladensburg	15096
32	Bladensburg	15097
33	Van Ness	14145
34	Van Ness	14146
35	Little Falls	14766
36	Little Falls	14769

2.5 PRIORITY FEEDER PROJECTS

These projects are included in the Feeder Improvement program.

Status: In response to the Commission's focus on preventing repeat Priority Feeders, Pepco has adjusted its feeder remediation strategy to a more comprehensive approach. Instead of focusing on locations where previous failures have occurred, the entire feeder is reviewed to address potential locations for future failures. The 2021 budget for the Priority Feeder projects was $1,832,735 and $3,684,726 was spent in 2021.

– PERFORMANCE[39]

Priority Feeders & Aggressive Initiatives

Feeder Performance and Aggressive Initiatives

Feeder Performance

[39] Order No. 16975 states the following at paragraphs 58 and 59, 60, and 105:
58. Decision: …We therefore require Pepco to provide in the 2013 Consolidated Report, the information recommended by the Staff including an explanation of any discrepancies between work planned and work completed…. In Order No. 15941, the Commission required Pepco to provide specific information regarding any 4 kV feeder that has appeared on the Priority Feeder List three times or any 13 kV feeder that has appeared on the Priority Feeder List four times. On June 13, 2012, Pepco filed a report pursuant to that Order, providing information on two 13 kV feeders, 14717 and 14768. The Commission believes it is necessary to expand the scope of Pepco's reporting on feeder improvement to include any feeder that has appeared on the priority feeder list more than twice. Therefore, we require Pepco to provide the information required in paragraph 13 of Order No. 15941 in the future Consolidated Reports for any feeder appearing more than twice on the Priority Feeder List….
59. In future Consolidated Reports, Pepco shall include the following information about each feeder on the Priority Feeder List:
(1) a detailed description of outages, including causes and corrective actions taken;
(2) the SAIDI, SAIFI, number of interruptions, and number of hours of customer interruptions for that feeder for each year beginning with the year the feeder first appeared on the Priority Feeder list;
(3) a map showing the feeder service area, including affected neighborhoods;
(4) an analysis of why past corrective actions failed;
(5) Pepco's proposed solution to the feeder's reliability problem, including an explanation of options considered with the cost/benefit analysis of each and justification for the option recommended;
(6) a cost/benefit analysis of the solution, including budget and cash flows by year, as well as any impact on the revenue requirement; and
(7) a detailed justification for its aggressive feeder remediation measure of replacing open wire secondary with triplex secondary conductor.
60. The Commission notes that in recent PIWG meetings, Pepco has indicated its intention to change the methodology which it uses to determine Priority Feeders. A change in methodology would diminish the value of the Priority Feeder List in determining historically poorly performing feeders and would lessen our ability to track and compare the historical data. Therefore, we require Pepco to provide two Priority Feeder Lists, using both the historical (CPI) and any new methodologies in the 2013, 2014 and 2015 Consolidated Reports. In addition, the Commission requires Pepco to provide the information required by paragraph 13 of Order No. 15941 for any feeder appearing more than twice on the Priority Feeder List using either the historical or any new method.
105.Pepco is DIRECTED to provide information on Priority Feeders consistent with paragraphs 58-60 herein;

Each year Pepco analyzes the performance of its feeders to determine the relative ranking of each feeder from the best to the least reliable. From this ranking, Pepco selects the least reliable two percent (2%) of its feeders (excluding the selected feeders from the prior year study) to analyze and identify actions which likely will improve the reliability of the feeders, and therefore the system.

Beginning in 2013, the Company began using the SPC (System Performance Contribution), a method that provides greater system performance improvement potential. The SPC value for each feeder is calculated using the following equation:

SPC = 75% x (Feeder CI / System CI) + 25% x (Feeder CMI / System CMI),

Where

Feeder CI = Customer Interruptions of the feeder System CI = Customer Interruptions of the total system
Feeder CMI = Customer Minutes of Interruption of the feeder System CMI = Customer Minutes of Interruption of the total system.

In addition, when selecting the annual priority feeders, the selections are made based on the combination of the following criteria:

1) Feeders blended performance ranking by SPC values (i.e., individual feeder contribution to system SAIFI and SAIDI);
2) Feeders that are not repeated from the year prior;
3) Feeders with a minimum SAIFI value of 2.00; and
4) Feeders experienced at least 10 outage occurrences in the evaluation period.

Additional analysis at the feeder level is conducted to ensure the proper feeders are selected and corrective actions are reasonable (e.g., excluding feeders with abnormal configuration at the time of the outage occurrence, when outage causes were remediated during initial outage restoration work, etc.).

Excluded from this annual study are the Priority Feeders from the prior year, which typically would not show the full results of corrective actions until a full year following the completion of the corrective actions.

As of December 2021, there are 765 feeders (4 kV and 13 kV) in the District of Columbia. Sixteen feeders represent 2% of the 765-feeder total. The sixteen 2021 Priority Feeders, along with customers served, are provided in Section 2.5, and each includes a narrative outlining the initial measures necessary to improve performance. Additional corrective actions may result from continuing analysis of the outage data and detailed engineering. These feeders originate from seven different substations.

Attachment C contains maps of the 2022 Priority Feeders. The priority feeder program will be an enhanced initiative including both reliability work routinely performed on the selection of priority feeders supplemented with more aggressive initiatives.

Cost/Benefit Discussion

Order No. 16975 requires that Pepco provide the following in this and future Consolidated Reports (paragraph 59, item 6):

(6) a cost/benefit analysis of the solution, including budget and cash flows by year 44, as well as any impact on the revenue requirement;

As described in previous ACRs, the measurement of benefits associated with feeder reliability projects generally depends on the outage history of the feeder and the likelihood that a portfolio of remediation activities will reduce or eliminate similar outages for the same or similar cause. Simply allocating a portion of the previous customer interruptions or customer minutes of interruption prior to the remediation activity is a way of qualifying the relative cost / benefit of individual remedial efforts. This is, however, not a dependable method of forecasting future feeder or aggregate system reliability because no remediation tactic is all inclusive of every possible outage cause. Likewise, this approach assumes all other inputs to system reliability are held constant (same weather, same animal events, same tree faults, etc.), which is unlikely.

Similarly, the measure and inclusion of cost/benefit per feeder or per individual initiative would potentially serve to reduce the field of options available to apply in feeder performance improvement. Some activities are not as efficient or economical as others based on a simple mathematical evaluation. However, the potential exclusion of these activities based on their relative inefficiency at the feeder or activity level would mean that the best overall portfolio of remedies could not be utilized in system level improvement. Further, with the advances in sectionalization technology, standard cost benefit analyses could drive a utility to employ only mitigation efforts rather than more appropriate but potentially more costly fault elimination tactics. Pepco evaluates each of these options and implements mitigation as well as elimination techniques when evaluating work to improve reliability of a feeder.

2.6 Aggressive Initiatives[40]

The Priority Feeder program is an enhanced initiative including both reliability work routinely performed on the selection of priority feeders supplemented with more aggressive initiatives.

Aggressive initiatives may include the following:

- Installation of tree wire in close configuration construction to replace bare wire through heavily treed areas where aggressive tree trim and standard cross-arm construction would have limited success or is restricted by ordinance or property owners.
- Installation of PAC for use as the main trunk of the feeder with the existing mainline reconfigured as fused laterals.
- Installation of automatic circuit reclosers (ACR) in loop scheme configuration to automatically sectionalize faulted sections of the feeder and provide automatic backup to unfaulted sections.
- Installation of remote operated load break switches into the loop scheme configuration with the automatic circuit reclosers.

Pepco's proposed aggressive initiatives to its underground distribution feeders are:

4 kV System

In addition to performing Very Low Frequency (VLF) testing and manhole inspections, the process of correcting identified issues also includes the following:

- Installation of tap-holes (switch points) at key locations to improve the ability to isolate problems as well as improving the ability to restore customers following each event.

- Perform a review of the failure history of the area for each failure and comparison of failure locations to replacement history. Perform proactive cable replacement of stretches that

[40] In Order No. 15152 paragraph 73, the Commission ordered the following:
73. Pepco is DIRECTED to investigate the viability of the "aggressive" initiatives for all least performing feeders, to file a progress report regarding the implementation of these initiatives where viable as part of the 2009 Consolidated Report, and to file quarterly progress reports thereafter, consistent with paragraph 62 of this Order;

In Order No. 15809 paragraph 11, the Commission ordered the following:
11. Pepco IS DIRECTED to include in its 2011 Consolidated Report a plan for development and application of "aggressive initiatives" to its underground distribution feeders;

were not previously replaced in the area.

Regarding Commission's recommendation (per Order No. 16975) to add switch points to 4kV feeders, over time these 4kV feeders will be converted to 13kV, in which the loop alternate feed design is inherent. In the interim, all of the 4kV systems have backup supply for trunk outages. And for lateral outages, Pepco is replacing cable, installing tap holes, and ultimately converting all current underground 4kV feeders to 13kV feeders.

13 kV System

In addition to performing VLF testing and manhole inspection, correcting identified issues include the following:

- Perform a review of the failure history of the area for each failure and compare failure locations to replacement history. Perform proactive cable replacement of stretches that were not previously replaced in the area.
- Replace all of the problem sections of cable.

For various reasons, not all of the "Aggressive Initiatives" are applied to each of the Priority Feeders. For example, if a particular feeder is completely underground, installing tree wire, PAC, ACR and remote operated load-break switches would not be applicable as these types of equipment are not used on underground feeders. Similarly, if a feeder is already equipped with remote switching capabilities and the switches are functioning properly, then simply increasing the number of remotely operated switches will generally not yield improvement. Further, if the predominant outage cause for a feeder is not tree-related, installing tree wire along the previous outage locations, will not yield performance improvement.

Order No. 16975 states the following at paragraph 58:

58. …In addition to the information required by paragraph 13 of Order No. 15941, the Commission also requires that Pepco provide detailed justification for its aggressive feeder remediation measure of replacing open wire secondary with triplex secondary conductor, as recommended by the OPC response.

The following is Pepco's explanation for replacing open wire secondary conductors with triplex conductors:

Triplex conductors are less susceptible to mechanical damage such as trees, winds, etc. They increase the distance between the primary and neutral conductors, which reduces the opportunity for primary related tree outages. Other miscellaneous upgrades will also be performed such as pole, hardwire, and equipment replacements due to deterioration. Upgrading will significantly reduce future equipment failures. Should damage occur, restoration is faster with the triplex conductors. Therefore, customers will experience lower number of outages as well as a shorter duration of outages. The cost to replace open wire secondary conductors with triplex conductors is approximately $40,000 per mile

2021 PRIORITY FEEDER PROGRAM

Order No. 16975 requires that Pepco provide the following in this and future Consolidated Reports (paragraph 59, item 1):

(1) a detailed description of outages, including causes and corrective actions taken:

2021 Priority Feeder Program - District of Columbia - Corrective Actions Proposed vs. Completed				
Rank	**Feeder**	**Proposed Corrective Actions, as filed in the 2021 Consolidated Report**	**Detailed Corrective Actions - Completed**	**Explanation of Variances/Comments**
	15709	- Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	- Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	N/A
	14712	- No mainline work proposed under the 2021 Priority Feeder Program (UG Feeder)	- No Work	N/A
	14022	- Install/Replace 5,100' of Primary Wire - Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	- Install/Replace 5,100' of Primary Wire - Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	N/A
	14758	- Install/Replace 2,100' of Primary Wire - Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	- Install/Replace 2,100' of Primary Wire - Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	N/A
	15010	- Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	- Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	Work on-going. To be completed December 2022
	14900	- Install/Replace 825' of Primary Wire - Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	- Install/Replace 825' of Primary Wire - Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	N/A
	15197	- Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	- Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	N/A
	15001	- Install/Replace 2,300' of Primary Wire - Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	- Install/Replace 2,300' of Primary Wire - Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	Work on-going. To be completed December 2022
	14023	- Install/Replace 1,500' of Primary Wire - Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	- Install/Replace 1,500' of Primary Wire - Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	Work on-going. To be completed September 2022
	15013	- Install/Replace 2,900' of Primary Wire - Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	- Install/Replace 2,900' of Primary Wire - Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	N/A
	14150	- Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	- Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	N/A
	00372	- Due to work performed on this feeder under the 2020 Comprehensive Feeder Program, no work is planned on this feeder under the 2021 Priority Feeder Program	- No Work	N/A
	15166	- Install/Replace 1,300' of Primary Wire - Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	- Install/Replace 1,300' of Primary Wire - Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	N/A
	14766	- Install/Replace 550' of Primary Wire - Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	- Install/Replace 550' of Primary Wire - Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	N/A
	14005	- Install/Replace 4,700' of Primary Wire - Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	- Install/Replace 4,700' of Primary Wire - Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	N/A
	14133	- Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	- Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.	N/A

Proposed Corrective Actions for 2022 Priority Feeders[41]

The following information provides an overview of the outages and proposed corrective actions for the 2022 Priority Feeders and detailed information regarding the equipment related events and/or outages. Please see Attachment C for maps of the 2022 Priority Feeders reflecting overhead and underground portions, and the Priority Feeders by District of Columbia Ward.

Pepco's OMS assigns event numbers based on length of time between interruptions. Therefore, during the trouble locating and restoration process, more than one event number may be generated and counted. For the sections that explain equipment failures, for mainline feeders, line fuses and transformers, the events were grouped by incidents.

2022 Priority Feeders

The following 16 feeders have been identified as priority feeders. Please note that some feeders, as stated below, will not have work performed in 2022 under the Priority Feeder program; rather, as specified below, some feeders had corrective work performed coincident with the outage(s) that caused the feeder to be a priority feeder or whose work is subsumed in another reliability program.

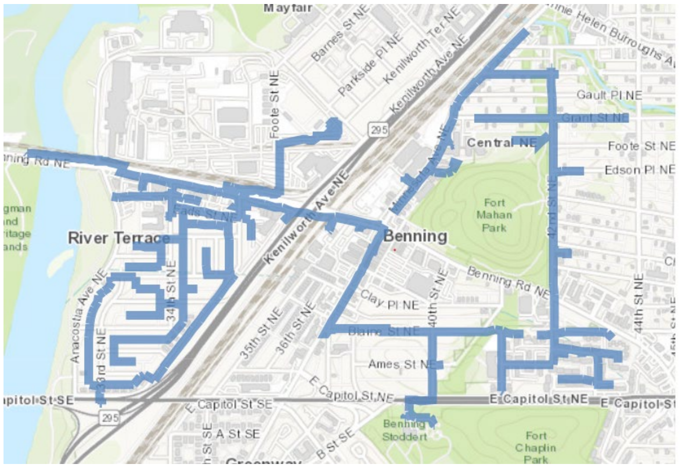
Please note that, in a change from previous years' reports, Pepco is now budgeting for the entire class of priority feeders rather than for each feeder. The 2022 budget for priority feeders is $2,285,462.[42]

Circuit: 15710

Feeder 15710				Oct.2020-Sept.2021 Reliability Indices (In Hours)			Feeder Miles			
County	Substation	Customers Served	Number of Outages	SAIFI	SAIDI	CAIDI	OH	UG	TOTAL	Repeated Last 2 Years?
DC	Benning a23013 7	2229	24	4.361	257.9	59.1	80%	20%	8.01	Y

[41] Actual equipment failures may be more or less than the number shown because a single event may give rise to more than one equipment failure and due to OMS limitations, that do not allow a single unique case to be identified in each line.
[42] The budget can be adjusted according to the needs of the program.

Feeder Map and Location:



Outage Data Summary (Past 3 years):

2019: (Oct 18-Sep 19) Ninety-eight percent (98%) of customer outages were due to 3 mainline outage events; 2 events were caused by Motor Vehicle, and 1 event was caused by Unknown. Zero customer outages occurred due to lateral events this year.

2020: (Oct 19-Sep 20) Eighty-four percent (84%) of customer outages were due to 1 mainline outage event; the event was caused by Animal/Bird. Zero customer outages occurred due to lateral events this year.

2021: (Oct 20-Sep 21) Ninety-seven percent (97%) of customer outages were due to 10 mainline outage events; 4 events were caused by Equipment Failure, 5 events were caused by Foreign Contact, and 1 event was caused by Tree ROW – Limb. One percent (1%) of customer outages were due to 2 lateral events; 1 event was caused by Foreign Contact, and 1 event was caused by Tree ROW – Limb.

Feeder Performance (Oct 20-Sep 21)

Outage Cause by SAIFI	SAIFI	% of Feeder
Equipment Failure	2.237	51%
Foreign Contact	1.480	34%
Tree ROW - Limb	0.626	14%
Animal/Squirrel	0.009	<1%
Animal/Bird	0.009	<1%

Outage Cause by SAIFI	SAIFI	% of Feeder
Unknown	0.000	<1%

Field Observations:

Feeder 15710 serves approximately 2,229 customers in the NE Benning area of Washington D.C. The feeder is a mix of commercial and residential services and is 80% overhead and 20% underground. The mainline portion of the feeder runs underground from the Benning Substation onto Benning Rd NE, where it transitions to overhead and proceeds to east southeast along Benning Rd NE. After the feeder crosses the railroad tracks it switches back to underground before Minnesota Ave NE. Once the feeder reaches Blaine St NE, it turns to the east. After a short distance on Blaine St NE, the circuit switches back to overhead and continues. An overhead lateral goes south at 40th St NE feeding residential areas. The mainline turns north onto 42nd St NE with several laterals coming off. The feeder continues north until Hayes St NE where it goes east then southeast at Minnesota Ave. A short lateral also travels north from there. The feeder continues and ends at the intersection of Minnesota Ave NE and Benning Rd NE.

Previous Actions Taken (Past 3 years):

No work performed within the last 3 years.

Planned Remediation (Current Year):

- Create WOs to address Animal issues at equipment locations

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

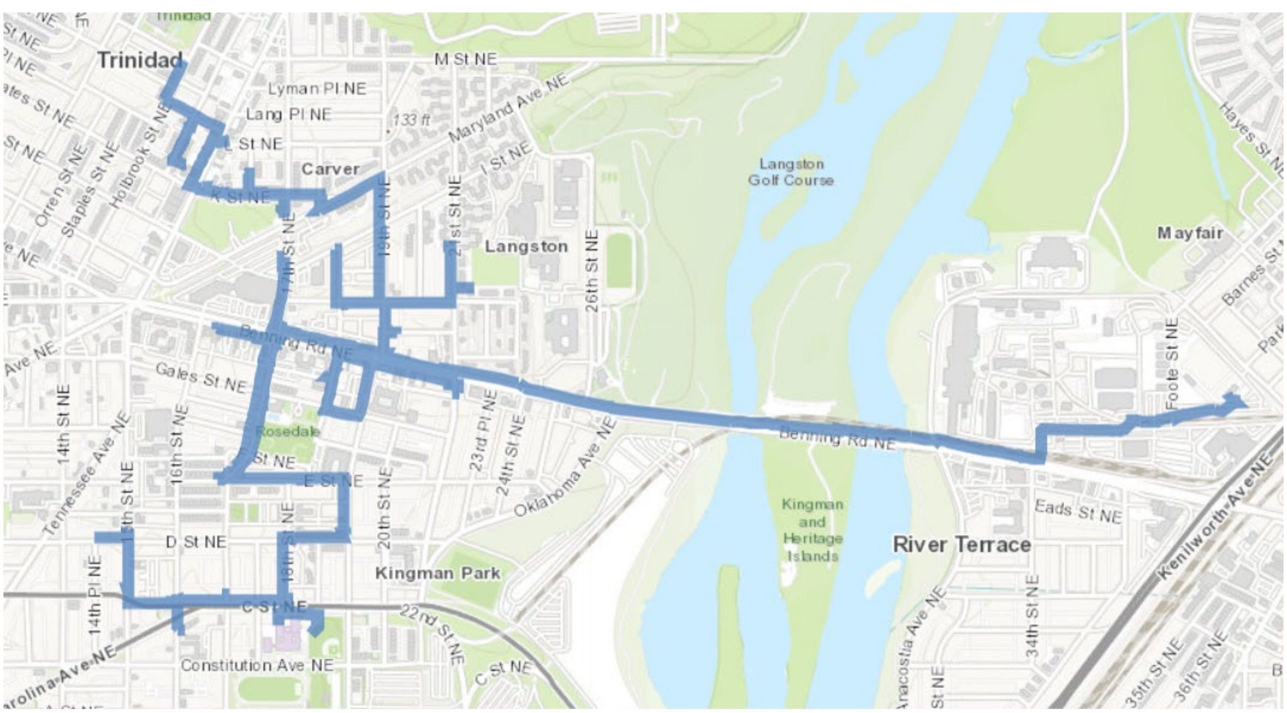
Anticipated Benefits:

The work on this feeder to address animal/BIL deficiencies will help to improve the resiliency of the feeder, thereby supplying a more reliable service to customers served by this feeder.

Circuit: 14713

County	Substation	Customers Served	Number of Outages	Oct. 2020-Sept. 2021 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Benning (7)	2,123	24	3.387	419.8	123.9	0%	100%	6.72	N

Feeder Map and Location:



Outage Data Summary (Past 3 years):

2019: (Oct 18-Sep 19) One hundred percent (100%) of customer outages were due to 3 mainline events; 3 events were caused by Equipment Failure. Zero customer outages occurred due to lateral events this year.

2020: (Oct 19-Sep 20) Ninety-one percent (91%) of customer outages were due to 4 mainline events; 4 events were caused by Unknown. Nine percent (9%) of customer outages were due to 2 lateral events; 1 event was caused by Animal/Bird, and 1 event was caused by Cable Cut – Unknown.

2021: (Oct 20-Sep 21) Eighty-three (83%) of customer outages were due to 9 mainline events; 6 events were caused by Equipment Failure, and 3 events were caused by Unknown. Sixteen percent (16%) of customer outages were due to 4 lateral events; 4 events were caused by Equipment Failure.

Feeder Performance (Oct 20-Sep 21)

Outage Cause by SAIFI	SAIFI	% of Feeder
Equipment Failure	3.267	96%
Unknown	0.118	3%
Cable Cut - Billable	0.002	<1%

Field Observations:

Feeder 14713 serves approximately 2,123 customers in NE Washington, DC. This feeder is 100% underground construction and feeds both residential and commercial customers. The feeder goes west on Benning Rd NE and after crossing the bridge over the Anacostia River on Benning Rd NE, this circuit feeds many residential neighborhoods and commercial businesses to the north and south of Benning Rd NE, with its westernmost boundaries being Holbrook St NE and 14th Pl NE.

Previous Actions Taken (Past 3 years):

No work performed within the last 3 years.

Planned Remediation (Current Year):

- This feeder will be investigated through underground inspection programs separate from the priority feeder projects to determine the appropriate improvement measures are taken on this circuit.

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

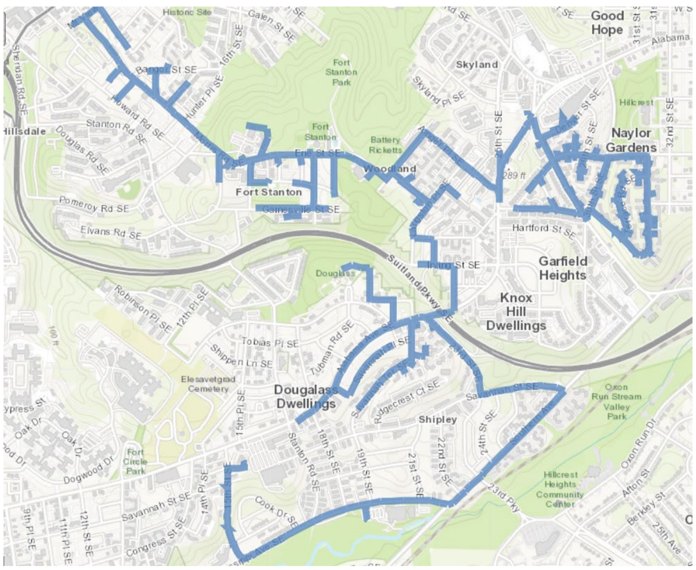
Anticipated Benefits:

Further investigation into the conditions on this feeder that can be optimized to improve customer reliability will reduce outages and feeder resiliency.

Circuit: 15173

County	Substation	Customers Served	Number of Outages	Oct. 2020-Sept. 2021 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Alabama Ave (136)	2,019	17	2.973	92.5	31.1	69%	31%	11.85	N

<u>Feeder Map and Location:</u>



<u>Outage Data Summary (Past 3 years)</u>:

2019: (Oct 18-Sep 19) One hundred percent (100%) of customer outages were due to 1 lateral events; 1 event was caused by Tree Row – Down. Zero customer outages occurred due to mainline events this year.

2020: (Oct 19-Sep 20) Zero customer outages occurred due to mainline or lateral events.

2021: (Oct 20-Sep 21) Ninety-eight percent (98%) of customer outages were due to 9 mainline events; 4 events were caused by Animal/Bird, 2 events were caused by Equipment Failure, 1 event was caused by Tree Outside ROW – Down, and 2 events were caused by Tree Row – Down. One percent (1%) of customer outages were due to 2 lateral events; 2 events were caused by Tree Outside ROW – Down.

Feeder Performance (Oct 20-Sep 21)

Outage Cause by SAIFI	SAIFI	% of Feeder
Equipment Failure	0.975	33%
Animal/Bird	0.973	32%
Tree Row - Down	0.969	32%
Tree Outside ROW - Down	0.027	1%
Animal/Other	0.021	1%
Animal/Squirrel	0.008	<1%
Load	0.000	<1%
Unknown	0.000	<1%

Field Observations:

Feeder 15173 serves approximately 2,019 customers in the Naylor Gardens and Garfield Heights neighborhoods in SE Washington D.C. The mainline portion of this feeder comes out of the substation on 15th St SE and goes south as underground until just after it turns northeast onto Mississippi Ave SE where it becomes overhead. The mainline continues until Southern Ave SE where it continues to go northeast. The line then continues into the cul-de-sac on Savannah St SE to continue west until it turns north onto 23rd St SE. 23rd St SE continues on a curve that takes it to a northwest direction. A lateral goes west at the intersection of Alabama Ave SE while the mainline continues east then north onto 24th St SE. The circuit continues going north by turning west onto Irving St SE then onto 23rd ST SE, onto Hartford St SE, then north on Langston Pl SE. The line continues and turns onto Raynolds Pl SE and another split continuing onward moving to Alabama Ave SE where it continues to move through the Naylor Gardens neighborhood.

Previous Actions Taken (Past 3 years):

No work performed within the last 3 years.

Planned Remediation (Current Year):

- Address guying at pole locations where current equipment has been identified in deteriorated condition.

- Set four new poles throughout the circuit where the feeder transitions from overhead to underground, relocating one of the UG feeds to the new poles, greatly reducing chances of outages on the full UG loop that result from the riser pole.

Milestones/Schedule:

Work on this feeder will require approximately 3 months to be completed.

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

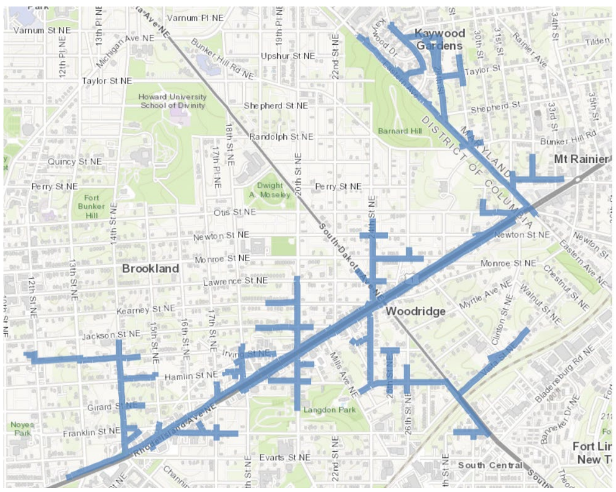
Anticipated Benefits:

The miscellaneous maintenance items to be addressed on this feeder will provide continued safety and security of Pepco's facilities on the overhead portion of this circuit. Additionally, the relocation of overhead to underground transition points to new poles will result in the lessened probability of outages throughout an entire URD loop. Therefore, customers will be served by more reliable feeds with mitigated risk of issues at a pole causing widespread disturbances on the underground portions of the feeder.

Circuit: 14014

County	Substation	Customers Served	Number of Outages	Oct. 2020-Sept. 2021 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	12th Irving (133)	2,074	24	1.868	89.5	47.9	91%	9%	9.84	N

<u>Feeder Map and Location:</u>



<u>Outage Data Summary (Past 3 years)</u>:

2019: (Oct 18-Sep 19) Ninety-nine percent (98%) of customer outages were due to 1 mainline event; 1 event was caused by Load. Zero customer outages occurred due to lateral events.

2020: (Oct 19-Sep 20) Eighty-four percent (84%) of customer outages were due to 5 lateral events; 1 event was caused by Animal/Other, 1 event was caused by Employee, 2 events were caused by Unknown, and 1 event was caused by Weather / Lightning. Zero customer outages occurred due to mainline events.

2021: (Oct 20-Sep 21) Eighty-six percent (86%) of customer outages were due to 5 mainline events; 1 event was caused by Equipment Failure, 1 event was caused by Foreign Contact, 1 event was caused by Unknown, and 2 events were caused by Weather / Wind. Twelve percent (12%) of customer outages were due to 5 lateral events; 1 event was caused by Animal/Squirrel, 1 event was caused by Equipment Failure, 2 events were caused by Foreign Contact, and 1 event was caused by Unknown.

Outage Cause by SAIFI	SAIFI	% of Feeder
Unknown	1.040	55%
Equipment Failure	0.402	22%
Foreign Contact	0.310	17%
Animal/Squirrel	0.077	4%
Weather / Wind	0.024	1%
Tree Row - Down	0.008	<1%
Tree ROW - Limb	0.007	<1%

Field Observations:

Feeder 14014 serves approximately 2,074 customers in NE Washington D.C. The feeder comes out onto Irving St NE east until 14th St NE then heads south until it intersects with Rhode Island Ave NE, heading to the northeast. The circuit keeps this path until it reaches Eastern Ave NE where it travels northwest until the feeder ends at an open recloser. The laterals along this main line are fused well but there are a handful of items that can be installed/replaced to improve reliability.

Previous Actions Taken (Past 3 years):

2018 ACR FDR 14014/14297- 12KA N.O. ACR

- Install 12KA NO ACR

Planned Remediation (Current Year):

- Create WO to address Animal issue at twenty-two (22) equipment locations
- Replace lightning arrestors at three (3) locations
- Install fuse for lateral tap at 810401-380650
- Replace guying at one (1) location
- Reconductor ~2,416’ of existing #2 Copper wire with 477 ACSR Treewire
    - Between 809402-350240 & 807403-620940 on Eastern Ave NE

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

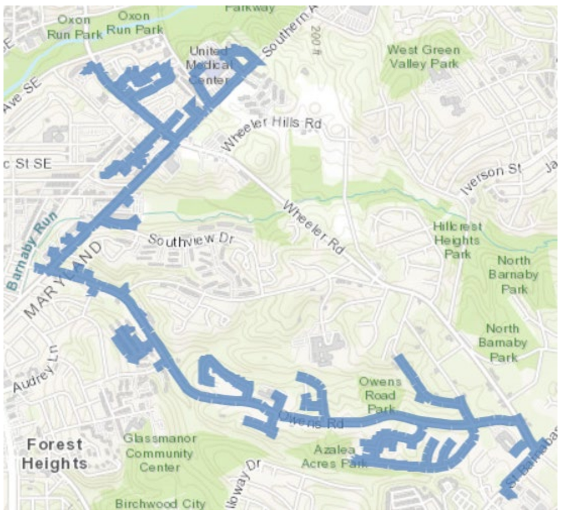
Anticipated Benefits:

The work on this feeder to address animal/BIL deficiencies and other miscellaneous maintenance items will help to improve the resiliency of the feeder, thereby supplying a more reliable service to customers served by this feeder. The reconductoring effort along Eastern Ave NE will increase the reliability of the feeder by installing a conductor that can perform more robustly to accommodate current load and growing needs for the future.

Circuit: 15085

County	Substation	Customers Served	Number of Outages	Oct. 2019-Sept. 2020 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	St. Barnabas (59)	1,588	11	1.438	435.0	302.5	63%	37%	11.49	N

Feeder Map and Location:



2019: (Oct 18-Sep 19) One hundred percent (100%) of customer outages events were due to 4 lateral events; 1 event was caused by Animal/Squirrel, 2 events were caused by Equipment Failure, and 1 event was caused by Weather / Lightning. Zero customer outages occurred due to mainline events this year.

2020: (Oct 19-Sep 20) Ninety-eight percent (98%) of customer outages were due to 2 mainline events. 1 event was caused by Motor Vehicle, and 1 event was caused by Weather / Lightning. One percent (1%) of customer outages were due to 1 lateral event; 1 event was caused by Unknown.

2021: (Oct 20-Sep 21) One hundred percent (100%) of customer outages events were due to 6 mainline events; 6 events were caused by Motor Vehicle. Zero customer outages occurred due to lateral events this year.

Feeder Performance (Oct 20-Sep 21)

Outage Cause by SAIFI	SAIFI	% of Feeder
Motor Vehicle	1.436	99%
Equipment Failure	0.001	<1%
Tree Row - Down	0.001	<1%

Feeder 15085 serves approximately 1,588 customers in the Glassmanor and Washington Highlands neighborhoods in Oxon Hill, MD and SE Washington D.C. The mainline portion of the feeder originates out of the St. Barnabas Substation. The feed travels along Saint Barnabas Rd, Wheeler Rd, and Owens Rd in Maryland. It then gets to Southern Ave SE and travels along the Maryland side of the street until it reaches Wheeler Rd/SE and switches sides. The lateral continues through Wheeler Rd SE and Bellevue Rd SE on the DC side and the mainline continues going northeast on Southern Ave SE. The feeder ends at a riser pole along Southern Ave SE. The mainline is all overhead while some of the laterals come off as underground.

Previous Actions Taken (Past 3 years):

Reconductor feeder 15085 & 15086 in breaker zone

- Remove 1500' of 3-1/0 ACSR from FDR(s) 15085 & 15086. Remove 815' 2-#2 CU PE secondary mainline from FDR 15086. Install 1500' of 3-477 ACSR tree wire on FDR(s) 15085 & 15086. Install 815' 4/0 triplex secondary mainline.

Arbor View Apts – Replace OH PRI/XMRs w/ URD PRI/PDMT XFMRs

Planned Remediation (Current Year):

- Create WO# to address animal issues at equipment locations
- Create WO# Replace guying at specified locations
- Create WO# Install flash guard at specified locations
- Reconductor ~936' of existing #4 Copper wire with 1/0 ACSR
    - 808358-25028 – B phase lateral on Norlinda Ave & Norlinda Pl

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

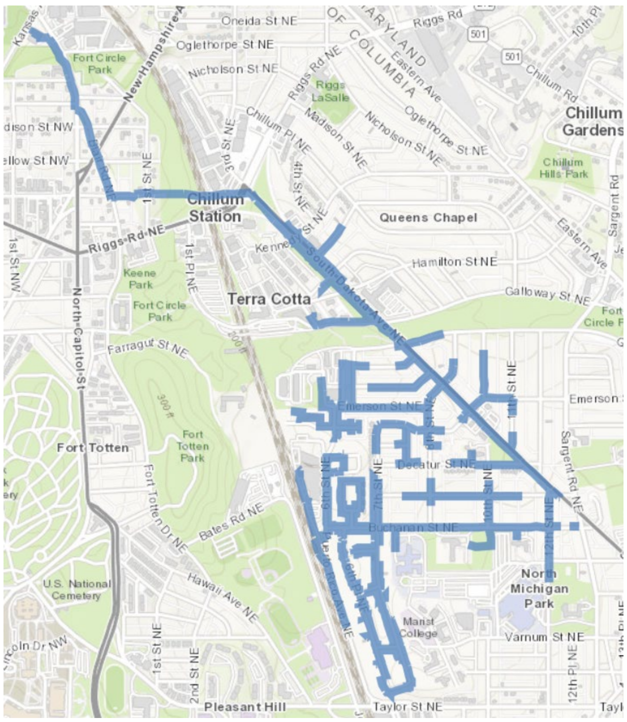
Anticipated Benefits:

The work on this feeder to address animal/BIL deficiencies and other miscellaneous maintenance items will help to improve the resiliency of the feeder and the reconductoring effort will provide greater reliability through newer facilities in this area of the circuit.

Circuit: 15018

County	Substation	Customers Served	Number of Outages	Oct. 2020-Sept. 2021 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Ft. Slocum (190)	1,943	18	1.607	140.5	87.4	43%	57%	11.74	N

Feeder Map and Location:



Outage Data Summary (Past 3 years):

2018: (Oct 17-Sep 18) Forty-nine percent (49%) of customer outages due to 8 lateral events; 2 events were caused by Cable Cut - Unknown, and 6 events were caused by Equipment Failure. Zero customer outages occurred due to mainline events this year.

2019: (Oct 18-Sep 19) Thirty-one percent (31%) of customer outages were due to 8 lateral events; 3 events were caused by Equipment Failure, and1 event was caused by Tree ROW – Limb. Zero customer outages occurred due to mainline events this year.

2020: (Oct 19-Sep 20) Ninety-six percent (96%) of customer outages were due to 13 mainline events; 6 events were caused by Equipment Failure, 1 event was caused by Tree Outside ROW - Down, 2 events were caused by Tree Outside ROW - Limb, 2 events were caused by Tree ROW - Limb, and 2 events were caused by Unknown. Less than One percent (<1%) of customer outages were due to 1 lateral events; 1 event was caused by Equipment Failure.

Feeder Performance (Oct 20-Sep 21)

Outage Cause by SAIFI	SAIFI	% of Feeder
Equipment Failure	0.760	41%
Tree Outside ROW - Limb	0.325	22%
Tree ROW - Limb	0.124	17%
Tree Outside ROW - Down	0.206	11%
Unknown	0.162	8%
Animal/Squirrel	0.016	1%
Load	0.008	<1%
Animal/Bird	0.005	<1%
Weather / Wind	0.001	<1%

Feeder 15018 serves approximately 1,943 customers in the Michigan Park and North Michigan Park neighborhoods in NE Washington D.C. The mainline portion of this feeder originates out of the Ft Slocum Substation and runs southeast underground down Blair Rd NW. Once it reaches Kennedy St NE it runs east and transitions to overhead. The line continues east to South Dakota Ave NE where it becomes underground again. The feeder then changes back to overhead at the recloser just before the Gallatin St NE intersection. The feed then goes onto 12th St NE briefly to turn west onto Buchanan St NE. The mainline turns west onto Decatur St NE until the line ends near Puerto Rico Ave NE.

Previous Actions Taken (Past 3 years):

No work performed within the last 3 years.

Planned Remediation (Current Year):

- Create WO to address Animal issue at nineteen (19) equipment locations
- Replace crossarms at five (5) locations
- Replace guying at four (4) locations
- Replace two-point brackets at seven (7) locations
- Install fuses for lateral taps at two (2) locations
- Replace pole & equipment at 801405-370830
- Re-stencil pole at two (2) locations
- Vegetation Management to perform tree trimming on feeder
- Create design for one (1) double riser locations to relocate one set of UG cables to a new pole set to split risers for UG loop

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

Anticipated Benefits:

The work on this feeder to address animal/BIL deficiencies and other miscellaneous maintenance items will help to improve the resiliency of the feeder. Installing new fuses at poles that transition between mainline and lateral will further increase the ability to sectionalize the circuit to isolate outages and protect the mainline, and the separation of underground feeds from the same pole will reduce risk of an entire URD loop experiencing a disturbance after an event at one pole.

Circuit: 15171

County	Substation	Customers	Number of	Oct. 2020-Sept. 2021 Reliability Indices	Feeder Miles	Repeated

		Served	Outages	(In Hours)						Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Alabama Ave (136)	1,790	12	1.659	169.9	102.4	58%	42%	9.64	N

Feeder Map and Location:

Outage Data Summary (Past 3 years):

2019: (Oct 18-Sep 19) Seventy-two percent (72%) of customer outages were due to 4 lateral events; 4 events were caused by Unknown. Zero customer outages occurred due to mainline events this year.

2020: (Oct 19-Sep 20) Fifteen percent (15%) of customer outages were due to 1 mainline event; 1 event was caused by Equipment Failure. Fifty-five percent (55%) of customer outages were due to 4 lateral events; 3 events were caused by Equipment Failure, and 1 event was caused by Tree Outside ROW – Limb.

2021: (Oct 20-Sep 21) Seventy-nine percent (79%) of customer outages were due to 5 mainline events; 5 events were caused by Animal/Squirrel. Nineteen percent (19%) of customer outages were due to 3 lateral events; 2 events were caused by Animal/Squirrel, and 1 event was caused by Unknown.

Feeder Performance (Oct 20-Sep 21)

Outage Cause by SAIFI	SAIFI	% of Feeder
Animal/Squirrel	1.649	>99%
Animal/Bird	0.004	<1%
Unknown	0.003	<1%
Equipment Failure	0.002	<1%
Vandalism	0.001	<1%

Field Observations:

Feeder 15171 serves approximately 1,790 customers in the Congress Heights, Douglass, and Shipley neighborhoods in SE Washington D.C. The mainline portion of the feeder originates out of the Alabama Ave Substation and runs along 15th St SE, Savannah Dr SE, Mississippi Ave SE, and Southern Ave SE. The feeder services mostly residential and some commercial customers. The feeder has a mix of old and new construction with existing copper wire still in place.

Previous Actions Taken (Past 3 years):

No work performed within the last 3 years.

Planned Remediation (Current Year):

- Create WO# to address to re-attach 3 Phase Primary to pole

- Create WO# to Install Spacers around poles 806367-630980, 809369-340460 & 808369-540530
- Need load study performed on padmount transformer 807368-030030 to determine customers for upgrade
- Reconductor ~822' of existing 1/0 Copper wire with 477 ACSR
  - Between 804367-830180 & 805367-561568 on Mississippi Ave
- Create design for seven (7) double riser locations to relocate one set of UG cables to a new pole set to split risers for UG loop

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	TBD	TBD
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

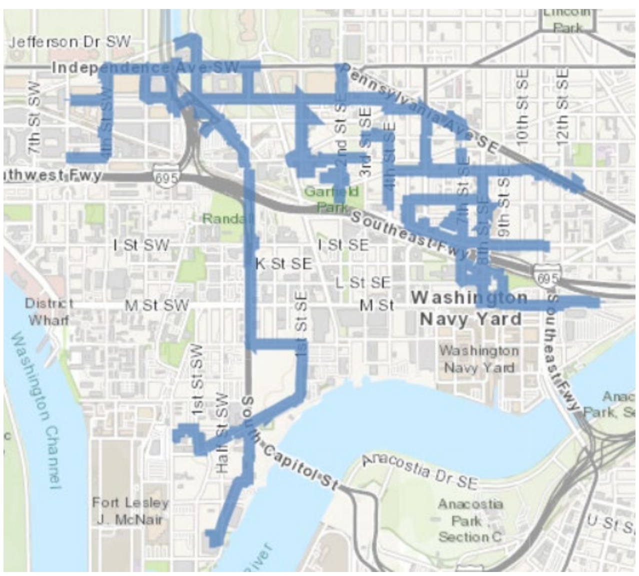
Anticipated Benefits:

The work on this feeder to address animal/BIL deficiencies and other miscellaneous maintenance items will help to improve the resiliency of the feeder. Installing phase spacers will reduce outages caused by conductor contact due to wind or tree events. The reconductoring effort on this feeder will increase the reliability of the feeder with newer, more durable conductor. The separation of multiple underground feeds from the same pole will reduce risk of an entire URD loop experiencing a disturbance after an event at one pole.

Circuit: 16003

County	Substation	Customers Served	Number of Outages	Oct. 2020-Sept. 2021 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Waterfront (223)	1,851	19	1.915	63.5	33.1	0%	100%	13.29	N

Feeder Map and Location



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Outage Data Summary (Past 3 years):

2019: (Oct 18-Sep 19) Ninety-one percent (91%) of customer outages were due to 16 mainline events; 16 events were caused by Equipment Failure. Six percent (6%) of customer outages were due to 3 lateral events; 3 events were caused by Equipment Failure.

2020: (Oct 19-Sep 20) Thirty-three percent (33%) of customer outages were due to 1 lateral event; 1 event was caused by Unknown. Zero customer outages occurred due to mainline events this year.

2021: (Oct 20-Sep 21) Eighty-seven percent (87%) of customer outages were due to 2 mainline events; 2 events were caused by Equipment Failure. Two percent (2%) of customer outages were due to 1 lateral event; 1 event was caused by Equipment Failure.

Feeder Performance (Oct 20-Sep 21)

FEEDER	Outage Cause by SAIFI	SAIFI	% of Feeder
16003	Equipment Failure	1.915	100%

Field Observations:

Feeder 16003 originates from the Waterfront substation in northwest Washington, DC, and serves approximately 1,851 customers. The feeder is 100% underground and provides power to both residential and commercial customers. The mainline emerges from the substation along Q St SW where the feeder runs east, then turning south to 13th St SW the mainline trunk changes direction to the northeast on Potomac Ave SW/SE until a bend where the road changes to 1st St SE where it runs north. It then turns west onto N St SE then turns north onto South Capital St SE. The mainline trunk of the feeder continues in this manner along South Capital St SE until the mainline trunk turns northwest onto Canal St SW. At the intersection of Canal St SW and C St SW the feeder has laterals to the west and north but the mainline continues east onto C St SW. The mainline then does a loop from going down 1st St SE to North Carolina Ave SE where it is fused off then travels back north to C St SE and continues east. The feeder continues eastward by turning onto 4th St SE and then Seward Sq SE then southwest onto Pennsylvania Ave SE where splits and went south down 6th ST SE as well but continues on Pennsylvania Ave SE and ends at 7th St SE.

Previous Actions Taken (Past 3 years):

Waterfront Switch Replacement – FDR 16003 – 800382-381197

Switch Replacement – FDR 16003 – 499 6th St SE, DC

- Remove existing 3-way switch on FDR 16003. Install NEW 4-way switch and 6x16' MH FDR 16003. Reconductor 15871, 16002, & 16003 to 3-600 1/c F.S. Reconductor 16003 mains from NEW switch to existing tapholes

Replace RL Sec with RN Sec Cable – Bundle 6 Ontario Rd

- Replace approximately 800ft of 250RL cable w/ 250RN cable

Planned Remediation (Current Year):

- This feeder will be investigated through underground inspection programs separate from the priority feeder projects to determine the appropriate improvement measures are taken on this circuit.

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments				

Completed Remediation Work: N/A

Anticipated Benefits:

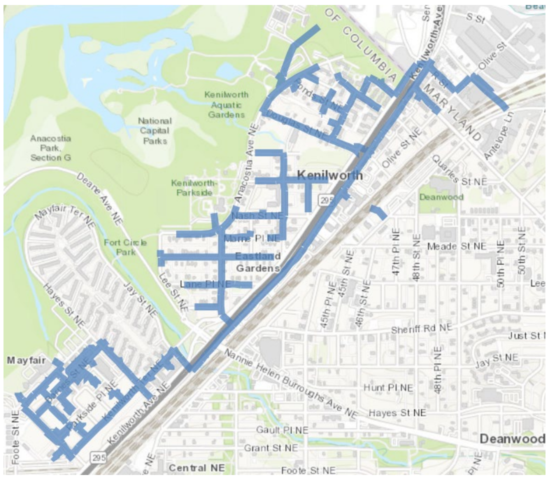
Further investigation into the conditions on this feeder that can be optimized to improve customer reliability will reduce outages and feeder resiliency.

Circuit: 14717

County	Substation	Customers Served	Number of Outages	Oct. 2019-Sept. 2020 Reliability Indices (In Hours)	Feeder Miles	Repeated Last 2

				SAIFI	SAIDI	CAIDI	OH	UG	Total	Years?
DC	Benning a23013 (7)	1,562	20	1.605	187.5	116.8	74%	26%	7.99	N

Feeder Map and Location:



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Outage Data Summary (Past 3 years):

2019: (Oct 18-Sep 19) Ninety-nine percent (99%) of customer outages were due to 2 mainline events; 1 event was caused by Animal/Bird, and 1 event was caused by Motor Vehicle. Zero customer outages occurred due to lateral events this year.

2020: (Oct 19-Sep 20) Ninety-two percent (92%) customer outages were due to 2 mainline events; 1 event was caused by Animal/Other, and 1 event was caused by Unknown. Seven percent (7%) of customer outages were due to 2 lateral events; 1 event was caused by Equipment Failure, and 1 event was caused by Weather / Lightning.

2021: (Oct 20-Sep 21) Eighty-three percent (83%) of customer outages were due to 6 mainline events; 2 events were caused by Animal/Squirrel, 3 events were caused by Equipment Failure, and 1 event was caused by Tree Outside ROW – Limb. Sixteen percent (16%) of customer outages were due to 3 lateral events; 1 event was caused by Animal/Squirrel, 1 event was caused by Load, and 1 event was caused by Motor Vehicle.

Feeder Performance (Oct 20-Sep 21)

Outage Cause by SAIFI	SAIFI	% of Feeder
Equipment Failure	1.104	69%
Animal/Squirrel	0.248	15%
Motor Vehicle	0.195	12%
Tree Outside ROW - Limb	0.051	3%
Animal/Bird	0.004	<1%
Foreign Contact	0.001	<1%
Load	0.001	<1%
Unknown	0.001	<1%

Feeder 14717 serves approximately 1,562 customers in Northeast Washington D.C. Originating from the Benning Substation; this circuit is 74% overhead and 26% underground. The mainline provides both residential and commercial service. The feeder comes out on Foote St NE and onto Kenilworth Ter NE where it travels northeast. It turns southeast onto Jay St NE, then northeast onto Kenilworth Ave NE. The feeder ends near the intersection of R St NE and Eastern Ave NE.

Previous Actions Taken (Past 3 years):

Benning Area Plan Feeder 14717

- Extend PAC on feeder 14717 from sub to switch – Benning area

2017 Benning Area Plan Feeder 14717 ML-1

2018 Benning Area Plan Feeder 14717 PAC Install

Move Pole on Kennilworth and Pole St NE

- Move pole 5 feet north

Install Normally Closed Switch Feeder 15711

2018 ACR Program – Install ACR on Feeder 14717

- Install a new 12kA ACR on pole 818391-163973

Planned Remediation (Current Year):

- Create WOs to address Animal issues at equipment locations
- Create design for five (5) double riser locations to relocate one set of UG cables to a new pole set to split risers for UG loop

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments				

Completed Remediation Work: N/A

Anticipated Benefits:

The work on this feeder to address animal/BIL deficiencies and other miscellaneous maintenance items will help to improve the resiliency of the feeder. The separation of multiple underground feeds from the same pole will reduce risk of an entire URD loop experiencing a disturbance after an event at one pole.

Circuit: 15204W

County	Substation	Customers Served	Number of Outages	Oct. 2020-Sept. 2021 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Tenth St (52)	1,109	18	1.274	197.8	155.3	0%	100%	4.36	N

<u>Feeder Map and Location:</u>

<u>Outage Data Summary (Past 3 years)</u>:

2019: (Oct 18-Sep 19) Eighty-three percent (83%) of customer outages were due to 4 lateral events; 2 events were caused by Equipment Failure, and 2 events were caused by Unknown. Zero customer outages occurred due to mainline events this year.

2020: (Oct 19-Sep 20) No customer outages due to mainline or lateral events occurred during this year.

2021: Oct 20-Sep 21) Seventy-eight percent (78%) of customer outages were due to 1 mainline event; 1 event was caused by Equipment Failure. Twenty percent (20%) of customer outages were due to 4 lateral events; 4 events were caused by Equipment Failure.

Feeder Performance (Oct 20-Sep 21)

Outage Cause by SAIFI	SAIFI	% of Feeder
Equipment Failure	1.273	>99%

Unknown	0.001	<1%

Field Observations:

Feeder 15204W serves approximately 1,109 customers in Northwest Washington D.C. Originating from the 10th St, DC Substation; all of this circuit consists of underground construction (100% underground construction). The mainline provides both residential and commercial service. The mainline emerges from the substation on L St NW and heads east to the nearest intersection. It then moves north up 10th St NW. The feeder then continues on N St NW to the east until it reaches 77th St NW to go north. At the intersection of 77th St NW and P St NW the feeder branches into all directions with laterals to feed commercial and residential services. The devices and conductor on this feeder are generally in good condition, however there are outage locations at manholes.

Previous Actions Taken (Past 3 years):

No work performed within the last 3 years.

Planned Remediation (Current Year):

- This feeder will be investigated through underground inspection programs separate from the priority feeder projects to determine the appropriate improvement measures are taken on this circuit.

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

Anticipated Benefits:

Further investigation into the conditions on this feeder that can be optimized to improve customer reliability will reduce outages and feeder resiliency.

Circuit: 14767

County	Substation	Customers Served	Number of Outages	Oct. 2020-Sept. 2021 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Little Falls (77)	969	25	1.390	212.7	153.0	77%	23%	11.94	N

Feeder Map and Location:

Outage Data Summary (Past 3 years):

2019: (Oct 18-Sep 19) Eighty-three percent (83%) of customer outages were due to 5 lateral events; 1 event was caused by Animal/Squirrel, 3 events were caused by Equipment Failure, 1 event was caused by Weather / Lightning. Zero customer outages occurred due to mainline events this year.

2020: (Oct 19-Sep 20) Seventy-four percent (74%) of customer outages were due to 8 lateral events; 2 events were caused by Animal/Squirrel, 2 events were caused by Equipment Failure, 2 events were caused by Tree Row - Down, 2 events were caused by Tree ROW - Limb. Zero customer outages occurred due to mainline events this year.

2021: (Oct 20-Sep 21) Seventy-six percent (76%) of customer outages were due to 3 mainline events; 2 events were caused by Tree Outside ROW - Down, 1 event was caused by Tree Row - Down. Twenty-one percent (21%) of customer outages were due to 9 lateral events; 1 event was caused by Animal/Squirrel, 3 events were caused by Load, 2 events were caused by Tree Outside ROW - Down, 1 event was caused by Tree Vine, 1 event was caused by Unknown, 1 event was caused by Weather / Lightning.

Feeder Performance (Oct 20-Sep 21)

Outage Cause by SAIFI	SAIFI	% of Feeder
Tree Outside ROW - Down	1.124	81%
Tree Row - Down	0.058	4%
Weather / Lightning	0.057	4%
Load	0.054	4%
Tree Vine	0.040	3%
Animal/Squirrel	0.025	2%
Equipment Failure	0.019	1%
Unknown	0.013	1%

Feeder 14767 serves approximately 969 customers in northwest Washington D.C. Originating from the Little Falls Substation; this circuit provides service to both commercial and residential customers, but mostly residential. This feeder is largely overhead (77% overhead and 23% underground) and emerges from the substation along MacArthur Blvd NW and travels southeast. After fused laterals and a recloser the overhead mainline reaches Ashby St NW where it continues east and then south on 49th St NW. The line continues onto W St NW and ends at the intersection with Foxhall Rd NW.

Previous Actions Taken (Past 3 years):

2018 Reliability Engineering FDR 14767 Reconductor w/ 477 TW & Paving Task

- Replace 4/0 ACSR bare with 477 ACSR TW and 477 AAC spacer cable

Feeder 14767 – 2017 Priority Feeder – XFMR #500920

- Heavy-up transformer to properly handle existing load, 50kva to 100kva

Planned Remediation (Current Year):

- Create WO to address Animal issues at six (6) equipment locations
- Vegetation Management to perform tree trimming on feeder
- Replace poles at four (4) locations if not being replaced under current WO#
- Re-stencil pole 773399-680450
- Replace transformer at 771398-520360
- Replace fuses at 771398-480030
- Replace crossarm at two (2) locations
- Create design for six (6) double riser locations to relocate one set of UG cables to a new pole set to split risers for UG loop

Additional Comments – All other outage reports issues have been addressed in the field.

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A

Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation: N/A

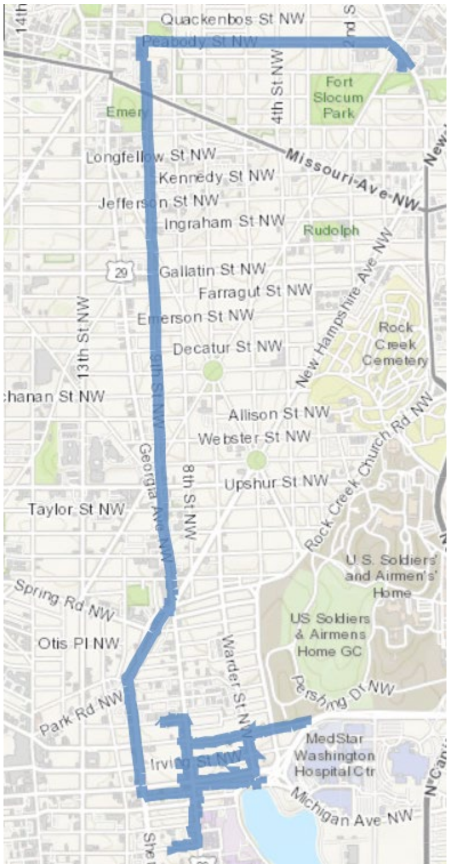
Anticipated Benefits:

The work on this feeder to address animal/BIL deficiencies and other miscellaneous maintenance items will help to improve the resiliency of the feeder. Addressing aging infrastructure with pole, crossarm, and equipment replacements will mitigate potential for equipment related outages, and the separation of multiple underground feeds from the same pole will reduce risk of an entire URD loop experiencing a disturbance after an event at one pole.

Circuit: 15002

County	Substation	Customers Served	Number of Outages	Oct. 2020-Sept. 2021 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Ft. Slocum (190)	1,033	10	1.330	185.3	139.3	0%	100%	5.53	N

Feeder Map and Location:



<u>Outage Data Summary (Past 3 years)</u>:

2019: (Oct 18-Sep 19) No customer outages due to mainline or lateral events occurred during this year.

2020: (Oct 19 - Sep 20) No customer outages due to mainline or lateral events occurred during this year.

2021: (Oct 20 - Sep 21) Sixty-four percent (64%) of customer outages were due to 1 mainline event; 1 event was caused by Equipment Failure. Twenty-seven percent (27%) of customer outages were due to 3 lateral events; 3 events were caused by Equipment Failure,

Feeder Performance (Oct 20 - Sep 21)

Outage Cause by SAIFI	SAIFI	% of Feeder
Equipment Failure	1.329	>99%
Source Lost	0.001	<1%

Field Observations:

Feeder 15002 serves approximately 1,033 customers in northwest Washington D.C. Originating from the Ft. Slocum Substation. All of this circuit consists of underground construction (100% underground). The feeder comes out from the substation onto Blair Rd NW and travels northwest onto North Dakota Ave NW then west onto Peabody St NW. Once the line reaches 9th St NW it continues south until the road merges onto Georgia Ave NW. The mainline then turns onto New Hampshire Ave NW towards the southwest. It then turns south onto Sherman Ave NW then east onto Hobart Pl NW. From here it begins servicing customers on Hobart Pl NW, Georgia Ave NW, Warder St NW, Irving St NW, and Kenyon St NW. These are a mix of residential and commercial services.

Previous Actions Taken (Past 3 years):

No work has taken place on this feeder in the previous three years.

Planned Remediation (Current Year):

- This feeder will be investigated through underground inspection programs separate from the priority feeder projects to determine the appropriate improvement measures are taken on this circuit.

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments				

Completed Remediation Work: N/A

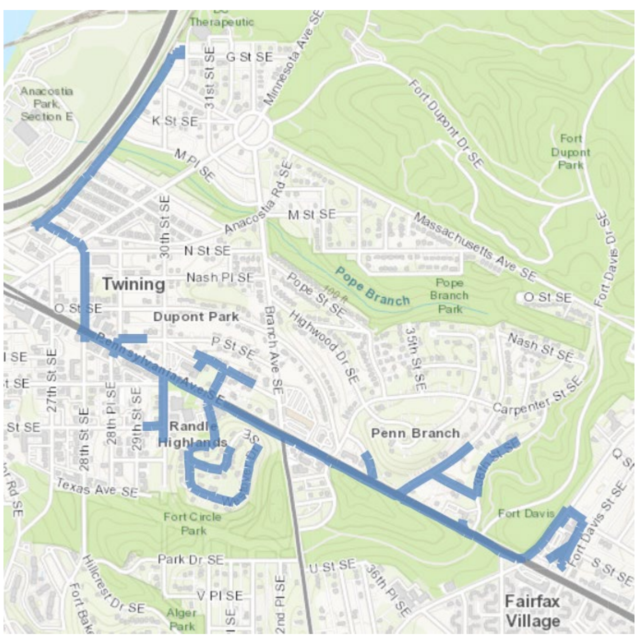
Anticipated Benefits:

Further investigation into the conditions on this feeder that can be optimized to improve customer reliability will reduce outages and feeder resiliency.

Circuit: 00118

County	Substation	Customers Served	Number of Outages	Oct. 2020-Sept. 2022 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Randle Hiland (71)	491	45	2.735	386.0	141.1	97%	3%	3.75	N

Feeder Map and Location:



Outage Data Summary (Past 3 years):

2019: (Oct 18-Sep 19) Zero outages occurred due to laterals or mainline.

2020: (Oct 19-Sep 20) Ninety-three percent (93%) of customer outages were due to 1 mainline event; 1 event was caused by Equipment Failure. Five percent (5%) of customer outages were due to 1 lateral event; 1 event was caused by Scheduled.

2021: (Oct 20-Sep 21) Ninety-five percent (95%) of customer outages were due to 5 mainline events; 3 events were caused by Equipment Failure, 1 event was caused by Tree Outside ROW - Down, and 1 event was caused by Tree ROW - Limb. Zero customer outages occurred due to lateral events this year.

Feeder Performance (Oct 20-Sep 21)

Outage Cause by SAIFI	SAIFI	% of Feeder
Equipment Failure	1.416	52%
Tree ROW - Limb	0.650	24%
Tree Outside ROW - Down	0.622	22%
Tree Outside ROW - Limb	0.041	1%
Scheduled	0.002	<1%
Unknown	0.002	<1%
Weather / Wind	0.002	<1%

Field Observations:

Feeder 00118 serves approximately 491 customers in southeast Washington D.C. Originating from the Randle Highlands substation, most of this circuit consists of mostly overhead construction (97% overhead, 3% underground). The line comes out onto G St SE and immediately turns onto Fairlawn Ave SE to travel southeast. It then turns southeast onto N St SE then south onto 28th St SE. It turns southeast onto Pennsylvania Ave SE. Eventually the feeder turns NE onto Alabama Ave SE and eventually ends at Ft. Davis substations at a circuit breaker.

Previous Actions Taken (Past 3 years):

FDR 00118 Install 12.5 KA ACR Line NC

Planned Remediation (Current Year):

- Create WO# to replace broken/damaged crossarms at specified locations
- Create WO# to Re-stencil pole facility ID's at specified locations
- Create WO# to replace padmount in pad condition at 813376-110330

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

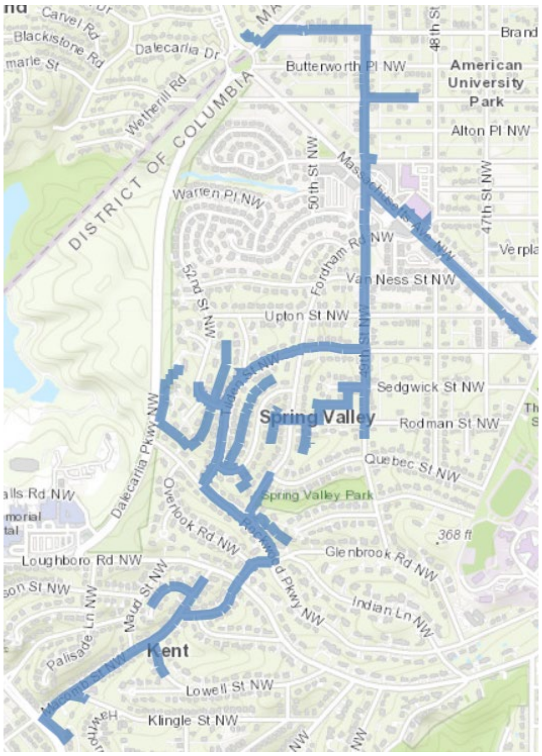
Anticipated Benefits:

The work on this feeder to address miscellaneous maintenance items will help to improve the resiliency of the feeder. Addressing aging infrastructure with crossarm and transformer replacements will mitigate potential for equipment related outages.

Circuit: 00144

County	Substation	Customers Served	Number of Outages	Oct. 2019-Sept. 2020 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Westmoreland (93)	283	14	3.583	730.2	203.8	59%	41%	4.67	N

<u>Feeder Map and Location:</u>



<u>Outage Data Summary (Past 3 years)</u>:

2019: (Oct 18-Sep 19) Eighty-one percent (81%) of customer outages were due to 6 mainline events; 5 events were caused by Equipment Failure, 1 event was caused by Tree ROW - Limb. Three percent (3%) of customer outages were due to 1 lateral event; 1 event was caused by Equipment Failure.

2020: (Oct 19-Sep 20) Fifty-five percent (55%) of customer outages were due to 4 lateral events; 1 event was caused by Equipment Failure, 1 event was caused by Tree Outside ROW - Down, and 2 events were caused by Tree ROW – Limb. Zero customer outages occurred due to mainline events this year.

2021: (Oct 20-Sep 21) Ninety-three percent (93%) of customer outages were due to 21 mainline events; 10 events were caused by Equipment Failure, 2 events were caused by Scheduled, 3 events were caused by Tree Outside ROW - Down, 6 events were caused by Unknown. Five percent (5%) of customer outages were due to 4 lateral events; 1 event was caused by Equipment Failure, 1 event was caused by Scheduled, 1 event was caused by Tree Outside ROW - Down, 1 event was caused by Tree Row – Down.

Feeder Performance (Oct 20-Sep 21)

Outage Cause by SAIFI	SAIFI	% of Feeder
Unknown	1.630	47%
Equipment Failure	0.881	25%
Scheduled	0.684	18%
Tree Outside ROW - Down	0.349	10%
Tree Row - Down	0.035	<1%
Tree ROW - Limb	0.004	<1%

Field Observations:

Feeder 00144 serves approximately 283 customers in northwest Washington D.C. Originating from the Westmoreland substation, most of this circuit consists of overhead construction (41% underground, and 59% overhead). The feeder comes out from the substation on Western Ave NW traveling north very briefly then east onto Brandywine St NW. The mainline continues south onto 49th St NW until it reaches Massachusetts Ave NW where it goes underground until before the road intersects with Fordham Rd NW. The line travels east onto Tilden St NW going underground again until it comes up at a recloser near Loughboro Rd NW and Glenbrook Rd NW. The mainline continues with laterals along the way to Palisades substation at a circuit breaker.

Previous Actions Taken (Past 3 years):

DC Plug Feeder 00308 – Relocate Feeders 00144 and 00394

Planned Remediation (Current Year):

- Create WO to address Animal issues at three (3) equipment locations
- Replace pole at 770400-340650
- Replace transformer at 771402-080400

- Reconductor ~166' of OW secondary to triplex (12 splices in span)
  - Between 769400-700230 & 769400-560140 on Macomb St

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

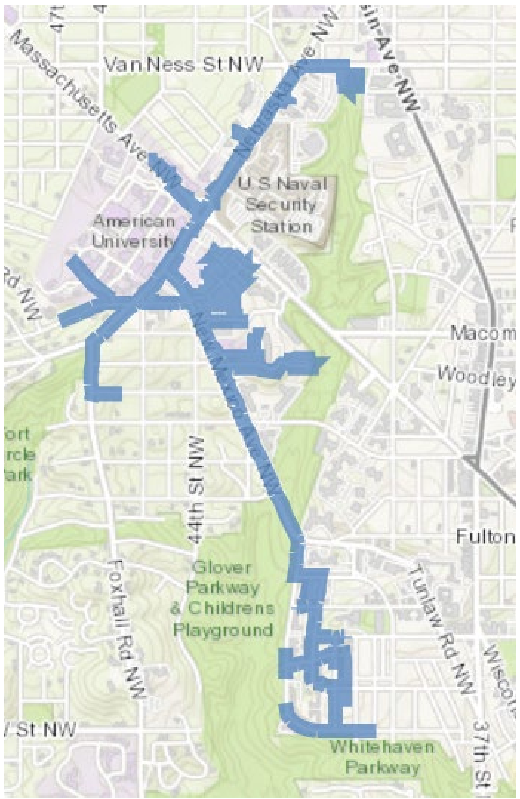
Anticipated Benefits:

The work on this feeder to address animal/BIL deficiencies and other miscellaneous maintenance items will help to improve the resiliency of the feeder. Addressing aging infrastructure with pole and equipment replacements will mitigate potential for equipment related outages, and the reconductoring of heavily spliced conductors will resolve outage concerns to provide more reliable service to customers in that area.

Circuit: 14132

County	Substation	Customers Served	Number of Outages	Oct. 2020-Sept. 2021 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Van Ness (129)	1,097	30	1.284	65.1	50.7	48%	52%	7.48	N

Feeder Map and Location:



Outage Data Summary (Past 3 years):

2019: (Oct 18-Sep 19) Ninety-three (93%) of customer outages were due to 4 lateral events; 1 event was caused by Equipment Failure, 3 events were caused by Unknown. Zero customer outages occurred due to mainline events this year.

2020: (Oct 19-Sep 20) Seventy-seven percent (77%) of customer outages were due to 12 lateral events; 9 events were caused by Equipment Failure, and 3 events were caused by Unknown. Zero customer outages occurred due to mainline events this year.

2021: (Oct 20-Sep 20) Seventy-eight percent (78%) of customer outages were due to 3 mainline events; 3 events were caused by Unknown. Fifteen percent (15%) of customer outages were due to 6 lateral events; 4 events were caused by Equipment Failure; 2 events were caused by Tree Outside ROW – Down.

Outage Cause by SAIFI	SAIFI	% of Feeder
Unknown	1.015	79%
Tree Outside ROW - Down	0.153	12%
Equipment Failure	0.101	8%
Tree ROW - Limb	0.014	1%
Animal/Squirrel	0.001	<1%

Field Observations:

Feeder 14132 serves approximately 1,097 customers in northwest Washington D.C. Originating from the Van Ness substation, the circuit construction is almost even (52% underground, and 48% overhead). The mainline emerges along Nebraska Ave NW and heads directly southwest, then turns and goes southeast on New Mexico Ave NW. It services customers near this intersection and then continues and services more customers to the south of where New Mexico Ave NW ends

Previous Actions Taken (Past 3 years):

No work is performed within the 3 years.

Planned Remediation (Current Year):

- Create WOs to address Animal issues at seven (7) equipment locations
- Replace guying at 773400-590790
- Vegetation Management to perform tree trimming on feeder
- Reconductor ~488’ of existing 3-1/0 AL wire & OW secondary with 3-1/0 ACSR wire & triplex
  - Between 77440-050990 & 773400-590790 on Rockwood Pkwy
- Reconductor ~504’ of existing OW secondary with triplex
  - Between 774399-030810 & 774399-540810 on Klingle St
- Install guying at 776397-770430(Easement may be required)
- Replace pole 777396-120370

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

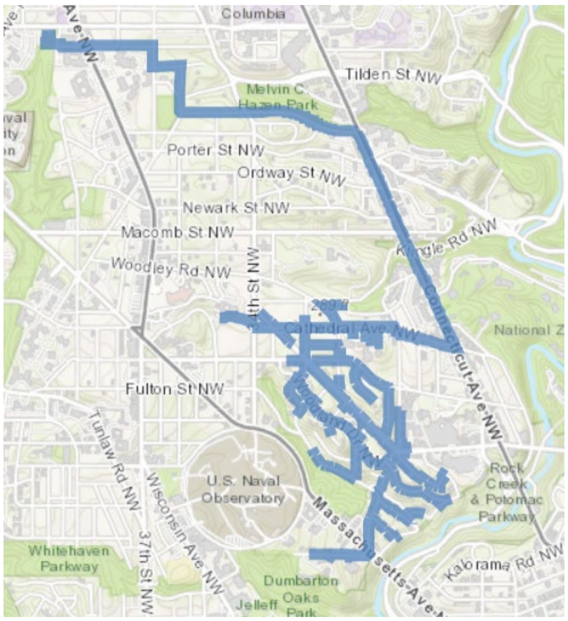
Anticipated Benefits:

The work on this feeder to address animal/BIL deficiencies and other miscellaneous maintenance items will help to improve the resiliency of the feeder. Addressing aging infrastructure with pole and equipment replacements will mitigate potential for equipment related outages, and the reconductoring of primary and secondary conductors will create a more robust and durable circuit thereby reducing customer outages.

Circuit: 14146

County	Substation	Customers Served	Number of Outages	Oct. 2020-Sept. 2021 Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
				SAIFI	SAIDI	CAIDI	OH	UG	Total	
DC	Van Ness (129)	449	20	2.595	181.7	70.02	52%	48%	8.27	N

<u>Feeder Map and Location:</u>



<u>Outage Data Summary (Past 3 years)</u>:

2019: (Oct 18-Sep 19) Eighty-one percent (81%) of customer outages were due to 1 mainline event. 1 event was caused by Equipment Failure. Seventeen percent (17%) of customer outages were due to 1 lateral event. 1 event was caused by Equipment Failure,

2020: (Oct 19-Sep 20) Ninety-three percent (93%) of customer outages were due to 3 mainline events; 2 events were caused by Equipment Failure, 1 event was caused by Tree Outside ROW – Limb. Zero customer outages occurred due to lateral events this year.

2021: (Oct 19-Sep 20) Ninety-seven percent (97%) of customer outages were due to 8 mainline events; 4 events were caused by Equipment Failure, 1 event was caused by Tree Outside ROW - Down, 1 event was caused by Tree Row - Down, 2 events were caused by Tree ROW - Limb. One percent (1%) of customer outages were due to 2 lateral events; 1 event was caused by Equipment Failure, 1 event was caused by Tree ROW – Limb.

Feeder Performance (Oct 20-Sep 21)

Outage Cause by SAIFI	SAIFI	% of Feeder
Equipment Failure	1.778	68%
Tree ROW - Limb	0.312	13%
Tree Row - Down	0.308	12%
Tree Outside ROW - Down	0.195	7%
Foreign Contact	0.002	<1%

Field Observations:

Feeder 14146 serves approximately 449 customers in northwest Washington D.C. Originating from the Van Ness substation, the majority of this circuit consists of overhead construction (48% underground, and 52% overhead). It is services mostly residential customers but also has commercial services. There are also several embassies on this feeder. The mainline runs along Cleveland Ave NW, 29th St NW, Garfield St NW, Cathedral Ave NW, Connecticut Ave NW, and Rodman St NW.

Previous Actions Taken (Past 3 years):

2018 ACR FDR 14146 - 12kA N.C. ACR

- Install NC ACR 12kA

Planned Remediation (Current Year):

- Create WO to address Animal issues at ten (10) equipment locations
- Replace fuse at 782397-230450
- Replace Lightning Arrestors at 782396-880870
- Replace crossarm brace at 783395-620780

- Replace crossarm & secondary bracket at 782396-150840
- Vegetation Management to perform tree trimming on feeder
- Replace poles at two (2) locations
- Create design for one (1) double riser locations to relocate one set of UG cables to a new pole set to split risers for UG loop

Milestones/Schedule:

	Design Complete	Permitting Complete	Release to Construction	Construction Complete
Proposed	N/A	N/A	N/A	N/A
Actual	N/A	N/A	N/A	N/A
Variance Comments	N/A	N/A	N/A	N/A

Completed Remediation Work: N/A

Anticipated Benefits:

The work on this feeder to address animal/BIL deficiencies and other miscellaneous maintenance items will help to improve the resiliency of the feeder. Addressing aging infrastructure with pole and equipment replacements will mitigate potential for equipment related outages, and the separation of underground feeds from one pole to multiple poles will reduce the chance of an outage on the entire URD feed due to an incident at the cable pole.

Review of 2020 Priority Feeder Program (Least Reliable Feeders)

Activities conducted to improve the performance of each of the feeders in the 2020 Priority Feeder Program are identified in Table 19.

Table 19

2020 2% Priority Feeder Program - District of Columbia - Completed Corrective Actions							
Rank	Feeder ID	Substation	Category		SPC Value	Completion Time	Corrective Actions
			OH	UG			
1	16003	Waterfront (223)	0%	100%	0.056	N/A	No corrective actions performed under the 2020 Priority Feeder Program. However, work was performed under miscellaneous program in Q3 2021 and the PILC replacement program in Q1 2022.
2	15094	Bladensburg (175)	39%	61%	0.051	N/A	No corrective actions performed under the 2020 Priority Feeder Program due to ongoing work taking place under the Ft. Lincoln reliability improvement initiative.
3	15707	Benning (7)	91%	9%	0.044	1st Quarter 2021	- Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.
4	15015	Ft. Slocum (190)	59%	41%	0.030	1st Quarter 2021	- Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.
5	16002	Waterfront (223)	0%	100%	0.028	N/A	No corrective actions performed under the 2020 Priority Feeder Program. However, work was performed under the PILC replacement program in Q3 2021.
6	15021	Ft. Slocum (190)	93%	7%	0.025	3rd Quarter 2020	- Install/Replace 4200' of Primary Wire - Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.
7	15702	Benning (7)	5%	95%	0.023	3rd Quarter 2020	- Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.
8	15710	Benning (7)	79%	21%	0.023	1st Quarter 2021	- Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.
9	15130	Walker Mill (15)	68%	32%	0.022	3rd Quarter 2020	- Install/Replace 1700' of Primary Wire - Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.
10	14261	Beech Road (159)	92%	8%	0.022	4th Quarter 2020	- Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.
11	14711	Benning (7)	7%	93%	0.017	1st Quarter 2021	- Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.
12	15867	Van Ness (129)	42%	58%	0.013	1st Quarter 2021	- Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.
13	14136	Van Ness (129)	24%	76%	0.013	1st Quarter 2021	- Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.
14	00211	G Street (28)	0%	100%	0.013	N/A	No corrective actions performed under the 2020 Priority Feeder Program due to ongoing work taking place under the G Street Conversion Plan.
15	00328	Ft. Dupont	97%	3%	0.011	1st Quarter 2021	- Install/Replace 4 Poles - Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.
16	14035	Suitland (134)	80%	20%	0.010	2nd Quarter 2022	- Install/Replace 1050' of Primary Wire - Miscellaneous upgrades such as fuse cutouts, animal guards, lightning arrestors, crossarms, missing grounds, uninsulated downguys, etc.

Aggressive Correction Action Program[43]

2.7 Annual Program for Repeat Priority Feeders

The review of the 16 feeders selected for the 2% Priority Feeder initiative with previous year selections show that two feeders (15710 and 16003) which were in the 2020 Priority Feeder Program reappeared on the 2022 Priority Feeder Program. When a feeder repeats, additional aggressive corrective actions are implemented. All of the corrective actions listed will be completed in 2022.

RELIABILITY STATISTICS*

Service Reliability Indices

SAIDI, SAIFI, and CAIDI are the specific indices used and provide information about both the duration and frequency of outages for customers. These indices are described as follows:

SAIDI - System Average Interruption Duration Index. Designed to provide information about the average time (in aggregate) that the customers served in a predefined area are interrupted.

SAIFI - System Average Interruption Frequency Index. Designed to give information about the average frequency of sustained interruptions per customer served in a predefined area.

CAIDI - Customer Average Interruption Duration Index. Designed to provide information about the average time required to restore service to the average customer experiencing a sustained interruption.

Each index is calculated several times, once with all outage data and then according to the specific significant event exclusions specified. The expectation is that the indices calculated with significant event related outage data excluded will provide a reflection of system performance under normal operating conditions. The indices calculated with all outage data will provide a reflection of the impact of significant events on the system. It is important to note that a year-to-year comparison of reliability indices calculated with all outage data would not be appropriate. The indices during a

[43] In Order No. 15152 issued on Pepco's 2008 Consolidated Report, the Commission stated (at paragraph 72):

72. PEPCO is DIRECTED, beginning with the 2009 Consolidated Report, to identify the feeders that are part of the separate annual program of corrective actions for reappearing least reliable feeders, describe the corrective actions planned for each feeder and the projected dates for completion of the corrective actions and explain whether the corrective actions improved the performance of these feeders consistent with paragraph 59 of this Order.

year in which major storms or events impact an electric utility will be substantially different from the indices during a year in which no such issues arise.

Service Outage Statistics [44][45]

Presented in Table 20 and 21 are the SAIDI, SAIFI and CAIDI values for the past five years at IEEE- 2.5 Beta Criteria. These reliability indices are provided for all sustained interruptions and all sustained interruptions excluding major events. A sustained interruption is defined as an interruption of five (5) minutes or greater. Table 20 shows performance indices including and excluding PEPCO major event days. Table 21 shows performance indices including and excluding District of Columbia major event days only.

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[44] In Order No. 16623 paragraphs 48, 62 and 63, the Commission stated the following:
48. …Therefore, we hereby require that Pepco include reliability calculations using District of Columbia-only data and relying on a Major Service Outage exclusion in the 2012 Consolidated Report and in future Consolidated Reports. We also require that Pepco include in its 2012 Consolidated Report a revised version of its reliability calculations from the 2010 and 2011 Consolidated Reports using D.C.-only data and excluding Major Service Outages. Pepco shall also include calculations of reliability indices for the entire Pepco system using system-wide data and Major Event Day exclusions, as well as reliability indices for Pepco D.C. using D.C.- only MEDs in the 2012 Consolidated Report and in future Consolidated Reports, so that we may make comparisons. For purposes of this requirement, the "reliability calculations" contained in the Consolidated Report include all calculations of SAIDI, SAIFI and CAIDI, discussion of failure rate data, and selection of Priority Feeders. (Footnote: Because the Aggressive Corrective Action Program requires the identification of feeders that have been listed as Priority Feeders in the past using system-wide, MED-excluding data, we will allow Pepco to continue to select ACAP feeders using that data. However, we require that a list of Priority Feeders using the new method of calculation be included in the 2012 Consolidated Report.)
62. Pepco is DIRECTED to include in the 2012 Consolidated Report reliability calculations using District of Columbia-only data and excluding Major Service Outages consistent with paragraph 48;
63. Pepco is DIRECTED to include in the 2012 Consolidated Report a revised version of the reliability calculations contained in the 2010 and 2011 Consolidated Report using District of Columbia-only data and excluding Major Service Outages consistent with paragraph 48

[45] In Order No. 16700 issued February 12, 2012, paragraphs 10 and 11, the Commission stated:
10. In establishing out new reliability performance standards, we decided that Pepco should be given a reasonable amount of time to "ramp up" to our new requirements. Therefore, we made the new SAIDI and SAIFI standards effective beginning in 2013. By replacing the prior rule with a new one, and giving Pepco a transition period, we created a "gap" in reliability measures. We saw no harm in a temporary suspension of reliability benchmarks, recognizing that the standards in effect for 2013 through 2020 would require significant improvement on Pepco's part, starting at once. For example, in order to meet our 2013 SAIDI target, Pepco must make either about a 9% improvement in both 2012 and 2013 or about an 18% improvement in 2013. Therefore, we saw no risk that Pepco would suffer a significant "backslide" in reliability because there were no effective standards in place for 2011 or 2012.
11. We do not believe that reestablishment (for the years 2011 and 2012) of the standards to which Pepco was previously held is necessary. (Footnote: We note that not all states have Electric Quality of Service Standards. For example, Pepco presently operates in Maryland without standards but is required to provide annual reliability indices pursuant to COMAR 20.50.07.06.) Nor has Pepco provided any reason for that reestablishment. Consequently, we decline to make the clarification that Pepco requests. However, we do expect that Pepco will continue to report on its reliability performance in its annual Consolidated Report and we concur with OPC in its suggestion that Pepco coordinate its data reporting so that Pepco calculations are a consistent "apples to apples" comparison from 2011 through 2013 and beyond. Therefore, as OPC has requested, we require Pepco to include in its annual report a description of its performance and a calculation of whether it would have met the appropriate SAIFI, SAIDI and CAIDI standards had they been in effect.
14. Pepco shall include in its 2012 and 2013 annual Consolidated Reports calculations of SAIDI, SAIFI, and CAIDI as described in paragraph 11.

Table 20 Pepco System Indices 2017-2021

Pepco System Indices 2017-2021 2.5 Beta (MED Exclusive - IEEE 1366-2012 Std, Pepco System Wide Based)					
SAIFI	**2017**	**2018**	**2019**	**2020**	**2021**
Sustained Outages	0.68	0.90	0.73	0.58	0.58
Sustained Less Major Storms	0.68	0.71	0.65	0.54	0.52
SAIDI (HOURS)	**2017**	**2018**	**2019**	**2020**	**2021**
Sustained Outages	1.03	2.70	1.22	0.92	1.12
Sustained Less Major Storms	1.03	0.98	0.97	0.78	0.85
CAIDI (HOURS)	**2017**	**2018**	**2019**	**2020**	**2021**
Sustained Outages	1.52	3.02	1.67	1.59	1.91
Sustained Less Major Storms	1.52	1.37	1.49	1.45	1.63

Table 21 District of Columbia System Indices 2017-2021

District of Columbia System Indices 2017-2021 2.5 Beta (MED Exclusive - IEEE 1366-2012 Std, District of Columbia System Wide Based)					
SAIFI	**2017**	**2018**	**2019**	**2020**	**2021**
Sustained Outages	0.55	0.64	0.59	0.40	0.45
Sustained Less Major Storms	0.55	0.54	0.49	0.37	0.41
SAIDI (HOURS)	**2017**	**2018**	**2019**	**2020**	**2021**
Sustained Outages	0.96	1.82	1.29	0.73	0.86
Sustained Less Major Storms	0.96	0.88	0.92	0.65	0.71
CAIDI (HOURS)	**2016**	**2017**	**2018**	**2019**	**2020**
Sustained Outages	1.73	2.83	2.20	1.81	1.94
Sustained Less Major Storms	1.73	1.64	1.86	1.74	1.71

Presented in Tables 22 and 23 are the SAIFI, SAIDI and CAIDI values for the past five years at IEEE-using MSO Criteria. Please note that the data presented in Tables 22 and 23 provide data using a different methodology (MSO criteria) than previous years. This change in the presentation of data can cause changes to historically reported data due to the different exclusion criteria**.**

Table 22 Pepco System Indices 2017-2021

Pepco System Indices 2017-2021 MSO Criteria (MED Exclusive - IEEE 1366-2012 Std, Pepco System Wide Based)					
SAIFI	**2017**	**2018**	**2019**	**2020**	**2021**
Sustained Outages	0.68	0.90	0.73	0.58	0.58
Sustained Less Major Storms	0.66	0.69	0.73	0.55	0.52
SAIDI (HOURS)	**2017**	**2018**	**2019**	**2020**	**2021**
Sustained Outages	1.03	2.70	1.22	0.92	1.12
Sustained Less Major Storms	1.01	0.93	1.22	0.82	0.88
CAIDI (HOURS)	**2017**	**2018**	**2019**	**2020**	**2021**
Sustained Outages	1.52	3.02	1.67	1.59	1.91
Sustained Less Major Storms	1.52	1.35	1.67	1.48	1.68

Table 23 District of Columbia System Indices 2017-2021

District of Columbia System Indices 2017-2021 MSO Criteria (MED Exclusive - IEEE 1366-2012 Std, District of Columbia System Wide Based)					
SAIFI	**2016**	**2017**	**2018**	**2019**	**2020**
Sustained Outages	0.55	0.64	0.59	0.40	0.45
Sustained Less Major Storms	0.55	0.53	0.59	0.40	0.45
SAIDI (HOURS)	**2016**	**2017**	**2018**	**2019**	**2020**
Sustained Outages	0.96	1.82	1.29	0.73	0.86
Sustained Less Major Storms	0.96	0.86	1.29	0.73	0.86
CAIDI (HOURS)	**2016**	**2017**	**2018**	**2019**	**2020**
Sustained Outages	1.73	2.83	2.20	1.81	1.94
Sustained Less Major Storms	1.73	1.63	2.20	1.81	1.94

Order No. 16975 states the following at paragraphs 62 and 106:

*62. **Decision:** The Commission directs Pepco to provide SAIDI and SAIFI statistics in the future Consolidated Reports calculated by both including and excluding cross- border feeders. Pepco shall identify which feeders it treats as "cross-border" for this purpose.*

*106. Pepco is **DIRECTED** to provide SAIDI and SAIFI information consistent with paragraph 62 herein;*

Table 24 District of Columbia Reliability Inclusive and Exclusive of Cross-Border Feeders (2021)

2021 IEEE MED Exclusive		
District of Columbia Reliability Statistics	SAIFI	SAIDI (Hours)
Excluding all cross-border feeders	0.33	0.57
Including all cross-border feeders	0.49	0.79

2021 DC MSO (& COMAR) Exclusive		
District of Columbia Reliability Statistics	SAIFI	SAIDI (Hours)
Excluding all cross-border feeders	0.35	0.67
Including all cross-border feeders	0.53	0.95

*Note- COMAR is a Maryland criteria and MSO is a DC criteria.

MSO and COMAR are not compatible with each other.

Comparison of Cross-Border Feeder Reliability Performance[46]

Pepco calculates reliability indices on a feeder level in the same way regardless of the location of a feeder. For feeders that have customers in both the District of Columbia and Maryland, the indices for these feeders are included for reporting purposes with the jurisdiction in which most customers on these feeders reside. Because feeders may switch between jurisdictions over time, to make their impact on reliability performance clear, Pepco presents system reliability performance both with and without both feeders assigned to the District of Columbia and Maryland, thereby allowing comparisons across different years.

Note: Feeders with two source substations listed are 4 kV primary network feeders and are supplied from two substations.

[46] The following is in response to the Commission's directive to:
[I]include in its 2015 Annual Consolidated Report an explanation of the metric or metrics it will use to report upon the reliability performance of its cross-jurisdictional feeders. This explanation is also to describe how Pepco's chosen metric(s) will allow reliability performance to be compared from year-to- year, when the jurisdictional status of a feeder changes between Maryland and the District
In The Matter of the Annual Consolidated Report of the Potomac Electric Power Company, Formal Case No. PEPACR-2014-01, Order No. 17816 at P 241 (February 27, 2015).

Table 25 Pepco 4kV & 13kV Cross Jurisdictional Feeders Serving Majority DC Customers (As of 12/31/2021)

PEPCO 4 & 13KV CROSS JURISDICTIONAL FEEDERS SERVING MAJORITY DC CUSTOMERS

(Based on customers served, not physical presence)

Feeder No.	Substation Name	Substation No.	Substation Name	Substation No.	MD Customers	DC Customers	% UG	% OH
120	Chesapeake Street	181	-	-	3	555	4%	96%
183	Chesapeake Street	181	-	-	146	367	13%	87%
205	Seat Pleasant	30	Fort Chaplin	70	4	484	1%	99%
308	Harrison	38-6	Westmoreland	93	4	569	96%	4%
327	Fort Dupont	58	Texas Ave.	111	59	248	5%	95%
328	Fort Dupont	58	Fort Davis	100	53	357	2%	98%
333	Chesapeake Street	181	-	-	60	491	9%	91%
366	Seat Pleasant	30	53rd Street, SE	48	3	538	3%	97%
368	53rd Street, SE	48	Fort Davis	100	64	517	4%	96%
372	Seat Pleasant	30	53rd Street, SE	48	187	594	4%	96%
388	53rd Street, SE	48	-	-	3	632	3%	97%
451	Fort Davis	100	Texas Ave.	111	82	129	4%	96%
476	Quesada	89	Oliver Street	146	3	305	17%	83%
14014	12th & Irving	133	-	-	694	1400	10%	90%
14015	12th & Irving	133	-	-	105	808	17%	83%
14016	12th & Irving	133	-	-	25	873	46%	54%
14031	Suitland	134	-	-	266	1015	13%	87%
14035	Suitland	134	-	-	530	864	39%	61%
14261	Beech Road	159	-	-	365	989	7%	93%
14352	Harrison	38	-	-	4	33	100%	0%
14717	Benning	7	-	-	32	1741	26%	74%
14758	N.R.L.	168	-	-	2	2178	34%	66%
14890	Harrison	38	-	-	218	610	17%	83%
14893	Harrison	38	-	-	5	9	100%	0%
14900	Harrison	38	-	-	287	1070	26%	74%
14987	Grant Avenue	183	-	-	936	1189	24%	76%
15085	St. Barnabas Road	59	-	-	767	943	37%	63%
15094	Bladensburg	175	-	-	1041	1489	61%	39%
15130	Walker Mill Road	15	-	-	754	1281	31%	69%
15171	Alabama Avenue	136	-	-	7	1778	42%	58%
15198	Takoma	27	-	-	97	1622	18%	82%
15199	Takoma	27	-	-	253	1745	28%	72%
15648	Little Falls	77	-	-	0	0	100%	0%
15649	Little Falls	77	-	-	1	0	100%	0%
15711	Benning	7	-	-	86	1654	12%	88%
15944	Van Ness	129	-	-	18	1347	17%	83%

Note: Feeders 15648 and 15649 supply the Dalecarlia Pumping Station (DC) and the Army Map Service (MD)

Note: Feeders with two source substations listed are 4 kV primary network feeders and are supplied from two substations.

Table 23 Pepco 4 & 13 kV Cross Jurisdictional Feeder s Serving a Majority Maryland Customers

PEPCO 4 & 13KV CROSS JURISDICTIONAL FEEDERS SERVING MAJORITY MARYLAND CUSTOMERS

(Based on customers served, not physical presence)

Feeder No.	Substation Name	Substation No.	Substation Name	Substation No.	MD Customers	DC Customers	% UG	% OH
152	Fort Dupont	58	Randle Highlands	71	188	150	2%	98%
365	53rd Street, SE	48	Fort Dupont	58	514	232	13%	87%
14032	Suitland	134	-	-	569	75	26%	74%
14033	Suitland	134	-	-	1663	264	15%	85%
14102	Tuxedo	148	-	-	927	69	11%	89%
14263	Linden	156	-	-	1815	66	20%	80%
14270	Linden	156	-	-	741	6	45%	55%
14271	Linden	156	-	-	724	621	22%	78%
14593	Sligo	9	-	-	141	3	100%	0%
14595	Sligo	9	-	-	115	1	100%	0%
14768	Little Falls	77	-	-	1269	8	26%	74%
14896	Harrison	38	-	-	615	353	14%	86%
14949	Wood Acres	154	-	-	1373	22	7%	93%
14979	Grant Avenue	183	-	-	1045	194	6%	94%
15082	St. Barnabas Road	59	-	-	2008	190	62%	38%
15086	St. Barnabas Road	59	-	-	612	190	32%	68%
15090	St. Barnabas Road	59	-	-	1411	62	12%	88%
15100	Bladensburg	175	-	-	663	659	16%	84%
15131	Walker Mill Road	15	-	-	1302	339	42%	58%
15132	Walker Mill Road	15	-	-	1740	105	21%	79%
15200	Takoma	27	-	-	835	584	15%	85%
15264	Takoma	27	-	-	999	655	14%	86%
15501	Little Falls	77	-	-	24	22	100%	0%
15502	Little Falls	77	-	-	16	7	100%	0%
15503	Little Falls	77	-	-	19	3	100%	0%
15504	Little Falls	77	-	-	152	1	100%	0%
15505	Little Falls	77	-	-	39	0	100%	0%
15506	Little Falls	77	-	-	443	9	100%	0%

15501- 15506 are part of the Little Falls Network Group and all are involved in serving at least one DC customer

14593 is part of the Sligo South LVAC Network group that supplies mainly Maryland Customers.

2.8 NEIGHBORHOOD ANALYSIS

Starting with Order No. 16623, the Commission has required a specific focus on neighborhoods in the Consolidated Report. This section addresses each of the neighborhood subjects required by the Commission.

In response to the Commission's requirements for reporting the neighborhoods impacted by reliability issues and remediation work, Pepco developed a comprehensive list of the feeders serving District of Columbia customers and the neighborhoods served by each in May of 2012. In order to provide neighborhood identification that is both accurate and consistent from one submission to another, Pepco is now using assessment neighborhoods as defined by the District of Columbia Office of Tax and Revenue (OTR) Real Property Tax Administration (RPTA). Pepco is assessing new methods to programmatically identify the neighborhoods each Pepco feeder serves and plans to further discuss these plans in the future.

Neighborhood Analysis Requirements

(A) Neighborhoods warranting infrastructure improvements due to increased load growth[47]

Response: See discussion for Neighborhood Item A below.

(B) Neighborhoods with decreased planned spending on 4 kV to 13 kV conversions[48]

(C) Neighborhoods with decreased planned spending on 4 kV to 13 kV conversions that are among previously identified Most Susceptible Neighborhoods[49]

(D) Explanation of how reduced conversion spending will improve reliability in Most Susceptible Neighborhoods[50]

Response: See discussion for Neighborhood Items B, C, and D below.

(E) Neighborhoods served by Priority Feeders

Response: See Priority Feeder discussion.[51]

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[47] Order No. 16623 states the following at paragraph 35:
35. We find Pepco's explanation to be credible but require further information on the neighborhoods in the District impacted by Pepco's changed plans. Specifically, we direct Pepco to identify those neighborhoods which warrant further infrastructure improvements due to increased load growth, including any explanation and data on Pepco's forecasts of load growth in those neighborhoods. (Footnote: In identifying neighborhoods, Pepco should use the methodology it used for defining and selecting neighborhoods in its May 20, 2011 submission to the Commission, or provide an explanation of why that methodology was not used. See F.C. Nos. 766, 982 and 991, Response of the Potomac Electric Power Company to Order No. 16347, May 20, 2011, Attachment 2.)…

[48] Order No. 16623 states the following at paragraph 35:
…Similarly, we require Pepco to identify those neighborhoods where planned spending on 4 kV to 13 kV conversion projects has decreased…

[49] Order No. 16623 states the following at paragraph 35:
…Further, we require that Pepco indicate if any of the neighborhoods it identifies pursuant to this paragraph is among the Most Susceptible Neighborhoods identified in Order No. 14626, Appendix A. (Footnote: See F.C. Nos. 766, 982, and 991, Order No. 16426, July 7, 2011, Appendix A.)…

[50] Order No. 16623 states the following at paragraph 35:
If any of the neighborhoods identified in this paragraph is among those Most Susceptible Neighborhoods, Pepco is directed to provide a full explanation of how its changed plans will improve reliability in that neighborhood.

[51] Order No. 16623 states the following at paragraph 46:
46. In connection with the second prong of our reliability efforts, our neighborhood initiative, we believe it is important to know whether any of the Priority Feeders are the feeders which serve the Most Susceptible Neighborhoods in the District. Beginning in the 2012 Consolidated Report, we require that Pepco identify the neighborhoods served by any Priority Feeders…

(F) Neighborhoods served by Repeat Priority Feeders[52]

Response: See Repeat Priority Feeder discussion.

(G) Neighborhoods served by equipment subject to failure data rate analysis[53]

Response: See Failure Data Rate Analysis discussion.

(H) Updated list of Most Susceptible Neighborhoods for Calendar Year 2011[54]

Response: See Neighborhood Item H, Most Susceptible Neighborhoods update below.

(I) Neighborhood information to be included in 2012 Consolidated Report[55]

Response: This information was included in the 2012 Consolidated Report as specified above.

(J) Directive to identify neighborhoods affected by changed plans[56]

Response: See discussion for Neighborhood Items A, B, C, and D below.

(K) Directive to provide information on neighborhoods[57]

Response: See discussion for Neighborhood Items E, F, G, H, and I.

Neighborhood Item A.

Neighborhoods with Increased Load Growth

Pepco forecasts load by substation using identified PNB load along with the load reducing effects of net energy metering and conservation programs (and DERs generally) to develop short term forecasts and uses trends plus knowledge of future planned development to develop a long-term forecast for each substation in the Pepco system.

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[52] Order No. 16623 states the following at paragraph 46:
…and any Repeat Priority Feeder (those in the ACAP program). (Footnote: In identifying neighborhoods, Pepco should use the methodology it used for defining and selecting neighborhoods in its May 20, 2011 submission to the Commission, or provide an explanation of why that methodology was not used. See F.C. Nos. 766, 982 and 991, Response of the Potomac Electric Power Company to Order No. 16347, May 20, 2011, Attachment 2.)...

[53] Order No. 16623 states the following at paragraph 46:
…Further, we require that Pepco identify the neighborhoods served by any equipment subject to the failure data rate analysis proposed by Pepco at the October 18, 2011 PIWG meeting for inclusion in the 2012 Consolidated Report. (Footnote: See October 18, 2011 PIWG Meeting Minutes at 1.)…

[54] Order No. 16623 states the following at paragraph 46:
We also require Pepco to update its list of Most Susceptible Neighborhoods to identify the neighborhood in each Ward experiencing the most frequent non-major outages in Calendar Year 2011.

[55] Order No. 16623 states the following at paragraph 46:
…This information should be included in the 2012 Consolidated Report

[56] Order No. 16623 states the following at paragraph 55:
55. Pepco is DIRECTED to identify neighborhoods affected by changed plans consistent with paragraph 35;

[57] Order No. 16623 states the following at paragraph 60:
60. Pepco is DIRECTED to provide information on neighborhoods consistent with paragraph 46;

There are areas where Pepco anticipates above average load growth, and these include the Mt. Vernon Square/Convention Center neighborhood (R.L.A.[58] (N.E.) assessment neighborhood), NoMa (R.L.A. (N.E.) assessment neighborhood), the Washington Navy Yard/Southwest (R.L.A. (S.W.) assessment neighborhood) neighborhood and the area around St. Elizabeth's Hospital and Columbia Heights.

Neighborhood Items B, C, D.

Neighborhoods with Decreased Planned Spending on 4 kV to 13 kV Conversions

Pepco does not currently estimate a material decrease in planned spending in 2021 compared to 2020 as conversions continue in the 12th Street SW, Georgetown, and North Capitol areas. Conversions will continue in North Capitol and 12th St. substations areas in 2021with the goal to have all load served by Spring of 2021 and Fall of 2021, respectively. Pepco is planning to complete the Anacostia 4 kV conversion project in 2021 with the conversion of the last remaining 4kV Feeder supplied from Anacostia Sub. 8.

Neighborhood Item F.[59]

Table 26 lists the feeders that have appeared more than once on the 2% Priority Feeder list, the years they appeared, and the neighborhoods they serve.

[58] Redevelopment Land Agency.
[59] In Order No. 15941 issued on August 18, 2010, the Commission stated at paragraphs 13 and 16, the following:

Table 26*: F*eeders that have appeared more than once on the 2% Priority Feeder *List*

Feeder	Years Appeared on Priority Feeder List Since 2001	Neighborhoods
27	2003, 2007, 2009	Shaw
53	2009, 2014	Columbia Heights, Park View
82	2007, 2015	Chevy Chase, Forest Hills, North Cleveland Park, Tenleytown Wakefield
211	2015, 2020	Capitol Hill
212	2014, 2016	Capitol Hill
227	2003, 2016	Barney Circle, Capitol Hill
228	2011, 2017	Barney Circle, Capitol Hill, Navy Yard
233	2010, 2016	East Potomac Park, LadyBird Johnson Park, National Mall - West Potomac Park, Southwest Federal Center
14001	2011, 2013	Bloomingdale, Eckington, Edgewood, Ledroit Park, Pleasant Plains
14004	2002, 2006	Bloomingdale, Eckington, Ledroit Park
14005	2001, 2021	Fort Lincoln, Gateway, Langdon
14006	2002, 2013, 2015	Brookland, Edgewood, Stronghold
14007	2001, 2003, 2005, 2008	Brookland, Michigan Park, Woodbridge, Catholic University, North Michigan Park
14008	2002, 2004, 2008, 2011	Brentwood, Ivy City, Langdon
14009	2013, 2017	Brookland, Catholic University, Eckington, Edgewood, Stronghold
14014	2001, 2004, 2006, 2013, 2017, 2019,2022	Brookland, Langdon, Woodridge
14015	2001, 2004, 2009	Brookland, Michigan Park, Woodbridge, Catholic University, North Michigan Park
14016	2003, 2016	Arboretum, Fort Lincoln, Gateway, Ivy City, Langdon, National Arboretum, Woodridge
14017	2006, 2015	Brookland, Catholic University, Michigan Park, Stronghold
14023	2006, 2019, 2021	Brentwood, Brookland, Eckington
14031	2014, 2018	Dupont Park, Fairfax Village, Good Hope, Hillcrest, Naylor Gardens, Penn Branch
14054	2004, 2007	Columbia Heights, Sixteenth Street Heights
14093	2001, 2019	Arboretum, Brentwood, Brookland, Gateway, Langdon, National Arboretum
14133	2011, 2021	Forest Hills, North Cleveland Park
14136	2010, 2012, 2014, 2020	Cathedral Heights, Cleveland Park, Glover Park, McLean Gardens
14146	2002, 2005,2022	Georgetown, Observatory Circle, Woodland-Normanstone Terrace, Woodley Park
14150	2012, 2021	American University Park, Cleveland Park, McLean Gardens
14200	2009, 2011, 2013, 2015, 2018	Bloomingdale, Brookland, Catholic University, Edgewood, Stronghold
14261	2017, 2020	Garfield Heights, Good Hope, Hillcrest, Naylor Gardens
14701	2001, 2003, 2010, 2012, 2017	Buena Vista
14702	2015, 2017	Anacostia, Fairlawn, Good Hope, Greenway, Baylor Gardens, Randle Highlands, Twining
14712	2007, 2021	Kingmand Park, Mayfair, Near Northeast, Trinidad
14717	2001, 2003, 2007, 2009, 2012, 2014, 2017, 2019,2022	Burrville, Deanwood, East Corner, Lincoln Heights, Mayfair
14729	2004, 2006	Columbia Heights, Park View, Petworth, Sixteenth Street Heights
14753	2003, 2009, 2014, 2017	Bellevue, Washington Highlands
14755	2002, 2017	Bellevue, Congress Heights, Washington Highlands
14758	2003, 2012, 2014, 2017, 2021	Anacostia Naval Station - Bolling Air Force Base, Bellevue, Washington Highlands
14766	2002, 2006, 2021	American University Park, Potomac Heights, Spring Valley
14767	2002, 2008, 2015, 2018,2022	Berkley, Kent, Potomac Heights, The Palisades, Wesley Heights
14786	2007, 2013, 2016, 2019	Brentwood, Capitol Hill, Gallaudet, Judiciary Square, Mount Vernon Square, Near Northeast
14787	2005, 2008, 2013	Capitol Hill, Gallaudet, Mount Vernon Square, Near Northeast, NoMa
14788	2007, 2013	Capitol Hill, Near Northeast, NoMa
14890	2008, 2011	American University Park, Chevy Chase, Friendship Heights
14900	2002, 2007, 2009, 2011, 2013, 2016, 2019, 2021	Bamaby Woods, Chevy Chase, Hawthorne
15009	2005, 2009, 2012, 2014	Manor Park, Riggs Park, Takoma
15011	2001, 2003, 2008, 2016	Brightwood, Sixteenth Street Heights
15012	2001, 2005	Manor Park, Petworth, Sixteenth Street Heights
15013	2003, 2006, 2017, 2019, 2021	Catholic University, Fort Totten, Manor Park, Pleasant Hill, Riggs Park, Stronghold
15014	2009, 2012, 2015, 2017	Fort Totten, Manor Park, Riggs Park
15016	2002, 2005	Manor Park, Riggs Park
15021	2005, 2014, 2018, 2020	Brightwood, Brightwood Park, Manor Park, Shepherd Park
15085	2014, 2017	Washington Highlands
15094	2012, 2018, 2020	Fort Lincoln, Woodridge
15130	2014, 2016, 2020	Benning Ridge, Civic Betterment, Fort Davis, Marshall Heights
15166	2010, 2013, 2021	Congress Heights, Shipley Terrace, Washington Highlands
15170	2006, 2010, 2015, 2018	Douglas, Good Hope, Naylor Gardens, Skyland
15171	2002, 2005, 2014,2022	Congress Heights, Shipley Terrace, Washington Highlands
15172	2006, 2010, 2012, 2019	Buena Vista, Douglas, Saint Elizabeths
15173	2014, 2018,2022	Anacostia, Buena Vista, Douglas, Garfield Heights, Knox Hill, Naylor Gardens, Shipley Terrace, Woodlands
15174	2010, 2013, 2015, 2018	Garfield Heights, Knox Hill, Shipley Terrace, Skyland, Woodlands
15197	2001, 2007, 2005, 2019, 2021	Crestwood, Petworth, Sixteenth Street Heights
15199	2001, 2004, 2010, 2012, 2014	Brightwood, Colonial Village, Riggs Park, Shepherd Park, Takoma
15206	2008, 2010	Bloomingdale, Ledroit Park, Logan Circle, Mount Vernon Square, Shaw, Tuxton Circle
15701	2001, 2003, 2005, 2010, 2015	Brentwood, Carver, Gallaudet, Ivy City, Kingman Park, Langston, Trinidad
15702	2005, 2012, 2016, 2020	Capitol Hill, Carver, Langston, National Arboretum, Near Northeast, Trinidad
15703	2004, 2006	Bamey Circle, Capitol Hill, Carver, Kingman Park, Langston
15705	2003, 2009, 2011, 2013, 2017	Deanwood, Eastland Gardens, Kenilworth, Mayfair
15706	2009, 2011, 2016	Benning, Benning Heights, Benning Ridge, Fort Dupont, Hillbrook, Mahaning Heights, Marshall Heights
15707	2007, 2010, 2013,2016, 2020	Deanwood, Hillbrook, Lincoln Heights, Mahaning Heights
15709	2004, 2006, 2008, 2010, 2018, 2021	Benning, Dupont Park, Fort Dupont, Greenway, River Terrace
15710	2013, 2017, 2020,2022	Benning, Benning Heights, Fort Dupont, Greenway, Kingman Park, Mahaning Heights, River Terrace
15801	2002, 2005, 2008, 2010, 2013	Kent, Potomac Heights, The Palisades
15867	2002, 2008, 2014, 2020	Cleveland Park, Forest Hills, North Cleveland Park, Woodland-Norman stone Terrace, Woodley Park
15943	2008, 2010, 2012, 2016	Burleith, Georgetown, Glover Park
15945	2011, 2013, 2015, 2018	American University Park, Tenleytown

Neighborhood Item H.

Most Susceptible Neighborhoods by Ward with Most Frequent Non-Major Outages in 2021

Most Susceptible Neighborhood Analysis

Pepco was directed to provide analysis regarding the neighborhoods that were most susceptible to outages as determined by outage data. Pepco's original approach as previously filed was based upon identifying where there was a SAIFI / SAIDI impact on a Ward basis based upon the feeders that served specific neighborhoods in that Ward. Pepco has now taken a more defined geospatial approach of determining the most susceptible neighborhoods based on customer's experiencing multiple interruptions (CEMI) within that individual neighborhood. Neighborhoods in which greater than 250 customers experienced 3 or more outages in a single year within the last two years were selected. The outage analysis is inclusive of major service outages (MSOs) in order to capture the true experience of the customer. See Table 27 for the analysis of the most susceptible neighborhoods.

Table 27: Most Susceptible Neighborhoods

Neighborhood	Ward	CEMI3+ 2020	CEMI3+ 2021	Priority Feeders 2021	Priority Feeders 2022
River Terrace	Ward 7	3	1023	15709	15710
Benning	Ward 7	2	818	15709	15710
Kingman Park	Ward 6	134	811	14712	14713
Pleasant Hill	Ward 5	51	661	15013	
Anacostia	Ward 8	5	496		15173
Bellevue	Ward 8	190	433	14758	
Shipley Terrace	Ward 8	55	419	15166	15173,15171
Mahaning Heights	Ward 7	21	365		15710
Buena Vista	Ward 8	156	364		15173
Michigan Park	Ward 5	100	364	14022	15018
Garfield Heights	Ward 8	0	358		15173
Washington Highlands	Ward 8	276	22	15166,14758	15171,15085
Trinidad	Ward 5	935	15	14712	14713
Brookland	Ward 5	456	3	14023,14022	14014
Congress Heights	Ward 8	268	1	15166	15171
Cleveland Park	Ward 3	308	1	14150	
American University Park	Ward 3	955	0	14766,14150	144,14132

Table 28 CEMIn Including Storms (MSO)

YEAR	CEMI3
2012	25.73%
2013	10.93%
2014	7.15%
2015	6.75%
2016	8.73%
2017	5.11%
2018	7.31%
2019	3.82%
2020	2.12%
2021	2.91%

From the analysis above, the 17 worst neighborhoods between 2020 and 2021 combined yielded 9 unique feeders to be remediated in 2022. Most of the feeders have been selected as part of a recent reliability program that also represents each neighborhood in this list. Additionally, the neighborhood list presented in this analysis represents 66% of the total DC customers that experienced three or more outages in 2021. See summary below:

- Feeders 15709, 14712, 15013, 14758, 15166, 14022, 14023, 14150, 14766, and 14150, were part of the 2021 Priority Feeder Program. The benefits on this work and other coincident work will be realized in 2022 and beyond.
- All remaining priority feeders are part of the 2022 Priority Feeder Program. The remediation work on these feeders is described above.

2.9 EQUIPMENT FAILURE RATES[60]

Pepco continues improvements to the quality of outage data. Outage data records are screened at multiple check points for accuracy. Control Center personnel review outage data daily for accuracy and make necessary edits to reflect actual circumstances. Asset Management staff performs several validation screens monthly to catch other data entry errors. Reliability Engineering staff daily review outage data and field crew comments as part of outage reviews, reliability improvement programs and when questionable data is encountered and works with Control Center staff to resolve remaining issues.

Analysis of Top Three Equipment Failure Modes[61]

This information identifies and analyzes the top three equipment failure modes in the District of Columbia with regards to total customers affected. In addition, it identifies feeders for corrective actions to remediate these failures in the future based on root cause determination where appropriate.

[60] Order No. 16975 states the following at paragraphs 95 and 118:
85. Decision: In its Comments, OPC identifies several instances in which outage data is inconsistent or erroneous. Pepco itself has identified several areas in which it can improve outage data quality. In an effort to ensure that the Commission and OPC is receiving accurate outage data, the Commission requires Pepco to report in its 2013 Consolidated Report on its efforts to improve the collection and accuracy of information regarding outages.
114.Pepco is DIRECTED to report on outage data quality improvement consistent with paragraph [95] herein.

[61] In Order No. 16091, the Commission stated among other things, at paragraph 59, the following:
59. …(5)…If data on failure rates for all variables is available for manhole events, Pepco shall include such information in its 2011 Consolidated Report. If such data is unavailable, we require the members of PIWG to discuss the need for and the availability of such data include in the 2011 Consolidated Report the PIWG conclusions and recommendations, if any.

Analysis of Top Three Equipment Failure Modes[62]

This information identifies and analyzes the top three equipment failure modes in the District of Columbia with regards to total customers affected. In addition, it identifies feeders for corrective actions to remediate these failures in the future based on root cause determination where appropriate.

For purposes of this analysis, the following definitions are established.

- Events – number of outage events
- CI – number of customers interrupted
- CMI – Customer minutes of interruption
- SAIFI – System Average Interruption Frequency Index
- SAIDI – System Average Interruption Duration Index
- CAIDI – Customer Average Interruption Duration Index

Table 29 details the reliability impacts of primary equipment failures tracked by Pepco

[62] In Order No. 16091, the Commission stated among other things, at paragraph 59, the following:
59. …(5)…If data on failure rates for all variables is available for manhole events, Pepco shall include such information in its 2011 Consolidated Report. If such data is unavailable, we require the members of PIWG to discuss the need for and the availability of such data include in the 2011 Consolidated Report the PIWG conclusions and recommendations, if any.

Table 29– Event Detail for Equipment Failures

Equipment Type	Number of Outages	Pct % NI	CI	Pct % CI	CMI	Pct % CMI	SAIFI	CAIDI	SAIDI
Cable	231	28.70%	17287	27.99%	1904833.85	27.33%	0.05	110	5.94
Distr. Ckt. Breaker	14	1.74%	9282	15.03%	1072912.17	15.39%	0.03	116	3.35
Switch	28	3.48%	8111	13.13%	735474.20	10.55%	0.03	91	2.29
Wire - Bare	22	2.73%	6145	9.95%	392944.85	5.64%	0.02	64	1.23
Fuse	38	4.72%	5796	9.38%	463281.43	6.65%	0.02	80	1.44
Elbow Insert	20	2.48%	3647	5.90%	806730.20	11.57%	0.01	221	2.52
Connection (i.e. Loose)	65	8.07%	3420	5.54%	134770.37	1.93%	0.01	39	0.42
ACR	3	0.37%	1279	2.07%	143301.08	2.06%	0.00	112	0.45
Transformer	73	9.07%	991	1.60%	353658.92	5.07%	0.00	357	1.10
Crossarm	9	1.12%	941	1.52%	176743.65	2.54%	0.00	188	0.55
Sectionalizer	2	0.25%	782	1.27%	264435.00	3.79%	0.00	338	0.82
Joint Failure	11	1.37%	765	1.24%	149478.95	2.14%	0.00	195	0.47
Wire - Covered	9	1.12%	756	1.22%	37130.75	0.53%	0.00	49	0.12
Insulator	7	0.87%	302	0.49%	33849.62	0.49%	0.00	112	0.11
Termination	3	0.37%	153	0.25%	45367.00	0.65%	0.00	297	0.14
Transformer - Subsurface	22	2.73%	132	0.21%	55261.33	0.79%	0.00	419	0.17
Transformer - Padmount	6	0.75%	109	0.18%	19063.23	0.27%	0.00	175	0.06
Bushing	16	1.99%	93	0.15%	13295.78	0.19%	0.00	143	0.04
Cutout	13	1.61%	80	0.13%	8425.38	0.12%	0.00	105	0.03
Pole	9	1.12%	10	0.02%	4760.90	0.07%	0.00	476	0.01
Transclosure	1	0.12%	7	0.01%	3605.00	0.05%	0.00	515	0.01
Service	2	0.25%	2	0.00%	654.03	0.01%	0.00	327	0.00
Splice	1	0.12%	1	0.00%	303.75	0.00%	0.00	304	0.00
Lightning Arrestor	1	0.12%	1	0.00%	134.48	0.00%	0.00	134	0.00
Total Primaries	606	75.28%	60092	97.28%	6820415.933	97.84%	0.19	113	21.27

Total Secondaries	199	24.72%	1680	2.72%	150535.6	2.16%	0.01	90	0.47

Total Primaries & Secondaries	805	100.00%	61772	100.00%	6970951.533	100.00%	0.19	113	21.74

Based on the number of customer outages, as shown above in highlighted rows, the top three classes of primary equipment failures contributing to SAIFI are cable, distribution circuit breakers and switch issues, accounting for 56.2% of total customers impacted and 53.3% of total customer minutes of interruption.

Cable Failure Analysis

Based on OMS data, the District of Columbia experienced 231 primary outages caused by cable failures during the period of analysis which affected 17,287 customers. There were 5 significant events that occurred accounting for 59.6% of the cable failure customer interruptions and 24.6% of the cable failure customer minutes of interruption. The first event occurred on 5/29/2021 out of the Waterfront substation. An underground cable failure accounted for 2,853 customer interruptions across circuits 16002 and 16003; this event also caused 32,144 customer minutes interrupted. Load was restored and no further action was required regarding this event. The second event occurred on 7/6/2021 out of the Benning substation. An underground cable failure on circuit 14713 accounted for 2,603 customer interruptions; this event also caused 260,434 customer minutes interrupted. Load was restored and no further action was required regarding this event. The third event occurred on 7/16/2021 out of the Alabama Avenue substation. An underground cable failure on circuit 15173 accounted for 1,968 customer interruptions; this event also caused 38,856 customer minutes interrupted. Repairs were made and no further action was required regarding this event. The fourth event occurred on 4/6/2021 out of the Waterfront substation. An underground cable failure accounted for 1,567 customer interruptions across circuits 16002 and 16003; this event also caused 72,134 customer minutes interrupted. Load was restored and no further action was required regarding this event. The fifth event occurred on 5/12/2021 out of the Van Ness substation. An underground cable failure on circuit 14136 accounted for 1,313 customer interruptions; this event also caused 64,532 customer minutes interrupted. Load was restored and temporary repairs were made; final repairs were made the next day.

Cables are selected for remediation based on outage history and repeat outages on sections of cable or repeat outages in neighborhoods. A program is in place to install interrupters on underground primary cable. An interrupter is a similar device to the recloser in that it can isolate the fault and restore service to customers that are not on the same section of the feeder as the outage. This will reduce the number of customer interruptions caused by cable failures and assist repair crews in locating the outage.

Table 30 – Cable Failure Rates

2021 (Jan 1 - Dec 31)	Mode of Failure: Cable Failure (Primary)			
	CI	%	CMI	%
YE Total	17,287	27.99%	1,904,834	27.33%
3 Major Events*	10,304	59.61%	468,101	24.57%

* % related to the total number of primary cable failure events

Analysis of these 231 cable failure events as reported by OMS revealed that 59.6% of the customers impacted by cable failure can be attributed to three events. See summary below:

Table 31 details the primary cable failure events causing the largest customer impact.

Table 31 – Event Detail for Cable Failures

Feeder	Substation	Date	CI	CMI	Cause	UG Miles	UG%	Comment
16002/16003	Waterfront	5/29/2021	2,853	32144	UG Cable Failure	25.79	100.0%	Load restored, no further action required
14713	Benning	7/6/2021	2,603	260,434	UG Cable Failure	6.7	99.7%	Load restored, no further action required
15173	Alabama Ave	7/16/2021	1,968	38,856	UG Cable Failure	3.65	30.8%	Repairs made, no further action required
16002/16003	Waterfront	4/6/2021	1,567	72,134	UG Cable Failure	25.79	100.0%	Load restored, no further action required
14136	Van Ness	5/12/2021	1,313	64,532	UG Cable Failure	6.22	76.1%	Load restored; temporary repair made. Final repairs occurred on next day
Total:			**10,304**	**468,100**				

Distribution Circuit Breaker Analysis

Based on OMS data, the District of Columbia experienced 14 distribution circuit breaker-related outages during the period of analysis which affected 9,282 customers. There were 5 significant events that attributed to 98.9% of the customers impacted and 99.2% of the customer minutes of interruption. The first event occurred on 6/3/2021 out of the Benning substation. A distribution circuit breaker failure accounted for 2,244 customer interruptions on circuit 14713; this event also caused 449,959 customer minutes interrupted. Load was restored and subsequent repairs occurred at a later date. The second event occurred on 6/3/2021 out of the Benning substation. A distribution circuit breaker failure accounted for 2,234 customer interruptions on circuit 15710; this event also caused 141,896 customer minutes interrupted. Load was restored and subsequent repairs occurred at a later date. The third event occurred on 6/3/2021 out of the Benning substation. A distribution circuit breaker failure accounted for 1,686 customer interruptions on circuit 15711; this event also caused 100,480 customer minutes interrupted. Load was restored and subsequent repairs occurred at a later date. The fourth event occurred on 6/3/2021 out of the Benning substation. A distribution circuit breaker failure accounted for 1,534 customer interruptions on circuit 14717; this event also caused 177,606 customer minutes interrupted. Load was restored and subsequent repairs occurred at a later date. The fifth event occurred on 6/3/2021 out of the Benning substation. A distribution circuit breaker failure accounted for 1,481 customer interruptions on circuit 15705; this event also caused 194,357 customer minutes interrupted. Load was restored and subsequent repairs occurred at a later date.

Table 32 – Distribution Circuit Breaker Failure Rates

2021 (Jan 1 - Dec 31)	Mode of Failure: Distr. Ckt. Breaker (Primary)			
	CI	%	CMI	%
YE Total	9,282	15.03%	1,072,912	15.39%
5 Major Events*	9,179	98.89%	1,064,298	99.20%

* % related to the total number of primary distr. ckt breaker events

Analysis of these 14 events as reported by OMS revealed that 98.9% of the customers impacted by distribution circuit breakers can be attributed to five events. See summary below:

Table 33 details the primary distribution circuit breaker events causing the largest customer impact.

Table 33 – Event Detail for Distribution Circuit Breakers

Feeder	Substation	Date	CI	CMI	Cause	UG Miles	UG%	Comment
14713	Benning	6/3/2021	2,244	449,959	Distr. Circuit Breaker Failure	6.7	99.7%	Load restored; subsequent repairs occurred at later date
15710	Benning	6/3/2021	2,234	141,896	Distr. Circuit Breaker Failure	1.6	20.0%	Load restored; subsequent repairs occurred at later date
15711	Benning	6/3/2021	1,686	100,480	Distr. Circuit Breaker Failure	1.35	12.2%	Load restored; subsequent repairs occurred at later date
14717	Benning	6/3/2021	1,534	177,606	Distr. Circuit Breaker Failure	2.08	26.0%	Load restored; subsequent repairs occurred at later date
15705	Benning	6/3/2021	1,481	194,357	Distr. Circuit Breaker Failure	3.03	40.4%	Load restored; subsequent repairs occurred at later date
Total:			**9,179**	**1,064,298**				

Switch Failure Analysis

Based on OMS data, the District of Columbia experienced 28 switch related outages during the period of analysis which affected 8,111 customers. There were 3 significant events that accounted for 89.4% of the customer interruptions and 68.5% of the customer minutes of interruption. The first event occurred on 5/23/2021 out of the Tenth Street substation. A switch failure caused 3,258 customers interrupted across feeders 15204R and 15204W and also accounted for 591,856 customer minutes interrupted. Crews made repairs accordingly and no further action was required regarding this event. The second event occurred on 9/30/2021 out of the Ft Slocum substation. A switch failure caused 2,257 customers interrupted across feeders 15004 and 15002 and also accounted for 20,012 customer minutes interrupted. Crews made repairs accordingly and no further action was required regarding this event. The third event occurred on 10/12/2021 out of the Benning substation. A switch failure caused 1,737 customers interrupted on feeder 15707 and also accounted for 18,094 customer minutes interrupted. Crews made repairs accordingly and no further action was required regarding this event.

Table 34: Switch Failure Rates

2021	Mode of Failure: Switch (Primary)			
(Jan 1 - Dec 31)	**CI**	**%**	**CMI**	**%**
YE Total	8,111	13.13%	735,474	10.55%
3 Major Events*	7,252	89.41%	504,116	68.54%

* % related to the total number of primary switch events

Analysis of these 28 events as reported by OMS revealed that 89% of the customers impacted by switch failure can be attributed to three events. See summary below:

Table 35 details the primary switch failure events causing the largest customer impact.

Table 35 Event Detail for Switch Failure Rates

Feeder	Substation	Date	CI	CMI	Cause	UG Miles	UG%	Comment
15204R/15204W	Tenth st	5/23/2021	3258	591,856	Switch failure	10.46	100.0%	Repairs made, no further action required
15004/15002	Ft Slocum	9/30/2021	2257	20,012	Switch failure	12.95	99.2%	Repairs made, no further action required
15707	Benning	10/12/2021	1,737	18,094	Switch failure	0.89	8.6%	Repairs made, no further action required
Total:			**7,252**	**629,962**				

Order No. 16975 states the following at paragraphs 68 and 109:

68. Decision: *Pepco is directed to report on efforts to reduce equipment failure in the 2013 Consolidated Report and in future Consolidated Reports*.

109. Pepco is DIRECTED *to report on its efforts to reduce equipment failure consistent with paragraph 68 herein;*

2.10 OUTAGE CAUSES

Interruptions to electric service can be caused by a range of occurrences, such as downed trees or limbs on power lines; high winds and lightning; heavy rain, snow, or ice; animals on equipment or power lines; traffic accidents that damage poles and equipment; underground construction accidents; and equipment failures.

The eight main outage causes in the OMS are:

- Animal – Outage caused by contact between Birds, Squirrels, Snakes and Other small animals and the distribution system;
- Equipment Failure - Includes Equipment Failures Only;
- Equipment Hit - Includes Cable Cuts, Motor Vehicle Hits and Foreign Contact;
- Others - Includes Employee, Fire, Load Shedding, Source Lost, Vandalism, Voltage;
- Overload - Includes Overloading only;
- Tree - Includes Outside ROW- Limb, Outside ROW-Down, Inside ROW-Limb, and Inside ROW-Down;
- Unknown - Includes Unknown Only indicates that the field responder did not know the cause of the outage; and
- Weather - Includes Flood, Ice, Lightning, Wind.

The following table reflects the outage cause options from which crews select when entering data into the Mobile application at the time of restoration. Through the Mobile NMS (Network Management System) completion window, crews have the ability to enter the event restoration information through drop down menus that are represented in the following table as well as any additional information through a free form text field. The outage cause selections are later classified into the categories above for reporting purposes. The detailed outage causes are maintained to assist in analysis of not only the cause of the outage but also the corrective actions necessary to reduce future outages.

An explanation of the selection categories from the drop-down menus follows Table 36 below.

Table 36

NON-PHI	WEATHER	OMS_CLASS	OMS_DEVICE	OMS_ACTION	OMS_CAUSE	OMS_DEVICE	OMS_PHASE	OMS_MANHOLE	OMS_AREA
Utility - Other	Clear	Dist Primary - OH	Mole	Assisted	Animal/Bird	Mole	+/-	Cable Burnout Visible	ACE - Glassboro
Utility - CATV	Extreme Cold	Dist Primary - UG	ACR	Braced	Animal/Other	ACR	A	Cable Smoking	ACE - Pleasantville
Utility - Phone	Extreme Heat	Dist Primary - URD	Autotransformer	Bypassed	Animal/Snake	Autotransformer	"A, +/-"	Cover - Double Action	ACE - Cape May
Utility - Other	Fog	Dist Secondary - OH	Bushing	Cleared/Cut in Clear	Animal/Squirrel	Bushing	AB	Cover - Rdwy Grate	ACE - Bridgeton
APGE	Ice	Dist Secondary - UG	Cable	Closed	Cable Cut - Billable	Cable	"AB, +/-"	Cover - Sdwk Grate	ACE - West Creek
Bad Address	Rain	Dist Secondary - URD	Capacitor	Disconn	Cable Cut - Marked Wrong	Capacitor	ABC	Cover - Slotted	ACE - Winslow
Cust Equip	Snow	Network	Connection (i.e. Loose)	Isolated	Cable Cut - Unknown	Connection (i.e. Loose)	"ABC, +/-"	Cover Displaced	Bay - Centreville
FD Disconn- left Disconn	Thunder/Lightning	St. Lgt.	Crossarm	Jumpered	Employee	Crossarm	AC	Gas Present	Bay - Harrington
FD Disconn- Reconnected	Windy	Substation	Cutout	Left MLSO	Equipment Failure	Cutout	"AC, +/-"	Joint Smoking	Bay - Millsboro
N/R No Response		Sub-Transmission	Distr. Ckt. Breaker	Made Safe	Fire	Distr. Ckt. Breaker	B	MH Fire	Bay - Salisbury
N/R Volt Checks OK		Traffic Signal	Elbow Insert	Made Tie	Foreign Contact	Elbow Insert	"B, +/-"	MH Smoking	NC - Christiana Line
No Access		Transmission	Fuse	Notified Customer	Load	Fuse	BC	Other	NC - North East Line
Ok by Phone		Dist Primary - OH	Insulator	Perm Repairs	Load Shedding	Insulator	"BC, +/-"	Structure Damage	Pepco - BSID
Ok On Arrival			Joint Failure	Reconnected	Motor Vehicle	Joint Failure	C	Water Above Cable	Pepco - Conduit
Modelling Error			Lightning Arrestor	Referred	Scheduled	Lightning Arrestor	"C, +/-"	Water Below Cable	Pepco - Cust Design DC
SCADA Error			Meter	Removed	Source Lost	Meter			Pepco - Cust Design MD
			Meter-Primary	Repaired	Tree ROW - Limb	Meter-Primary			Pepco - Distribution Test
			None	Replaced	Tree Row - Down	None			Pepco - Meter
			PAC / Spacer Cable	Temp Repairs	Tree Outside ROW - Limb	PAC / Spacer Cable			Pepco - OH Forestville
			Pole	Voltage Check	Tree Outside ROW - Down	Pole			Pepco - OH Rockville
			Regulator	Intentional Unplanned	Unknown	Regulator			Pepco - UG Benning
			Relay	Intentional Planned	Vandalism	Relay			Pepco - UG Rockville
			Sectionalizer	Maintenance Safety Scheme	Voltage - F/L or H/L	Sectionalizer			Pepco - URD - Forestville
			Service		Weather / Flood	Service			Pepco - URD - Rockville
			Splice		Weather / Ice	Splice			Veg - ACE - Cape May
			Street Light / Traffic		Weather / Lightning	Street Light / Traffic			Veg - ACE - Glassboro
			Switch		Weather / Salt	Switch			Veg - ACE - Bridgeton
			Switch - Gang Op		Weather / Wind	Switch - Gang Op			Veg - ACE - Pleasantville
			Termination		Tree Vine	Termination			Veg - ACE - Winslow
			Transclosure			Transclosure			Veg - ACE - West Creek
			Transformer			Transformer			Veg - DPL - Christiana
			Transformer - Padmount			Transformer - Padmount			Veg - DPL - North East
			Transformer - Subsurface			Transformer - Subsurface			Veg - DPL - Centreville
			Wire - Bare			Wire - Bare			Veg - DPL - Salisbury
			Wire - Covered			Wire - Covered			Veg - DPL - Millsboro
			CLF			CLF			Veg - PEPCO - Rockville
									Veg - PEPCO - Forestville
									Veg - PEPCO - Benning
									Veg - Transmission ACE
									Veg - MD Transmission DPL
									Veg - DE Transmission DPL
									Veg - Transmission PEPCO

- **Non-PHI** - If the event is not caused by Pepco equipment or if it is impossible to complete the request (e.g., bad address) crews must select one item from the Non-PHI list box of the MDS restoration screen indicating the circumstances, such as other utility, customer equipment, APGE (advise party to get electrician). If a selection is made from this list, the crew can complete and close ticket without further information. If no selection is made, then the event is on Pepco equipment and additional information is needed to complete the record.
- **Weather** - Crew must select from the list the observed weather conditions at the time of the outage.
- **Class** - Crew must select one item from the drop-down list describing the construction type.
- **Device** - Crew must select the clearing device.
- **Action** - Crew selects the action taken to restore the event/outage.
- **Cause/problem** - Crew must select the cause of the event. A ticket cannot be closed without a cause selection if the event was on Pepco equipment.
- **Equipment Failure** - Crew must enter information about the failed device related to the event if equipment failure is the cause / problem selected.
- **Phase** - Selection box for the phase(s) impacted by the event/outage.
- **Manhole** - Selection box for items describing the contents of a manhole.
- **Follow-up Area -** For an event that needs additional work but does not require immediate attention, a crew may select a follow-up area. For example, in the case of a URD cable failure where all load is restored through a common tie, the event would have a follow-up selection.

The most common causes of power outages are equipment failures and vegetation. High winds, heavy rain or snow and ice can cause trees or branches to topple and tear down power lines. Tree limbs brushing or resting on the lines cause short circuits and blown fuses. As shown in Table 37, there are several different equipment types that fall under the "Equipment Failure" category. One such type is fuse-related outages. The job of the fuse is to protect equipment. If a fuse blows, it is not an equipment failure but rather the fuse is performing its designed function. As a result, there are fewer actual "Equipment Failures" than are captured by the OMS.

If a non-Pepco construction crew digs a foot or two in the wrong direction, damage to an underground power line could cause an instant disruption of electric service or could cause damage that may not result in a power outage until days, weeks or months later.

Vehicles that damage utility poles or equipment can also cause power outages. Small animals, like squirrels, sometimes chew into lines or come into contact with a piece of equipment and an energized line, causing a fault and subsequent interruption of electric service.

An event classified as "Unknown" indicates that the field responder did not know the cause of the outage and this classification is used most frequently where a service interruption results from the operation of a protective device such as a fuse or recloser. These devices protect the electric distribution system from damage by sensing fault current on a particular circuit and activating a break in the flow of current. Typically, if there is no discernable damage to the circuit and the cause of the fault is not evident in the vicinity of the protective device that was activated, the device will be replaced or reset, and the circuit re-energized. If the device holds (no fault current is detected), the field responder may report "Equipment Failure" or "Unknown" as a cause and move on to the next trouble call assigned. The operation of these protective devices are not equipment failures because the fuse or recloser is operating correctly when it opens to isolate a fault further down the line. Occasionally, the field responder may find a probable cause some distance from the protective device involved (such as a tree branch on the ground underneath the overhead lines), but, for the most part, crews are focused on restoration of service rather than full investigation of the cause of any interruption (where this is not immediately evident).

Table 37 contains District of Columbia outage cause data for calendar year 2021.

Table 37

Equipment Type	Number of Outages	Pct % NI	CI	Pct % CI	CMI	Pct % CMI	SAIFI	CAIDI	SAIDI
ACR	3	0.37%	1279	2.07%	143301.08	2.06%	0.00	112	0.45
Bushing	16	1.99%	93	0.15%	13295.78	0.19%	0.00	143	0.04
Cable	231	28.70%	17287	27.99%	1904833.85	27.33%	0.05	110	5.94
Connection(i.e. Loose)	65	8.07%	3420	5.54%	134770.37	1.93%	0.01	39	0.42
Crossarm	9	1.12%	941	1.52%	176743.65	2.54%	0.00	188	0.55
Cutout	13	1.61%	80	0.13%	8425.38	0.12%	0.00	105	0.03
Distr. Ckt. Breaker	14	1.74%	9282	15.03%	1072912.17	15.39%	0.03	116	3.35
Elbow Insert	20	2.48%	3647	5.90%	806730.20	11.57%	0.01	221	2.52
Fuse	38	4.72%	5796	9.38%	463281.43	6.65%	0.02	80	1.44
Insulator	7	0.87%	302	0.49%	33849.62	0.49%	0.00	112	0.11
Joint Failure	11	1.37%	765	1.24%	149478.95	2.14%	0.00	195	0.47
Lightning Arrestor	1	0.12%	1	0.00%	134.48	0.00%	0.00	134	0.00
Pole	9	1.12%	10	0.02%	4760.90	0.07%	0.00	476	0.01
Sectionalizer	2	0.25%	782	1.27%	264435.00	3.79%	0.00	338	0.82
Service	2	0.25%	2	0.00%	654.03	0.01%	0.00	327	0.00
Splice	1	0.12%	1	0.00%	303.75	0.00%	0.00	304	0.00
Switch	28	3.48%	8111	13.13%	735474.20	10.55%	0.03	91	2.29
Termination	3	0.37%	153	0.25%	45367.00	0.65%	0.00	297	0.14
Transclosure	1	0.12%	7	0.01%	3605.00	0.05%	0.00	515	0.01
Transformer	73	9.07%	991	1.60%	353658.92	5.07%	0.00	357	1.10
Transformer - Padmount	6	0.75%	109	0.18%	19063.23	0.27%	0.00	175	0.06
Transformer - Subsurface	22	2.73%	132	0.21%	55261.33	0.79%	0.00	419	0.17
Wire - Bare	22	2.73%	6145	9.95%	392944.85	5.64%	0.02	64	1.23
Wire - Covered	9	1.12%	756	1.22%	37130.75	0.53%	0.00	49	0.12
Total Primaries	606	75.28%	60092	97.28%	6820415.933	97.84%	0.19	113	21.27
Total Secondaries	199	24.72%	1680	2.72%	150535.6	2.16%	0.01	90	0.47
Total Primaries & Secondaries	805	100.00%	61772	100.00%	6970951.533	100.00%	0.19	113	21.74

2.11 VM BUDGET, TREE-RELATED OUTAGES[63][64]

Table 38 shows District of Columbia distribution tree trimming expenses (not including poles, substation mowing, or storm-related tree trimming) and budgets. Provided are actual and budgeted amounts for 2013-2021.

Pepco's VM program includes increased trimming above all three-phase and single-phase lines. For three-phase lines it also includes the removal (with permission) of any limbs identified by Pepco Arborist planners that have a probability of breaking and falling into the conductors.

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[63] In Order No. 16623 at paragraphs 37 and 56, the Commission ordered the following:
37. Decision: …We require Pepco to explain why it has decreased its budget for tree trimming over the last seven years, if tree trimming is the most important factor impacting customers suffering from power outages. Pepco should include that explanation in the 2012 Consolidated Report.
56. Pepco is DIRECTED to provide an explanation of its budget for tree trimming consistent with paragraph 37.
[64] Order No. 16975 states the following at paragraphs 43 and 99:
43. Decision: The Commission finds Pepco's explanation of its budget variance for the single year 2011 insufficient to explain budget variances that totaled 26.9% below budget for five of the last six years. Therefore, the Commission requires Pepco to explain the budget variances that have occurred from 2006-2011 in its 2013 Consolidated Report. Additionally, we agree with Staff Recommendation #3 and require Pepco to include an explanation of any budget variance in its vegetation management expenditures and its EIVM expenditures in future years' Consolidated Reports. We are extremely concerned about the explanation provided in the Consolidated Report for why vegetation management expenditures were below budget in five of the last six years. Pepco stated that "while actual expenditures were below budget, work was completed consistent with planning." This is an inadequate explanation for a repeated failure to spend budgeted amounts on tree-trimming – arguably, the "most important factor impacting customers suffering from power outages." We therefore require Pepco to expand upon its explanation. If Pepco means that, through efficiencies, all the work intended to be accomplished in the budget was actually accomplished for less, then we direct Pepco to document what was intended to be included in the budget and what efficiencies were achieved so that the budgeted work was accomplished at a lower cost. The Commission also requires Pepco to explain what impact these efficiencies had on the budget process in subsequent years. If Pepco's statement about planning has some other meaning, we direct Pepco to provide it and to show what "planning" was involved, by whom and when. We also expect a precise and detailed explanation of why such planning would result in expenditures consistently, and significantly, below the budgeted amounts for a number of years. Further, we agree with OPC's suggestion that Pepco explain why its program does not include increased trimming above the three phase tap line or the single tap lines. Pepco is directed to provide this information in the 2013 Consolidated Report.
99. Pepco is DIRECTED to provide an explanation of budget variances for its own vegetation management work as directed in paragraph 43 herein;

Table 38

Pepco District of Columbia O & M Tree Trimming Costs									
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Actual									
Tree Trimming – DC	**$2,352,567**	**$2,164,336**	**$2,238,654**	**$2,269,634**	**$2,365,759**	**$1,705,410**	**$2,124,929**	**$2,052,518**	**$1,899,418**
Budget/Forecast									
Tree Trimming – DC	**$2,218,342**	**$2,113,300**	**$2,324,572**	**$2,335,008**	**$2,412,774**	**$2,480,616**	**$2,522,296**	**$2,368,906**	**$2,945,059**
Variance	**($134,225)**	**($51,036)**	**$85,918**	**$65,374**	**$47,015**	**$775,206**	**$397,367**	**316,388**	**$1,045,641**
Tree Trimming – DC									
Notes:									
1. Excludes pole inspections, substation mowing costs									

Yearly Data on Tree Trimming & Tree-Related Outages

In accordance with Order No. 15621,[65] presented in the following tables, is Pepco's "yearly data on vegetation management by feeder and wards (or multiple wards) compared to the Company's tree down and tree limb outage causes listed in its monthly power outage reports." The tables list the outages coded as tree-related in 2021, also sorted by feeder, allowing for a comparison between the two sets of tables. It is possible that additional outages may have been caused by trees but with causes coded as weather or unknown if fallen trees or limbs were not found at the site.

[65] In Order No. 15621 at paragraph 5, the Commission ordered the following:
5. Pepco shall file within the Company's annual Consolidated Reports to the Commission, yearly data on tree trimming by feeder and wards (or multiple wards) compared to the Company's tree down and tree limb outage causes listed in its monthly power outage reports beginning with the Company's 2010 Consolidated Report.

Table 39 Pepco District of Columbia 2021 Vegetation Management Plan

Circuit	Voltage	Ward
99	4KV	DC WARD 7
117	4KV	DC WARD 4
118	4KV	DC WARD 7
132	4KV	DC WARD 3
133	4KV	DC WARD 4
152	4KV	DC WARD 7
227	4KV	DC WARD 6
228	4KV	DC WARD 6
229	4KV	DC WARD 6
244	4KV	DC WARD 7
308	4KV	DC WARD 3
327	4KV	DC WARD 7
328	4KV	DC WARD 7
345	4KV	DC WARD 8
347	4KV	DC WARD 8
348	4KV	DC WARD 8
349	4KV	DC WARD 8
365	4KV	DC WARD 7
367	4KV	DC WARD 7
368	4KV	DC WARD 7
369	4KV	DC WARD 7
380	4KV	DC WARD 7
381	4KV	DC WARD 7
383	4KV	DC WARD 7

Circuit	Voltage	Ward
385	4KV	DC WARD 7
386	4KV	DC WARD 7
387	4KV	DC WARD 7
388	4KV	DC WARD 7
413	4KV	DC WARD 3
414	4KV	DC WARD 4
451	4KV	DC WARD 7
476	4KV	DC WARD 3
479	4KV	DC WARD 8
481	4KV	DC WARD 5
482	4KV	DC WARD 4
485	4KV	DC WARD 4
488	4KV	DC WARD 4
489	4KV	DC WARD 5
490	4KV	DC WARD 5
491	4KV	DC WARD 4
494	4KV	DC WARD 8
495	4KV	DC WARD 8
496	4KV	DC WARD 8
499	4KV	DC WARD 8
14031	13KV	DC WARD 7
14032	13KV	DC WARD 7
14033	13KV	DC WARD 7
14035	13KV	DC WARD 7
14102	13KV	DC WARD 7

Circuit	Voltage	Ward
14158	13KV	DC WARD 7
14263	13KV	DC WARD 4
14271	13KV	DC WARD 4
14715	13KV	DC WARD 7
14769	13KV	DC WARD 3
14852	13KV	DC WARD 4
14890	13KV	DC WARD 3
14891	13KV	DC WARD 4
14894	13KV	DC WARD 3
14896	13KV	DC WARD 3
14900	13KV	DC WARD 3
14945	13KV	DC WARD 3
14949	13KV	DC WARD 3
14979	13KV	DC WARD 4
14987	13KV	DC WARD 4
15001	13KV	DC WARD 4
15003	4KV	DC WARD 4
15006	13KV	DC WARD 4
15007	13KV	DC WARD 4
15008	13KV	DC WARD 4
15009	13KV	DC WARD 4
15010	13KV	DC WARD 4
15011	13KV	DC WARD 4
15012	13KV	DC WARD 4
15013	13KV	DC WARD 5

Circuit	Voltage	Ward
15014	13KV	DC WARD 5
15015	13KV	DC WARD 4
15016	13KV	DC WARD 5
15018	13KV	DC WARD 4
15021	13KV	DC WARD 4
15082	13KV	DC WARD 8
15086	13KV	DC WARD 8
15090	13KV	DC WARD 8
15094	13KV	DC WARD 6
15100	13KV	DC WARD 6
15130	13KV	DC WARD 8
15131	13KV	DC WARD 8
15132	13KV	DC WARD 8
15165	13KV	DC WARD 8
15166	13KV	DC WARD 8
15167	13KV	DC WARD 8
15168	13KV	DC WARD 8
15169	13KV	DC WARD 8
15170	13KV	DC WARD 8
15171	13KV	DC WARD 8
15172	13KV	DC WARD 8
15173	13KV	DC WARD 8
15174	13KV	DC WARD 8
15175	13KV	DC WARD 8
15176	13KV	DC WARD 8

Circuit	Voltage	Ward
15177	13KV	DC WARD 8
15178	13KV	DC WARD 8
15179	13KV	DC WARD 8
15183	13KV	DC WARD 8
15197	13KV	DC WARD 4
15247	13KV	DC WARD 8
15458	13KV	DC WARD 5
15459	13KV	DC WARD 5
15631	13KV	DC WARD 8
15632	13KV	DC WARD 8
16000	13KV	DC WARD 2
16001	13KV	DC WARD 2
34012	34KV	DC WARD 3
34013	34KV	DC WARD 3
34924	34KV	DC WARD 7
34955	34KV	DC WARD 3 & 4
34973	34KV	DC WARD 3

Tree-Related Outages in 2021 (Inclusive IEEE 1366 – 2012 Std)

Table 40

Event ID	Outage Date	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Feeder	Customers Affected	Customer Minutes
2768431	**1/2/21**	3:52	**10:49**	417.00	**Dist Primary - OH**	Tree Row - Down	15130	11	4587.00
2768598	**1/3/21**	7:51	**11:05**	193.77	**Dist Primary - OH**	Tree Outside ROW - Limb	14031	9	1743.90
2773643	**1/26/21**	10:11	**10:33**	22.00	**Dist Primary - OH**	Tree ROW - Limb	14146	151	3322.00
2773643	**1/26/21**	10:11	**11:39**	88.00	**Dist Primary - OH**	Tree ROW - Limb	14146	2	176.00
2778893	**2/13/21**	14:50	**0:17**	567.00	**Dist Primary - OH**	Tree Outside ROW - Down	14145	11	6237.00
2778954	**2/13/21**	18:32	**1:42**	429.57	**Dist Primary - OH**	Tree Outside ROW - Limb	15001	1	429.57
2778961	**2/13/21**	14:50	**18:22**	212.00	**Dist Primary - OH**	Tree Outside ROW - Down	14145	21	4452.00
2778981	**2/13/21**	18:34	**1:42**	427.05	**Dist Primary - OH**	Tree Outside ROW - Limb	15001	1	427.05
2781490	**2/23/21**	15:39	**19:21**	221.95	**Dist Primary - OH**	Tree Outside ROW - Limb	15009	29	6436.55
2781494	**2/23/21**	15:40	**19:21**	220.07	**Dist Primary - OH**	Tree Outside ROW - Limb	15009	17	3741.13
2782677	**2/28/21**	13:02	**14:52**	110.00	**Dist Secondary - OH**	Tree Outside ROW - Down	14765	1	110.00
2786728	**3/16/21**	17:57	**21:05**	188.00	**Dist Secondary - OH**	Tree Outside ROW - Limb	14261	1	188.00
2789788	**3/28/21**	22:19	**23:51**	92.00	**Dist Secondary - OH**	Tree Outside ROW - Limb	15198	1	92.00
2789795	**3/28/21**	22:26	**2:25**	238.48	**Dist Secondary - OH**	Tree Outside ROW - Down	15944	1	238.48
2789915	**3/28/21**	22:27	**2:25**	237.23	**Dist Secondary - OH**	Tree Outside ROW - Down	15944	1	237.23
2789916	**3/28/21**	22:24	**18:43**	1218.17	**Dist Secondary - OH**	Tree Outside ROW - Down	15944	1	1218.17
2789956	**3/29/21**	7:20	**10:24**	183.35	**Dist Secondary - OH**	Tree ROW - Limb	15707	1	183.35
2790037	**3/29/21**	8:31	**11:03**	152.00	**Dist Primary - OH**	Tree Outside ROW - Down	14133	28	4256.00
2790262	**3/29/21**	8:31	**17:43**	552.00	**Dist Primary - OH**	Tree Outside ROW - Down	14133	17	9384.00
2790501	**3/29/21**	15:00	**18:42**	222.00	**Dist Secondary - OH**	Tree Outside ROW - Down	308	1	222.00
2790519	**3/29/21**	22:33	**22:59**	26.00	**Dist Primary - OH**	Tree Outside ROW - Down	15001	8	208.00
2790520	**3/29/21**	22:33	**23:00**	27.00	**Dist Primary - OH**	Tree Row - Down	15001	1	27.00
2791039	**3/31/21**	14:14	**16:20**	126.00	**Dist Primary - OH**	Tree Row - Down	14146	153	19278.00
2791377	**4/1/21**	5:56	**9:26**	210.00	**Dist Primary - OH**	Tree Outside ROW - Down	14132	54	11340.00
2791377	**4/1/21**	8:43	**9:26**	43.00	**Dist Primary - OH**	Tree Outside ROW - Down	14132	81	3483.00
2791407	**4/1/21**	9:03	**9:41**	38.00	**Dist Primary - OH**	Tree Outside ROW - Down	14132	1	38.00
2793470	**4/9/21**	11:47	**13:13**	86.00	**Dist Secondary - OH**	Tree Outside ROW - Limb	14009	1	86.00
2793841	**4/11/21**	15:22	**16:32**	70.00	**Dist Primary - OH**	Tree ROW - Limb	14014	16	1120.00
2795135	**4/17/21**	7:28	**8:36**	67.37	**Dist Secondary - OH**	Tree Vine	15801	6	404.20
2796231	**4/21/21**	12:13	**18:39**	385.62	**Dist Secondary - OH**	Tree Outside ROW - Limb	15943	1	385.62
2796375	**4/21/21**	18:11	**21:57**	225.28	**Dist Primary - OH**	Tree Outside ROW - Down	14133	1	225.28
2797098	**4/25/21**	3:08	**3:59**	51.00	**Dist Secondary - OH**	Tree ROW - Limb	14806	1	51.00
2798615	**4/30/21**	11:42	**22:51**	668.05	**Dist Primary - OH**	Tree Outside ROW - Down	14146	1	668.05
2798616	**4/30/21**	11:44	**21:29**	584.38	**Dist Primary - OH**	Tree Outside ROW - Down	14146	4	2337.53
2798672	**4/30/21**	13:03	**19:25**	381.73	**Dist Primary - OH**	Tree ROW - Limb	15197	10	3817.33
2798809	**4/30/21**	16:12	**19:28**	195.85	**Dist Primary - OH**	Tree ROW - Limb	15174	18	3525.30
2799013	**4/30/21**	16:56	**21:44**	287.68	**Dist Primary - OH**	Tree Row - Down	132	61	17548.68
2799013	**4/30/21**	16:56	**7:12**	855.68	**Dist Primary - OH**	Tree Row - Down	132	14	11979.57

Event ID	Outage Date	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Feeder	Customers Affected	Customer Minutes
2799014	**4/30/21**	16:56	**20:37**	220.62	**Dist Primary - OH**	Tree ROW - Limb	14132	8	1764.93
2799039	**5/1/21**	3:59	**4:27**	28.00	**Dist Primary - OH**	Tree ROW - Limb	451	221	6188.00
2799053	**4/30/21**	17:02	**8:56**	953.35	**Dist Secondary - OH**	Tree Row - Down	65	1	953.35
2799089	**4/30/21**	17:04	**18:46**	101.43	**Dist Primary - OH**	Tree Outside ROW - Down	99	17	1724.37
2799151	**4/30/21**	17:13	**22:31**	318.08	**Dist Primary - OH**	Tree Row - Down	64	1	318.08
2799161	**4/30/21**	17:14	**18:46**	91.20	**Dist Primary - OH**	Tree Outside ROW - Down	99	17	1550.40
2799328	**4/30/21**	17:39	**22:11**	272.00	**Dist Primary - OH**	Tree Outside ROW - Down	14132	32	8704.00
2799359	**4/30/21**	17:48	**18:46**	57.20	**Dist Primary - OH**	Tree Outside ROW - Down	99	55	3146.00
2799435	**4/30/21**	18:08	**18:46**	38.00	**Dist Primary - OH**	Tree Outside ROW - Down	99	1	38.00
2799506	**4/30/21**	18:33	**2:45**	492.00	**Dist Primary - OH**	Tree ROW - Limb	15710	17	8364.00
2799668	**4/30/21**	19:47	**19:59**	11.13	**Dist Primary - OH**	Tree Row - Down	132	30	334.00
2799678	**4/30/21**	19:51	**19:59**	7.35	**Dist Primary - OH**	Tree Row - Down	132	22	161.70
2799681	**4/30/21**	19:52	**19:58**	5.38	**Dist Primary - OH**	Tree Row - Down	132	1	5.38
2799902	**4/30/21**	23:10	**9:49**	639.00	**Dist Secondary - OH**	Tree Outside ROW - Down	60	1	639.00
2799937	**5/1/21**	0:05	**10:37**	632.00	**Dist Primary - OH**	Tree Outside ROW - Limb	15174	14	8848.00
2800029	**4/30/21**	17:01	**3:58**	657.00	**Dist Primary - OH**	Tree Outside ROW - Limb	451	35	22995.00
2800120	**5/1/21**	10:36	**10:51**	15.00	**Dist Primary - OH**	Tree Row - Down	133	1	15.00
2800147	**5/1/21**	11:08	**11:54**	46.00	**Dist Secondary - OH**	Tree Outside ROW - Down	65	1	46.00
2800466	**5/2/21**	14:20	**15:37**	77.00	**Dist Primary - OH**	Tree Outside ROW - Down	144	40	3080.00
2800941	**5/3/21**	18:54	**19:33**	39.00	**Dist Primary - OH**	Tree ROW - Limb	14890	2	78.00
2801135	**5/4/21**	10:29	**11:20**	51.00	**Dist Primary - OH**	Tree ROW - Limb	15011	57	2907.00
2801150	**4/30/21**	17:15	**20:52**	217.00	**Dist Secondary - OH**	Tree Outside ROW - Limb	15945	1	217.00
2801372	**5/4/21**	19:20	**20:22**	61.48	**Dist Secondary - OH**	Tree ROW - Limb	52	17	1045.22
2801786	**5/5/21**	15:52	**17:08**	75.72	**Dist Secondary - OH**	Tree Outside ROW - Limb	15016	1	75.72
2808841	**5/26/21**	20:22	**7:25**	662.18	**Dist Primary - OH**	Tree ROW - Limb	15009	18	11919.30
2808862	**5/26/21**	20:26	**20:44**	17.65	**Substation**	Tree Outside ROW - Down	14767	781	13784.65
2808907	**5/26/21**	20:36	**8:02**	685.35	**Dist Primary - OH**	Tree ROW - Limb	117	10	6853.50
2808915	**5/26/21**	20:38	**10:54**	855.87	**Dist Primary - OH**	Tree Row - Down	15015	25	21396.67
2808930	**5/26/21**	20:35	**22:56**	141.00	**Dist Primary - OH**	Tree Row - Down	14133	14	1974.00
2808939	**5/26/21**	20:26	**0:29**	242.03	**Substation**	Tree Outside ROW - Down	14767	192	46470.40
2809009	**5/26/21**	20:55	**5:41**	526.00	**Dist Secondary - OH**	Tree Outside ROW - Limb	15950	1	526.00
2809194	**5/26/21**	20:35	**8:37**	722.00	**Dist Primary - OH**	Tree Row - Down	14133	3	2166.00
2809256	**5/27/21**	0:31	**2:46**	135.00	**Dist Primary - OH**	Tree Outside ROW - Down	14767	7	945.00
2809478	**5/27/21**	11:15	**21:08**	592.53	**Dist Primary - OH**	Tree ROW - Limb	14900	2	1185.07
2810076	**5/28/21**	18:08	**21:15**	186.05	**Dist Primary - OH**	Tree ROW - Limb	14015	1	186.05
2810244	**5/29/21**	6:31	**8:52**	140.37	**Dist Primary - OH**	Tree Outside ROW - Down	14133	1	140.37
2810350	**5/29/21**	14:38	**15:37**	59.00	**Dist Secondary - OH**	Tree Outside ROW - Limb	14752	1	59.00
2811515	**6/2/21**	13:42	**13:57**	15.00	**Dist Secondary - OH**	Tree Outside ROW - Limb	324	1	15.00
2813242	**6/6/21**	10:27	**11:34**	67.00	**Dist Primary - OH**	Tree Outside ROW - Down	15175	323	21641.00
2813918	**6/7/21**	17:08	**17:34**	25.38	**Dist Primary - OH**	Tree Row - Down	14900	2	50.77
2814617	**6/9/21**	8:49	**13:11**	261.63	**Dist Primary - OH**	Tree ROW - Limb	15001	25	6540.83
2815251	**6/10/21**	12:30	**14:33**	122.07	**Dist Secondary - OH**	Tree Outside ROW - Limb	128	1	122.07

Event ID	Outage Date	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Feeder	Customers Affected	Customer Minutes
2815420	**6/10/21**	19:50	**3:17**	446.90	**Dist Secondary - OH**	Tree Outside ROW - Down	15867	1	446.90
2815458	**6/10/21**	21:20	**23:14**	114.00	**Dist Primary - OH**	Tree ROW - Limb	15801	1	114.00
2815671	**6/11/21**	12:45	**18:52**	367.00	**Dist Primary - OH**	Tree Outside ROW - Down	132	21	7707.00
2815852	**6/11/21**	21:14	**22:17**	63.00	**Dist Primary - OH**	Tree Outside ROW - Limb	14758	451	28413.00
2816089	**6/12/21**	15:25	**19:09**	223.67	**Dist Secondary - OH**	Tree ROW - Limb	97	1	223.67
2816537	**6/14/21**	11:54	**12:01**	7.00	**Dist Primary - OH**	Tree Outside ROW - Limb	14717	81	567.00
2817816	**6/16/21**	19:33	**7:15**	701.55	**Dist Primary - OH**	Tree Outside ROW - Down	15706	40	28062.00
2818925	**6/20/21**	12:17	**13:21**	64.00	**Dist Secondary - OH**	Tree ROW - Limb	347	1	64.00
2820655	**6/22/21**	5:14	**10:17**	302.05	**Dist Primary - OH**	Tree ROW - Limb	15199	19	5738.95
2821877	**6/25/21**	8:27	**13:10**	282.85	**Dist Secondary - OH**	Tree ROW - Limb	15009	1	282.85
2823774	**7/1/21**	7:10	**8:42**	91.52	**Dist Primary - OH**	Tree ROW - Limb	15801	6	549.10
2824300	**7/1/21**	15:12	**21:09**	356.90	**Dist Secondary - OH**	Tree Outside ROW - Limb	15011	13	4639.70
2824333	**7/1/21**	15:08	**13:15**	1327.00	**Dist Primary - OH**	Tree Outside ROW - Down	117	88	116776.00
2824333	**7/1/21**	15:14	**13:15**	1321.00	**Dist Primary - OH**	Tree Outside ROW - Down	117	19	25099.00
2824333	**7/1/21**	15:25	**13:15**	1310.00	**Dist Primary - OH**	Tree Outside ROW - Down	117	6	7860.00
2824333	**7/1/21**	15:27	**13:15**	1308.00	**Dist Primary - OH**	Tree Outside ROW - Down	117	16	20928.00
2824333	**7/1/21**	15:27	**13:15**	1308.00	**Dist Primary - OH**	Tree Outside ROW - Down	414	3	3924.00
2824333	**7/2/21**	8:22	**13:15**	293.00	**Dist Primary - OH**	Tree Outside ROW - Down	117	12	3516.00
2824333	**7/2/21**	8:22	**13:15**	293.00	**Dist Primary - OH**	Tree Outside ROW - Down	414	262	76766.00
2824400	**7/1/21**	15:27	**11:33**	1206.00	**Dist Primary - OH**	Tree Outside ROW - Limb	14900	8	9648.00
2824441	**7/1/21**	15:31	**4:46**	795.00	**Dist Primary - OH**	Tree Outside ROW - Limb	118	10	7950.00
2825260	**7/1/21**	21:15	**4:34**	438.02	**Dist Primary - OH**	Tree ROW - Limb	15094	13	5694.22
2825279	**7/1/21**	21:30	**6:29**	539.00	**Dist Secondary - OH**	Tree Outside ROW - Limb	14017	14	7546.00
2825310	**7/1/21**	21:39	**20:32**	1373.00	**Dist Secondary - OH**	Tree ROW - Limb	15710	1	1373.00
2825480	**7/1/21**	15:15	**10:12**	1136.88	**Dist Primary - OH**	Tree ROW - Limb	15944	104	118235.87
2825481	**7/1/21**	15:15	**12:59**	1303.88	**Dist Primary - OH**	Tree ROW - Limb	15944	134	174720.37
2825582	**7/2/21**	6:09	**16:26**	616.23	**Dist Primary - OH**	Tree Outside ROW - Limb	15944	1	616.23
2825887	**7/2/21**	10:26	**0:48**	861.08	**Dist Primary - OH**	Tree ROW - Limb	15944	1	861.08
2826298	**7/2/21**	17:30	**5:51**	740.25	**Dist Primary - OH**	Tree Row - Down	14031	1	740.25
2827080	**6/6/21**	9:14	**10:26**	72.00	**Dist Primary - OH**	Tree Outside ROW - Down	15175	1	72.00
2827081	**6/6/21**	9:14	**10:26**	72.00	**Dist Primary - OH**	Tree Outside ROW - Down	15175	1	72.00
2827082	**6/6/21**	9:14	**10:26**	72.00	**Dist Primary - OH**	Tree Outside ROW - Down	15175	1	72.00
2827588	**7/7/21**	6:11	**13:43**	451.87	**Dist Primary - URD**	Tree Row - Down	14016	1	451.87
2828472	**7/8/21**	21:43	**9:02**	678.33	**Dist Primary - OH**	Tree Outside ROW - Down	14767	109	73938.33
2828545	**7/8/21**	23:41	**0:58**	76.32	**Dist Secondary - OH**	Tree Row - Down	14752	1	76.32
2829813	**7/12/21**	3:01	**5:03**	121.97	**Dist Secondary - OH**	Tree Outside ROW - Down	128	1	121.97
2831858	**7/16/21**	15:58	**18:12**	133.13	**Dist Primary - OH**	Tree ROW - Limb	15867	4	532.53
2831861	**7/16/21**	16:06	**18:45**	158.80	**Dist Primary - OH**	Tree ROW - Limb	15867	1	158.80
2831966	**7/17/21**	2:40	**6:31**	230.40	**Dist Primary - OH**	Tree Row - Down	14146	1	230.40
2832899	**7/18/21**	17:50	**21:22**	212.00	**Dist Secondary - OH**	Tree Outside ROW - Down	15197	18	3816.00
2834656	**7/21/21**	13:22	**14:59**	97.00	**Dist Primary - OH**	Tree Outside ROW - Limb	14758	378	36666.00
2834656	**7/21/21**	13:45	**14:34**	49.00	**Dist Primary - OH**	Tree Outside ROW - Limb	14758	1783	87367.00

Event ID	Outage Date	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Feeder	Customers Affected	Customer Minutes
2834704	**7/21/21**	13:40	**16:08**	148.00	**Dist Primary - OH**	Tree ROW - Limb	14753	1	148.00
2834708	**7/21/21**	13:44	**20:46**	422.00	**Dist Secondary - OH**	Tree Row - Down	15085	1	422.00
2835996	**7/23/21**	13:17	**15:47**	149.50	**Dist Primary - OH**	Tree ROW - Limb	14753	81	12109.50
2836020	**7/23/21**	14:36	**16:30**	114.72	**Dist Primary - OH**	Tree ROW - Limb	14755	1	114.72
2836410	**7/25/21**	15:38	**15:49**	11.00	**Dist Secondary - OH**	Tree Outside ROW - Limb	485	24	264.00
2836482	**7/26/21**	7:54	**9:53**	119.00	**Dist Secondary - OH**	Tree Outside ROW - Limb	15009	1	119.00
2836859	**7/26/21**	19:12	**22:41**	209.57	**Dist Primary - OH**	Tree Outside ROW - Down	15013	516	108136.40
2836886	**7/26/21**	19:18	**0:49**	330.47	**Dist Primary - OH**	Tree Outside ROW - Limb	14200	569	188035.53
2836886	**7/26/21**	19:18	**6:44**	685.47	**Dist Primary - OH**	Tree Outside ROW - Limb	14200	174	119271.20
2836895	**7/26/21**	19:24	**0:07**	283.13	**Dist Primary - OH**	Tree Outside ROW - Limb	14200	11	3114.47
2836927	**7/26/21**	19:12	**3:55**	523.03	**Dist Primary - OH**	Tree Outside ROW - Down	15013	893	467068.77
2836942	**7/26/21**	19:20	**4:19**	538.23	**Dist Primary - OH**	Tree Row - Down	14014	16	8611.73
2837303	**7/26/21**	20:24	**8:00**	695.88	**Dist Secondary - OH**	Tree Outside ROW - Limb	15199	1	695.88
2837457	**7/26/21**	20:28	**2:58**	390.00	**Dist Primary - OH**	Tree Outside ROW - Limb	14987	27	10530.00
2837787	**7/26/21**	19:18	**4:59**	581.00	**Dist Primary - OH**	Tree Outside ROW - Limb	14200	1	581.00
2837787	**7/26/21**	19:18	**6:10**	652.00	**Dist Primary - OH**	Tree Outside ROW - Limb	14200	588	383376.00
2837903	**7/27/21**	5:03	**6:12**	69.00	**Dist Secondary - OH**	Tree Outside ROW - Limb	14987	1	69.00
2838335	**7/27/21**	14:25	**16:45**	139.35	**Dist Primary - URD**	Tree Row - Down	15013	1	139.35
2838491	**7/27/21**	21:59	**3:31**	331.33	**Dist Secondary - OH**	Tree ROW - Limb	144	1	331.33
2840501	**8/1/21**	13:47	**18:29**	282.00	**Dist Primary - OH**	Tree ROW - Limb	15012	19	5358.00
2840516	**8/1/21**	14:26	**18:50**	263.02	**Dist Secondary - OH**	Tree Outside ROW - Limb	467	1	263.02
2840564	**8/1/21**	17:55	**18:30**	35.00	**Dist Primary - OH**	Tree Outside ROW - Limb	15012	20	700.00
2841847	**8/6/21**	1:43	**4:00**	137.00	**Dist Secondary - OH**	Tree Outside ROW - Down	15946	1	137.00
2842848	**8/9/21**	10:49	**12:30**	101.00	**Dist Secondary - OH**	Tree ROW - Limb	14022	1	101.00
2843050	**8/9/21**	18:38	**23:21**	283.00	**Dist Primary - OH**	Tree Outside ROW - Down	14016	14	3962.00
2843368	**8/9/21**	18:38	**5:56**	678.00	**Dist Primary - OH**	Tree Row - Down	14016	45	30510.00
2843569	**8/11/21**	0:00	**13:06**	786.27	**Dist Secondary - OH**	Tree Outside ROW - Down	15867	1	786.27
2843932	**8/10/21**	17:38	**20:29**	170.20	**Dist Primary - OH**	Tree Outside ROW - Limb	132	5	851.00
2843983	**8/10/21**	17:53	**23:15**	321.30	**Dist Primary - OH**	Tree ROW - Limb	14132	8	2570.40
2843988	**8/11/21**	3:26	**4:47**	81.00	**Dist Primary - OH**	Tree Outside ROW - Down	14146	82	6642.00
2844031	**8/10/21**	20:02	**1:25**	323.00	**Dist Primary - OH**	Tree ROW - Limb	118	322	104006.00
2844035	**8/10/21**	18:25	**22:54**	268.42	**Dist Primary - OH**	Tree Outside ROW - Down	383	61	16373.42
2844084	**8/10/21**	18:33	**19:10**	37.00	**Dist Primary - OH**	Tree ROW - Limb	15710	1324	48988.00
2844162	**8/10/21**	18:36	**23:19**	282.77	**Dist Primary - OH**	Tree ROW - Limb	15710	53	14986.63
2844163	**8/10/21**	18:36	**0:49**	372.50	**Dist Primary - OH**	Tree Outside ROW - Limb	15130	12	4470.00
2844191	**8/10/21**	18:42	**1:00**	378.00	**Dist Secondary - OH**	Tree Outside ROW - Limb	349	58	21924.00
2844238	**8/10/21**	18:46	**22:30**	224.00	**Dist Primary - OH**	Tree Outside ROW - Down	451	9	2016.00
2844241	**8/10/21**	18:46	**0:00**	314.00	**Dist Secondary - OH**	Tree Row - Down	368	1	314.00
2844502	**8/10/21**	20:20	**3:50**	449.15	**Dist Primary - OH**	Tree ROW - Limb	451	19	8533.85
2844865	**8/10/21**	18:25	**5:13**	648.30	**Dist Primary - OH**	Tree Outside ROW - Down	383	318	206159.40
2846514	**8/12/21**	12:05	**13:40**	94.43	**Dist Primary - OH**	Tree ROW - Limb	14146	1	94.43
2848706	**8/14/21**	1:27	**6:42**	315.00	**Dist Primary - OH**	Tree ROW - Limb	14987	13	4095.00

Event ID	Outage Date	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Feeder	Customers Affected	Customer Minutes
2849021	**8/15/21**	1:39	**7:07**	327.97	**Dist Primary - OH**	Tree Outside ROW - Down	14146	1	327.97
2849227	**8/15/21**	20:03	**20:24**	21.00	**Dist Secondary - OH**	Tree Outside ROW - Down	14031	1	21.00
2849650	**8/17/21**	2:01	**7:11**	309.47	**Dist Primary - OH**	Tree ROW - Limb	15011	28	8665.07
2849708	**8/17/21**	6:25	**9:05**	160.00	**Dist Primary - OH**	Tree ROW - Limb	14146	7	1120.00
2849734	**8/17/21**	7:50	**7:59**	8.67	**Dist Primary - OH**	Tree Row - Down	15173	1507	13060.67
2849734	**8/17/21**	7:50	**10:11**	141.48	**Dist Primary - OH**	Tree Row - Down	15173	449	63526.02
2849856	**8/17/21**	8:00	**11:28**	208.00	**Dist Primary - OH**	Tree Outside ROW - Down	15173	31	6448.00
2849871	**8/17/21**	8:00	**14:37**	397.00	**Dist Primary - OH**	Tree Outside ROW - Down	15173	5	1985.00
2849874	**8/17/21**	11:29	**14:37**	188.00	**Dist Primary - OH**	Tree Outside ROW - Down	15173	18	3384.00
2850683	**8/18/21**	18:12	**19:49**	96.52	**Dist Primary - OH**	Tree ROW - Limb	128	1	96.52
2850685	**8/18/21**	18:12	**19:49**	97.00	**Dist Primary - OH**	Tree ROW - Limb	128	76	7372.00
2850691	**8/18/21**	18:17	**19:49**	91.97	**Dist Primary - OH**	Tree ROW - Limb	128	1	91.97
2850696	**8/18/21**	18:30	**19:49**	79.00	**Dist Primary - OH**	Tree ROW - Limb	128	1	79.00
2851037	**8/20/21**	6:28	**11:00**	271.75	**Dist Primary - OH**	Tree Outside ROW - Down	14752	70	19022.50
2851272	**8/20/21**	12:14	**15:50**	216.00	**Dist Secondary - OH**	Tree Outside ROW - Down	14022	17	3672.00
2851479	**8/20/21**	21:13	**23:45**	152.00	**Dist Secondary - OH**	Tree Row - Down	380	1	152.00
2851750	**8/21/21**	17:28	**18:20**	51.82	**Dist Primary - OH**	Tree Outside ROW - Limb	118	10	518.17
2852982	**8/23/21**	15:09	**18:52**	222.05	**Dist Secondary - OH**	Tree ROW - Limb	14752	1	222.05
2853758	**8/25/21**	21:48	**22:33**	45.38	**Dist Secondary - OH**	Tree ROW - Limb	467	11	499.22
2854063	**8/26/21**	16:08	**22:28**	380.80	**Dist Primary - OH**	Tree Outside ROW - Limb	15010	1	380.80
2854106	**8/26/21**	16:19	**0:41**	501.58	**Dist Secondary - OH**	Tree ROW - Limb	15021	1	501.58
2854116	**8/27/21**	2:11	**2:33**	22.00	**Dist Primary - OH**	Tree Row - Down	144	10	220.00
2854119	**8/26/21**	16:20	**22:28**	368.23	**Dist Secondary - OH**	Tree ROW - Limb	15010	10	3682.33
2854131	**8/26/21**	16:26	**22:28**	361.88	**Dist Primary - OH**	Tree Outside ROW - Limb	15010	19	6875.78
2854524	**8/26/21**	16:21	**6:22**	2281.32	**Dist Primary - OH**	Tree Outside ROW - Down	144	21	47907.65
2854855	**8/27/21**	14:28	**18:09**	221.30	**Dist Primary - OH**	Tree Outside ROW - Limb	15018	562	124370.60
2854856	**8/27/21**	14:29	**14:43**	14.20	**Dist Primary - OH**	Tree Outside ROW - Limb	15018	264	3748.80
2854898	**8/27/21**	14:29	**14:45**	15.55	**Dist Primary - OH**	Tree Outside ROW - Down	15018	400	6220.00
2855301	**8/28/21**	0:00	**8:45**	525.00	**Dist Secondary - OH**	Tree Outside ROW - Down	14765	1	525.00
2855359	**8/27/21**	17:36	**21:00**	204.00	**Dist Primary - OH**	Tree Outside ROW - Down	14035	862	175848.00
2855655	**8/27/21**	20:35	**6:22**	586.05	**Dist Primary - OH**	Tree Outside ROW - Down	144	16	9376.80
2855657	**8/27/21**	20:37	**20:54**	16.73	**Dist Primary - OH**	Tree Outside ROW - Down	144	5	83.67
2855766	**8/26/21**	16:21	**6:24**	2283.00	**Dist Primary - OH**	Tree Outside ROW - Down	144	6	13698.00
2855975	**8/28/21**	15:13	**16:55**	102.00	**Dist Primary - OH**	Tree ROW - Limb	14135	8	816.00
2857770	**9/1/21**	13:00	**19:54**	413.72	**Dist Secondary - OH**	Tree ROW - Limb	14766	1	413.72
2857892	**8/29/21**	17:19	**17:45**	26.00	**Dist Secondary - OH**	Tree Outside ROW - Down	15001	1	26.00
2857954	**9/1/21**	21:44	**21:50**	6.55	**Dist Primary - OH**	Tree ROW - Limb	87	7	45.85
2857955	**9/1/21**	18:39	**21:44**	184.58	**Dist Primary - OH**	Tree ROW - Limb	87	1	184.58
2858091	**9/1/21**	21:09	**21:27**	17.38	**Dist Primary - OH**	Tree ROW - Limb	87	21	365.05
2858348	**8/26/21**	16:19	**23:35**	436.00	**Dist Secondary - OH**	Tree Outside ROW - Down	15021	1	436.00
2858349	**8/26/21**	16:19	**1:52**	573.00	**Dist Secondary - OH**	Tree Outside ROW - Down	15021	1	573.00
2858411	**8/26/21**	16:19	**1:29**	550.00	**Dist Secondary - OH**	Tree Outside ROW - Down	15021	1	550.00

Event ID	Outage Date	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Feeder	Customers Affected	Customer Minutes
2858802	**9/3/21**	13:42	**14:22**	39.70	**Dist Primary - OH**	Tree Outside ROW - Down	118	312	12386.40
2858802	**9/3/21**	13:42	**14:22**	39.70	**Dist Primary - OH**	Tree Outside ROW - Down	244	353	14014.10
2858811	**9/3/21**	14:14	**14:26**	12.58	**Dist Primary - OH**	Tree Outside ROW - Down	244	1	12.58
2859247	**8/26/21**	16:19	**1:29**	550.00	**Dist Primary - OH**	Tree Outside ROW - Down	15021	1	550.00
2861036	**8/26/21**	16:02	**18:45**	163.00	**Dist Primary - OH**	Tree ROW - Limb	15006	1	163.00
2861037	**8/26/21**	16:02	**18:45**	163.00	**Dist Primary - OH**	Tree ROW - Limb	15006	1	163.00
2861038	**8/26/21**	16:02	**18:45**	163.00	**Dist Primary - OH**	Tree ROW - Limb	15006	1	163.00
2861039	**8/26/21**	16:02	**18:45**	163.00	**Dist Primary - OH**	Tree ROW - Limb	15006	1	163.00
2862666	**9/17/21**	16:17	**6:24**	847.00	**Dist Primary - OH**	Tree Row - Down	181	18	15246.00
2862760	**9/17/21**	16:35	**6:27**	831.48	**Dist Primary - OH**	Tree Row - Down	14767	56	46563.07
2863947	**9/22/21**	15:21	**19:39**	257.98	**Dist Primary - OH**	Tree ROW - Limb	15801	306	78942.90
2863958	**9/22/21**	15:30	**1:03**	572.98	**Dist Primary - OH**	Tree Outside ROW - Limb	117	6	3437.90
2863997	**9/22/21**	15:21	**19:39**	257.98	**Dist Primary - OH**	Tree ROW - Limb	15801	1	257.98
2863998	**9/22/21**	15:43	**19:44**	240.72	**Dist Primary - OH**	Tree ROW - Limb	181	1	240.72
2864007	**9/22/21**	15:45	**22:55**	429.37	**Dist Secondary - OH**	Tree Outside ROW - Down	14133	1	429.37
2864022	**9/22/21**	15:48	**21:27**	338.50	**Dist Primary - OH**	Tree ROW - Limb	14765	23	7785.50
2864140	**9/22/21**	15:21	**21:18**	356.28	**Dist Primary - OH**	Tree ROW - Limb	15801	513	182773.35
2864141	**9/22/21**	16:24	**23:52**	447.95	**Dist Primary - OH**	Tree Outside ROW - Limb	117	10	4479.50
2864373	**9/23/21**	1:38	**4:50**	191.25	**Dist Primary - OH**	Tree ROW - Limb	15944	6	1147.50
2864392	**9/23/21**	2:30	**2:55**	24.08	**Dist Secondary - OH**	Tree ROW - Limb	15197	3	72.25
2864509	**9/23/21**	7:49	**12:58**	308.58	**Dist Primary - OH**	Tree Row - Down	467	11	3394.42
2864547	**9/23/21**	8:49	**12:57**	247.30	**Dist Primary - OH**	Tree Row - Down	467	10	2473.00
2865555	**9/27/21**	1:26	**3:55**	149.00	**Dist Primary - OH**	Tree Outside ROW - Down	144	39	5811.00
2866004	**9/28/21**	13:38	**16:01**	142.17	**Dist Primary - OH**	Tree ROW - Limb	15009	1	142.17
2866275	**9/29/21**	16:47	**17:05**	17.58	**Dist Secondary - OH**	Tree Row - Down	15867	1	17.58
2867184	**9/22/21**	15:40	**4:51**	791.00	**Dist Secondary - OH**	Tree Outside ROW - Down	414	1	791.00
2867185	**9/22/21**	22:24	**0:17**	113.00	**Dist Secondary - OH**	Tree Outside ROW - Down	414	1	113.00
2867371	**9/22/21**	16:38	**19:26**	168.00	**Dist Secondary - OH**	Tree ROW - Limb	118	1	168.00
2867373	**9/22/21**	16:38	**17:50**	72.00	**Dist Secondary - OH**	Tree ROW - Limb	118	1	72.00
2868914	**10/9/21**	16:11	**16:20**	9.13	**Dist Primary - OH**	Tree Outside ROW - Limb	14031	1270	11599.33
2868921	**10/9/21**	16:21	**17:44**	83.98	**Dist Primary - OH**	Tree Outside ROW - Limb	14031	549	46106.85
2868946	**10/9/21**	16:59	**17:09**	10.00	**Dist Primary - OH**	Tree Outside ROW - Down	14031	1	10.00
2868955	**10/9/21**	16:21	**17:34**	73.00	**Dist Primary - OH**	Tree Outside ROW - Limb	14031	20	1460.00
2868964	**10/9/21**	16:21	**22:15**	354.65	**Dist Primary - OH**	Tree ROW - Limb	14031	7	2482.55
2871272	**10/16/21**	17:12	**17:22**	10.00	**Dist Primary - OH**	Tree Outside ROW - Limb	117	58	580.00
2871419	**10/17/21**	16:32	**18:26**	113.63	**Dist Secondary - OH**	Tree ROW - Limb	14022	1	113.63
2872839	**10/21/21**	20:36	**21:33**	56.33	**Dist Secondary - OH**	Tree ROW - Limb	15198	1	56.33
2873968	**10/25/21**	19:58	**21:42**	103.58	**Dist Primary - OH**	Tree ROW - Limb	14987	34	3521.83
2874635	**10/26/21**	16:01	**17:49**	107.42	**Dist Secondary - OH**	Tree Outside ROW - Down	102	15	1611.25
2874714	**10/26/21**	17:05	**21:41**	275.13	**Dist Secondary - OH**	Tree Outside ROW - Limb	15175	1	275.13
2874748	**10/26/21**	17:23	**17:54**	31.05	**Dist Secondary - OH**	Tree Outside ROW - Down	102	1	31.05
2874917	**10/26/21**	19:18	**20:51**	92.88	**Dist Primary - OH**	Tree ROW - Limb	14987	6	557.30

Event ID	Outage Date	Begin Time	End Time	Outage Duration	Sub Cause	Outage Cause	Feeder	Customers Affected	Customer Minutes
2874972	**10/26/21**	19:52	**21:50**	117.27	**Dist Primary - OH**	Tree Row - Down	15945	1	117.27
2875044	**10/26/21**	22:30	**6:28**	478.98	**Dist Primary - OH**	Tree ROW - Limb	14900	4	1915.93
2875061	**10/26/21**	23:32	**5:35**	363.18	**Dist Primary - OH**	Tree Outside ROW - Limb	117	1	363.18
2875167	**10/27/21**	11:42	**11:55**	13.30	**Dist Secondary - OH**	Tree Outside ROW - Limb	15010	1	13.30
2876111	**10/29/21**	10:16	**13:30**	194.00	**Dist Primary - OH**	Tree Row - Down	15945	435	84390.00
2876142	**10/29/21**	10:16	**15:22**	306.00	**Dist Primary - OH**	Tree Row - Down	15945	43	13158.00
2876142	**10/29/21**	10:16	**10:04**	1428.00	**Dist Primary - OH**	Tree Row - Down	15945	119	169932.00
2876172	**10/29/21**	10:38	**17:52**	433.63	**Dist Primary - OH**	Tree Row - Down	144	13	5637.23
2876465	**10/29/21**	16:52	**19:39**	166.63	**Dist Secondary - OH**	Tree Row - Down	128	1	166.63
2876760	**10/30/21**	9:37	**14:40**	302.13	**Dist Primary - OH**	Tree Row - Down	14132	2	604.27
2877168	**10/31/21**	20:04	**21:09**	64.63	**Dist Secondary - OH**	Tree Outside ROW - Down	15945	1	64.63
2879182	**11/7/21**	10:59	**12:02**	62.13	**Dist Secondary - OH**	Tree Outside ROW - Limb	15944	1	62.13
2879375	**11/8/21**	10:03	**10:10**	6.63	**Dist Primary - OH**	Tree ROW - Limb	347	16	106.13
2880645	**11/12/21**	2:57	**5:36**	158.18	**Dist Primary - OH**	Tree ROW - Limb	490	5	790.92
2880645	**11/12/21**	2:57	**5:36**	158.18	**Dist Primary - OH**	Tree ROW - Limb	15001	24	3796.40
2882595	**11/18/21**	19:17	**20:22**	64.13	**Dist Secondary - OH**	Tree Outside ROW - Limb	14014	1	64.13
2886209	**11/26/21**	20:32	**20:39**	7.00	**Dist Secondary - OH**	Tree ROW - Limb	15009	1	7.00
2886210	**11/26/21**	11:40	**16:47**	307.00	**Dist Secondary - OH**	Tree Outside ROW - Down	15011	1	307.00
2886211	**11/26/21**	14:20	**15:09**	49.00	**Dist Secondary - OH**	Tree Outside ROW - Down	15011	1	49.00
2886695	**5/1/21**	4:28	**13:43**	555.00	**Dist Primary - OH**	Tree Outside ROW - Limb	451	1	555.00
2888185	**12/9/21**	17:41	**18:58**	76.83	**Dist Secondary - OH**	Tree ROW - Limb	387	1	76.83
2891827	**12/27/21**	16:46	**17:23**	36.85	**Dist Primary - OH**	Tree ROW - Limb	144	11	405.35

Pepco tracks the District of Columbia System Tree SAIFI and SAIDI to measure the effectiveness of VM. Tree SAIFI and SAIDI measures the level of vegetation-caused outages. The following tables present data showing the System Tree SAIFI and SAIDI (in minutes) for the Pepco District of Columbia service territory for 2017 to 2021, based on the Major Service Outage ("MSO") exclusion criteria.

Table 41

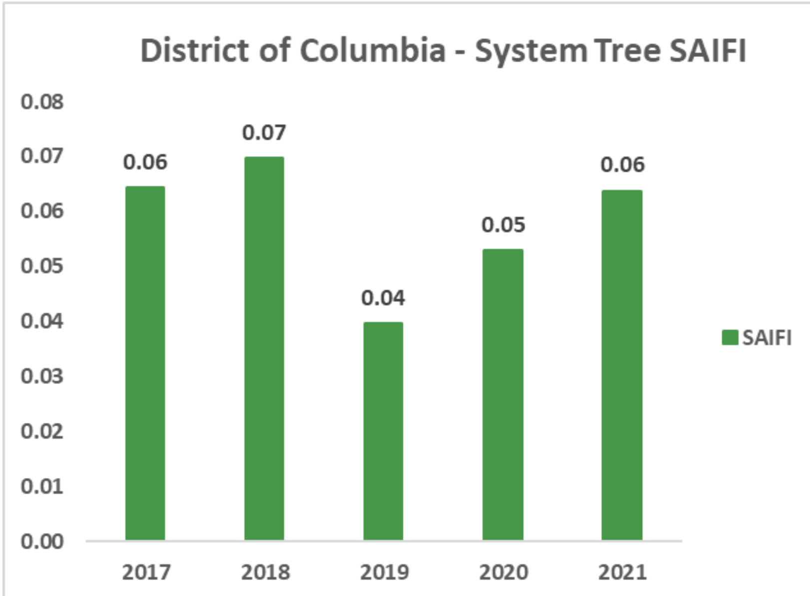
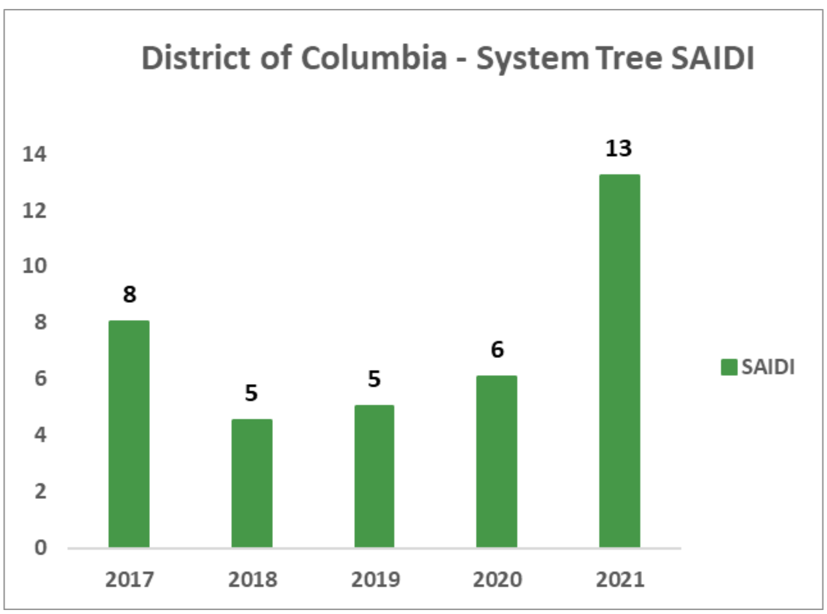


Table 42



2.12 ELECTRICITY QUALITY OF SERVICE STANDARDS (EQSS)

The Commission introduced the EQSS to establish standards and requirements for ensuring that electric utilities operating in the District of Columbia meet an adequate level of quality and reliability in the electric service provided to District residents. On February 29, 2008, the Commission issued a Notice of Final Rulemaking (NOFR) on the EQSS. The EQSS are now adopted as Chapter 36, Electricity Quality of Service Standards in Title 15 of the District of Columbia Municipal Regulations. Subsequently on July 25, 2008, the Commission issued a NOFR on Compliance Reporting. Pepco and all electricity suppliers within the District of Columbia were directed to collect EQSS data on a monthly basis and retain the reporting data for seven (7) years. Further, quarterly submissions, containing monthly data, are to be filed with the Commission on April 30, July 30, October 30 and January 30 for the prior three (3) months respectively. Specific Consolidated Report requirements from the EQSS portion of the

D.C.M.R. are listed on the footnote.[66]

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[66] Progress on current corrective action plans [on customer calls answered] shall be included in the utility's annual Consolidated Report.

The utility shall report the actual call center performance during the reporting period in the annual Consolidated Report of the following year.

Progress on any current corrective action plans [on call abandonment rates] will be included in the utility's annual Consolidated Report.

The utility shall report the actual performance obtained during the reporting period in the annual Consolidated Report of the following year.

The utility shall complete installation of new residential service requests within ten (10) business days of the start date for the new installation.

Progress on any current corrective action plans [on new residential service installation requests] will be included in the utility's annual Consolidated Report.

The utility shall report the actual performance obtained during the reporting period in the annual Consolidated Report of the following year.

3603.5 The utility shall report on the progress of the corrective action plan [on repeat least performing feeders] in the Annual Consolidated Report submitted to the Commission.

The utility shall report on the number and percentage of non-major service outages that extend beyond the twenty-four (24) hour standard and the reasons each such outage extended beyond the twenty-four (24) hour standard.

The report drafted pursuant to Section 3603.8 shall be included in the annual Consolidated Report on reliability data.

Electricity Quality of Service Standards Results

January – December 2021 Aggregate Totals

The utility shall report on the progress of the corrective action plan [on SAIFI, SAIDI and CAIDI benchmarks] in the annual Consolidated Report submitted to the Commission.

The utility shall also, per the orders of the Commission, continue current requirements of reporting annual reliability indices of SAIFI, SAIDI and CAIDI (with and without major events) in the annual Consolidated Report of the following year.

3601	Reporting Requirements for Service Outages, Incidents and Power Quality Complaints						
Standards			2021 Aggregate Totals				
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3601.2/ 3601.6	Report major and non-major service outages by telephone and e-mail within one (1) hour after the utility has determined that a major service outage occurred or after the utility becomes aware of the incident.	Report by telephone and e-mail **within one (1) hour.**	270	100%	See FC Nos. 982 & 1002, Pepco's Quarterly EQSS filings dated Apr. 30, 2021; Jul. 29, 2021; Nov. 1, 2021; and Jan. 28, 2022.		
3601.3/ 3601.8	Each telephone and e-mail report on major and non-major outages should contain a) the location, b) Wards affected, c) # of customers out of service, d) cause of the outage, e) the estimated repair time, and, for major outages, f) notification of progress to major outage status.	Each 3601.3 report must contain **(a) - (f)**, each 3601.8 report must contain **(a) - (e)**.	270	100% (Except for ward data)	See FC Nos. 982 & 1002, Pepco's Quarterly EQSS filings dated Apr. 30, 2021; Jul. 29, 2021; Nov. 1, 2021; and Jan. 28, 2022.		
3601.4	Report periodically (frequency to be determined by the Commission's Office of Engineering) regarding the status of the major service outage.	**TBD**	NA	NA			

3601	Reporting Requirements for Service Outages, Incidents and Power Quality Complaints						
Standards			2021 Aggregate Totals				
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3601.5	Specific restoration information, including restoration times, shall be provided to District customers by customer service representatives and the automated voice response unit.	**TBD**	NA	NA			
3601.9/ 3601.11	Report by telephone all manhole incidents (smoking manholes, manhole fires, manhole explosions) and all incidents that result in the loss of human life and/or personal injury requiring hospitalization within thirty (30) minutes upon receiving notice of the incident.	Report **within 30 minutes** of receiving **notice of incident.**	2	100%	See FC Nos. 982 & 1002, Pepco's Quarterly EQSS filings dated Apr. 30, 2021; Jul. 29, 2021; Nov. 1, 2021; and Jan. 28, 2022.		
3601.10/ 3601.12	Telephone and e-mail reporting of incidents to include: a/b) location/description of the incident, b/c) Ward, c/d) customers and/or persons affected, d/e) cause of incident, e) estimated repair and/or restoration time (for manhole incidents), and f) steps utility will take to provide assistance (for personal injury incidents).	**Each 3601.10 report must contain (a) - (e)**, each 3601.12 report must contain **(a) - (f)**.	2	100% (Except for ward data)	See FC Nos. 982 & 1002, Pepco's Quarterly EQSS filings dated Apr. 30, 2021; Jul. 29, 2021; Nov. 1, 2021; and Jan. 28, 2022.		

3601	Reporting Requirements for Service Outages, Incidents and Power Quality Complaints							
Standards			**2021 Aggregate Totals**					
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status	
3601.13/ 3601.15	Written reports concerning non-major service outages and/or manhole incidents shall be submitted to OE and OPC within five (5) days from the date of the event occurrence. Written reports on the loss of human life/personal injury shall be submitted within five (5) days of receiving notice of the incident.	Submit 3601.13 report **within 5 days of event,** and 3601.15 report **within 5 days of receiving notice.**	270	97%	See FC Nos. 982 & 1002, Pepco's Quarterly EQSS filings dated Apr. 30, 2021; Jul. 29, 2021; Nov. 1, 2021; and Jan. 28, 2022.			
3601.14/ 3601.16	At a minimum: each written report on non-major service outages and/or manhole incidents shall state, a) description, b) location, c) Wards, d) time of the outage, e) repair and restoration times, f) duration of outage(s) in hrs/min., g) total # of customers, h) total # of manholes, i) classification of the manhole incident(s); each written report on loss of human life and/or personal injury shall state, a) description, b) location, c) Ward, d) exact time, e) total # of customers, f) assistance steps, g) time it took assistance to arrive, h) steps to prevent reoccurrence.	Each 3601.14 report must contain **(a) - (i)**, each 3601.16 report must contain **(a) - (h)**.	270	100%				
3601.17	Provide a detailed report on non-major service outages, manhole incidents, and/or incidents that result in the loss of human life or personal injury to the Productivity Improvement Working Group (PIWG) every quarter.	Submit all applicable reports to the PIWG **every quarter**.	0	100%				

3601	Reporting Requirements for Service Outages, Incidents and Power Quality Complaints						
Standards			**2021 Aggregate Totals**				
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3601.18	File a written report concerning major service outages within 3 weeks following the end of the outage.	File the required written report **to each office within three (3) weeks** of the end of a major service outage.	0	NA			
3601.19	Specifies minimum requirements for the contents of the written report for major service outages. ***Please refer to the EQSS for (a)-(o) as they are very detailed and are not listed here.***	Each written report must **contain** information **from (a) - (o).**	NA	NA			
3601.2	Submit a written report on the Outage Management System's (OMS) actual performance during the major service outage within 30 days after restoration efforts are completed.	Submit written report **within 30 days** after restoration.	NA	NA			
3601.21/ 3601.23	Record and report the number of power quality complaints received, types of complaints received, results of subsequent investigations, corrective actions taken, and the time it took to resolve the customer's problem.	Submit the report **45** days after each **six (6) month** reporting period.	2 See reports filed May 14, 2021 and Nov. 15 2021 in FC Nos. 982 & 1002	NA			

3602	Customer Service Standards							
Standards			2021 Aggregate Totals					
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3602.1	Maintain a customer service (walk-in) office located in the District of Columbia.	Notify location of **one (1)** office.	701 9th St NW, Washington, DC 20068	100%			
3602.2	Answer at least seventy (70) percent of all customers' phone calls received within thirty (30) seconds and maintain records delineating customer phone calls answered by a utility representative or an automated operator system. Utility shall measure and report on the average customer wait time for a customer transferred from an automated operator system to a utility representative.	70% of received calls answered within **30** seconds	678,185 (Total calls) Call answering rate = 92%	100%			
3602.4/ 3602.6/ 3602.7	Develop a corrective action plan if 3602.2 standard is not met. Report on the progress of current corrective action plans and actual call center performance in the annual Consolidated Report.	Written corrective action plan in CR	NA	NA			
3602.8	Call abandonment rate must be maintained below ten (10) percent.	Call abandonment rate **below 10%**	4,566 (Calls abandoned) Call abandonment rate = 1%	100%			
3602.10/ 3602.12/ 3602.13	Develop a corrective action plan if 3602.8 standard is not met. Report on the progress of current corrective action plans and actual call center performance in the annual Consolidated Report.	Written corrective action plan in CR	NA	NA			

3602	Customer Service Standards (cont'd.)						
Standards			2021 Aggregate Totals				
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3602.14	Complete installation of new residential service requests within ten (10) business days of the start date for the new installation.	Service requests installed within **10** days of start.	NA	NA			
3602.16	Submit a written report on its performance in 3602.14 every six (6) months.	One report every six **(6)** months.	2 See reports filed May 14, 2021 and Dec. 2, 2021 in FC Nos. 982 & 1002	NA			
3602.19/ 3602.21/ 3602.22	Develop a corrective action plan if 3602.14 standard is not met. Report on the progress of current corrective action plans and actual performance in the annual Consolidated Report.	Written corrective action plan in CR		NA			

3603	Reliability Standards						
Standards			2021 Aggregate Totals				
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3603.1	Implement a plan to improve the performance of the two (2) percent least performing feeders.	Written plan identifying the 2% LP feeders targeted.	See Consolidated Report Filed 4/15/2020	100%			
3603.3/ 3603.5	If the utility fails to comply with 3603.1, a corrective action plan is required. Report on the progress of the corrective action in the Consolidated Report.	Written corrective action plan in CR	See Consolidated Report Filed 4/15/2021	100%			
3603.7/ 3603.8	Complete service restoration within 24 hours following a non-major service outage. Report on the number and percentages of outages that extend beyond the 24 hour standard and the causes for the extended outages.	Restoration within **24** hrs. Written report on 24 hr exceedance in CR	268	98%	See FC Nos. 982 & 1002, Pepco's Quarterly EQSS filings dated Apr. 30, 2021; Jul. 29, 2021; Nov. 1, 2021; and Jan. 28, 2022.		
3603.10/ 3603.11/ 3603.12/ 3603.13	Utility shall not exceed the benchmark levels established for the System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), and the Customer Average Interruption Duration Index (CAIDI).	Refer to Order No. 16700.	NA (Refer to Order No. 18148)	NA			
3603.14/ 3603.16/ 3603.17	Develop a corrective action plan if 3603.10 standard is not met. Report on the progress of current corrective action plans and actual performance in the annual Consolidated Report.	Document Corrective action plan in CR	NA	NA			

3604	**Billing Error Notification**							
Standards			**2021 Aggregate Totals**					
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status	
3604.1	Inform Commission and OPC of a billing error when it affects 100 or more customers or the number of affected customers is equal to or more than two (2) percent of the utility's or service provider's customer base (whichever is less). If the customer base is less than 100, report errors when two (2) or more customers are affected.	Notices when 100, or 2%, or 2 or more customers are affected.	5	100%				
3604.2/ 3604.3	Submit an initial billing error notification (by e-mail) within one (1) business day of discovering or being notified of the error, submit a written report within 14 calendar days and a final written report within 60 calendar days.	Initial notification within one **(1)** b/day, 1st written report within **14** c/days, final written report within 60 c/days.	2	100%				
3604.4	Initial billing error notification shall contain: a) type of billing error, b) when discovered, c) how discovered, and d) # of customers affected.	Notification must contain **(a) - (d)**.	NA	NA				
3604.5	Follow-up written report shall contain: a) type of billing error, b) when it occurred, c) # of customers affected, d) the cause of the error and correction status, and, e) timeline for completing correction plan.	Report must contain **(a) - (e)**, and show closeout of **(d) within 60 days**.	NA	NA				

3604	**Billing Error Notification (cont'd.)**						
Standards			**2021 Aggregate Totals**				
Section	Standard	Measure	Total # of Events	% Compliant (w/measure)	Corrective Action	Due Date	Status
3604.6/ 3604.7	Final written report shall contain: a) type of billing error, b) when it occurred, c) # of customers affected, d) duration of the billing error(s), e) corrective and preventive measures taken, and, f) lessons learned, if any. Commission shall determine whether further investigation is necessary.	Report must contain **(a) - (f)**.	2	100%			

Non-Major Outages, Restoration Completion Within 24 Hours

In accordance with Section 3603.8 in the EQSS, Pepco is to include in the Consolidated Report the number and percentage of non-major customer outages that extend beyond the 24-hour standard and the causes for these extended service outages. A Major Service Outage in the District of Columbia, as defined in Section 3699.1, Definitions, of the EQSS states, *"customer interruption occurrences and durations during time periods when 10,000 or more of the electric utility's District of Columbia customers are without service and the restoration effort due to this major service outage takes more than 24 hours."*

Table 43 provide the required information.

For 2021, there were 2 (of 270) non-major outages that extended beyond 24 hours.

Table 43: Percentage of Non-Major Outages that Extended Beyond 24 Hours

Total number of Non-Major Outages extending beyond 24 hours	2
Total number of Non-Major Outages: January 1 - December 31, 2021	270
Percentage of Non-Major Outages extending beyond 24 hours	0.74%

Table 44: 2021 Non-Major Outages Extending Beyond 24 Hours

2021 Non-Major Outage Reporting to the Public Service Commission of the District of Columbia - Outages Exceeding 24 Hours

Report Sequence Number	Outage Sequence Number	Manhole Sequence Number*	Month	Day of Outage	OH or UG	Outage Cause/ Incident Description	Location	Quadrant	Ward	Time of Outage/ Incident	Actual Restoration Time	Duration of Outage Hours / min		Max No. of Cust. Affected	Reason for Outage Exeeding 24 Hours to Restore	Feeder No.
	210		AUGUST	27	OH	Weather/lightning/services dropped (14766) - Permanent repairs, services restored.	4900 Blk of Upton St NW w/o 49th St NW	NW	3	1631 (8/26)	1941	27	10	3	This event exceeded 24 hrs. due to storms on the system resulting in fallen trees/limbs, requiring multiple repairs for restoration.	14766
	213		AUGUST	27	OH	Tree limb/service dropped (14766) - Removed, services restored.	4000 Blk Fordham Rd NW s/o Upton St NW	NW	3	1631 (8/26)	1847	26	16	10	This event exceeded 24 hrs. due to storms on the system resulting in fallen trees/limbs, requiring multiple repairs for restoration.	14766

PART 3: 2020 MANHOLE EVENT REPORT

Section 3 2021 MANHOLE EVENT REPORT[67]

Part 3 of the Consolidated Report includes manhole event information, underground failure analysis results, detailed tracking trends in reportable events based on manhole cover type, and Pepco's cable splice records for 2021. The appendices provide detail regarding manhole events, and Pepco's manhole inspection program.

[67] In Order No. 16091 issued on December 10, 2010, the Commission stated at paragraphs 56, 59, 65, and 66 the following:
56. Decision. Pepco has agreed to make the recommended changes in the 2011 Consolidated Report with the exception of data on failure rates. We require that the members of the PIWG discuss the need for and feasibility of providing data on failure rates in future Consolidated Reports and include in the 2011 Consolidated Report the PIWG conclusions and recommendations, if any.
59. Decision. We adopt the Staff's recommendation and require Pepco to: (1) combine the Manhole Events portion of the failure analysis report with Part 3 of the Consolidated Report; (2) include data in the 2011 Consolidated Report that separates 4 kV primary failures from 13 kV primary failures;
(3) include data in the 2011 Consolidated Report that separates 4 kV from 13 kV manhole events; (4) include trend analyses for "Use of Slotted Manhole Covers;" and (5) include in the Cable Splice or Joint Database section of the Consolidated Report, cable type, age, type of splice and other pertinent information, except that cable type and age can be excluded if unavailable. If data on failure rates for all variables is available for manhole events, Pepco shall include such information in its 2011 Consolidated Report. If such data is unavailable, we require the members of PIWG to discuss the need for and the availability of such data include in the 2011 Consolidated Report the PIWG conclusions and recommendations, if any.
65. Pepco IS DIRECTED to include a discussion of failure data rates in the agenda for the Productivity Improvement Working Group, consistent with Paragraphs 56 and 59 of this Order; and
66. Pepco IS DIRECTED to include additional Manhole Event data in the 2011 Consolidated Report, consistent with Paragraph 59 of this Order.

In Order No. 15152 paragraphs 76 and 66, the Commission ordered the following:
76. PEPCO is DIRECTED to include as part of the 2009 Consolidated Report a proposed plan for significantly reducing manhole events consistent with paragraph 66 of this Order…

3.1 2021 MANHOLE EVENT INTRODUCTION

Pepco herein submits its annual Manhole Event Report for 2021 in accordance with Order Nos. 11716, 13812, 15620 and 16091.

Summary of 2021 Manhole Events

During 2021, there were a total of 25 reportable manhole events in the District of Columbia. Of these 25 manhole events, 16 were classified as Smoking Manholes (S), 8 were classified as Manhole Explosions (E), and 1 were classified as Manhole Fires (F). All 25 events occurred on the 13 kV system. There were 0 events that occurred on the 4 kV system and 0 events occurred on the 69kV system. Appendix 3A is a list of the 2021 manhole events, categorized and described as directed in Order Nos. 11716, 13812, 15620 and 16091.

3.2 UNDERGROUND FAILURE ANALYSIS

Order No. 17074 Requirement

38. *The Order further noted OPC's statement that according to Pepco, its replacement program would screen all feeders by collecting the number of underground faults experienced by each feeder in the last ten years and feeders with five or more faults ("5-in1-10") would be further analyzed for replacement. [Footnote: See F.C. 766-ACR-12, Order No. 16975, paragraph 75.] ...Thus, we direct Pepco to report on the results of its screening program along with Pepco's recommendations for further analysis and replacement in the ACR starting with 2013.*

40. *... Some progress should have been made in the development of a tracking mechanism for PILC actual replacement and Pepco should be able to report on the actualization of its strategy with data that will help the Commission to better understand Pepco's future plans for PILC replacement and examine the results of its PILC Replacement Strategy. Thus, the Company is required to report on the actualization of its PILC Replacement Strategy in the ACR and to include in the report the information identified in Recommendations 8(c), (d) and (e). If the requested information is not available, Pepco shall provide a reasonable substitute that will allow the Commission to assess the progress that Pepco has made and intends to make in the implementation of its PILC Replacement Strategy for the ten-year period from 2012 to 2021.*

Pepco Response – Corrective Actions

Pepco is currently in the process of analyzing available data of the underground electric system faults in the District of Columbia. Feeders with at least five faults within ten years were identified for further analysis. From that list of feeders, those that are already being addressed as part of Pepco's Reliability program and/or other strategies—or programs that would address these issues on the feeders—were removed to avoid duplication of efforts.

In 2021 targeted PILC replacement was performed on eight feeders, shown below in Table 45.

Table 45: PILC Replacement Status

Year	Feeder ID	PILC Replaced & In Service(ft)
2021	14531	5932
2021	14535	7268
2021	14536	4022
2021	14537	1965
2021	14538	8025
2021	14539	2420
2021	16002	6778
2021	16003	7901

In Pepco's 2001 "Alternative Design Proposal to Pepco's 15kV Paper Insulated Lead Covered Power Cables (PILC)" study, Pepco estimated there were 1,109 miles of primary lead cables on the Pepco system in the District of Columbia. Given the current configuration of the District of Columbia underground system, which includes varied duct and manhole sizes, it is not possible to know how many of those miles are non-replaceable. Reconfiguring the manholes and ducts would allow most of Pepco's PILC cable to be replaceable, albeit at significant cost and time. As stated in Pepco's PILC Replacement Strategy, in line with most other electric utilities and with industry best practice, Pepco has not committed to replacing a fixed number of miles of PILC each year and has not identified a year by which full replacement of primary PILC would be expected. Instead, Pepco is seeking opportunistic replacement based on conditions, which it expects to be a more cost-effective replacement strategy.

Consequently, Pepco cannot provide an estimate of the number of miles of PILC that will be replaced by EPR for the 10-year period from 2012 through 2021. Since 2001, Pepco has replaced 9 2 miles of PILC in the District of Columbia both through the opportunistic replacement approach, and planned jobs. This data is reflected in the Table below.

Table 46: PILC Replacement: 2001-Present

Years	***PILC Replaced Footage***	***PILC Replaced Mileage***
2001	0	0
2002	0	0
2003	0	0
2004	7,733	1
2005	27,981	5
2006	14,322	3
2007	26,341	5
2008	26,217	5
2009	28,217	5
2010	25,593	5
2011	17,824	3
2012	35,571	7
2013	17,037	3
2014	25,882	5
2015	23,414	4.4
2016	14,158	2.7
2017	27,936	5.3
2018	50,123	9.5
2019	30,712	5.8
2020	41,289	7.82
2021	44,311	8.39
Total	***440,350***	***91.79***

Underground (UG) Failure Analysis

The results of Pepco's annual UG failure analyses are presented below, in compliance with Order No. 12735 paragraph 138.[68]

In analyzing the performance of the Pepco UG system, it is necessary to distinguish three different measures of system performance:

- Equipment Failures
- Outages
- Reportable Events (RE)

An RE is a reported explosion, fire, or smoke in a manhole. Some Pepco equipment failures may result in customer outages, REs or both. However, not all Pepco equipment failures result in an outage and/or an RE. This is due to the redundancy of some components of the system, especially on secondary networks. In fact, for the underground secondary networks, most equipment failures do not result in customer outages because each network is fed by multiple primary feeders, and each customer can be fed from multiple transformers and secondary mains, making them less susceptible to outages. Further, some underground outages or events are not initiated by equipment failures, but are in fact caused by accidents, such as dig-ins by excavation contractors, failures of non-Pepco equipment, such as District of Columbia owned streetlight cables or gas company equipment.

There are three types of manhole reportable events:

- Explosions
- Fires
- Smoking

Of these three types, from 2017– 2021 smoking manhole events account for the majority of all manhole events experienced in the District. See Figure 9.

[68] In Order No. 12735, paragraph 138, the Commission ordered the following:
138.Pepco shall file a report that summarizes the results of the failure analyses conducted for the calendar year 2002, 30 days from the issuance date of this Report and Order, and subsequently, to file an annual report on the results of the failure analysis group to the PIWG;

Figure 9: Manhole Events - Smoking (2017-2021)

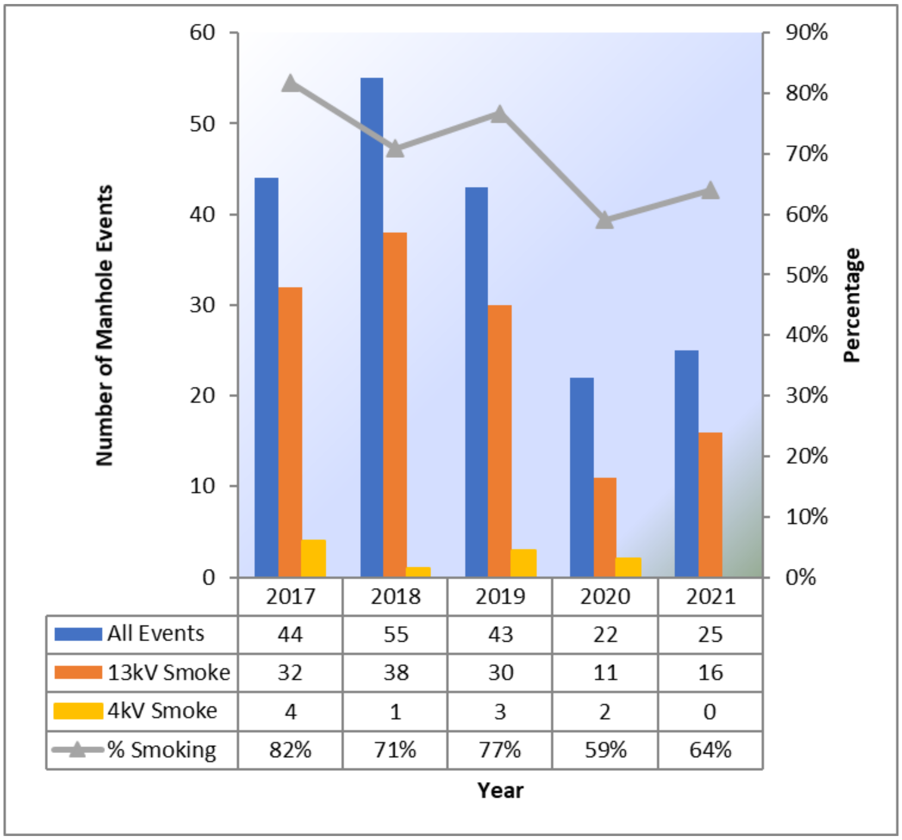
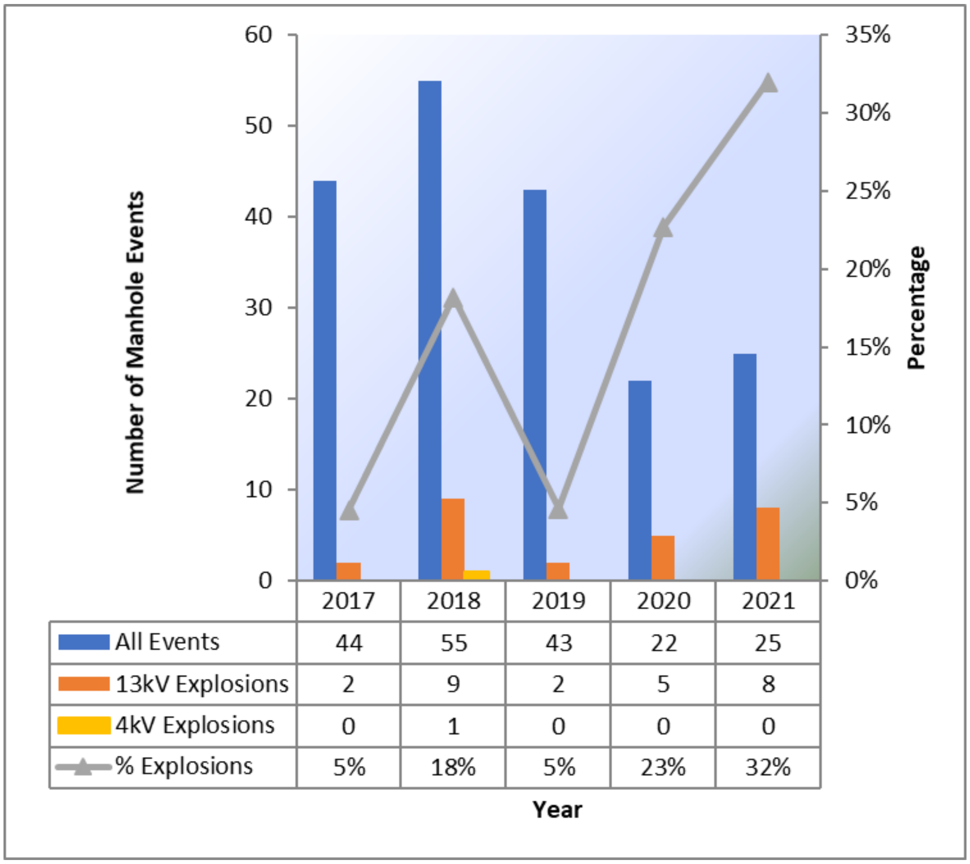


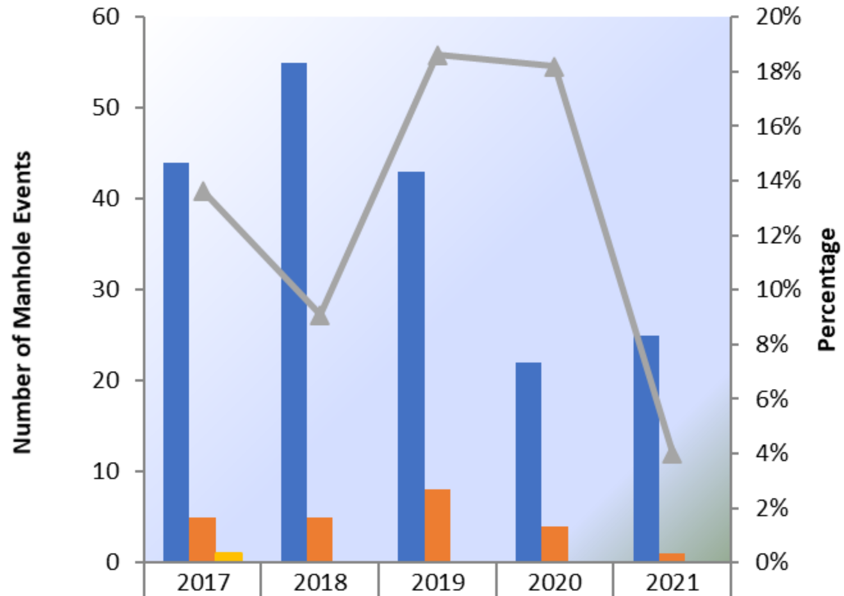
Figure 10 breaks down the number of manhole fires and manhole explosions as compared to the total number of events. As reflected below, explosions and fires occur less frequently than smoking manholes.

Figure 10: Manhole Events - Explosions (2017-2021)



	2017	2018	2019	2020	2021
All Events	44	55	43	22	25
13kV Explosions	2	9	2	5	8
4kV Explosions	0	1	0	0	0
% Explosions	5%	18%	5%	23%	32%

Figure 11: Manhole Events - Fires (2017-2021)

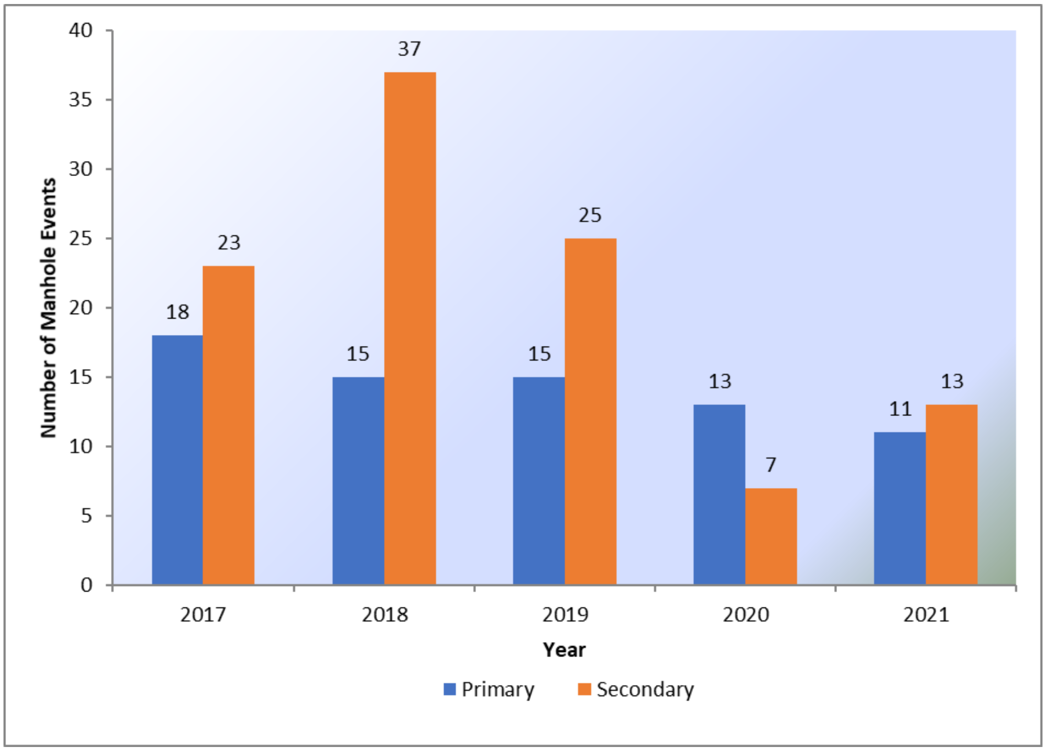


	2017	2018	2019	2020	2021
All Events	44	55	43	22	25
13kV Fires	5	5	8	4	1
4kV Fires	1	0	0	0	0
% Fires	14%	9%	19%	18%	4%

Year

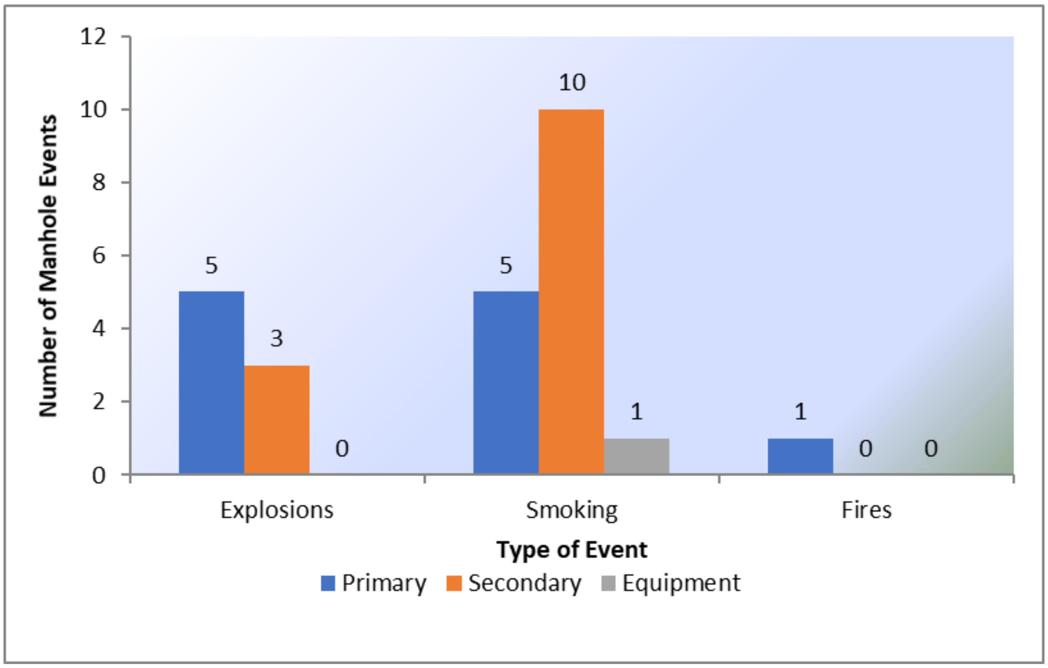
Since 2017, on average most of the manhole events experienced in the District have occurred on Pepco's secondary equipment. See Figure 12.

Figure 12: Manhole Events by Type of Equipment (2017-2021)



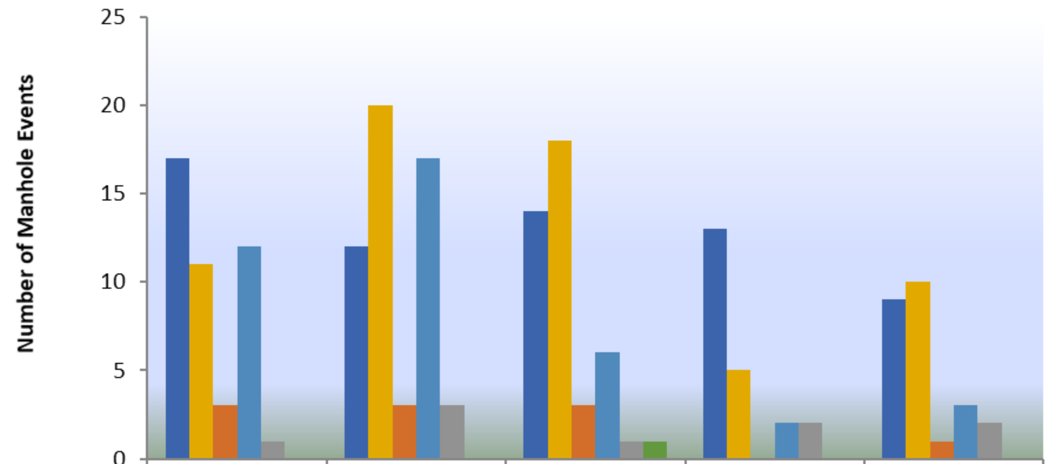
In 2021, 0 manhole fires occurred on the secondary systems. Smoking manholes occurred more on the secondary system, and manhole explosions occurred more on the primary system. Figure 3.5 depicts this breakdown. See Figure 13.

Figure 13: Manhole Events by Type and Equipment (2021)



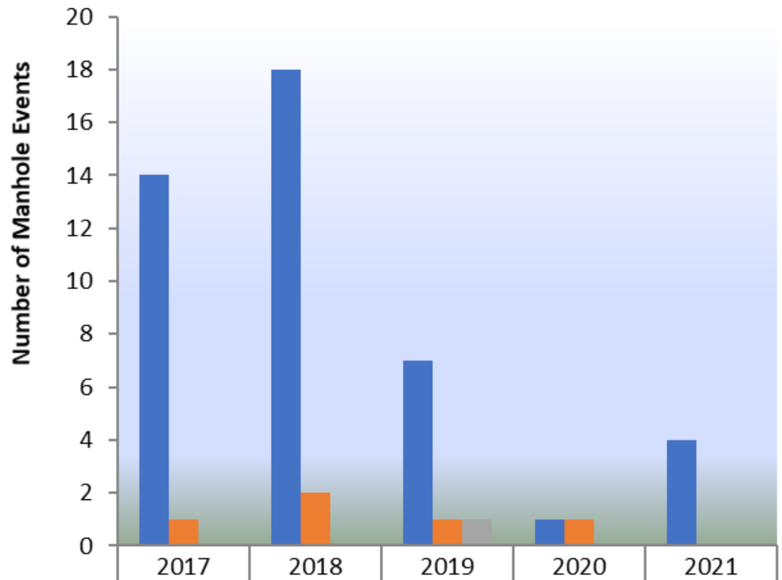
Slotted manhole covers are designed to minimize the frequency and impact of manhole events by allowing gas and smoke to vent from manholes in the event of an underground failure. This provides an early warning and prevents build-up of gases to potentially explosive proportions; thereby allowing energy to disperse more easily should an event occur. The tradeoff when installing slotted covers is that they allow more water and street run-off contaminants to enter the manhole than solid covers. More analysis on the effects of slotted covers and manhole events is presented in the slotted manhole cover section of this report. See Figure 13 and Figure 14 for a breakdown of manhole event by event type, voltage class, and cover type.

Figure 14: Manhole Events by Type, Equipment, and Manhole Cover (2017-2021)



	2017	2018	2019	2020	2021
Solid Primary	17	12	14	13	9
Solid Secondary	11	20	18	5	10
Slotted Primary	3	3	3	0	1
Slotted Secondary	12	17	6	2	3
Grated Primary	1	3	1	2	2
Grated Secondary	0	0	1	0	0

Figure 15: Slotted Manhole Events by Type (2017-2021)



	2017	2018	2019	2020	2021
Slotted Smoking	14	18	7	1	4
Slotted Fire	1	2	1	1	0
Slotted Explosions	0	0	1	0	0

By design, primary cable is more insulated than secondary cable. Whereas primary cable and its accessories are designed to their voltage rating and are shielded, secondary cable and its accessories are not shielded. As a result of less physical protection, secondary cable and its accessories are more likely to fail due to a breach in the insulation. Since 2017, the leading cause of manhole reportable events in the District is insulation-related, such as insulation deterioration. See Figures 16 through 20.

Figure 16: Selected Failure Causes (2017)

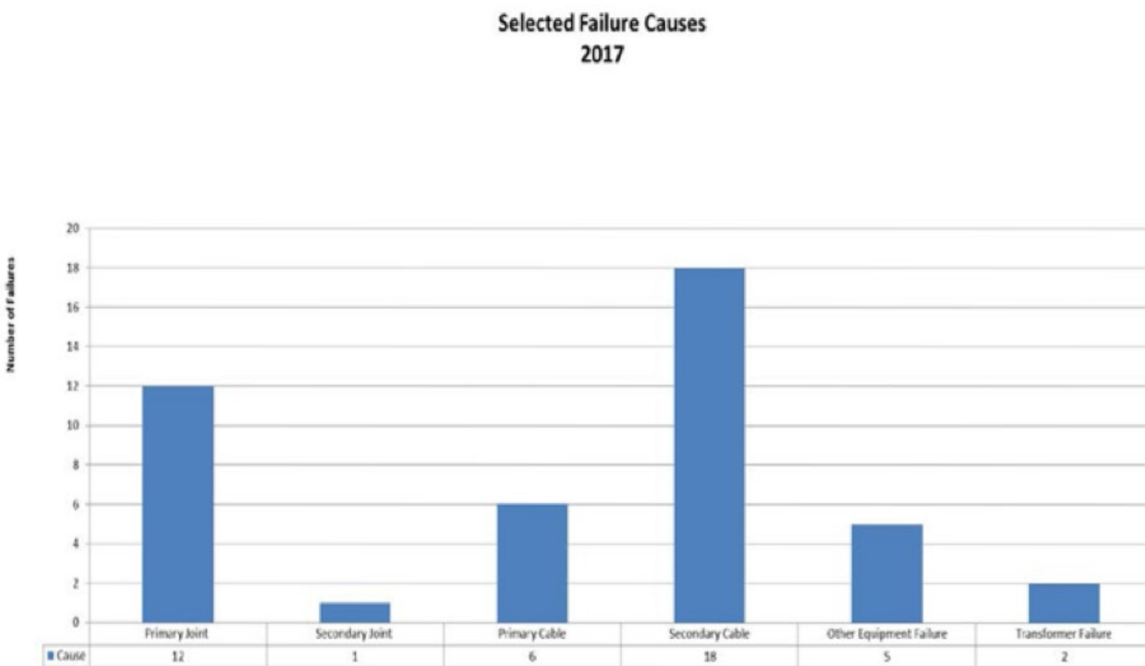


Figure 17: Selected Failure Causes (2018)

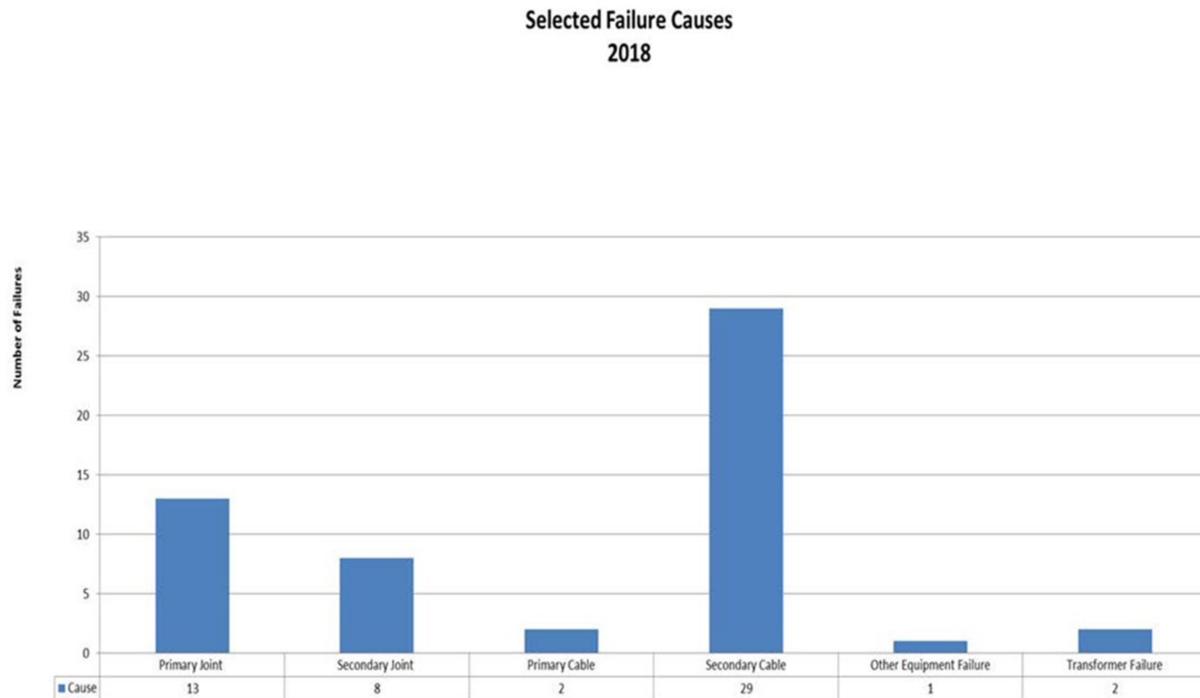


Figure 18 Selected Failure Causes (2019)

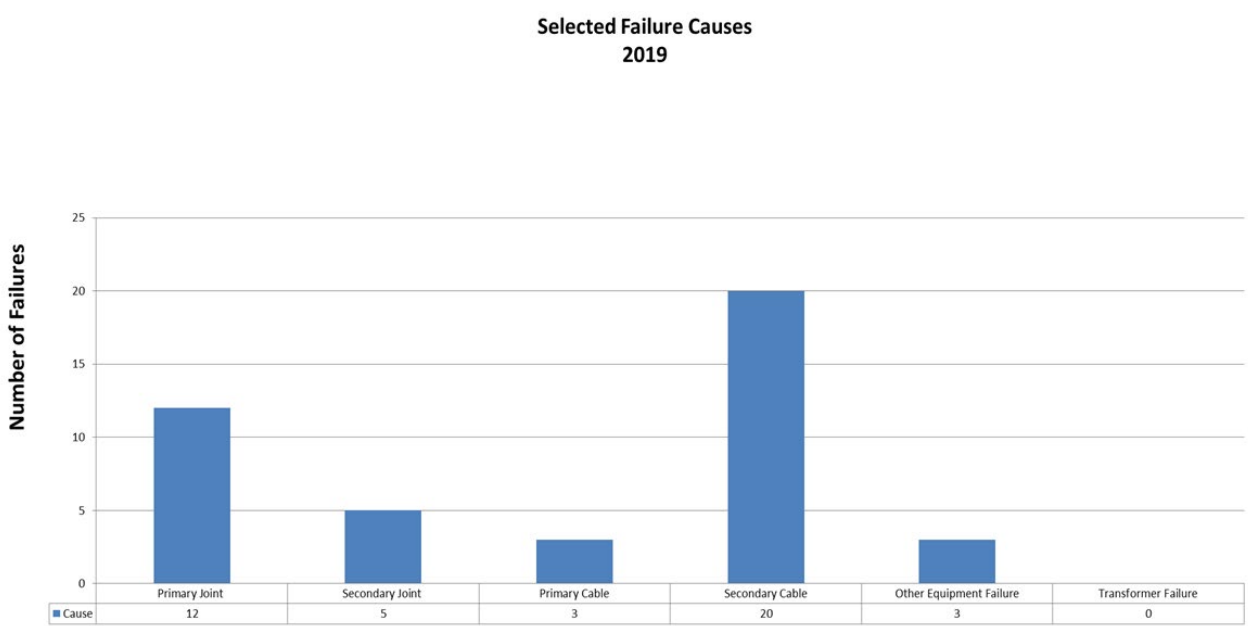


Figure 19 Selected Failure Causes (2020)

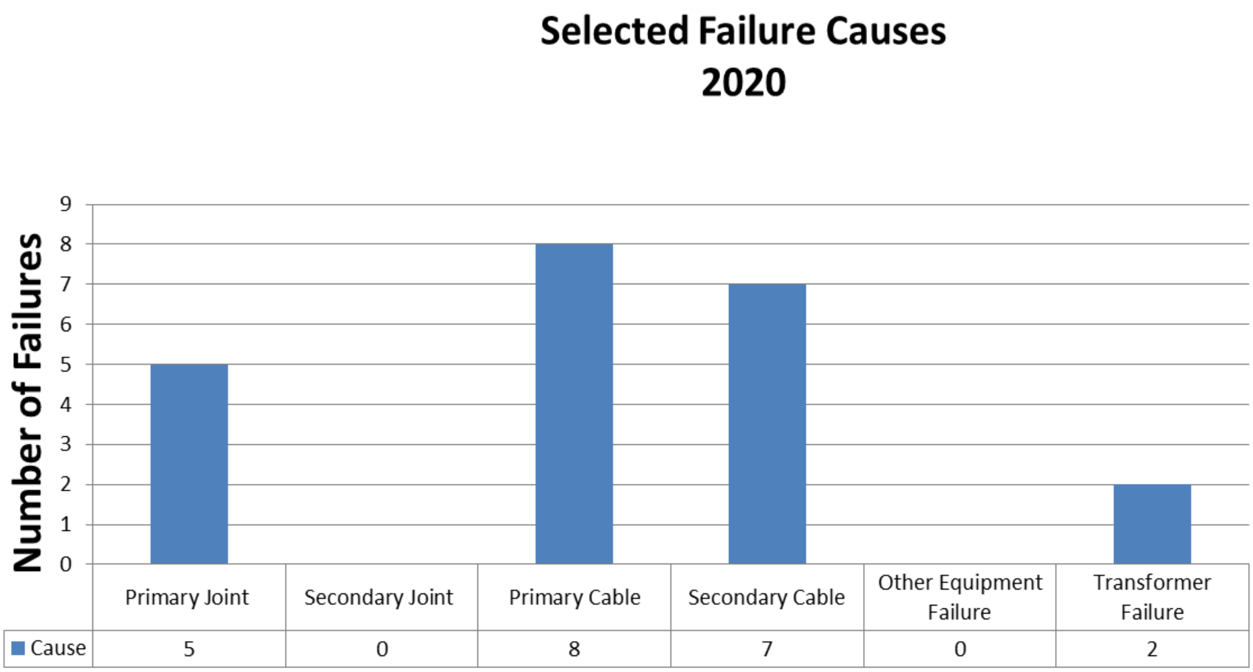
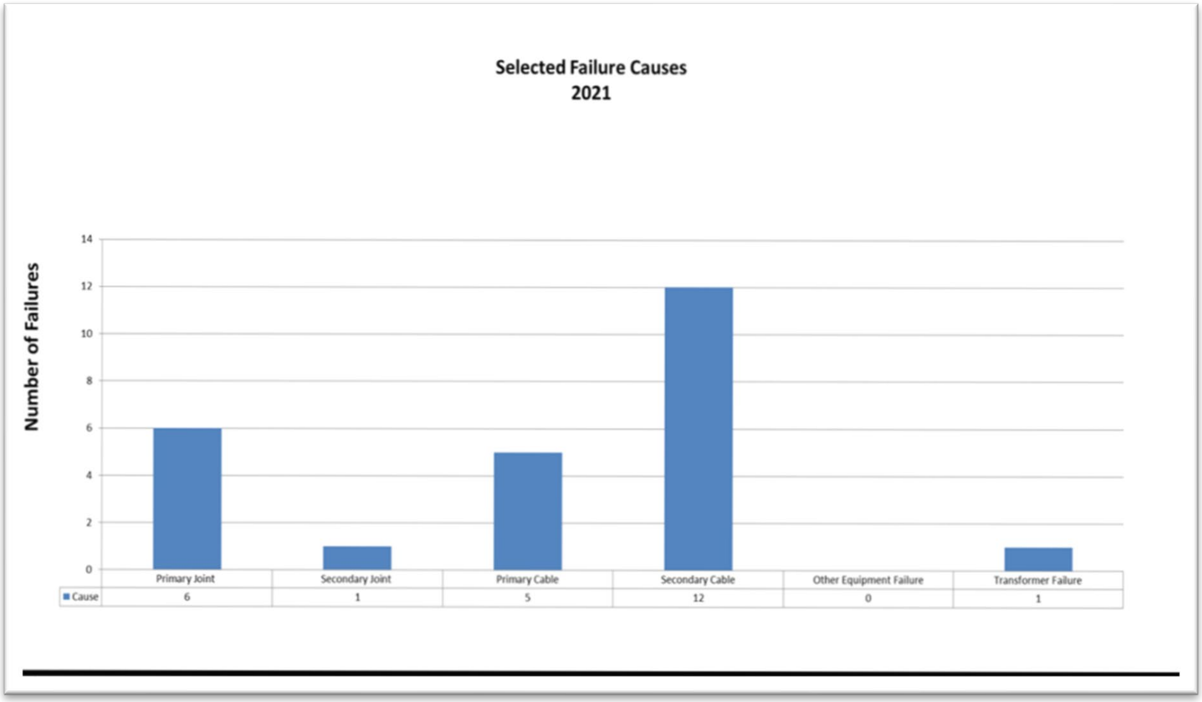


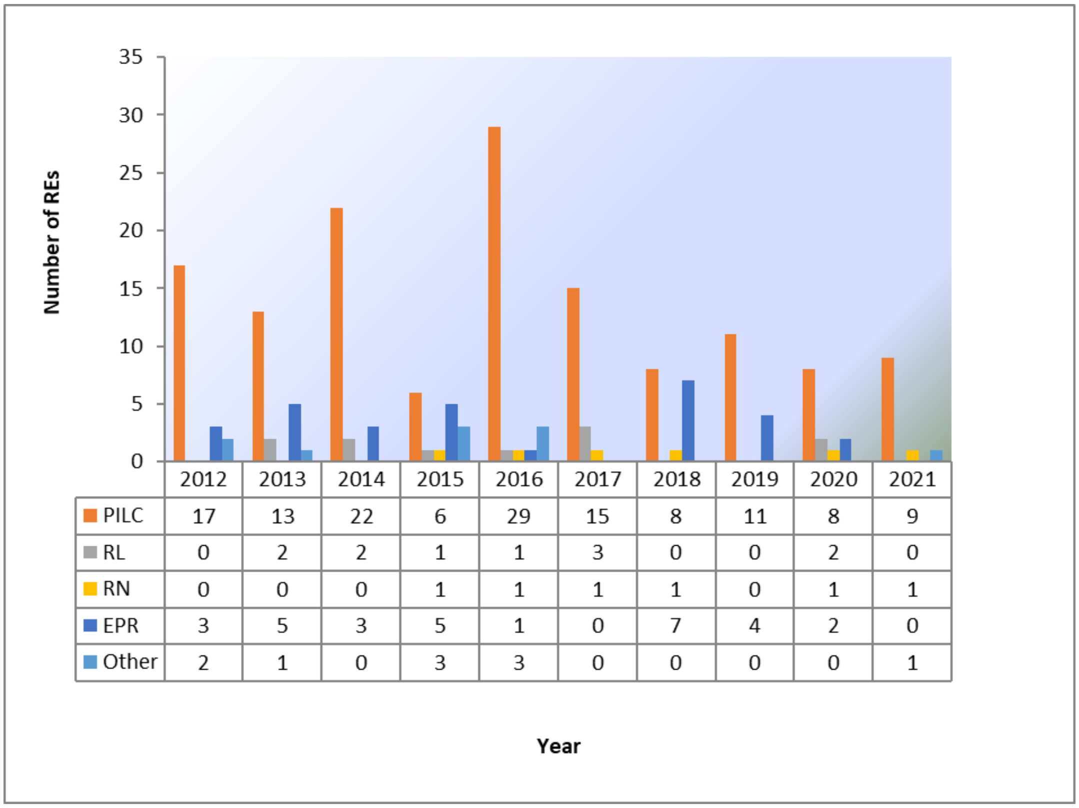
Figure 20 Selected Failure Causes (2021)



3.3 Selected Failure Causes (2021)

The type of insulation related to cable and joint failures resulting in a reportable event for secondary equipment does not provide a discernible trend in reportable events caused by Rubber Lead (RL), Rubber Neoprene (RN), or other insulation types (Figure 21). RL secondary cable is an outdated technology and has not been installed on the system for more than twenty years. It is not possible to trend future reportable events associated with this cable type.

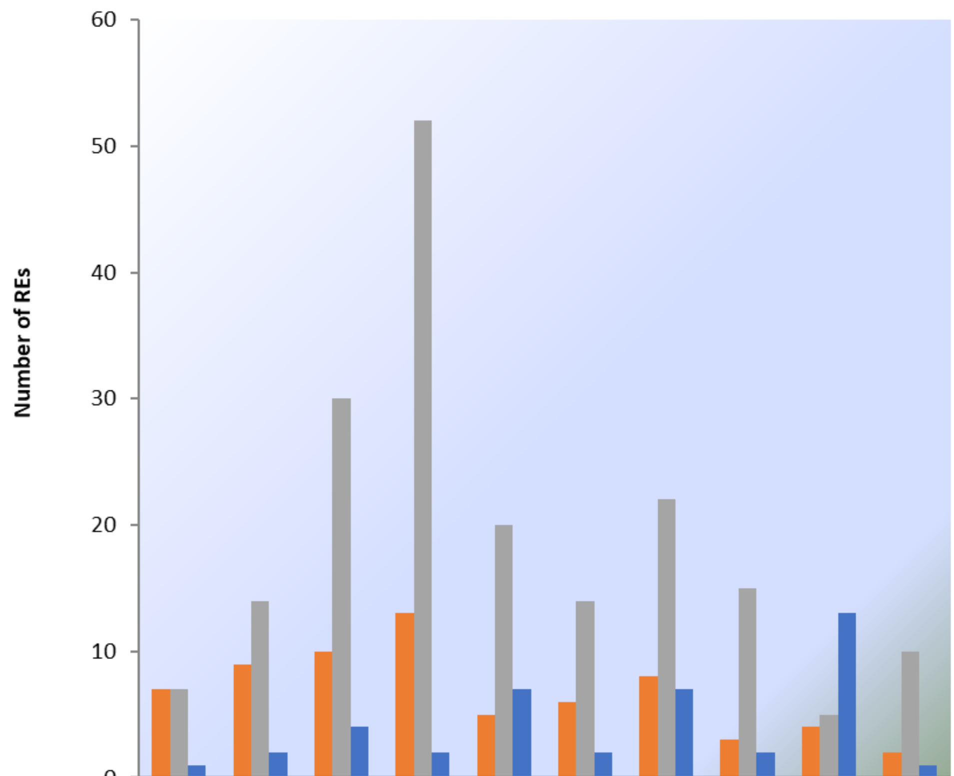
Figure 21: Insulation Type of Secondary REs (2012-2021)



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
PILC	17	13	22	6	29	15	8	11	8	9
RL	0	2	2	1	1	3	0	0	2	0
RN	0	0	0	1	1	1	1	0	1	1
EPR	3	5	3	5	1	0	7	4	2	0
Other	2	1	0	3	3	0	0	0	0	1

PILC is the predominant primary cable on the Pepco underground system. Consequently, most primary cable reportable events involve PILC cable (Figure 22).

Figure 22: Insulation Type of Primary REs (2012-2021)

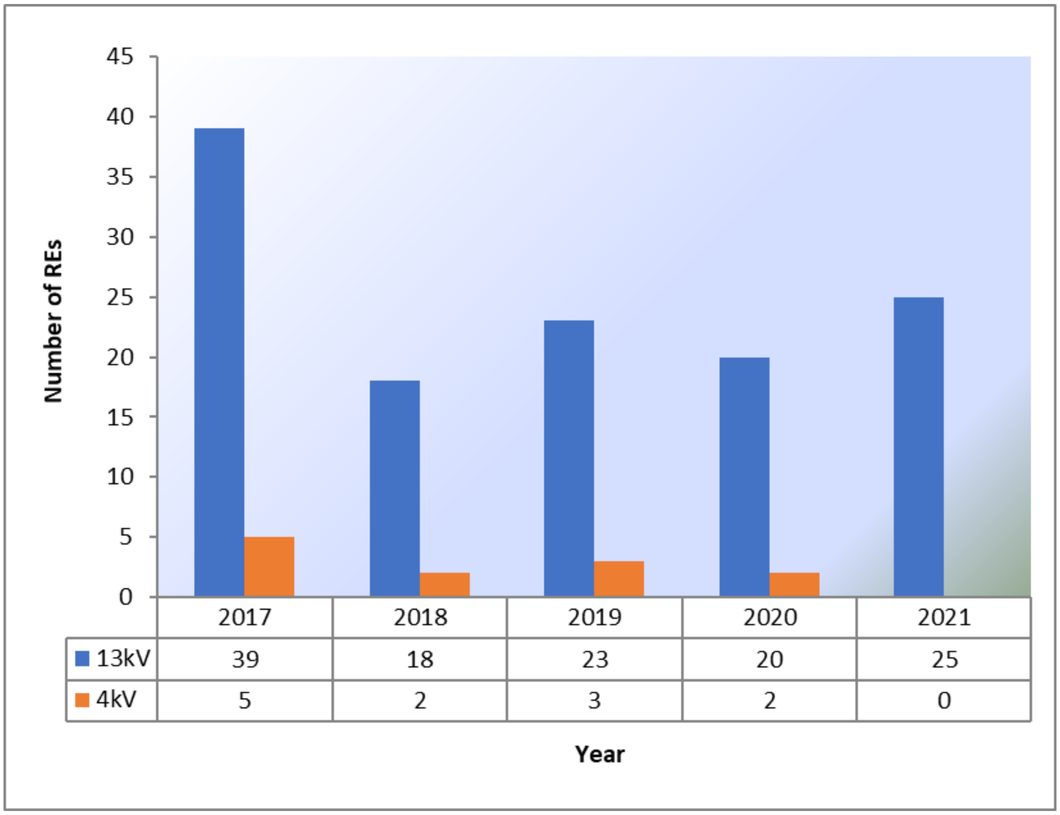


	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
RL	7	9	10	13	5	6	8	3	4	2
RN	7	14	30	52	20	14	22	15	5	10
Other	1	2	4	2	7	2	7	2	13	1

Year

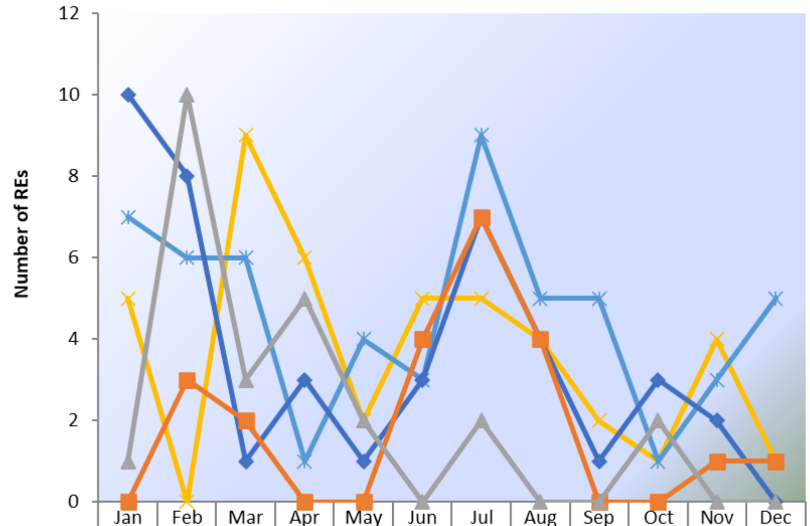
Most reportable events involving primary equipment occur on 13 kV feeders (Figure 23). 4 kV is a vintage technology and the majority of Pepco's underground system is 13 kV.

Figure 23: Voltage Class of Primary REs (2017-2021)



In addition, moisture plays a major role in the deterioration of both primary and secondary cable insulation. When a significant amount of precipitation occurs in the District, moisture and contaminants from the street, such as motor oil, lawn chemicals, etc., enter into the manholes and affect cable insulation. Additionally, snow/ice melt chemicals ingress after a storm can also penetrate cable insulation and lead to failure. While moisture affects all cable insulation, since secondary cable is not as robust or of the same design as primary cable, secondary cable is inherently more likely to fail under adverse weather conditions. A comparison of Figures 24 and 25 suggests that total moisture accumulation affects the number of reportable events.

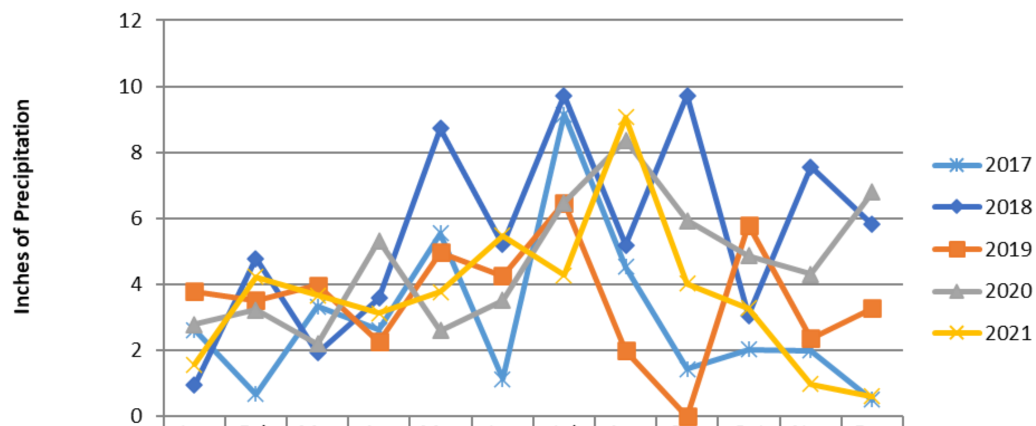
Figure 24: Reportable Events by Month (2017-2021)



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	5	0	9	6	2	5	5	4	2	1	4	1
2018	7	6	6	1	4	3	9	5	5	1	3	5
2019	10	8	1	3	1	3	7	4	1	3	2	0
2020	0	3	2	0	0	4	7	4	0	0	1	1
2021	1	10	3	5	2	0	2	0	0	2	0	0

Year

Figure 25: Total Precipitation in Inches by Month (2017-2021)



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	2.61	0.68	3.32	2.62	5.55	1.13	9.15	4.53	1.43	2.02	2	0.5
2018	0.94	4.79	1.92	3.59	8.73	5.21	9.73	5.19	9.73	3.06	7.56	5.82
2019	3.78	3.52	3.97	2.27	4.97	4.26	6.48	2	0	5.8	2.37	3.28
2020	2.78	3.22	2.19	5.33	2.60	3.51	6.47	8.37	5.93	4.86	4.31	6.79
2021	1.57	4.23	3.67	3.12	3.77	5.48	4.27	9.07	4.03	3.27	0.98	0.6

Year

The Failure Analysis Section will show failure analysis for all manhole incidents in the District to determine trends and remediation activities.

3.4 Slotted Manhole Covers [69]

New Slotted Manhole Cover Program Locations

In its 2013 Consolidated Report, Pepco discussed its criteria for selecting areas for installation of slotted manhole covers. This included areas with high load growth and potential business development. There were no slotted covers installed in 2021.

Historical Slotted Manhole Cover Program[70]

Pepco installed grated manhole covers over single and three-phase transformer installations, and network transformer installations in roadways and sidewalks. Their purpose is to assist in the dissipation of heat from the transformers. To explore the potential of an expanded application of vented manhole covers to non-transformer locations, Pepco contracted the Electric Power Research Institute (EPRI) to simulate manhole explosions. The simulations were specifically designed to test the effectiveness of solid, slotted and grated manhole covers in minimizing displacement of covers under fault conditions. The test data showed that the installation of slotted covers minimizes the frequency and impact of manhole events in three main ways:

1. Energy released may escape through the slotted cover without lifting or displacing it;
2. Smoke can provide an early warning of cable faults, thus preventing more serious events from occurring; or
3. Explosions or fires may be avoided by the dissipation of combustible gases.

Based on these findings, Pepco installed custom-designed, slotted manhole covers in high volume pedestrian traffic areas of the District of Columbia where the low voltage alternating current network exists. The installation of slotted manhole covers has enhanced public safety

[69] Order No. 16975 states the following at paragraphs 74 and 111:
85. Decision: …We agree with the Staff that a manhole replacement program that concluded in 2004 may no longer be appropriate, given business development in new areas of the District. We therefore require Pepco to reexamine the criteria used to select locations for the installation of slotted manhole covers and to report on this reexamination in the 2013 Consolidated Report.
114.Pepco is DIRECTED to revisit criteria used to select locations for installing slotted manhole covers consistent with paragraph 74 herein;

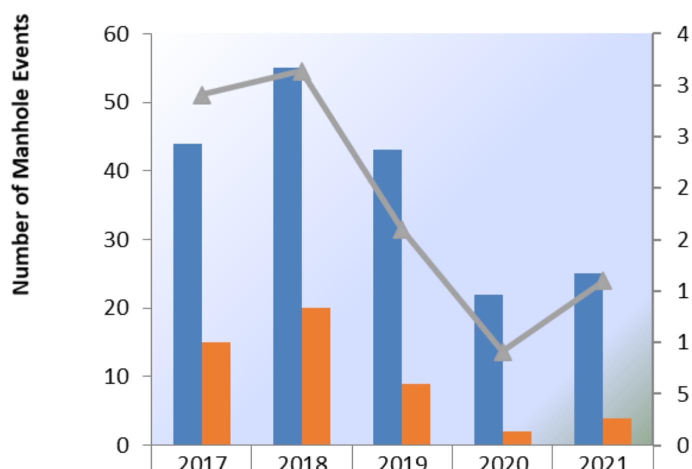
[70] In Order No. 16091 issued on December 10, 2010, the Commission stated among other things, at paragraph 59, the following:
59. … (4) include trend analysis for "Use of Slotted Manhole Covers;"

while minimizing potential damage to underground electric facilities. The installation program was concluded in 2004 with an overall total of 7,880 slotted manhole covers having been installed.

In Order No. 14093, the Commission approved Pepco's proposal to suspend further slotted manhole installations provided the Company submit an analysis of manhole events and failure rates associated with slotted covers, including recommended actions for 2008 by October 27, 2007, and continue to monitor debris accumulation in manholes with slotted covers. Pepco filed its analysis on August 21, 2007.

Pepco realizes that the openings in the covers, while allowing gases to vent, also allow rain, snow, dirt, debris and chemicals into manholes. As a result, Pepco continues to monitor debris accumulation in manholes with slotted covers. Of the 25 reportable manhole events that occurred in the District of Columbia in 2021, 4 involved manholes fitted with slotted covers.[74] Over the five-year period from 2017 through 2021, there were 189 reportable manhole events. Of these, 50 (26%) occurred in manholes with slotted covers. See Figure 26.

Figure 26: Manhole Events Involving Slotted Covers



	2017	2018	2019	2020	2021
All Events	44	55	43	22	25
# Events Slotted Covers	15	20	9	2	4
% Slotted	34%	36%	21%	9%	16%

Year

The rate of manhole events on these slotted covers is disproportional to the total population of these covers on the system. Currently there are slotted covers deployed on about 13% of manholes within the Pepco system yet we are consistently seeing slotted covers account for upwards of 29% of the total manhole events each year. This coupled with the fact that the current Pepco designed slotted covers are not 100% ADA compliant has led Pepco to reconsider the design for vented manhole covers.

With the support of EPRI, an Exelon utility peer group was formed to research manhole events and mitigation techniques. As a result of this research group, all Exelon utilities have aligned on a new design for vented manhole covers. These new manhole covers use a 3% vented design as compared to the current 23% slotted cover. Additionally, the new manhole cover design is fully ADA compliant.

3.5 Cable Splice or Joint Records[71]

Pepco repair crews complete a "Splice Manifest" report which records, among other things, the location, date, type of splice, the splicer's name and the foreman's name. Table 47 contains information from the "Splice Manifest" report for 2021 maintenance work performed. The splicer and foreman names have been redacted from the table.

Table 47: 2021 Splice Data (District of Columbia)

Date	Location	Type of Splice
01/04/21	Rhode Island & Montana Ave., NE	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
01/04/21	Rhode Island & Montana Ave., NE	3-1/C Cold Shrink Potheads #2 to 4/0
01/04/21	Chesapeake & Overlook, SW	3-1/C Cold Shrink Potheads 350 to 600
01/04/21	Chesapeake & Overlook, SW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
01/08/21	30th btwn K & C&O Canal, NW	200 AMP Elbows
01/08/21	30th btwn K & C&O Canal, NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
01/13/21	3945 Connecticut Ave., NW	#2 Y Splices
01/13/21	3945 Connecticut Ave., NW	3/C P.L. to 3 1/C EPR or XLP Trif. Joint #2 - 1/0 or 4/0
01/15/21	1000 6th St., SW	200 AMP Elbows
01/15/21	1000 6th St., SW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
01/25/21	15th & D St., SE	200 AMP Elbows
01/25/21	15th & D St., SE	4kV Branch Heat Shrink
01/26/21	Connecticut Ave. & H St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
01/26/21	Connecticut Ave. & H St., NW	3-1C, #2 Loadbreak Elbows

[71] In Order No. 16091, the Commission stated among other things, at paragraph 59, the following:
59. …(5) include in the Cable Splice or Joint Database section of the Consolidated Report, cable type, age, type of splice and other pertinent information, except that cable type and age can be excluded if unavailable.

Date	Location	Type of Splice
01/27/21	11th & E St. NW	3-1C, #2 Loadbreak Elbows
01/29/21	4850 Connecticut Ave., NW	200 AMP Elbows
01/29/21	4850 Connecticut Ave., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
01/31/21	2740 Porter St., NW	3-1C, #2 Loadbreak Elbows
02/01/21	6th & Chesapeake, SE	3-1/C 4/0 or 350 Straight Heat Shrink Splices
02/03/21	2740 Porter St., NW	3/C P.L. to 3 1/C EPR or XLP Trif. Joint #2 - 1/0 or 4/0
02/03/21	Wisconsin & M St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
02/03/21	Wisconsin & M St., NW	3-1/C URD Slip on Splices
02/05/21	4th & P St., SW	Separable 3 Way Cable Joint
02/05/21	4th & P St., SW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
02/05/21	4th & P St., SW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
02/05/21	4th & P St., SW	3-1/C 500 or 600 Straight Heat Shrink Splices
02/10/21	13th & O St., NW	3-1/C URD Slip on Splices
02/11/21	6th & Pennsylvania Ave., NW	Test Cap 500 3/C up to 750 3/C
02/12/21	Malcolm X & South Capitol	3-1/C 500 or 600 Straight Heat Shrink Splices
02/12/21	7824 Eastern Ave., Rdwy	200 AMP Elbows
02/12/21	7824 Eastern Ave., Rdwy	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
02/16/21	1312 9th St., NW	3-1/C URD Slip on Splices
02/16/21	1330 9th St., NW	3-1/C URD Slip on Splices
02/17/21	419 7th St., NW	3-1C, #2 Loadbreak Elbows
02/17/21	419 7th St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
02/18/21	4701 Willard Ave.	3-1/C URD Slip on Splices
02/18/21	4701 Willard Ave.	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
02/18/21	First & H St., NE	Top Test Cap Lead 1/C 500 KCM
02/21/21	1401 Okie St., NE	3-1/C 4/0 or 350 Straight Heat Shrink Splices
02/22/21	New Hampshire Ave. & V St., NW	3-1/C URD Slip on Splices
02/22/21	16th St. & V St., NW	3-1/C URD Slip on Splices
02/26/21	12th & D St., SE	200 AMP or 600 AMP Deadbreaks
03/01/21	15th & D St., SE	4/0 Cold Shrink
03/01/21	10th & M St., NW	Single Branch Joint 350 3/C to 600 3/C
03/02/21	999 9th St., NW	200 AMP Elbows
03/03/21	1615 New Hampshire Ave., NW	3-1/C URD Slip on Splices
03/03/21	1615 New Hampshire Ave., NW	3-1/C 500 or 600 Straight Heat Shrink Splices
03/03/21	1615 New Hampshire Ave., NW	200 AMP or 600 AMP Deadbreaks
03/03/21	1615 New Hampshire Ave., NW	3-1C, #2 Loadbreak Elbows
03/03/21	3393 Donnell Dr.	200 AMP Elbows
03/03/21	3393 Donnell Dr.	3-1/C URD Slip on Splices
03/04/21	Quebec Pl. & Warder St., NW	200 AMP Elbows
03/06/21	24th & Benning Rd., NE	3-1/C URD Slip on Splices
03/06/21	24th & Benning Rd., NE	Separable 3 Way Cable Joint
03/10/21	3506 Georgia Ave., NW	3-1/C URD Slip on Splices
03/10/21	3506 Georgia Ave., NW	200 AMP Elbows
03/11/21	25th & M St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
03/11/21	25th & M St., NW	Separable 3 Way Cable Joint
03/11/21	25th & M St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
03/20/21	13th & I St., NE	200 AMP Elbows
03/20/21	13th & I St., NE	200 AMP or 600 AMP Deadbreaks
03/20/21	13th & I St., NE	3-1/C 4/0 or 350 Straight Heat Shrink Splices
03/21/21	21st & C St., NW	Separable 3 Way Cable Joint
03/21/21	21st & C St., NW	3-1/C 4/0 or 350 Straight Heat Shrink Splices

Date	Location	Type of Splice
03/22/21	4th & M St., SW	3-1/C 500 or 600 Straight Heat Shrink Splices
03/22/21	4th & M St., SW	3/C P.L. to 3 1/C EPR or XLP Trif. Joint 500 to 600
03/22/21	D & 7th St., SW	Single Branch Joint 350 3/C to 600 3/C
03/22/21	1400 Buckeye Dr., SW	3-1/C URD Slip on Splices
03/23/21	12th & Independent Ave., SW	3-1/C 500 or 600 Straight Heat Shrink Splices
03/23/21	12th & Independent Ave., SW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
03/23/21	2201 C St., NW	Separable 3 Way Cable Joint
03/23/21	1st & G St NE	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
03/23/21	3rd & Virginia Ave., SW	Single Branch Joint 350 3/C to 600 3/C
03/23/21	3rd & D St., SW	Single Branch Joint 350 3/C to 600 3/C
03/24/21	3rd St. & E St., SW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
03/24/21	3rd St. & E St., SW	3-1/C 500 or 600 Straight Heat Shrink Splices
03/24/21	6th & Georgia Ave., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
03/26/21	1900 Half St., SW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
03/26/21	1667 K St., NW	200 AMP Elbows
03/26/21	1667 K St., NW	3-1/C URD Slip on Splices
03/28/21	3rd & G St., SW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
03/29/21	John McCormick & Michigan Ave., NE	3-1/C 4/0 or 350 Straight Heat Shrink Splices
03/29/21	7th & Michigan Ave., NE	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
04/06/21	11th & Rhode Island Ave., NW	3-1/C URD Slip on Splices
04/07/21	Georgia Ave. & Hamilton St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
04/07/21	905 16th St., NW	#2 Test Cap Heat Shrink
04/07/21	Potomac & Grace, NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
04/08/21	6th & Pennsylvania Ave., SE	200 AMP or 600 AMP Deadbreaks
04/08/21	6th & Pennsylvania Ave., SE	3-1/C 500 or 600 Straight Heat Shrink Splices
04/08/21	1575 Eye St., NW	200 AMP Elbows
04/08/21	1575 Eye St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
04/09/21	26th Btwn M & Pennsylvania Ave., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
04/09/21	26th Btwn M & Pennsylvania Ave., NW	200 AMP Elbows
04/09/21	1411 K St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
04/09/21	1411 K St., NW	200 AMP Elbows
04/14/21	3500 Fort Lincoln Dr., NE	200 AMP Elbows
04/14/21	3500 Fort Lincoln Dr., NE	3-1/C URD Slip on Splices
04/20/21	6th & Chesapeake, SE	Cold Shrink Straights
04/20/21	6th & Chesapeake, SE	3-1/C Cold Shrink Potheads 350 to 600
04/21/21	1627 I St., NW	200 AMP Elbows
04/21/21	1627 I St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
04/21/21	1st & Louisiana Ave., NW	3-1/C URD Slip on Splices
04/21/21	1st & Louisiana Ave., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
04/21/21	Ford Dr. & Grant St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
04/21/21	Ford Dr. & Grant St., NW	3-1/C Cold Shrink Potheads 350 to 600
04/23/21	1015 15th St., NW	200 AMP Elbows
04/23/21	1015 15th St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
04/23/21	900 6th St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
04/26/21	New Jersey Ave. & E St., NW	3-1/C 4/0 Cold Shrink Straights
04/26/21	New Jersey Ave. & E St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
04/27/21	1875 H St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
04/27/21	1875 H St., NW	200 AMP Elbows
04/28/21	17th & I St., NW	Separable 4 Way Cable Joint
04/28/21	Connecticut & Eye St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)

Date	Location	Type of Splice
04/28/21	17th & I St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
04/28/21	Wisconsin & M St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
04/28/21	Wisconsin & M St., NW	200 AMP Elbows
04/28/21	30th & M St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
04/28/21	30th & M St., NW	200 AMP Elbows
05/03/21	2nd & Randolph Rd., NE	3-1/C Cold Shrink Potheads 350 to 600
05/03/21	2nd & R St., NE	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
05/04/21	2nd & Constitution Ave., NW	Network Transformer H.V. 200 AMP deadbreak terminal 13kV comp.
05/04/21	2nd & Constitution Ave., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
05/05/21	9th & French St., NW	3-1/C URD Slip on Splices
05/05/21	39th & Rodman St., NW	3-1/C URD Slip on Splices
05/07/21	Champlain Substation	3-1/C Cold Shrink Potheads 350 to 600
05/07/21	Champlain Substation	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
05/10/21	401 K St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
05/10/21	401 K St., NW	200 AMP Elbows
05/10/21	9th & E St., NE	Test Cap 500 3/C up to 750 3/C
05/12/21	1625 L St., NW	200 AMP Elbows
05/14/21	39th & Cathedral Ave., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
05/14/21	39th & Cathedral Ave., NW	3-1/C 500 or 600 Straight Heat Shrink Splices
05/17/21	6th & Independence Ave., SW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
05/17/21	6th & Independence Ave., SW	3-1/C 500 or 600 Straight Heat Shrink Splices
05/17/21	19th & G St., NW	Double Branch Joint 350 3/C to 600 3/C
05/18/21	625 Monroe St., NE	200 AMP Elbows
05/18/21	625 Monroe St., NE	3-1/C Cold Shrink Potheads #2 to 4/0
05/18/21	625 Monroe St., NE	3-1/C URD Slip on Splices
05/19/21	New Jersey Ave. & E St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
05/19/21	4501 Connecticut Ave., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
05/19/21	4501 Connecticut Ave., NW	200 AMP Elbows
05/20/21	T St.. & Half St., SW	34kV Straights
05/20/21	T St.. & Half St., SW	34kV Heat Shrink
05/20/21	8th & L St., SE	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
05/20/21	8th & L St., SE	200 AMP Elbows
05/21/21	L St. Btwn 6th & 7th St.	200 Amp Elbows
05/21/21	L St. Btwn 6th & 7th St.	Tape Joints
05/21/21	South Capitol & Potomac Ave., SE	3-1/C 500 or 600 Straight Heat Shrink Splices
05/23/21	11th & O St. NW	3-1/C 500 or 600 Straight Heat Shrink Splices
05/23/21	11th & O St. NW	200 Amp or 600 Amp Deadbreaks
05/25/21	19th & L St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
05/25/21	19th & L St., NW	3-1C, #2 Loadbreak Elbows
05/25/21	25th & Pennsylvania Ave., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
05/25/21	25th & Pennsylvania Ave., NW	200 AMP Elbows
05/26/21	940 25th St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
05/26/21	940 25th St., NW	200 AMP Elbows
05/26/21	14th & K St., SE	3-1/C #2 Tape Joints
05/27/21	19th & M St., NW	3-1C, #2 Loadbreak Elbows
05/28/21	24th & C St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
05/28/21	24th & C St., NW	200 AMP Elbows
05/28/21	19th & I St., NW	3-1/C 500 or 600 Straight Heat Shrink Splices
05/28/21	19th & I St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
05/30/21	1st & Independence Ave., SE	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)

Date	Location	Type of Splice
06/04/21	G St. & Bayley Pl., SE	3-1/C Cold Shrink Potheads #2 to 4/0
06/05/21	3500 International Dr., NW	200 AMP Elbows
06/06/21	295 & Malcolm X Ave.	3-1/C Cold Shrink Potheads #2 to 4/0
06/06/21	295 & Malcolm X Ave.	200 AMP Elbows
06/09/21	18th & New Hampshire Ave., NW	200 AMP Elbows
06/09/21	18th & New Hampshire Ave., NW	200 AMP or 600 AMP Deadbreaks
06/09/21	18th & New Hampshire Ave., NW	3-1/C URD Slip on Splices
06/10/21	7TH & K St., NW	#2 Head Shrink Test Caps
06/11/21	10th & Pennsylvania Ave., SE	Single Branch Joint 4/0 3/C and below
06/11/21	10th & Pennsylvania Ave., SE	3-1/C 4/0 or 350 Straight Heat Shrink Splices
06/12/21	2500 Calvert St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
06/12/21	2500 Calvert St., NW	200 AMP or 600 AMP Deadbreaks
06/14/21	2nd & W St., NW	3-1/C URD Slip on Splices
06/15/21	19th & L St., NW	3/C HS Test Cap
06/16/21	4100 Cathedral Ave., NW	3-1/C Cold Shrink Potheads 350 to 600
06/16/21	4100 Cathedral Ave., NW	3-1/C 4/0 or 350 Straight Heat Shrink Splices
06/17/21	10th & Florida Ave., NW	Tape Joints
06/17/21	10th & Florida Ave., NW	3-1/C Cold Shrink Potheads #2 to 4/0
06/18/21	30th & M St., NW	Straight Joint 350 3/C to 600 3/C
06/18/21	30th & M St., NW	Single Branch Joint 350 3/C to 600 3/C
06/21/21	Benning Rd. & Oklahoma Ave., NE	3-1/C 500 or 600 Straight Heat Shrink Splices
06/22/21	W. Virginia Ave. & Owen Pl., NE	3-1/C URD Slip on Splices
06/23/21	9th & Florida Ave.	3/C P.L. to 3-1/C EPR or XlLP Trif Joint #2 to 4/0 (Heat Shrink)
06/23/21	9th & Florida Ave.	3-1/c 500 or 600 Straight Heat Shrink Splices
06/23/21	2712 Cathedral Ave., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
06/23/21	12th & Florida Ave., NE	3-1/C 500 or 600 Straight Heat Shrink Splices
06/24/21	26th & K St., NW	200 AMP Elbows
06/24/21	26th & K St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
06/25/21	10th & Constitution, NW	3/C P.L. to 3-C EPR or XLP Trif Joint 350 to 600 (Heat Shrink)
06/25/21	27th & Constitution, NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
06/25/21	F St., & N. Capitol, NW	3-l/C, #2 Loadbreak Elbows
06/25/21	F St., & N. Capitol, NW	3/C P.L. to 3-1/C EPR or XlLP Trif Joint #2 to 4/0 (Heat Shrink)
06/25/21	22nd & New Hampshire Ave., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
06/25/21	22nd & New Hampshire Ave., NW	200 AMP Elbows
06/28/21	2415 MLK Jr. Ave., SE	3-1/C Cold Shrink Potheads 350 to 600
06/28/21	3101 Cathedral Dr., NW	3-1/C Cold Shrink Potheads 350 to 600
06/28/21	3101 Cathedral Dr., NW	3-1/c 500 or 600 Straight Heat Shrink Splices
06/28/21	16th & K St., NW	200 Amp Elbows
06/29/21	Wisconsin & Jenifer, NW	200 AMP Elbows
06/29/21	Wisconsin & Jenifer, NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
06/29/21	17th Pl. & R St., SE	3-1/C Cold Shrink Potheads 350 to 600
06/29/21	17th Pl. & R St., SE	3-1/C 500 EPR Flatstrap Tape Joints
07/03/21	21st & Benning Rd., NE	3-1/C URD Slip on Splices
07/03/21	21st & Benning Rd., NE	Separable 3 Way Cable Joint
07/06/21	2nd & Constitution Ave., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
07/06/21	2nd & Constitution Ave., NW	200 AMP or 600 AMP Deadbreaks
07/07/21	Benning Rd. & Oklahoma Ave., NE	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
07/08/21	NWC Newport Pl. & 21st St., NW	3-1/C Test Caps
07/08/21	1342 V St., NW	3/C P.L. to 3 1/C EPR or XLP Trif. Joint #2 - 1/0 or 4/0
07/08/21	1342 V St., NW	3-1/C URD Slip on Splices

Date	Location	Type of Splice
07/09/21	21st & L St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
07/09/21	21st & L St., NW	Separable 3 Way Cable Joint
07/09/21	21st & L St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
07/09/21	New Jersey & E St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
07/09/21	1301 V St., NW	200 AMP Elbows
07/09/21	1301 V St., NW	3-1/C URD Slip on Splices
07/09/21	329 Anacostia Rd., SE	3-1/C Cold Shrink Potheads #2 to 4/0
07/09/21	329 Anacostia Rd., SE	3-1/C URD Slip on Splices
07/10/21	14th & T St., NW	3-1/C 4/0 or 350 Straight Heat Shrink Splices
07/10/21	14th & T St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
07/13/21	2nd & D St., SW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
07/13/21	2nd & D St., SW	3-1/C 500 or 600 Straight Heat Shrink Splices
07/14/21	3254 M St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
07/14/21	14th & V St., NW	Separable 3 Way Cable Joint
07/14/21	14th & V St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
07/15/21	2121 P St., NW	200 AMP Elbows
07/15/21	2121 P St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
07/15/21	New Jersey & Indiana, NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
07/15/21	New Jersey & Indiana, NW	3-1/C 500 or 600 Straight Heat Shrink Splices
07/19/21	2200 Adams Pl., NE	3-1/C Cold Shrink Potheads #2 to 4/0
07/19/21	2200 Adams Pl., NE	200 AMP Elbows
07/19/21	18th & H St., NW	3-1/C URD Slip on Splices
07/19/21	6200 Oregon Ave., NW	3-1/C Cold Shrink Potheads #2 to 4/0
07/19/21	6200 Oregon Ave., NW	3-1C, #2 Loadbreak Elbows
07/20/21	19th & L St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
07/20/21	1229 Savannah Pl., SE	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
07/20/21	1229 Savannah Pl., SE	3-1/C 4/0 or 350 Straight Heat Shrink Splices
07/22/21	1575 Eye St., NW	3-1/C 4/0 or 350 Straight Heat Shrink Splices
07/22/21	1575 Eye St., NW	3-1/C Cold Shrink Potheads #2 to 4/0
07/23/21	3840 39th St.,NW	200 AMP Elbows
07/23/21	2020 K St., NW	3-1/C URD Slip on Splices
07/23/21	2020 K St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
07/23/21	Georgia Ave. & Gresham Pl., NW	3-1/C URD Slip on Splices
07/26/21	9201 Edgeworth Dr.	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
07/26/21	9201 Edgeworth Dr.	3-1/C 4/0 or 350 Straight Heat Shrink Splices
07/27/21	17th & O St., NW	3-1/C URD Slip on Splices
07/27/21	17th & O St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
07/29/21	8015 Rhode Island Ave.	3-1/C 500 or 600 Straight Heat Shrink Splices
07/30/21	400 Michigan Ave., NE	200 AMP Elbows
07/30/21	400 Michigan Ave., NE	Tape Joints
08/02/21	740 15th St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
08/02/21	740 15th St., NW	200 AMP Elbows
08/03/21	I St. &t 14th St., NW	200 AMP Elbows
08/03/21	I St. &t 14th St., NW	3-1/C #2 URD to 3-1/C #2 PILC
08/04/21	Opp. 1444 14th St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
08/04/21	Opp 1444 I St., NW	200 AMP or 600 AMP Deadbreaks
08/05/21	594 Brummell Ct., NW	3-1/C URD Slip on Splices
08/05/21	Blair Rd. & Brummell Ct., NW	3-1/C Cold Shrink Potheads #2 to 4/0
08/13/21	Davenport & Connecticut Ave, NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
08/16/21	5th & W St., NE	3-1/C URD Slip on Splices

Date	Location	Type of Splice
08/16/21	Connecticut & Nebraska, NW	3-1/C Cold Shrink Straight
08/18/21	800 Independence Ave, SW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
08/18/21	23rd & Virginia Ave., NW	3/C P.L. to 3-1/C EPR or XlLP Trif Joint #2 to 4/0 (Heat Shrink)
08/18/21	23rd & Virginia Ave., NW	200 Amp Elbows
08/19/21	1208 Wisconsin Ave., NW	200 AMP Elbows
08/19/21	1208 Wisconsin Ave., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
08/20/21	1130 17th St., NW	#2 Heat Shrink Test Cap
08/21/21	South Cap. & Firth Sterling, SE	3-C URD Slip on Splices
08/23/21	New Jersey & North Carolina, SE	3-1/C URD Slip on Splices
08/23/21	N. Carolina & 1st St., SE	3-1/C URD Slip on Splices
08/30/21	13th F St., NW	Tape Test Cap
09/01/21	New Jersey Ave. - Indiana Ave.	Straight Joint 350 3/c to 600 3/c
09/02/21	700 K St.,NW	200 AMP Elbows
09/02/21	700 K St.,NW	200 AMP or 600 AMP Deadbreaks
09/02/21	700 K St.,NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
09/09/21	7910 Woodmont Ave	#2 URD Test Caps
09/12/21	1st & G St NE	3/CPL. to 3-1/C EPR or XLP Trif. Jt. #2 to 4/0 (Heat Shrink)
09/12/21	1st & G St NE	3-1/C URD Slip on Splices
09/13/21	7910 Woodmont Ave	3-1C, #2 Loadbreak Elbows
09/13/21	7910 Woodmont Ave	3-1/C URD Slip on Splices
09/13/21	7910 Woodmont Ave	200 AMP and 600 AMP Deadbreaks
09/14/21	1st & Michigan Ave., NW	Single Branch Joint 4/0 3/C and below
09/15/21	2404 Wisconsin Ave., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
09/15/21	2404 Wisconsin Ave., NW	3-1/C 500 or 600 Straight Heat Shrink Splices
09/17/21	16th & I St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
09/18/21	2600 Virginia Ave., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
09/18/21	2600 Virginia Ave., NW	200 AMP Elbows
09/20/21	1401 Fairmont St., NW	200 AMP Elbows
09/20/21	1401 Fairmont St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
09/21/21	12th & E St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
09/21/21	12th & E St., NW	200 AMP Elbows
09/21/21	13th F St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
09/22/21	7th & Independence Ave., SW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
09/22/21	6th St. & Independence Ave., SW	3-1/C 500 or 600 Straight Heat Shrink Splices
09/22/21	Michigan Ave. & Monroe St., NE	3-1/C 500 or 600 Straight Heat Shrink Splices
09/22/21	Michigan Ave. & Monroe St., NE	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
09/23/21	Amtrak Yard	3-1/C Cold Shrink Potheads 350 to 600
09/23/21	2140 L St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
09/23/21	2140 L St., NW	3-1/C URD Slip on Splices
09/24/21	2400 M St., NW	Test Cap 350 3/C and below
09/24/21	Delaware & I St., SW	3-1/C URD Slip on Splices
09/24/21	3295 Sutton Pl., NW	3-1/C URD Slip on Splices
09/28/21	5th & O St., NW	3-1/C URD Slip on Splices
09/28/21	5th & O St., NW	200 AMP Elbows
09/29/21	17th & R St., SE	3-1/C Cold Shrink Potheads 350 to 600
09/29/21	17th & R St., SE	Tape Joints
09/30/21	19th & M St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
09/30/21	23rd & N, St., NW	200 AMP Elbows
10/04/21	17th & K St., NW	Test Cap #2 3-1/C
10/04/21	1090 Ohio Dr.	3-1/C URD Slip on Splices

Date	Location	Type of Splice
10/05/21	7th & Michigan Ave., NE	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
10/05/21	7th & Michigan Ave., NE	Cold Shrink Straights
10/05/21	8th & D St., NW	200 AMP Elbows
10/06/21	39th & Newark, NW	3-1/C URD Slip on Splices
10/06/21	39th & Newark, NW	200 AMP or 600 AMP Deadbreaks
10/07/21	22nd & H St., NW	200 AMP Elbows
10/07/21	22nd & H St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
10/08/21	1619 Massachusetts Ave., NW	200 AMP Elbows
10/08/21	1619 Massachusetts Ave., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
10/11/21	Channing Pl. & Reed St., NE	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
10/11/21	Channing Pl. & Reed St., NE	3-1/C URD Slip on Splices
10/11/21	Channing Pl. & Reed St., NE	3-1/C #2 Y-Splice
10/11/21	31st & M St., NW	4kV Branch Tape Joints
10/12/21	4220 Minnesota Ave., NE	200 AMP or 600 AMP Deadbreaks
10/12/21	1117 H St., NW	200 AMP Elbows
10/12/21	1117 H St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
10/14/21	9111 Edgeworth	3-1/C URD Slip on Splices
10/14/21	4th & E St., SE	3-1/C URD Slip on Splices
10/14/21	NWC Newport Pl. & 21st St., NW	200 AMP Elbows
10/14/21	NWC Newport Pl. & 21st St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
10/15/21	2121 P St., NW	200 AMP Elbows
10/16/21	2055 L St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
10/16/21	2055 L St., NW	200 AMP Elbows
10/20/21	1130 17th St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
10/20/21	1130 17th St., NW	200 AMP Elbows
10/21/21	2515 K St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
10/21/21	2515 K St., NW	200 AMP Elbows
10/21/21	4850 Connecticut Ave., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
10/21/21	4850 Connecticut Ave., NW	200 AMP Elbows
10/23/21	Van Ness & Wisconsin Ave., NW	200 AMP Elbows
10/23/21	Van Ness & Wisconsin Ave., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
10/27/21	3005 Van Ness St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
10/27/21	3005 Van Ness St., NW	200 AMP Elbows
10/28/21	Buzzard Sub, SW	Test Cap
10/28/21	3270 M St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
10/28/21	3270 M St., NW	Tape Joints
11/01/21	18th & Belmont, NW	3-1/C URD Slip on Splices
11/03/21	Channing Pl. & Reed St., NE	Separable 3 Way Cable Joint
11/03/21	Channing Pl. & Reed St., NE	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
11/03/21	Channing Pl. & Reed St., NE	3-1/C URD Slip on Splices
11/06/21	8555 16th St.	200 AMP Elbows
11/06/21	8555 16th St.	3-1/C URD Slip on Splices
11/09/21	4th & I St., SW	34Kv 500 1/C Straights
11/10/21	400 C St., SW	3-1/C URD Slip on Splices
11/10/21	400 C St., SW	200 AMP Elbows
11/10/21	Georgia & Morton	3-1/C URD Slip on Splices
11/11/21	13th & F St., NW	200 AMP Elbows
11/11/21	13th & F St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
11/13/21	New Jersey & C St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600
11/14/21	4th & M St., SW	3-1/C 500 or 600 Straight Heat Shrink Splices

Date	Location	Type of Splice
11/15/21	3270 M St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
11/15/21	3270 M St., NW	#2 Tape Joints
11/16/21	Half & M St., SW	Straight Joint 350 3/C to 600 3/C
11/17/21	4th & M St., SW	3-1/C 500 or 600 Straight Heat Shrink Splices
11/17/21	4th & M St., SW	34Kv 3-1/C Straight Joints
11/19/21	22nd & H St., NW	200 AMP Elbows
11/19/21	22nd & H St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
11/22/21	Michigan & Park Pl., NE	3-1/C URD Slip on Splices
11/22/21	Michigan & Park Pl., NE	200 AMP Elbows
11/22/21	4th & M St., SW	3- 1/C 34kV Heat Shrink Straights
11/23/21	4th & M St., SW	34kV Trif. Joints
11/29/21	4th & M St., SW	34Kv 3-1/C Straight Joints
11/30/21	4th & M St., SW	34Kv Trif. Joint 600 kcm
12/02/21	3129 Hawthorne Dr., NE	200 AMP Elbows
12/02/21	7th & Michigan Ave., NE	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
12/02/21	1775 Pennsylvania Ave., NW	200 AMP Elbows
12/02/21	4907 Wisconsin Ave., NW	3-1/C 4/0 or 350 Straight Heat Shrink Splices
12/03/21	I St. & V St., SW	Cold Shrink Straights
12/03/21	I St. & V St., SW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
12/07/21	17th & C St., NW	3-1/C URD Slip on Splices
12/07/21	17th & C St., NW	200 AMP Elbows
12/08/21	1735 New York Ave., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
12/08/21	1735 New York Ave., NW	200 AMP Elbows
12/08/21	431 New York Ave., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
12/08/21	431 18th St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint 350 to 600 (Heat Shrink)
12/08/21	38th & Newark, NW	200 AMP Elbows
12/08/21	38th & Newark, NW	3-1/C URD Slip on Splices
12/09/21	6th & L St., NW	3-1/C URD Slip on Splices
12/09/21	6th & L St., NW	200 AMP Elbows
12/14/21	1055 5th St., NW	200 AMP Elbows
12/14/21	1055 5th St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
12/15/21	1050 Connecticut Ave., NW	200 AMP Elbows
12/15/21	1050 Connecticut Ave., NW	3/C P.L. to 3 1/C EPR or XLP Trif. Joint #2 - 1/0 or 4/0
12/16/21	750 1st St., NE	3-1/C URD Slip on Splices
12/16/21	C St. & 53rd, SE	3-1/C 500 or 600 Straight Heat Shrink Splices
12/17/21	14th & N St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
12/17/21	14th & N St., NW	200 AMP Elbows
12/21/21	18th & H St., NW	200 AMP Elbows
12/23/21	Alley W/S 921 Wayne Ave., NW	200 AMP Elbows
12/23/21	Rhode Island Ave. & 4th St., NE	3-1/C URD Slip on Splices
12/29/21	900 Brendwood Rd.	3-1/C URD Slip on Splices
12/29/21	2400 M St., NW	200 AMP Elbows
12/29/21	2400 M St., NW	3/C P.L. to 3-1/C EPR or XLP Trif. Joint #2 to 4/0 (Heat Shrink)
12/29/21	900 Brendwood Rd.	3-1/C URD Slip on Splices
12/30/21	1006 Connecticut Ave., NW	3-1C, #2 Loadbreak Elbows
12/30/21	1006 Connecticut Ave., NW	3-1/C Cold Shrink Potheads #2 to 4/0

Appendix 3A: 2021 Manhole Events[72]

New Manhole Event Information

At the December 13, 2011, and February 16, 2012, PIWG meetings, it was decided that the following types of additional information related to manhole events would be included in future Consolidated Reports. The following categories of information have been included in this year's Consolidated Report.

- Incident Date
- Work Order/Request #
- Address
- Grid Number
- Feeder Number
- Manhole cover type (solid, slotted, roadway, round, sidewalk)
- Manhole Condition (clean, water below cable, water above cable, debris above cable)

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[72] In Order No. 11716 ordering paragraph 3, the Commission ordered the following:

3. PEPCO shall file an annual report on the previous calendar year's manhole incidents;

Order No. 16975 states the following at paragraphs 72 and 110:

72. Decision: We accept the Staff's recommendation and require Pepco to include grid numbers and Siemens' inspection dates on manhole event reports. Each year over 200 manholes are selected through stratified sampling criteria and inspected by Siemens. Including grid numbers and inspection dates will help to identify manhole events traced to the manholes recently inspected, manholes located along Pepco's Priority Feeders, and manholes with and adjacent to recent manhole events. This will enhance independent/third party validation and quality assurance of the manhole inspection program.

110. Pepco is DIRECTED to provide grid numbers consistent with paragraph 72 herein;

- Voltage class (600V, 4kV, 13kV, 34kV, 69kV)
- Type of equipment (transformer, protector, cable, switch, straight joint, branch joint, trifurcating joint, transition joint, other)
- Equipment description: details specifics of the equipment such as size, insulation, phases, type of joint
- Repair description: details repair work
- A description of the failure mode (not previously recorded)
- A determination if the failure is a repeating event at this location (not previously recorded)

Pepco undertook a substantial database conversion during 2012 to make these additions to enhance summary reporting and analysis. The duration of the repair effort, which was outstanding in the database conversion effort as of the 2013 Consolidated Report, is now included within the database.

The listing of 2021 Manhole Events is provided in the following table:

Table 48

2021 MANHOLE EVENT REPORT - DISTRICT OF COLUMBIA														
As of :	4/7/22													
EVENT No.	DATE	LOCATION	WARD	Quad	FDR	EVENT TYPE	Failure Type	Prim/Sec	Cable Size	Insulation	MANHOLE COVER	MH Size	DESCRIPTION/CAUSE	ACTION
DC21-01	1/31/2021	92 R ST NW	5	NW	15462	Smoke	Secondary Cable	Secondary	#2 AWG	RN	Solid	2'x2'	house service for 92 R st	Cut off service to abandoned property at 92 R St
DC21-02	2/3/2021	WISCONSIN AVE & M ST, NW (SEC)	2	NW	15402	Smoke	Primary Cable	Primary	4/0 AWG	PILC	Solid	6'X14'	4/0 - #2 3/C PILC STRAIGHT JOINT	REPLACED CABLE W/ #2 URD FROM MH -066286 TO -062355, MADE TRIFURCATING TRANSITION SPLICE & 3 SLIP-ONS
DC21-03	2/9/2021	GEORGIA AVE & COLUMBIA RD NW		NW	15002	Smoke	Secondary Cable	Secondary	500 KCM	RN	Solid	6'X12'	3 phase 500kcm secondary mains failure	Replace 370 feet of secondary mains spanning 10 manholes between 793398-313635 & 793398 -338933.
DC21-04	2/10/2021	1334 VERMONT AVE, NW	2	NW	14365	Explosion	Secondary Cable	Secondary	250 KCM	RN	Solid	6'X8'	BURNED UP SECONDARY MAINS	REPLACED TWO SETS OF 3 PHASE 250 WITH 4/0 BC FROM MH 248454 TO 270508 AND ONE SET FROM 270508 TO MH 274560
DC21-05	2/13/2021	2131 FLORIDA AVE, NW	2	NW	14733	Smoke	Secondary Cable	Secondary	250 KCM	RN	Solid	2.5'x2.5'	BURNED UP SECONDARY MAINS	MADE PERM REPAIRS, REPLACED SECONDARY MAINS
DC21-06	2/13/2021	1620 33RD ST, NW	2	NW	15997	Smoke	Secondary Cable	Secondary	250 KCM	RN	Slotted	6'x10'	BURNED UP SECONDARY MAINS	MADE PERM REPAIRS, REPLACED SECONDARY MAINS
DC21-07	2/14/2021	610 RHODE ISLAND AVE, NE	5	NE	14010	Smoke	Secondary Cable	Secondary	250 KCM	RN	Solid	6'x10'	BURNED UP SECONDARY MAINS	MADE TEMP REPAIRS
DC21-08	2/19/2021	1619 HOBART ST, NW	1	NW	15762	Smoke	Secondary Joint	Secondary	250 KCM	RL	Solid	3'x3'	BLOWN BRANCH JOINT	MADE TEMP REPAIRS TO RESTORE LOAD
DC21-09	2/20/2021	15TH & P ST, NW	2	NW	14732	Smoke	Secondary Cable	Secondary	250 KCM	RN	Slotted	6'x10'	BURNED UP SECONDARY MAINS	INSTALLED 100 FT OF TWO SETS OF 250 SECONDARY MAINS
DC21-10	2/20/2021	2215 ADAMS ST, NE	5	NE	14005	Smoke	Secondary Cable	Secondary	250 KCM	RN	Slotted	6'x10'	BURNED UP SECONDARY MAINS	MADE REPAIRS TO CABLE AND DUCT LINE
DC21-11	2/27/2021	1618 BELMONT ST, NW	1	NW	15339	Smoke	Secondary Cable	Secondary	250 KCM	EPR	Solid	3x3	BURNED UP SECONDARY MAINS	ISOLATED STRETCH, RESTORED LOAD
DC21-12	3/18/2021	918 O ST, NW	2	NW	15207R	Smoke	Secondary Cable	Secondary	1/0 AWG	RL	Solid	2.3X2.3	BURNED UP SECONDARY CABLE	MADE PERM REPAIRS.
DC21-13	3/22/2021	3RD ST, S/O D ST SW	6	SW	15603	Explosion	Primary Joint	Primary	350 KCM	PILC	Solid	6X14	350/350/4/0 BRANCH JOINT	REPLACED CABLE AND REMADE BRANCH & STRAIGHT JOINTS
DC21-14	3/24/2021	2300 6TH ST NW	1	NW	15640	Explosion	Primary Joint	Primary	600 KCM	PILC	Solid	6X12	3/C PILC STRAIGHT JOINT - FAULT IN JOINT	MADE PERM REPAIRS
DC21-15	4/6/2021	POTOMAC ST $ GRACE ST, NW	2	NW	14557	Explosion	Primary Cable	Primary	4/0 AWG	PILC	Grated	6X13	FAULT IN CABLE OUTSIDE OF JOINT	MADE PERM REPAIRS
DC21-16	4/13/2021	1201 PENNSYLVANIA AVE, SE	6	SE	209	Explosion	Secondary Cable	Secondary	#4 AWG	RN	Solid	3X3	CABLE BURNT UP, POSSIBLY IGNITING GAS IN HOLE	CUT STREETLIGHT CABLE IN CLEAR
DC21-17	4/25/2021	1ST & NEW JERSEY AVE, NW	6	NW	14416	Explosion	Secondary Cable	Secondary	250 KCM	RN	Solid	4X6	SECONDARY CABLE BURING IN DUCT LINE	CUT OFF CABLE GOING NORTH, SOUTH, WSAT & WEST TO EVENT HOLE
DC21-18	4/26/2021	1875 H ST, NW	2	NW	15381	Smoke	Primary Joint	Primary	#2 AWG	EPR	Solid	5X8	#2 TRIFURCATING TRANSITION SPLICE	REPLACED W/ #2 URD CABLE FROM 787388-758514 TO 787388-785532 & MADE 1 TRIFURCATING TRANSITION SPLICE & 3 #2 REMOLD ELBOWS
DC21-19	4/27/2021	WISCONSIN AVE & M ST, NW		NW	14548	Fire	Primary Joint	Primary	#2 AWG	PILC	Solid	6X12	#2 3/C PILC STRAIGHT JOINT	REPLACED W/ #2 URD CABLE FROM 782390-013286 TO 782390-017210 & MADE 1 TRIFURCATING TRANSITION SPLICE & 3 PREMOLD ELBOWS
DC21-20	5/16/2021	601 INDEPENDENCE AVE, SW	6	SW	15296W	Smoke	Primary Cable	Primary	600 KCM	PILC	Solid	6X12	FAILED TRANSITION JOINT	REPLACED 725' OF PILC CABLE WITH 600KCM FLAT STRAP AND R/S/C
DC21-21	5/18/2021	SEC HALF ST & T ST, SW		SW	34902	Smoke	Primary Cable	Primary	500 KCM	PILC	Solid	6X12	FAILED CABLE	REPLACED 550 FEET OF 500 3-PHASE PILC CABLE
DC21-22	7/14/2021	2121 P ST, NW	2	NW	14586	Smoke	Primary Joint	Primary	#2 AWG	PILC	Slotted	6X12	BLOWN #2 HEAT SHRINK JOINT #2 PILC TO #2 URD	REPLACED 100 FEET URD CABLE & R/S/C
DC21-23	7/20/2021	1229 SAVANNAH ST, SE	8	SE	15626	Explosion	Primary Joint	Primary	600 KCM	PILC	Solid	6X12	600 3/C STRAIGHT JOINT	REMOVE 720' OF 600 3/C PILC & REPLACE WITH 720' OF 600 FLAT STRAP, MADE 1 HEAT SHRINK JOINT & 3 STRAIGHT JOINTS
DC21-24	10/4/2021	K ST & CONN AVE, NW		NW	14506	Smoke	Equipment	Primary	#2 AWG		Grated	6X14	NETWORK TRANSFORMER	TEST CAP CABLE TO RESTORE FEEDER, TRANSFORMER TO BE REPLACED AT A LATER DATE
DC21-25	10/12/2021	4020 MINNESOTA AVE, NE		NE	15707	Explosion	Primary Cable	Primary	500 KCM	RN	Solid	6X12	A PHASE DEAD BREAK ELBOW	REPLACED OIL SWITCH

Table 48: Continued

2021 MANHOLE EVENT REPORT - DISTRICT OF COLUMBIA

As of : 4/7/22

EVENT No.	DATE	Work Order	LOCATION	Event Voltage	FAILURE MODE	REPEAT EVENT	4kV / 13kV	Manhole Condition	NO. OF CUST.	Outage (hr/min)	Repair Duration	DATE INSPECTED BY SIEMENS	LAST INSPECTION	Facility ID	Personal injury or property damage
DC21-01	1/31/2021		92 R ST NW	120/240V	Secondary Cable	No	13kV	Water Below Cable	68	21:32	124		1/6/2017	796393-517003	No
DC21-02	2/3/2021		WISCONSIN AVE & M ST, NW (SEC)	13kV	Primary Cable	No	13kV	Water Below Cable/Debris					N/A	782389-066286	No
DC21-03	2/9/2021		GEORGIA AVE & COLUMBIA RD NW	120/208V	Secondary Cable	No	13kV	CLEAN	134	11:39	459		11/20/2015	793398-313635	No
DC21-04	2/10/2021		1334 VERMONT AVE, NW	120/208V	Secondary Cable	No	13kV	WATER ABOVE CABLE	9	20:31	911		5/25/2017	791391-248454	No
DC21-05	2/13/2021		2131 FLORIDA AVE, NW	120/208V	Secondary Cable	No	13kV	DEBRIS	1	20:32	480		N/A	786393-370025	No
DC21-06	2/13/2021		1620 33RD ST, NW	120/208V	Secondary Cable	No	13kV	WATER BELOW CABLE	0	10:15	204		3/26/2019	781392-085384	No
DC21-07	2/14/2021		610 RHODE ISLAND AVE, NE	120/208V	Secondary Cable	No	13kV	WATER ABOVE CABLE	0	14:55			4/15/2016	800396-605038	No
DC21-08	2/19/2021		1619 HOBART ST, NW	120/240V	Secondary Joint	No	13kV	OTHER - MUD	0	13:29			9/17/2019	789398-107587	No
DC21-09	2/20/2021		15TH & P ST, NW	120/208V	Secondary Cable	No	13kV	WATER ABOVE CABLE	0	11:15			4/6/2017	790391-147900	No
DC21-10	2/20/2021		2215 ADAMS ST, NE	120/208V	Secondary Cable	No	13kV	WATER ABOVE CABLE	1	8:26	86		11/27/2018	807395-116635	No
DC21-11	2/27/2021		1618 BELMONT ST, NW	120/240V	Secondary Cable	No	13kV	DEBRIS	16	11:46	136		2/28/2019	788395-970563	No
DC21-12	3/18/2021		918 O ST, NW	120/240V	Secondary Cable	No	13kV	WATER ABOVE CABLE	4	18:12	258		7/14/2016	792391-883508	No
DC21-13	3/22/2021		3RD ST, S/O D ST SW	13kV	Primary Joint	No	13kV	WATER BELOW CABLE					11/24/2020	795382-571892	No
DC21-14	3/24/2021		2300 6TH ST NW	13kV	Primary Joint	No	13kV	CLEAN					9/19/2014	793396-741143	No
DC21-15	4/6/2021		POTOMAC ST $ GRACE ST, NW	13kV	Primary Cable	No	13kV	CLEAN	1	18:54	75		N/A	781389-332864	No
DC21-16	4/13/2021		1201 PENNSYLVANIA AVE, SE	120/208V	Secondary Cable	No	13kV	DEBRIS	0	21:28	136		11/2/2017	802381-806821	No
DC21-17	4/25/2021		1ST & NEW JERSEY AVE, NW	120/208V	Secondary Cable	No	13kV	WATER BELOW CABLE					N/A	796387-445028	No
DC21-18	4/26/2021		1875 H ST, NW	13kV	Primary Joint	No	13kV	DEBRIS	0				11/10/2016	787388-758514	No
DC21-19	4/27/2021		WISCONSIN AVE & M ST, NW	13kV	Primary Joint	No	13kV	DEBRIS	0				N/A	782390-013286	No
DC21-20	5/16/2021		601 INDEPENDENCE AVE, SW	13kV	Primary Cable	No	13kV	WATER BELOW CABLE	0				N/A	794383-071873	No
DC21-21	5/18/2021		SEC HALF ST & T ST, SW	13kV	Primary Cable	No	13kV	WATER BELOW CABLE	0				N/A	796376-894442	No
DC21-22	7/14/2021		2121 P ST, NW	13kV	Primary Joint	No	13kV	CLEAN	0				1/13/2014	786391-476962	No
DC21-23	7/20/2021		1229 SAVANNAH ST, SE	13kV	Primary Joint	No	13kV	CLEAN	0				8/15/2018	802367-970680	No
DC21-24	10/4/2021		K ST & CONN AVE, NW	13kV	Equipment	No	13kV	DEBRIS	0				1/4/2017	788389-810399	No
DC21-25	10/12/2021		4020 MINNESOTA AVE, NE	13kV	Primary Cable	No	13kV	CLEAN	373	11:02	508		N/A	814387-545166	No

Table 49

Notes:
25 events :11 primary (5 S, 1 F, 5 E), 13 secondary (10 S, 0 F, 3 E),1 Equipment (1 S, 0 F, 0 E)
4 events involved slotted manhole covers (4 S, 0 F,0 E),
19 events involved solid manhole covers (11 S, 1 F, 7 E)
2 events involved grated manhole covers (1 S, 0 F, 1 E)

Event category breakdown:			
Smoking manholes	16		
Manhole fires	1		
Manhole explosions	8		
Total:	25		
Northwest	17	Georgetown:	5
Northeast	3		
Southwest	3		
Southeast	0		
Total:	23		

Events Summary 13kV
25 events :11 primary (5 S, 1 F, 5 E), 13 secondary (10 S, 0 F, 3 E),1 Equipment (1 S, 0 F, 0 E)

Event category breakdown:			
Smoking manholes	16		
Manhole fires	1		
Manhole explosions	8		
Total:	25	Georgetown:	5

Events Summary 4kV
0 events :0 primary (0 S, 0 F, 0 E), 0 secondary (0 S, 0 F, 0 E),

Event category breakdown:			
Smoking manholes	0		
Manhole fires	0		
Manhole explosions	0		
Total:	0	Georgetown:	0

Events Summary 69kV
0 events :0 primary (0 S, 0 F, 0 E)

Event category breakdown:			
Smoking manholes	0		
Manhole fires	0		
Manhole explosions	0		
Total:	0		
		Georgetown:	0

First Quarter 2021 - Summary		
Insulation Deterioration by Cable Type:		
Paper Insulated Lead Cable (PILC)	3	
Rubber Lead (RL)	2	
Rubber Neoprene (RN)	8	
Ethylene Propylene Rubber (EPR)	1	
Cross Link Polyethylene (XLP)	0	
Other (Braided)	0	
Other	1	
Non-Pepco	0	
Non-Cable related	0	a/
TOTAL	15	

Third Quarter 2021 - Summary		
Insulation Deterioration by Cable Type:		
Paper Insulated Lead Cable (PILC)	0	
Rubber Lead (RL)	0	
Rubber Neoprene (RN)	0	
Ethylene Propylene Rubber (EPR)	0	
Cross Link Polyethylene (XLP)	0	
Other (Braided)	0	
Other (URD)	0	
Non-Pepco	0	
Non-Cable related	0	b/
TOTAL	11	

Second Quarter 2021 - Summary		
Insulation Deterioration by Cable Type:		
Paper Insulated Lead Cable (PILC)	6	
Rubber Lead (RL)	0	
Rubber Neoprene (RN)	2	
Ethylene Propylene Rubber (EPR)	1	
Cross Link Polyethylene (XLP)	0	
Other (Braided)	0	
Other (URD)	0	
Non-Pepco	0	
Non-Cable related	0	a/
TOTAL	9	

Fourth Quarter 2021 - Summary		
Insulation Deterioration by Cable Type:		
Paper Insulated Lead Cable (PILC)	0	
Rubber Lead (RL)	0	
Rubber Neoprene (RN)	1	
Ethylene Propylene Rubber (EPR)	0	
Cross Link Polyethylene (XLP)	0	
Other (Braided)	0	
Other	0	
Non-Pepco	0	
Non-Cable related	1	b/
TOTAL	1	

a/ Transformer
b/ Network Transformer

Appendix 3B: 2021 Manhole Inspection Program[73]

APPENDIX 3B - MANHOLE INSPECTION PROGRAM (MIP)

Pepco began development of its manhole inspection program in 1999. By the end of 2006, Pepco had performed a total of 79,295 inspections, completing Phase I. Phase II of the Company's Manhole Inspection Program began in 2007 and was completed in the first quarter of 2013 with a total of 69,670 inspections. Phase III of the Company's Manhole Inspection Program began in 2013 and was completed in 2018 with a total of 66,836 inspections. Phase IV of the manhole inspection program is currently underway. A total of 10,798 manholes were inspected in 2021.

Manhole inspections represent a significant undertaking that involve the visual assessment of the underground manholes and vaults and the equipment contained in them, taking load readings of low voltage cables and reviewing the integrity of cable splices. Supervisory personnel review records and corrective actions are identified and tracked. Data obtained during the inspections can be used to ascertain whether the secondary cables are overloaded or are likely to be overloaded under peak load conditions using appropriate de-rating factors and factors to simulate peak conditions. Inspections are also designed to identify load variations between phases which could indicate

[73] In Order No. 11716, the Commission stated the following:

> *PEPCO is hereby directed to include the following information in its [manhole inspection] reports beginning in July 2000:*
> 1. *The general location of the manholes inspected, including the street or streets where the manholes are located and the blocks bounding the street, e.g., M Street, NW, between 23rd and 28th streets;*
> 2. *The number of manholes inspected in the month, broken down as to the number of manholes containing primary cables only, both primary and secondary cables, and secondary cables only;*
> 3. *The number of primary cable problems found;*
> 4. *The number of secondary cable problems found;*
> 5. *The type of cable problems found in each manhole, categorized as to the physical degradation or damage of the cable, overheating, overloading, damaged splice and deteriorated cable or splice due to age;*
> 6. *The number of manholes with problems;*
> 7. *The corrective actions taken for each cable and manhole problem found; and*
> 8. *Other general condition of the manhole such as whether it contained water, oil, grease, debris, and whether the manhole cover and the manhole are in good mechanical condition.*

possible imbalanced conditions. By identifying such instances and taking appropriate actions, Pepco will continue to improve and maintain the reliability of its system.

Inspection Priority Definitions

As a result of the merger, new procedures and processes are in place across the Pepco region for planning and prioritizing corrective maintenance activities. Beginning in 2019, Pepco has adopted the Exelon work screening and prioritization practices in the manhole inspection program. All corrective maintenance reportable conditions (CMs) are classified into one of four categories under the Exelon model: P10, P20, P30, or P40. A description of each deficiency is shown below:

<u>P10:</u> Immediate response required; work item until complete or until corrective actions allow the downgrading of the priority. Priority 10 CMs should not exceed 3 days. These items have a direct and immediate impact to safety, SAIFI, or SAIDI.

<u>P20:</u> Priority 20 CMs are usually completed within 14 days and should not exceed 30 days. corrective plans shall be created for Priority 20 CMs that exceed 30 days. These items have a high probability of affecting SAIFI, SAIDI, or safety.

<u>P30:</u> Priority 30 CMs are typically completed within 9 months and should absolutely not exceed 1 year. A corrective plan shall be created for priority 30 CMs that exceed 1 year. These items have a moderate probability of affecting SAIFI or CAIDI if not addressed within a year's timeframe. For priority 30 CMs that require completion before the 9-month target, an agreed upon need date shall be established through the work screening process. All changes in proposed need date require approval.

<u>P40:</u> Work not meeting the criteria for a P10, P20, or P30 shall be considered a P40 and completed not to exceed the predominant maintenance cycle interval. Impact on SAIFI or CAIDI would only result if the condition rapidly degrades. A priority 40 CM shall not exceed 1 year past the determined preventative maintenance cycle for the associated equipment class.

Current Program Status

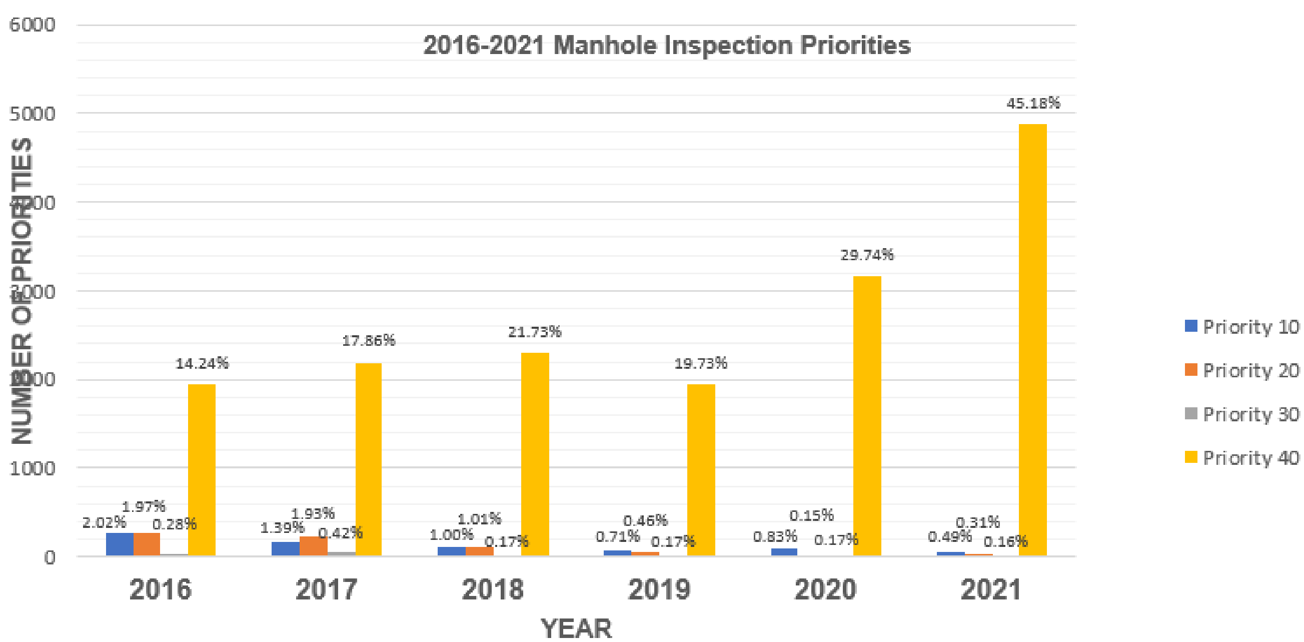
During 2021, the MIP has identified the following remediation Priorities:

Percentage of CY 2021

	Priorities Count	Priorities
Priority Code 10	53	1%
Priority Code 20	33	.6%
Priority Code 30	17	.3
Priority Code 40	4878	98%

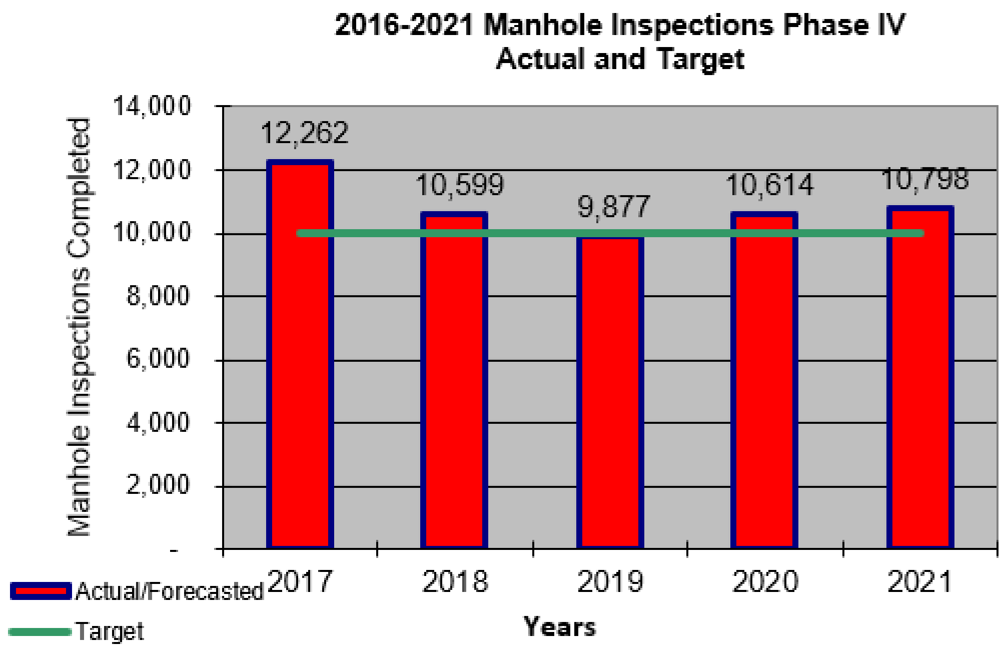
Inspectors are conducting more comprehensive and thorough inspections which have resulted in a substantial increase in Priorities found. In 2021, approximately 46% of the manholes inspected revealed potential areas of concern that have been or are in the process of being addressed. Figure 27 provides a graphical representation of the number of manholes and the percentage of overall inspections with priority conditions.

Figure 27: Manhole Inspection Priorities – Phase IV



With the implementation of the Manhole Inspection Quality Control (QC) Program, inspection Priorities have increased from 1,866 in 2015 to 4981 priorities in 2021. The majority of the increase is related to Priority 40 conditions, which are not considered an imminent risk and must be remediated within 12 months and the increase can be attributed at least in part to more rigorous inspections.

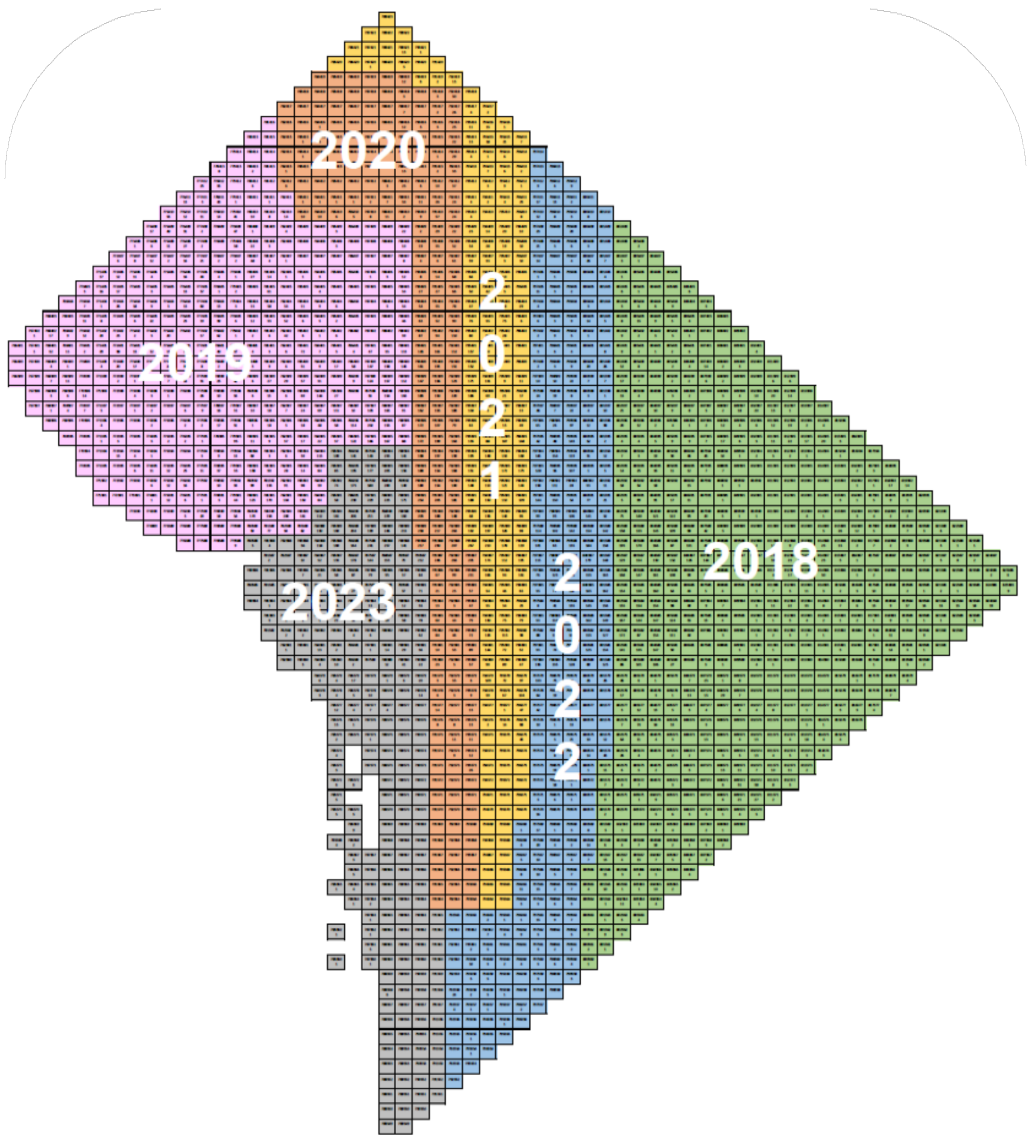
Figure 28: Manhole Inspections Completed – Phase IV



In 2017, a comprehensive analysis on the manhole population in the District was performed using GIS extracts. Using these records, a more efficient inspection plan was created for the next complete cycle in the District. Additionally, the tracking mechanism for manhole inspections was changed for inspections occurring in 2018 and forward. Previously, inspections were assigned on a 1,000' x 1,000' "plat" basis rather than by individual manholes. This left room for gaps and a small number of missing inspections. Moving forward, all manhole inspections will be tracked on an individual manhole level, leaving no room for errors or missing inspections.

With the new GIS extract that was performed, a grouping of manholes based on geographic location was performed to solidify the inspection plan for the next six years. Figure 29 below shows the manhole inspection map of the District for years 2018-2023. Each colored region has an equivalent number of manholes within it, equally divided between six inspection years. This plan will improve the crew efficiency and future corrective maintenance work planning as crews would not be able to mobilize across the city every year.

Figure 29: 2018-2023 Manhole Inspection Plan



Quality Control Program

The manhole inspection program QA/QC process is broken into three parts that is to be followed by Aldridge Electric:

- Office Review: A minimum of 15% of the inspected locations are to be reviewed in office after the inspections are complete and the information is uploaded into the manhole inspection database. This review process consists of the following:
  - Review photos to ensure quality of 360 and Still shots labeled accurately
  - Verify if manhole cleaning is required based off photos
  - Verify Output of assessment pdf is accurately filled out
  - Verify CM work
  - Verify all manhole locations deemed out of scope or missing.

- Field Inspection Review: A minimum of 8% of the inspected location are reviewed which include a review of inspectors' work (setup, assessment, safety, etc.) on site at the time of inspection, by the field leadership team.
  - 2 AE Foreman training and performing quality inspections full time
  - 1 AE General Foreman providing oversite and quality inspections when available
  - 1 AE Construction Manager overseeing subcontractor full time

- Field CM Review Process: A minimum of 7% of the inspected locations are reviewed by Foreman and PM daily with 360 completion photos to verify accuracy of work performed. A completion log is filled out by crew leader for every manhole worked.
  - 1 AE Foreman performing quality inspections full time
  - 1 AE General Foreman providing oversite and quality inspections when available
  - Verify installed items vs. called out items in assessment
  - Field Lead identifies all CM work is complete
  - Verify 360 photo taken upon completion
  - Crew leader reviewing original assessment to verify accuracy at every location visited

2021 Quality Control Metrics

OFFICE REVIEW (15% Min)			
Month	Locations Visited	QA/QC Performed	%
JANUARY	1045	1002	95.89%
FEBRUARY	1094	1056	96.53%
MARCH	1701	1587	93.30%
APRIL	948	902	95.15%
MAY	886	802	90.52%
JUNE	1147	1042	90.85%
JULY	1035	985	95.17%
AUGUST	1065	1042	97.84%
SEPTEMBER	1096	1035	94.43%
OCTOBER	1009	985	97.62%
NOVEMBER	1185	1115	94.09%
DECEMBER	930	925	99.46%

FIELD ASSESSMENTS (8% Min)			
Month	Assessments Completed	QA/QC Performed	%
JANUARY	892	72	8.07%
FEBRUARY	933	78	8.36%
MARCH	1244	152	12.22%
APRIL	808	82	10.15%
MAY	750	87	11.60%
JUNE	1031	122	11.83%
JULY	738	81	10.98%
AUGUST	911	97	10.65%
SEPTEMBER	929	105	11.30%
OCTOBER	878	78	8.88%
NOVEMBER	956	102	10.67%
DECEMBER	846	116	13.71%

FIELD CMs PERFORMED (7% Min)			
Month	CMs Completed	QA/QC Performed	%
JANUARY	98	10	10%
FEBRUARY	0	0	0%
MARCH	0	0	0%
APRIL	0	0	0%
MAY	76	13	17%
JUNE	81	13	16%
JULY	71	10	14%
AUGUST	107	18	17%
SEPTEMBER	50	8	16%
OCTOBER	204	18	9%
NOVEMBER	163	15	9%
DECEMBER	213	25	12%

Appendix 3C: Network Accuracy Procedure Report[74]

[74] In Order No. 16709 paragraphs 9 and 10, the Commission ordered the following:

9. *The Commission is satisfied that Pepco has developed a reasonable plan to ensure that its underground cables are adequately sized for existing and future loads. However, we do want to monitor Pepco's diligence in performance and the results of implementation of its network modeling, GIS updates, and timely network technology improvements going forward. We, therefore, direct the Company to file periodic reports to keep the Commission and interested parties apprised of the status of several ongoing projects as follows:*
    a. *Pepco is directed to provide a detailed status report on those eight networks that are currently undergoing analysis under the Company's Network Accuracy Procedure including the corrective actions that were identified by December 2011. This report on the eight networks should be added to the Company's 2012 Consolidated Report or filed as a Supplement to the 2012 Consolidated Report if the 2012 Report has already been filed or it is too late to include it for publication in the 2012 Report; and*
    b. *Pepco is directed to file a detailed status report on the results of its modeling and analysis and the implementation of its remedial actions on all of its remaining networks under its Network Accuracy Procedure. This report on the remaining networks should also be added to the 2012 Consolidated Report (or filed as a Supplement to the 2012 report if the 2012 Report has already been filed or it is too late to include it for publication in the 2012 Report) with updates in each subsequent year's report. The status report on those remaining networks shall include corrective actions that have been scheduled and those that have been completed.*

THEREFORE, IT IS ORDERED THAT:

10. Pepco shall comply with the directives set forth in paragraph 9 herein.

Network Accuracy Procedure Report

Status Report of the Analysis of the Remaining District of Columbia Networks, in Accordance with the Network Accuracy Procedure.

As reported in 2021, all investigations of Pepco's LVAC networks in the District of Columbia have been completed. Pepco has adopted the network accuracy procedure and intends to continue reviewing the accuracy of the LVAC networks; however, Pepco will not report further on this procedure's results in the ACR.

PART 4: REFERENCES

SECTION 4.1 – ABBREVIATIONS AND ACRONYMS

2005 Plan - Vegetation Management Plan for Utility Tree Pruning – D.C.
A&G - Administrative & General
AC - Alternating Current
ACR - Automatic Circuit Reclosers
AFP - Assist Fire/Police
AMI - Advanced Metering Infrastructure
ANSI - American National Standards Institute
AQL - Acceptable Quality Level
ASR - Automatic Sectionalizing and Restoration
CAD - Computer Aided Design
CAIDI - Customer Average Interruption Duration Index
CBM - Condition Based Maintenance
CIC - Crisis Information Center
CIS - Customer Information System
CMT - Crisis Management Team
COG - Council of Governments
COOP - Continuity of Operations
CPI - Composite Performance Index
CRP - Comprehensive Reliability Plan
DA - Distribution Automation
D.C. - District of Columbia
DDOT - District of Columbia Department of Transportation
DGA - Dissolved Gas in oil Analysis
DOE - Department of Energy
DOT - Department of Transportation
DPWT - Department of Public Works and Transportation
DRTU - Digital Remote Terminal Unit
E - Manhole Explosion
ECA - Equipment Condition Assessment EMA
- Emergency Management Agency EMF -
Electromagnetic Field
EMS - Energy Management System
EOC - Emergency Operations Center
EOP - Emergency Operations Plan
EPR - Ethylene Propylene Rubber cable
EPRI - Electric Power Research Institute
EQSS - Electricity Quality of Service Standards ERIP
- Emergency Restoration Improvement Project
ETR - Estimated Time of Restoration
F - Manhole Fire
FAA - Federal Aviation Administration

FEMA	-	Federal Emergency Management Agency
FERC	-	Federal Energy Regulatory Commission
FTE	-	Full Time Equivalent
GIS	-	Geographic Information System
GWD	-	Graphical Work Design
GWh	-	Gigawatt-hour
HMPE	-	High Molecular weight Polyethylene
HSEMA	-	Homeland Security and Emergency Management Agency
HVCA	-	High-Volume Call Answering
IEEE	-	Institute of Electrical and Electronics Engineers
ICS	-	Incident Command System
IMT	-	Incident Management Team
ISA	-	International Society of Arboriculture
IST	-	Incident Support Team
kV	-	Kilovolt
LTC	-	Load Tap Changer
LVAC	-	Low Voltage Alternating Current (Network)
MDS	-	Mobile Dispatch System
MDT	-	Mobile Data Terminal
MED	-	Major Event Day
MIP	-	Manhole Inspection Program
MOV	-	Metal Oxide Varistor
MVA	-	Megavolt Ampere
MVAR	-	Megavolt Ampere Reactive
MWh	-	Megawatt-hour
NERC	-	North American Electric Reliability Corporation
NIMS	-	National Incident Management System
NOC	-	Network Operating Center
NOFR	-	Notice of Final Rulemaking
OCB	-	Oil Circuit Breaker
OH	-	Overhead
O&M	-	Operations and Maintenance
OMS	-	Outage Management System
OPC	-	Office of the People's Counsel
OTR	-	Office of Tax and Revenue
P&A	-	Planning & Analysis
PAC	-	Phase Angle Control or Pre-assembled Arial Cable
PCA	-	Palisades Citizens Association
PCB	-	Polychlorinated Biphenyls
PDM	-	Predictive Maintenance
Pepco	-	Potomac Electric Power Company
PH	-	Pepco Holdings LLC
PIP	-	Productivity Improvement Plan
PIWG	-	Productivity Improvement Working Group
PILC	-	Paper Insulated Lead Cable
PJM	-	PJM Interconnection
PLC	-	Power Line Carrier
PNB	-	Prospective New Business report
QC	-	Quality Control

RCM	-	Reliability Centered Maintenance
RE	-	Reportable Event
RFC	-	Reliability First Corporation
RL	-	Rubber Lead
RN	-	Rubber Neoprene
ROW	-	Right of Way
RPTA	-	Real Property Tax Administration
RTO	-	Regional Transmission Organization
RTU	-	Remote Terminal Unit
S	-	Smoking Manhole
SAIDI	-	System Average Interruption Duration Index
SAIFI	-	System Average Interruption Frequency Index
SCADA	-	Supervisory Control and Data Acquisition SEC
	-	Security Exchange Commission
SGIG	-	Smart Grid Investment Grant
SMECO	-	Southern Maryland Electric Cooperative
SOS	-	Standard Offer Service
StormMan	-	Oracle Storm Management module/function
T&D	-	Transmission and Distribution
TGR	-	Tree Growth Regulator
TOA	-	Transformer Oil Analyst
UFA	-	Urban Forestry Administration
UG	-	Underground
URD	-	Underground Residential Distribution
VAR	-	Volt-ampere Reactive
VLF	-	Very Low Frequency
VM	-	Vegetation Management
WMIS	-	Work Management Information System
XLPE	-	Cross Link Polyethylene

SECTION 4.2 – TECHNICAL TERMS AND DIAGRAMS

This section contains definitions, explanations and diagrams used in discussing electric system operations, design characteristics, and performance.

Alternating Current (AC)

A current, which reverses at regularly recurring intervals of time and that has alternately positive and negative values.

Ampere

The "ampere" is the basic unit of current equal to the flow of one coulomb of charge passing a point in one second. It is also the amount of current that is allowed to flow when a difference of potential of one volt is applied to a resistance of one ohm.

Ampere-hour

The flow of current per hour. Ten ampere-hours is equal to the flow of 10 amperes for a period of one hour or the flow of one ampere for ten hours.

Arrester

A device that provides an alternate path for surge currents caused by over-voltage resulting from lightning or switching surges.

Battery

Two or more cells electrically connected for producing electric energy. A device that transforms chemical energy into electric energy.

Cable Joint

A connection between two or more separate lengths of cable with the conductors in one length connected individually to conductors in other lengths and with the protecting sheaths so connected as to extend protection over the joint.

Cable Rack

A device usually secured to the wall of a manhole, cable raceway, or building to provide support for cables.

Cable Splice

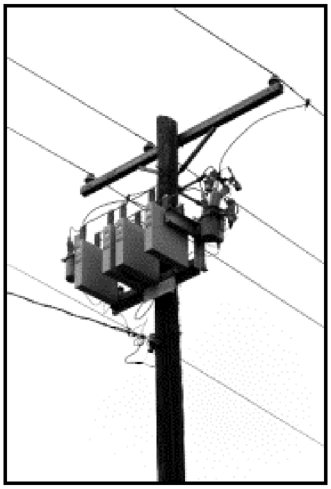
See Cable Joint

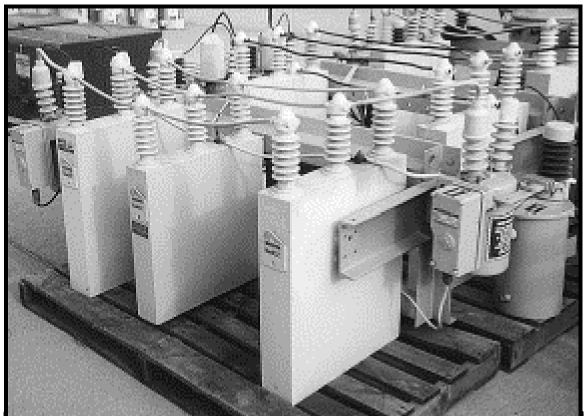
CAIDI (Customer Average Interruption Duration Index)

Represents the average time required to restore service to the average customer per sustained interruption. Mathematically equal to SAIDI divided by SAIFI.

Capacitor

An electrical device for storing a charge of electricity and returning it to the line. It is used to balance the inductance of a circuit, since its action is opposite in phase to that of inductive apparatus; it throws the current ahead of the electromotive force in phase. It is made of alternate plates of tinfoil and insulating material. The size of plates and the thickness of insulating material determine the capacity for holding electric charge. Capacity is measured, practically, in micro-farads, millionths of a farad.





Capacitors

Circuit

A conductor or system of conductors through which an electric current is intended to flow.

Circuit Breaker

A device designed to open and close a circuit by non-automatic overload of current without damage to itself when properly applied within its rating.

Conductor

A material that allows the flow of electricity; a metal wire, in the center of an electrical cable, through which current flows.

Conduit

A pipe, most often made of polyvinyl chloride, used for the installation of cables underground.

CPI (Composite Performance Index)

A distribution feeder performance measuring index created by combining 4 industry standard reliability indicators. The indicators used in CPI are Number of Interruptions (NI), Number of Customer Hours of Interruption (CHI), System Average Interruption Frequency (SAIF) and System Average Interruption Duration (SAID).

Cycle

One complete set of positive and negative values of an alternating current.

Duct

A single enclosed runway for conductors or cables.

Duct Bank

An arrangement of conduit providing one or more continuous ducts between two points.

Efficiency

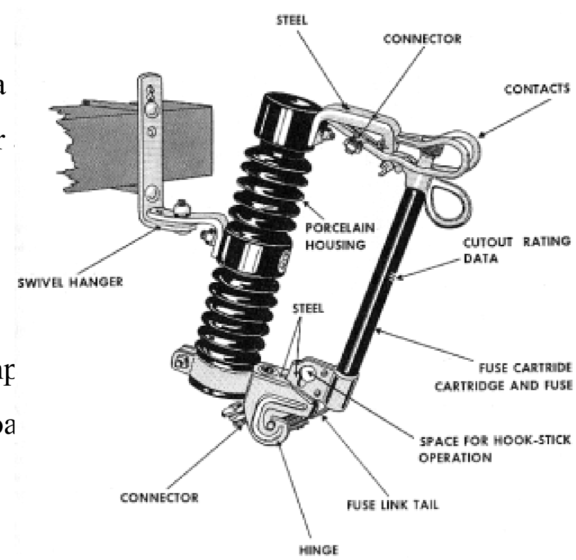
The ratio of the useful output to the input of energy, power, quantity of electricity, etc.

Fault Current

A current that flows from one conductor to ground or to another conductor owing to an abnormal connection (including an arc) between the two. Note: A fault current flowing to ground may be called a ground fault current.

Fuse

An electrical safety device consisting of, or including, a d
interrupts the circuit when the current exceeds a particular



Fuse Cutout

A device that is used to de-energize and re- energize comp h
protects the line and components from the effect of overloa

Fuse Element

The part of a fuse that melts and interrupts the circuit when excessive current flow occurs.

Ground

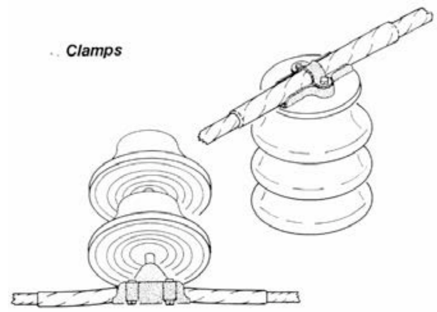
A conducting connection, whether intentional or accidental, by which an electric circuit or equipment is connected to the earth or to some conducting body that serves in place of the earth.

Inductance

The process that produces a voltage due to interaction of a conductor, a magnetic field, and relative motion between them.

Insulator

A material that offers a great deal of resistance to electron flow.



Kilowatt-Ampere (kVA)

The unit of apparent power in alternating current circuits as distinguished from kilowatts which represent true power.

Kilowatt (kW)

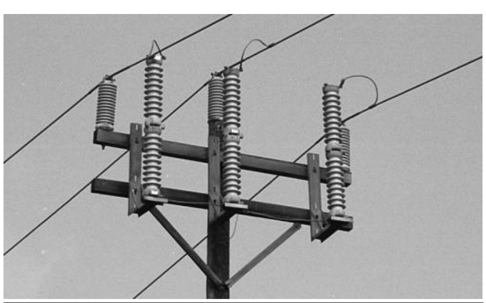
A unit of electric power equal to one thousand watts.

Kilowatt-hour (kWh)

The work performed by one kilowatt of electric power during one hour.

Lightning Arrester

A device that has the property of reducing the voltage of a surge applied to its terminals by the surge current to ground. It is capable of interrupting follow current if present and restores itself to original operating conditions.



Load Factor

The ratio of the average load over a designated period of time to the peak load occurring in that period.

Low Voltage (LV)

600 volts and lower.

Manhole

A subsurface chamber, large enough for a man to enter, in the route of one or more conduit runs and affording facilities for placing and maintaining in the runs, conductors, cables, and any associated apparatus.

Megawatt (MW)

One million watts.

Network

An aggregation of interconnected conductors consisting of feeders, mains, and services.

Overload

A load greater than the rated load of an electrical device.

Paper-Insulated Lead Cable (PILC)

A primary cable designed with paper insulation wrapped around a shielded conductor and covered with a flexible lead covering.

Phase

The relative time of change in values of current or electromotive force. Values that change exactly together are in phase. Difference in phases is expressed in degrees, a complete cycle or double reversal being taken as 360 deg. A 180-deg phase difference is complete opposition in phase.

Polychlorinated Biphenyls (PCB)

A toxic environmental contaminant requiring special handling and disposal in accordance with US Environmental Protection Agency Regulations. No longer used in transformers.

Pothead

A device used to protect the connection between a URD and an overhead system. A pothead also provides a termination for the URD cable insulation.

Power

The rate of doing work or the rate of expending energy. The unit of electrical power is the watt. Power is calculated by multiplying current time voltage.

Power Factor (pf)

The ratio of the actual power of an alternating current as measured by a wattmeter, to the apparent power, as indicated by ammeter and voltmeter reading. The power factor of an inductor, capacitor or insulator is an expression of their losses. The ratio of total watts to the total root-mean-square (RMS) volt-amperes. It is a mathematical term whose value is less than or equal to unity, or one. This term is used to show the relationship between volt-amperes (which is the basis for rating transformers, generators, etc.) and watts which is the measure of usable power delivered. A low power factor results in a lower usable power delivery or consumption for a given value of electric current than would result with a high power factor. The result of a low power factor is higher losses through the wires, cables, and other electrical apparatus.

$$pf = \frac{\sum Watts}{\sum RMS\ VoltsxAmperes}$$

Preassembled Aerial Cable (PAC)

Preassembled Aerial Cable (PAC) is an installation of three single underground cables triplexed together and installed on the overhead distribution system in heavily wooded areas. Each of the three conductors is a fully insulated cable grouped together in a package that is supported by a metallic messenger. The installation is more robust than tree wire and has the ability to withstand falling tree limbs.

Primary Circuit

The higher voltage circuit in a URD system that carries power to the transformers.

Protective Relay

A relay whose function is to detect conditions of an abnormal or dangerous nature and to initiate appropriate control circuit action.

Reactive Power

The product of voltage and the out-of-phase component of alternating current generally measured in kilovars (kVAR). Reactive power decreases the substation's ability to deliver real power and increases system losses.

Reactor

A device, the primary purpose of which is to introduce reactance into a circuit.

230 kV Reactor

Real Power

The rate, generally measured in kilowatts (kW), of generating, transferring, or using energy. The power which serves the customers' end-use electrical devices and the power for which the customer is metered.

Relay

An electric device that is designed to interpret input conditions in a prescribed manner and, after specified conditions are met, to respond to cause contact operation or similar abrupt change in associated electric control circuits.

Remote Terminal Unit (RTU)

A device that controls substation equipment.

SAIDI (System Average Interruption Duration Index)

Average time customers are interrupted. Mathematically equal to the sum of Customer Interruption Hours divided by Total Number of Customers Served.

SAIFI (System Average Interruption Frequency Index)

Average frequency of sustained interruptions per customer. Mathematically equal to the sum of Number of Customer Interruptions divided by Total Number of Customers Served.

SCADA (Supervisory Control and Data Acquisition) System

A system that allows dispatchers to monitor and control substation equipment from a central location; also provides documentation for record keeping.

Secondary

Referring to the energy output side of transformers or the conditions (voltages) usually encountered at this location.

Short-Circuit

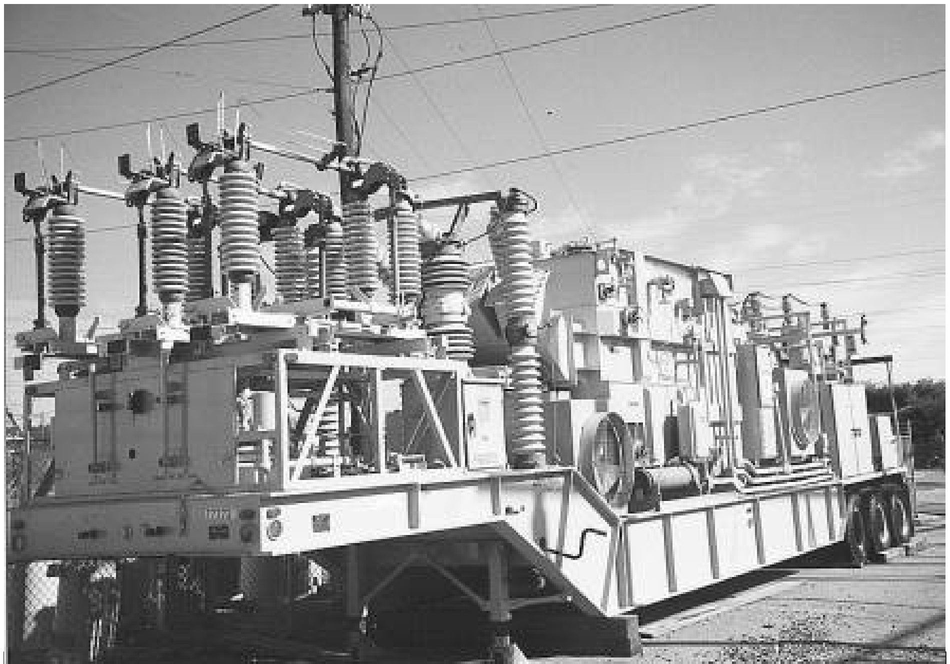
An abnormal connection of relatively low resistance, whether made accidentally or intentionally, between two points of different potential in a circuit.

Splice

A joint used for connecting in series, two lengths of conductor or cable.

Substation

An assemblage of equipment for purposes other than generation or utilization, through which electric energy in bulk is passed for the purpose of switching or modifying its characteristics. Note: A substation is of such size or complexity that it incorporates one or more buses, a multiplicity of circuit breakers, and usually is either the sole receiving point of commonly more than one supply circuit, or it sectionalizes the transmission circuits passing through it by means of circuit breakers.



Mobile Substation

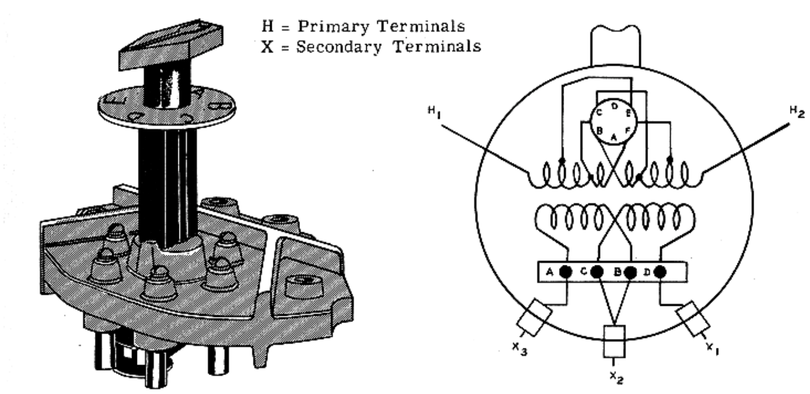
Switchgear

A general term covering switching and interrupting devices and their combination with associated control, metering, protective, and regulating devices, also assemblies of these devices with associated interconnections, accessories, enclosures, and supporting structures, used primarily in connection with the generating, transmission, distribution and conversion of electric power.

Tap

Connections that allow a transformer's turns ratio to be adjusted by adding turns to or subtracting turns from the transformer's primary or secondary winding. A connection brought out of a winding at some point between its extremities to permit changing the voltage or current ratio (general). An intermediate point in an electric circuit where a connection may be made.

A Tap Changer is Used to Adjust the Turns Ratio of a Transformer



No Load Tap Changer

Typical Internal Wiring of Transformer with Tap Changer

Tap Changer

A device for changing the turns ratio of a transformer.

Telemetering

Transmission of intelligence such as meter readings over a long distance, usually from stations to the dispatcher's office, by direct wire or carrier current.

Three-Phase Circuit

A combination of circuits energized by alternating voltages that differ in phase by one-third, that is, 120 degrees.

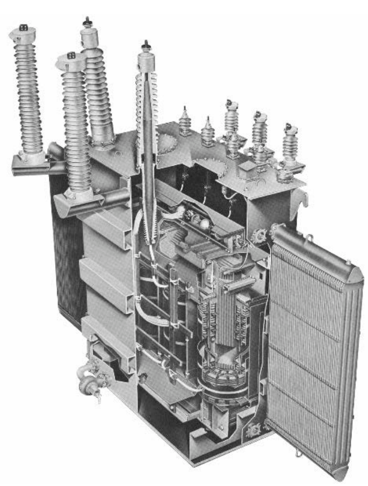
Three-Wire System

A system of electric supply comprising three conductors, one of which, known as the neutral wire, is maintained at a potential midway between the potential of the other two, referred to as the outer conductors. There are two distinct voltages of supply, one being twice the other.

Transformer

A component used to change AC voltage to meet specific requirements. A device consisting of a winding with tap or taps, or two or

more coupled windings, with or without a magnetic core, for introducing mutual coupling between electric circuits.



Transmission Line

A line used for electric-power transmission.

URD System

A local distribution system designed primarily to be buried in the ground and to serve residential customers.

VAR

Reactive volt-amperes.

Volt

Unit of measure for voltage. One volt is defined as the voltage necessary to drive a current of one ampere through a resistance of one ohm.

Voltage

Electric potential or potential difference expressed in volts.

Watt

Unit of measure for electric power, equal to the amount of power produced when one volt causes one ampere of current to flow.

Watt-hour

Basic unit used to measure electrical energy. Watt-hours are determined by multiplying power by time. One watt-hour is the amount of energy used when one watt of power is delivered to an electrical device for one hour.

SECTION 4.3 – SELECTED COMMISSION ORDERS

COMPREHENSIVE PLAN

System Planning

The initial requirements for the Comprehensive Plan section of the Consolidated Report were delineated in hearings taking place from November 5-7, 2001. The Commission requested that the Company provide a Comprehensive Plan detailing proposed changes to the electric system for the purposes of meeting load growth or maintaining system reliability. On pages 143-144 of the hearing transcript, Pepco's witness Mr. Gausman explained the nature of the Company's existing plans for the distribution and transmission systems:

We have plans for each of our substations in D.C., and in each of those plans we address the needs for that location, what the growth forecast is, what type of construction is going to be needed for expansion in the distribution system in each of those locations… Now when you go up to the transmission level or the substation supply level, there you have a plan that is addressing a larger area of the town because you're looking at the whole capacity of the system.

The Company expanded its responses to the Commission's requests in the first filed Comprehensive Plan. Since that date, the Company's Comprehensive Plans have been expanded based on several Commission directives. The report that follows either expands upon the discussion in the initial hearings requesting the Consolidated Report or responds to subsequent Commission directives as cited below.

The following section of the report addresses system plans based on forecasted load growth.

In Order No. 12804 paragraph 53 B, the Commission stated the following:

53. The 2003 PIP is hereby APPROVED, provided that PEPCO:

(b) Submit quarterly reports to the PIWG as well as a report in the 2004 and subsequent PIPs on its plans for implementing the recommendations for alleviating the anticipated transmission constraints identified in the RTEP report;

Load Forecasting

In the initial November 5-7, 2001 hearings requiring the production of the Comprehensive Plan, the following topics were discussed, as cited on pages 141-144 of the hearing transcript:

Comprehensive long-term planning on the underground system

Pepco's 10-year construction plans

Distribution load growth forecasts by substation

Transmission/substation supply load growth forecasts

In order No. 12735 issued on May 16, 2003 the Commission stated at paragraph 139, the following:

PEPCO shall file the additional information not included in its expurgated comprehensive plan as outlined below, within three months of the issuance date of this Report and Order:

Customer growth projections by District of Columbia wards (including historical comparisons);

Load growth projections encompassing commercial and residential development by District of Columbia wards (including historical comparisons);

The summary should cover a 10-year planning horizon while historical comparisons should provide at least five years of history.

In Order No. 12804 paragraph 53, the Commission stated the following:

The 2003 PIP is hereby APPROVED, provided that PEPCO:

Provide the projected zonal and projected default (i.e., SOS) load data for the District of Columbia to the PIWG on a quarterly basis as well as in the 2004 and subsequent PIPs;…

Power Factors

In Order No. 10133, the Commission directed Pepco to include performance factors relating to the transmission and distribution (T&D) system in future PIPs.

"PEPCO…was directed to…provide in future PIP reports forecasts of plant performance factors which are based on analyses of both the projected performance and the prior year's actual performance"(page 10, Section B).

"…the Commission finds it entirely appropriate to include performance measures for PEPCO's transmission and distribution in the mix of issues examined by the PIWG and reported in the PIP"(page 12, third paragraph).

By way of compliance with the above requirements, in the September 1993 PIWG Meeting, Pepco proposed reporting performance data on its 13 kV distribution substation power factors.

Substation

In the initial November 5-7, 2001 hearings requiring the production of the Comprehensive Plan, Commissioner Meyers stated the following (page 266 of the hearing transcript):

But what we were talking about here yesterday was that the comprehensive plan would include… any rebuilt substations you might have; any new substations you might have…

Distribution

In the initial November 5-7, 2001 hearings requiring the production of the Comprehensive Plan, Commissioner Meyers stated the following (pages 266-267 of the hearing transcript):

But what we were talking about here yesterday was that the comprehensive plan would include… anything that you might envision to account for distribution load growth…

In Order No. 12735 issued on May 16, 2003, the Commission stated the following at paragraphs 74 and 135:

74. During the November 2001 hearings the Commission requested that PEPCO submit a comprehensive plan to include a current assessment of, and future plans for, its underground distribution and network facilities.[179] *The Commission requested the plan as a tool to evaluate PEPCO's planning methodology and to assess PEPCO's ability to anticipate and respond to changing conditions in its underground distribution system…*

135. PEPCO shall file the additional information not included in its expurgated comprehensive plan as outlined below, within three months of the issuance date of this Report and Order:

(c) Listing of underground distribution projects, such as the Adams-Morgan neighborhood project (including budgets, time schedules, and expected benefits) by secondary vs. primary system by District of Columbia wards affected, but not specific locations;

The summary should cover a 10-year planning horizon while historical comparisons should provide at least five years of history.

Technology

In Order No. 12804 paragraph 53 E, the Commission stated the following:

53. The 2003 PIP is hereby APPROVED, provided that PEPCO:

(e) Provide to the PIWG, quarterly status reports on the new Technology Initiatives being undertaken by Pepco. An annual status report should be included in the 2004 and future PIPs. The status reports should include current accomplishments, plans for the future, and anticipated completion dates.

SCADA

The initial requirements for the Comprehensive Plan section of the Consolidated Report were delineated in hearings taking place from November 5-7, 2001. On page 313 of the hearing transcript, Commissioner Meyers stated the following:

We're going to ask Pepco to please include a section on reporting and monitoring in the comprehensive plan… And just as a quick for instance of this real-time systems control and data acquisition system, SCADA, what could it do? Give me a for instance there.

DA

In Order No. 12804 paragraph 53 E, the Commission stated the following:

53. The 2003 PIP is hereby APPROVED, provided that PEPCO:

(e) Provide to the PIWG, quarterly status reports on the new Technology Initiatives being undertaken by Pepco. An annual status report should be included in the 2004 and future PIPs. The status reports should include current accomplishments, plans for the future, and anticipated completion dates.

OMS

In Order No. 13422 on the 2004 Consolidated Report, paragraph 66, the Commission stated the following:

The 2004 Consolidated Report: Productivity Improvement Plan and Comprehensive Plan is hereby APPROVED, provided that PEPCO:

Report in the 2005 Consolidated Report, due February 15, 2005, on the corrective actions taken to fix the OMS;…

CIS

The initial requirements for the Comprehensive Plan section of the Consolidated Report were delineated in hearings taking place from November 5-7, 2001. On page 503 of the hearing transcript, Commissioner Meyers stated the following:

You've been a leader in CADS all along, computer assisted data systems. There's some discussion here about various other types of reporting and monitoring systems…

Power Delivery Information Systems Projects

In Order No. 12735, paragraph 139, the Commission stated the following:

PEPCO shall file the additional information not included in its expurgated comprehensive plan as outlined below, within three months of the issuance date of this Report and Order:…

Listing of power delivery information system projects with implementation schedules, annual costs, and milestones;

Listing of new technology investigations with decisions, annual costs, and implementation schedules;

…The summary should cover a 10-year planning horizon while historical comparisons should provide at least five years of history.

Equipment Standards

The initial requirements for the Comprehensive Plan section of the Consolidated Report were delineated in hearings taking place from November 5-7, 2001. On page 149 of the hearing transcript, Commissioner Meyers stated that the Comprehensive Plan should include:

…not only [the 10-year underground construction budget and 4 kV to 13 kV conversion], but… incorporating standards of what you want this to look like…

Equipment Inspections

In Order No. 16091, paragraphs 46 and 63, the Commission stated the following:

46. Decision. ... we shall require that Pepco provide a list of the types of equipment for which a "run to failure" method applies and those for which a preventive method applies. (Footnote: If other maintenance methods are used, Pepco shall describe them as well.) The Commission requires that Pepco provide an explanation of why different maintenance methods apply to *different types of equipment. We also require a description of the "test procedures" that Pepco uses to assess the performance and remaining life of the equipment. (Footnote: See Pepco comments at 7.) Further, Pepco shall provide an estimate of the current book value of equipment maintained under each method used by Pepco. The 2011 Consolidated Report shall include this description of maintenance policies and methods.*

63. Pepco IS DIRECTED to provide a description of its maintenance policies and methodologies, consistent with paragraph 46 of this Order;

Storm Readiness / ERIP

In Order No. 15152 at paragraph 71, the Commission ordered the following:

71. PEPCO is DIRECTED to prepare an action plan to reduce service restoration times and improve SAIDI and CAIDI performance, consistent with Order No. 14643 issued November 30, 2007 and herein, to be included in the 2009 Consolidated Report;

Order No. 15568 followed, requiring the following:

32. The Commission directs Pepco to report to each meeting of the PIWG on its Action Plan. That report should include a written description of the steps taken pursuant to the Plan. For example, in connection with the item that includes "Develop a process design and implement training," Pepco should describe the design and the training given to crews, including the number of employees who have availed themselves of the training. In addition, Pepco should be prepared to answer questions about the progress of the Action Plan from other members of the PIWG.

52. Pepco IS DIRECTED to report to each meeting of the PIWG on its Action Plan, consistent with Paragraph 32 of this Order;

Electricity Quality of Service Standards

Specific Consolidated Report requirements from the EQSS portion of the D.C.M.R. are listed below.

Progress on current corrective action plans [on customer calls answered] shall be included in the utility's annual Consolidated Report.

The utility shall report the actual call center performance during the reporting period in the annual Consolidated Report of the following year.

Progress on any current corrective action plans [on call abandonment rates] will be included in the utility's annual Consolidated Report.

The utility shall report the actual performance obtained during the reporting period in the annual Consolidated Report of the following year.

The utility shall complete installation of new residential service requests within ten (10) business days of the start date for the new installation.

Progress on any current corrective action plans [on new residential service installation requests] will be included in the utility's annual Consolidated Report.

The utility shall report the actual performance obtained during the reporting period in the annual Consolidated Report of the following year.

3603.5 The utility shall report on the progress of the corrective action plan [on repeat least performing feeders] in the Annual Consolidated Report submitted to the Commission.

The utility shall report on the number and percentage of non-major service outages that extend beyond the twenty-four (24) hour standard and the reasons each such outage extended beyond the twenty-four (24) hour standard.

The report drafted pursuant to Section 3603.8 shall be included in the annual Consolidated Report on reliability data.

The utility shall report on the progress of the corrective action plan [on SAIFI, SAIDI and CAIDI benchmarks] in the annual Consolidated Report submitted to the Commission.

The utility shall also, per the orders of the Commission, continue current requirements of reporting annual reliability indices of SAIFI, SAIDI and CAIDI (with and without major events) in the annual Consolidated Report of the following year.

Industry Comparisons

In Order No. 15568 paragraph 57, the Commission ordered the following:

57. Pepco IS DIRECTED to provide a report on the Electric Utilities Best Practices, consistent with Paragraph 50 of this Order. This report shall be included in that 2010 Consolidated Report; and shall include the best practices of the electric utility industry on improving reliability and outage restoration (from the Benchmarking Studies). Pepco shall submit a continuous improvement plan, including resourcing, specific performance targets, and milestone dates to achieve the reliability and outage restoration performance of the best (quartile) performing (comparable) utilities in the Benchmarking Studies.

Implementation of Twenty Best Practices

In Order No. 16091 paragraph 61, the Commission stated the following:

61. Pepco IS DIRECTED to include a "2011 Best Practices Report" in its 2011 Consolidated Report describing its on-going implementation of no fewer than twenty of the best practices identified in the 2009 Polaris Program, consistent with Paragraph 22 of this Order;

22. Decision. First, we conclude that Pepco has complied with the requirements of Paragraphs 32 and 52 of Order No. 15568. Second, as to the Staff's Recommendation that Pepco file a "Best Practices Report" from the PA Consulting's 2009 Polaris Transmission and Distribution Benchmarking Program, we agree that a report may be helpful in assuring that best practices continue to be implemented. Therefore, the

Commission shall require that Pepco include in its 2011 Consolidated Report a section entitled "2011 Best Practices Report" in which Pepco shall describe its on-going implementation of no fewer than twenty of the best practices identified in the 2009 Polaris Program included in the 2010 Consolidated Report as Appendix 2D. The twenty best practices selected by Pepco should be those judged to have the most impact on reliability and outage restoration performance. Pepco shall report on all its activities during 2010 to implement these best practices, including data on staffing levels, expenses and results. This requirement is separate from the requirement to produce a "Continuous Improvement Plan," as is described more fully in Section IV.A.1.f.

PA Consulting Recommendations

In Order No. 15632 issued in these proceedings, the Commission states at paragraph 5 the following:

5. Pepco shall file with the Company's annual Consolidated Reports to the Commission data on the Company's measures to continue to address each of the recommendations made by PA Consulting and the effectiveness of the Company's approaches to improve CAIDI and SAIDI to at least the average of PA Consulting benchmarks. This obligation shall begin with the 2010 Consolidated Report.

In Order No. 15568 issued October 7, 2009 in these proceedings, the Commission states at paragraph 52 the following:

*52. Pepco IS **DIRECTED** to report to each meeting of the PIWG on its Action Plan, consistent with Paragraph 32 of this Order;*

32. The Commission directs Pepco to report to each meeting of the PIWG on its Action Plan. That report should include a written description of steps taken pursuant to the Plan. For example, in *connection with the item that includes "Develop a process design and implement training." Pepco should describe the design and the training given to the crews, including the number of employees who have availed themselves of the training. In addition, Pepco should be prepared to answer questions about the progress of the Action Plan from other members of the PIWG.*

In Order No. 16091 issued in these proceedings, the Commission states at paragraph 22 the following:

22. *Decision. First, we conclude that Pepco has complied with the requirements of Paragraphs 32 and 52 of Order No. 15568.*

PRODUCTIVITY IMPROVEMENT PLAN

Productivity Improvement Plan

In Order No. 15152 on the 2008 Consolidated Report, paragraph 68, the Commission ordered the following:

The Productivity Improvement Working Group, which includes OPC, provided a reasonable definition of a productivity improvement project in 2006. Specifically, the PIWG states:

T&D productivity improvement projects were considered those projects that will increase T&D system efficiency by reducing losses and improve[ing] system reliability, and which may defer more costly additions to the electric system. (Footnote: F.C. No. 766, Decision on Consideration of OPC's T&D Productivity Improvement Working Group in Response to Commission Order No. 13754, filed July 6, 2006 ("2006 PIWG Report"), at 2.)

The power serving the District's Standard Offer Service customers is now procured through a wholesale procurement process by PEPCO and, as such, productivity improvement is applicable only to transmission and distribution issues. We find the PIWG's definition of a productivity improvement project workable and adopt it here.

The PIWG also provided a reasonable definition of comparative cost analysis for reliability projects. The PIWG suggested that the comparative cost analysis used for reliability projects should "consist *of a comparison of the cost of alternative reliability improvement solutions as well as any differences in relative reliability improvement." (Footnote: 2006 PIWG Report at 2.) …*

Reliability Statistics

Page 190 of the transcript for the November 5-7, 2001, hearings documents Commissioner Cartagena as stating the following:

You testified earlier that you have a 10-year plan for updating the system or addressing whatever changes are required with regards to that. Does that 10-year plan contain reliability goals or other measurable performance objectives? In other words, are there some kinds of standards that we can look at and will give us an idea of whether the company is hitting or missing those standards and objectives with regards to its plan?

This section of the Consolidated Report addresses the Company's performance with respect to reliability standards and Electricity Quality of Service Standards.

Targeted Reliability Indices

In Order No. 12735, paragraph 139, the Commission ordered the following:

PEPCO shall file the additional information not included in its expurgated comprehensive plan as outlined below, within three months of the issuance date of this Report and Order:

Targeted reliability indices (including historical comparisons); and

The summary should cover a 10-year planning horizon while historical comparisons should provide at least five years of history.

Also, in paragraph 142, the Commission directed the Company to file performance indices for the District of Columbia only.

PEPCO is DIRECTED to work with the PIWG to develop target system reliability indices for the District of Columbia, only.

Vegetation Management

In Order No. 15621 at paragraph 5, the Commission ordered the following:

5. Pepco shall file within the Company's annual Consolidated Reports to the Commission, yearly data on tree trimming by feeder and wards (or multiple wards) compared to the Company's *tree down and tree limb outage causes listed in its monthly power outage reports beginning with the Company's 2010 Consolidated Report.*

Priority Feeders & Aggressive Initiatives

The Electricity Quality of Service Standard D.C.M.R. 3603.6 states the following:

3603.6 The utility shall continue the current reporting of the worst performing (lowest two (2) percent) feeders (utility methodology) and corresponding corrective action plans, with the action taken in year 1 and the subsequent performance in year 2 in the annual Consolidated Report.

In Order No. 15152 paragraph 73, the Commission ordered the following:

73. Pepco is DIRECTED to investigate the viability of the "aggressive" initiatives for all least performing feeders, to file a progress report regarding the implementation of these initiatives where viable as part of the 2009 Consolidated Report, and to file quarterly progress reports thereafter, consistent with paragraph 62 of this Order;

In Order No. 15809 paragraph 11, the Commission ordered the following:

11. Pepco IS DIRECTED to include in its 2011 Consolidated Report a plan for development and application of "aggressive initiatives" to its underground distribution feeders;

Repeat Priority Feeders

In Order No. 15152 issued on Pepco's 2008 Consolidated Report, the Commission stated (at paragraph 72),

*72. PEPCO is **DIRECTED**, beginning with the 2009 Consolidated Report, to identify the feeders that are part of the separate annual program of corrective actions for reappearing least reliable feeders, describe the corrective actions planned for each feeder and the projected dates for completion of the corrective actions and explain whether the corrective actions improved the performance of these feeders consistent with paragraph 59 of this Order;*

In Order No. 15941 issued on August 18, 2010, the Commission stated at paragraphs 13 and 16, the following:

13. Beginning with the 2011 Consolidated Report, Pepco shall identify any feeders that have appeared more than once on the Priority Feeder List, by year from the first Priority Feeder List in 2002, so that it shall be apparent how many times each feeder has appeared on the Priority Feeder List…

16. Pepco IS DIRECTED to identify in its 2011 and successive Consolidated Reports, each feeder that has appeared more than once on the Priority Feeder List.

4 to 13 kV Conversions

These projects are a continuation of the 2011 Reliability Projects, as required by Order No. 16091 at paragraph 64 and referenced paragraphs 50 and 53:

*64. Pepco IS **DIRECTED** to provide detailed schedules and budgets for conversion projects, as well as justification for any non-minor deviations from these , consistent with Paragraphs 50 and 53 of this Order;*

50. <u>Decision.</u> We agree with the Staff recommendation and require Pepco to provide justification for any deviations from the plan schedules and annual budgets for 4 kV to 13 kV conversion projects in its Consolidated

Reports, excluding minor deviations of less than 5%. This information may be provided in the discussion of "Reliability Projects."

53. Decision. ...we have not adopted the Staff's "replace or rebuild" recommendation. However, we agree that future Consolidated Reports should contain detailed schedules and budgets for Reliability Projects, as well as justification for deviations from those schedules and budgets. We shall require Pepco to submit such schedules in future Consolidated Reports.

Manhole Event Report

In Order No. 16091 issued on December 10, 2010, the Commission stated at paragraphs 56, 59, 65, and 66 the following:

56. Decision. Pepco has agreed to make the recommended changes in the 2011 Consolidated Report with the exception of data on failure rates. We require that the members of the PIWG discuss the need for and feasibility of providing data on failure rates in future Consolidated Reports and include in the 2011 Consolidated Report the PIWG conclusions and recommendations, if any.

59. Decision. We adopt the Staff's recommendation and require Pepco to: (1) combine the Manhole Events portion of the failure analysis report with Part 3 of the Consolidated Report; (2) include data in the 2011 Consolidated Report that separates 4 kV primary failures from 13 kV primary failures; (3) include data in the 2011 Consolidated Report that separates 4 kV from 13 kV manhole events; (4) include trend analyses for "Use of Slotted Manhole Covers;" and (5) include in the Cable Splice or Joint Database section of the Consolidated Report, cable type, age, type of splice and other pertinent information, except that cable type and age can be excluded if unavailable. If data on failure rates for all variables is available for manhole events, Pepco shall include such information in its 2011 Consolidated Report. If such data is unavailable, we require *the members of PIWG to discuss the need for and the availability of such data include in the 2011 Consolidated Report the PIWG conclusions and recommendations, if any.*

Pepco IS DIRECTED to include a discussion of failure data rates in the agenda for the Productivity Improvement Working Group, consistent with Paragraphs 56 and 59 of this Order; and

Pepco IS DIRECTED to include additional Manhole Event data in the 2011 Consolidated Report, consistent with Paragraph 59 of this Order.

In Order No. 15152 paragraphs 76 and 66, the Commission ordered the following:

76. PEPCO is DIRECTED to include as part of the 2009 Consolidated Report a proposed plan for significantly reducing manhole events consistent with paragraph 66 of this Order…

In Order No. 12735, paragraph 138, the Commission ordered the following:

Pepco shall file a report that summarizes the results of the failure analyses conducted for the calendar year 2002, 30 days from the issuance date of this Report and Order, and subsequently, to file an annual report on the results of the failure analysis group to the PIWG;

Slotted Manhole Covers

In Order No. 16091 issued on December 10, 2010, the Commission stated among other things, at paragraph 59, the following:

59. …(4) include trend analyses for "Use of Slotted Manhole Covers;" 60.

Cable Splice or Joint Database

In Order No. 16091, the Commission stated among other things, at paragraph 59, the following:

59. *...(5) include in the Cable Splice or Joint Database section of the Consolidated Report, cable type, age, type of splice and other pertinent information, except that cable type and age can be excluded if unavailable.*

Failure Rates

In Order No. 16091, the Commission stated among other things, at paragraph 59, the following:

59. ...(5)...If data on failure rates for all variables is available for manhole events, Pepco shall include such information in its 2011 Consolidated Report. If such data is unavailable, we require the members of PIWG to discuss the need for and the availability of such data include in the

2011 Consolidated Report the PIWG conclusions and recommendations, if any.

Appendix 3A –Manhole Events and Summary of Selected Failures

In Order No. 11716 ordering paragraph 3, the Commission ordered the following:

PEPCO shall file an annual report on the previous calendar year's manhole incidents;

Appendix 3B – Manhole Inspection Program

In Order No. 11716, the Commission stated the following:

PEPCO is hereby directed to include the following information in its [manhole inspection] reports beginning in July 2000:

The general location of the manholes inspected, including the street or streets where the manholes are located and the blocks bounding the street, e.g., M Street, NW, between 23rd and 28th streets;

The number of manholes inspected in the month, broken down as to the number of manholes containing primary cables only, both primary and secondary cables, and secondary cables only;

The number of primary cable problems found;

The number of secondary cable problems found;

The type of cable problems found in each manhole, categorized as to the physical degradation or damage of the cable, overheating, overloading, damaged splice and deteriorated cable or splice due to age;

The number of manholes with problems;

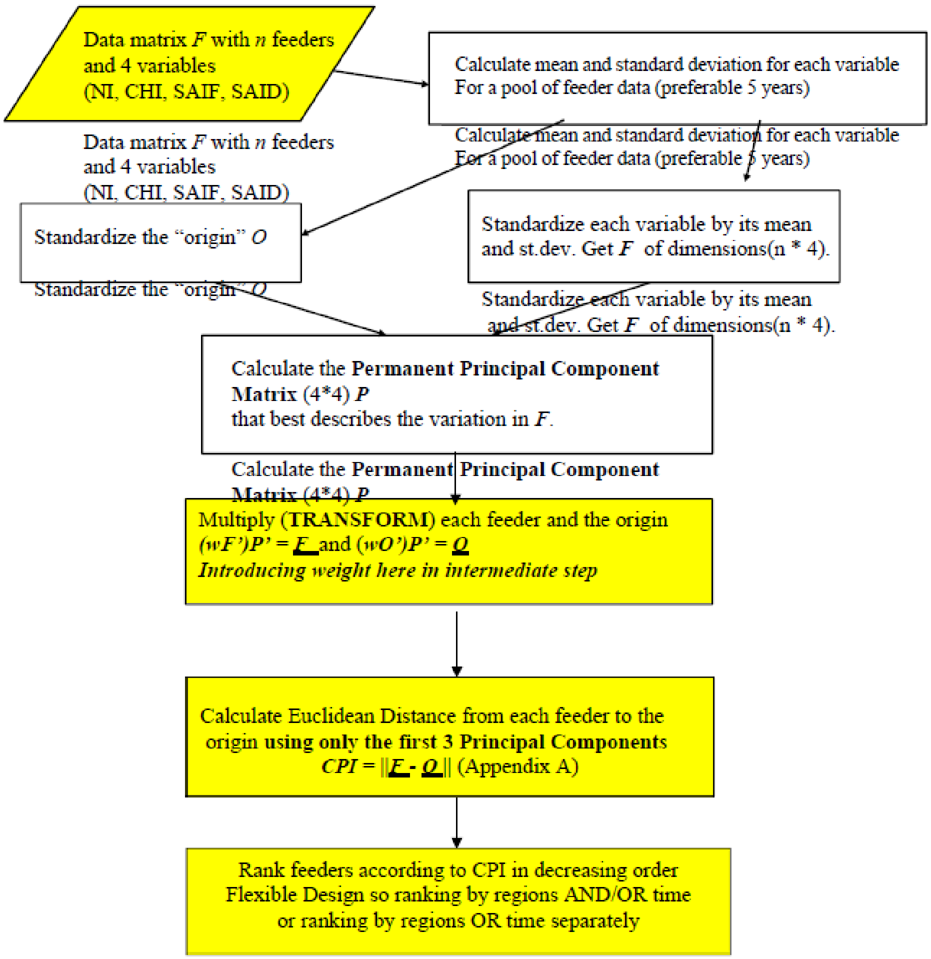
The corrective actions taken for each cable and manhole problem found; and

8. *Other general condition of the manhole such as whether it contained water, oil, grease, debris, and whether the manhole cover and the manhole are in good mechanical condition.*

Description of Calculation Process

The following flow chart (Figure 4.4-B) illustrates the process for calculating the Composite Performance Index for a feeder.

Figure 4.4-B -- Illustration of CPI Concep



Description of Euclidean Distance to Derive CPI

Definitions

Principal Component Matrix (each row is Principal Component vector)

$$P = \begin{bmatrix} PC_1 \\ PC_2 \\ PC_3 \\ PC_4 \end{bmatrix} = \begin{bmatrix} pc_{1,NI} & pc_{1,CHI} & pc_{1,SAIF} & pc_{1,SAID} \\ pc_{2,NI} & pc_{2,CHI} & pc_{2,SAIF} & pc_{2,SAID} \\ pc_{3,NI} & pc_{3,CHI} & pc_{3,SAIF} & pc_{3,SAID} \\ pc_{4,NI} & pc_{4,CHI} & pc_{4,SAIF} & pc_{4,SAID} \end{bmatrix}$$

Original Feeder Data

$$originalFeeders = F = \begin{bmatrix} f_{1,NI} & f_{1,CHI} & f_{1,SAIF} & f_{1,SAID} \\ f_{2,NI} & . & . & . \\ . & . & . & . \\ f_{n,NI} & . & . & f_{n,SAID} \end{bmatrix}$$

Weight

$$W = \begin{bmatrix} w_{NI} & 0 & 0 & 0 \\ 0 & w_{CHI} & 0 & 0 \\ 0 & 0 & w_{SAIF} & 0 \\ 0 & 0 & 0 & w_{SAID} \end{bmatrix}$$

Standard Deviation

$$\Sigma = \begin{bmatrix} \sigma_{NI} & 0 & 0 & 0 \\ 0 & \sigma_{CHI} & 0 & 0 \\ 0 & 0 & \sigma_{SAIF} & 0 \\ 0 & 0 & 0 & \sigma_{SAID} \end{bmatrix}$$

Intermediate Calculations

$$M = \Sigma * W = \begin{bmatrix} \sigma_{NI} & 0 & 0 & 0 \\ 0 & \frac{w_{CHI}}{\sigma_{CHI}} & 0 & 0 \\ 0 & 0 & \frac{w_{SAIF}}{\sigma_{SAIF}} & 0 \\ 0 & 0 & 0 & \frac{w_{SAID}}{\sigma_{SAID}} \end{bmatrix}$$

Transformation

$$\hat{F} = F * M * P'$$

$$\hat{F} = \begin{bmatrix} f_{1a} & f_{1b} & f_{1c} & f_{1d} \\ f_{2a} & . & . & . \\ . & . & . & . \\ f_{na} & . & . & f_{nd} \end{bmatrix}$$

Where

F is the original feeder data matrix (size n*4)

M is the intermediate calculation matrix (size 4*4)

P' is the (transposed) principal component matrix (size 4*4)

Finalization of CPI – Euclidean Distance Method

For each feeder *i* take the values for the 3 first components of row *i* in the last matrix above.

$$CPI_{f_i} = \sqrt{f_{ia}^2 + f_{ib}^2 + f_{ic}^2}$$

ATTACHMENT A

FACT SHEET

PHI

ENVIRONMENTAL STEWARDSHIP & SUSTAINABILITY:

VEGETATION MANAGEMENT ON RIGHTS-OF-WAY

A reliable supply of electricity is essential to the safety, security, economy and welfare of our nation and the communities where we live and work. To ensure the safe and reliable delivery of electricity to our customers, PHI must manage vegetation near its transmission and distribution lines and other facilities to prevent interruptions, blackouts and wildfires. PHI's regulated power delivery operations are required to maintain transmission and distribution rights-of-way so that trees, shrubs and other vegetation do not pose preventable hazards to power lines, poles or other facilities. PHI uses "best practices" to manage vegetation around electricity infrastructure, selecting among mechanical, chemical (herbicides), cultural, and biological control methods for the most suitable approach to meeting safety and reliability needs while maintaining or improving habitats for the region's indigenous flora and fauna. PHI employs professional, certified foresters and arborists to administer their vegetation management program.

VEGETATION MANAGEMENT: THE BASICS

- Utilities maintain right-of-way lands on a regular basis in order to provide for the safe transmission and distribution of electricity.
- Utilities must identify and utilize the most direct, least intrusive route possible when constructing power lines, in order to minimize both the amount of land used and any environmental impact.
- Trees and other vegetation beneath power lines must be properly maintained to avoid causing interruptions of electric service by growing into, falling through or knocking down power lines.
- In cooperation with federal, state, and local authorities, PHI, like most utilities, implements integrated vegetation management strategies to minimize overall risk to people and the environment while providing safe and reliable electric service.

HOW DOES PHI MANAGE VEGETATION NEAR ITS POWER LINES?

- PHI carefully selects vegetation management practices that balance environmental concerns, public needs, safety and cost-effectiveness.
- PHI partners with state, regional and local groups to create and maintain numerous natural habitats on its rights-of-way.
- PHI minimizes the use of EPA-approved herbicides through the selection and use of proper application methods, equipment and technology.

- PHI promotes native flora and fauna through intergrated vegetation management of our rights-of-way;
- PHI enhances vegetation management projects through cultivation or planting of compatible native vegetation;
- PHI protects native rare species populations that could otherwise be impacted by rights-of-way establishment, construction or maintenance;
- PHI manages rights-of-way areas to maintain wildlife habitat and protect threatened and endangered species habitat; and
- PHI reduces the introduction and control the spread of nonnative invasive species or noxious weeds in rights-of-way and adjacent lands.

Recognized Excellence

- All PHI utilities (Atlantic City Electric, Delmarva Power and Pepco) are active in community outreach and educational efforts to promote its **Right Tree, Right Place** initiative. **Right Tree, Right Place** advocates planting each tree species where it will thrive and not planting large species where they will interfere with power lines once they reach mature height.
- All PHI utilities have been named **Tree Line USA** Utilities by the Arbor Day Foundation. The Tree Line program is sponsored by the foundation in cooperation with the National Association of State Foresters. It recognizes utilities that demonstrate a program of quality tree care, annual tree worker training, public education, tree planting, and energy conservation through tree planting.
- PHI has longstanding commitments to vegetation management and green infrastructure efforts to help promote the sequestration of carbon dioxide by trees and other vegetation to stabilize and gradually reduce greenhouse gas emissions.

ATTACHMENT B

Category	Description	2021 Actuals
Customer	61934: PEPCO DC 600 4th St SW - The Kiley	89,295
Customer	61958: PEPCO DC 1015 REAR IRVING ST NW_	(4)
Customer	62908: PEPCO DC 1500 RHODE ISLAND AVE NW - MH CON CBL - NBC	355,338
Customer	63609: Pepco DC 1200 3rd St NE	1,463,842
Customer	63635: Pepco DC- Yards ML 1A & Parcel G	37,003
Customer	63661: Pepco DC- Yards ML 1B	537,390
Customer	63663: Pepco DC- Wharf Phase 2	3,542,125
Customer	63666: Pepco DC 1000 South Capitol St SE	835,267
Customer	63698: PEPCO DC Parks at Walter Reed	4,521,453
Customer	63702: Pepco DC- 680 Rhode Island Avenue, NE (Blocks 1A, 1B, 2B)	55,220
Customer	63710: Pepco DC- 2607 Reed Street, NE	926,398
Customer	63718: Pepco DC- 1676 Maryland Ave NE	91,356
Customer	63722: Pepco DC- 400 Florida Ave NE	526,979
Customer	63725: Pepco DC- 500 Penn Ave NE	369,687
Customer	63727: Pepco DC- 1500 Harry Thomas WY NE	146,391
Customer	63785: PEPCO DC H Street Bridge Replacement Facility Relocation Project	1,446,619
Customer	64433: Pepco DC: Yards Temp Parcel I & G	128,355
Customer	64794: PEPCO DC 4669 South Capitol St SW Distribution	64,547
Customer	64882: PEPCO DC 699 14th St NW Lincoln Proptery Company	158,136
Customer	64889: PEPCO DC NSERD 3016 Dumbarton St NW	1,004,473
Customer	65698: Pepco DC 1801 E ST SE CREF	1,511
Customer	66164: PEPCO DC 119 D St NE	(5,708)
Customer	66165: PEPCO DC 1530 First St SW	337
Customer	66206: PEPCO DC 2122 14th St NW	35,436
Customer	66415: PEPCO DC 3900 WISCONSIN AVE NW - EAST and WEST PODIUM	1,194,996
Customer	66429: PEPCO DC 1112 First St NW	(655)
Customer	66496: PEPCO DC 515 22nd St NW	922
Customer	66498: Pepco DC Jet U Apts 843-867 21st St NE	31,706
Customer	66504: PEPCO DC 31st St Bridge & C&O Reconstruction	28,504
Customer	66702: Pepco DC - Interconnections, Telecom	11,182
Customer	68911: PEPCO-DC Community Solar Distribution Line/Sub	96,960
Customer	68912: PEPCO-DC Community Solar Telecomm Line/Sub	(27,214)
Customer	69558: Pepco DC 1701 H St NE	751,166
Customer	70031: 1005 1ST ST NE- NBC (DLPCS1W029)	1,046,005
Customer	70063: 1309 E ST SE- WR 3564796- COMMERCIAL NETWORK SERVICE- NBC (DLPCS6W027)	30,805
Customer	70117: 1550 1ST ST SW- NBC (DLPCS6W036)	164,038
Customer	70177: 301/331 N St NE- NBC (DLPCS6W044)	4,162
Customer	70554: BBNL 808 Bladensburg Road NE-NBC (DLPCS6W023)	15,496
Customer	71214: DC Highway Relocations (UDLPCH0W)	2,341,033
Customer	71223: DC: Facility Relocations(Non-Highway) (UDLPCS3W)	(78,751)
Customer	71225: PEPCO DC New Load, Servs & St Lights, Non-Network (UDLPCS1W	(16,408)
Customer	71231: DDOT DC South Capitol Street Relocation 34kV UG (UDLPCSCAP2)	1,288,101
Customer	72355: Meter Equipment DC (DLPCMR2DXX)	1,581,004
Customer	72359: Meter Install DC (UDLPCMR2DX)	1,491,817
Customer	73695: St Eliz East Campus Stage 1 Phase 1 - NBC (DLPCS1W007)	13,107
Customer	74412: 818 POTOMAC AVE SE- NBC (DLPCS1W048)	3,489
Customer	75092: NB Residential Pepco DC	20,983,467
Customer	75093: NB Commercial Pepco DC	22,089,111
Customer	75095: PEPCO DC NB Network Commercial	8,782,156
Customer	75450: PEPCO DC Hill East, DC General	7,833
Customer	75837: PEPCO DC CREF 4520 3rd St SE	7,040
Customer	76365: PEPCO_DC Streetcar Project Distribution	430,434
Customer Total		**78,602,951**
Load	62504: Pepco DC Alabama Ave Breakers Installation	1,226,787
Load	62900: Pepco DC Alabama Ave. Sub 136 Feeder 15166 Battery Substation	1,854,339
Load	62935: Pepco DC Alabama Ave. Sub 136 Feeder 15166 Battery Distribution	42,730
Load	62978: PEPCO DC Relay at Florida Ave Sub for Harvard Cutover	70,215
Load	64195: Pepco DC Champlain Rebuild - 13 kV Champlain Load Transfers	1,483,779
Load	65194: Harvard Rebuild - 13 kV Harvard Re-Load Pepco DC	383,690
Load	66729: Pepco DC Northeast Sub. 212 East Network Group Push Pipe to Union Market	690,580
Load	70096: 13kV Distribution Cutovers "F" St to "L" St DC (UDLPLM7W27)	4,098,544
Load	70432: Alabama Ave Sub 136 - Transfer 1.3 MVA 15177 to 15176 (UDLPLM7W3)	24,354
Load	70433: Alabama Ave Sub 136: Extend 7 Fdrs to Retire Anacostia (UDLPLWF1)	402,828

Category	Description	2021 Actuals
Load	70439: Anacostia: Convert 4 to 13kv Dist Line (UDLPLWF3)	187,639
Load	71138: Convert Alabama Ave. Sub 136 Feeder 15178 and 15165 from a 3-wire to a 4-	645,073
Load	71411: Dist Feeder Load Relief - DC (UDLPLM7W)	187,571
Load	71630: F St Sub Rebuild (69kV) (UDSPLM718A)	405,069
Load	71864: Harvard Rebuild - Distribution Upgrade to 230/13kV, 210 MVA (UDSPRD8AD2)	483,960
Load	71867: Harvard Rebuild - 13 kV Harvard Load Transfers (UDLPRM4WA6)	19,535
Load	72137: L St Sub Capacity Expansion Work (UDSPLM722A)	2,313,258
Load	72525: Mt Vernon Sq Sub: Construct 230/13kv Sub (UDSPLMV3)	9,283,423
Load	72527: Mt Vernon Sq Sub: Extend 3 Distribution Fdrs - Relieve S052 (UD	79,996
Load	72529: Mt Vernon Sq Sub: Extend LVAC (UDLPLMV1)	188,320
Load	73787: Substation Retirements-DC. (UDSPRD8RN)	208,794
Load	73839: Takoma to Sligo 69kV Line: Install Three 69kV Feeders (UDLPLM72	2,796,592
Load	73902: Transformer Load Management (TLM) Pep - DC (UDLPLM7W21)	701,027
Load	73918: Trinidad Sub 106 - Retire (UDSPRD8RO)	259,440
Load	74083: Waterfront Sub - Establish Waterfront North LVAC Network Group	1,123,215
Load	74084: Waterfront Sub - Install 4th Transformer (UDSPLM7WF4)	(126,817)
Load	74087: Waterfront Sub-Extend Fdrs: Transfer HV, Metro, Distrib frm Sta	2,997,097
Load	74349: Benning 4kV Area-Phase Balancing to Fix Voltage Drop Issues (UD	125,100
Load Total		**32,156,136**
Reliability	62161: New Jersey Ave Reliability Initiative - Pepco DC	522,287
Reliability	62214: Pepco DC Plug Third Biennial Installs	165,273
Reliability	62215: Pepco DC DC PLUG FEEDER 00308	(296,199)
Reliability	62219: Pepco DC DC PLUG FEEDER 14900	550,001
Reliability	62221: Pepco DC PLUG FEEDER 00368	485,573
Reliability	62222: Pepco DC DC PLUG FEEDER 14758	1,524,533
Reliability	62223: Pepco DC DC PLUG FEEDER 14007	2,349,855
Reliability	62224: Pepco DC DC PLUG FEEDER 15009	2,903,021
Reliability	62269: FEP Physical Security - Pepco (DC): New Jersey Ave Sub 161	1,555
Reliability	63208: Pepco DC Alabama Ave. Sub 136 Feeder 15166 Battery Fiber/Telecom	17,250
Reliability	63429: Pepco DC - ITE Air Circuit Breakers	(12,660)
Reliability	63506:PEPCO(DC) FEP Physical Security-Little Falls	591,060
Reliability	63507:PEPCO(DC) FEP Physical Security-Florida Ave	226,657
Reliability	63509:PEPCO(DC):FEP- Physical Security-Georgetown	393,652
Reliability	63510:PEPCO(DC): FEP- Physical Security-Northeast	229,289
Reliability	63511: PEPCO DC Dist FEP Physical Security: Southwest	369,595
Reliability	63531:PEPCO(DC) FEP- Physical Security-Benning115k V	186,861
Reliability	63556:Pepco DC DC Plug Feeder 00308 - Removal	107,320
Reliability	63560: Pepco DC DC Plug Feeder 14900 - Removal	1,183
Reliability	63628 Pepco DC Dist: Substation Infrastructure - DC	238,521
Reliability	63632: Pepco: DC- Storm Water Retention Credit	721,590
Reliability	63645: Pepco DC - UG SCADA Interrupter Install/Replace	103,242
Reliability	63680: Pepco DC Dist: Buzzard 230/34kV Substation	1,911,540
Reliability	63707 PEPCO DC: Potomac River Sta. C - Relocate Feeder 69012R	313,819
Reliability	63926: Double Wood Pole Removals - Pepco DC	1,584,147
Reliability	64183: PEPCO DC CM I Street Pumps, Bushings & Gasket Replacements	102,729
Reliability	64355: Pepco DC: Roof Replacements Distribution	285,301
Reliability	64357: Pepco DC: Sub Ventilation Distribution	100,008
Reliability	64365: Pepco DC: Sub Imprv. & add. Distribution	3,920,620
Reliability	64396: PEPCO DC: Dist- Three 42MVA Spare Transformers	1,773,681
Reliability	64407: PEPCO DC DIST-33MVA Spare Transformer	7,761
Reliability	64724: PEPCO DC: Mobile Distribution Transformer for Urban Area	1,970,413
Reliability	64922 PEPCO DC: DIST-Two 56 MVA Spare Transformers	339,359
Reliability	65551 Pepco DC- DIST:Benning Sub. 41 69kV T18 Spare	985,029
Reliability	65553: PEPCO DC: DIst- Benning Sub. 41 69kV GIS	730,663
Reliability	65555: PEPCO:DC-DIST:22nd Street, Sub. 124.T4	270,026
Reliability	65557 Pepco DC - Dist Benning T12 Install	2,919,719
Reliability	65582:PEPCO:DC Directional Overcurrent Relays	49,487
Reliability	66111: Pepco DC: Dist Flood Mitigation	212,674
Reliability	67127: PEPCO DC OH Poles Removal for FEP	67,022
Reliability	67161: PEPCO DC 69016 Georgetown Cable Section Replacement	215,308
Reliability	67259: PEPCO DC Termination Replacement Program- 69 kV DC	439,981
Reliability	67471 PEPCO DC: Florida Ave T2 Replacement	4,518,135
Reliability	67509: Pepco DC DC PLUG FEEDER 467	196,903

Category	Description	2021 Actuals
Reliability	67511: Pepco DC DC PLUG FEEDER 14767	199,283
Reliability	67513: Pepco DC DC PLUG FEEDER 15001	2,079,616
Reliability	67514: Pepco DC DC PLUG FEEDER 15021	426,203
Reliability	67519: Pepco DC DC PLUG FEEDER 14008	1,499,399
Reliability	67522: Pepco DC DC PLUG FEEDER 14093	192,393
Reliability	67523: Pepco DC DC PLUG FEEDER 118	214,175
Reliability	67524: Pepco DC DC PLUG FEEDER 14702	185,984
Reliability	67525: Pepco DC DC PLUG FEEDER 15166	1,570,216
Reliability	67526: Pepco DC DC PLUG FEEDER 15171	215,985
Reliability	67577: Georgetown 4kV Conversion (North Section) - Pepco DC	686,561
Reliability	68148: 17000 PEP DC Declared Storms CAPITAL ONLY D1453	603,452
Reliability	68327 Pepco DC - CM OH Work identified via 'COVID-19 Incremental Hospital Fdr PM	4,110
Reliability	68426: Pepco VA Dist - Spare Reactor/Transformer Purchase & #4 Install Sta C	584,158
Reliability	68523: PEPCO DC Harvard Spare Transformer	357,767
Reliability	68608:PEPCO DC Benning T19 Spare	115,057
Reliability	68612: PEPCO DC L St T1 Replacement	63,572
Reliability	68613: PEPCO DC L St T2 Replacement	10,899
Reliability	68614: PEPCO DC L St. T3 Replacement	10,899
Reliability	68615: PEPCO DC L St T4 Replacement	10,927
Reliability	68616: PEPCO DC L St Spare Transformer Repalcement	1,724,117
Reliability	68756: Pepco Dist 22nd St., Switchgear replacement (DC)	34,415
Reliability	68759: Pepco Dist - 9Th Street T3 Replacement DC	30,845
Reliability	68779: Pepco Dist DC Little Falls T4 Replacemnt	673,204
Reliability	68855: Tree Wire/Spacer Cable Installation - Pepco DC	48,091
Reliability	69096: PEPCO DC Florida T4	34,003
Reliability	69594: Pepco DC Benning T9 replacement	61,346
Reliability	70024: 092 Nebraska Ave T1 B-0659 Transformer/LTC Replace (ECA) (UDSPRD8AD7) DC	86,506
Reliability	70053: 12th & Irv. Area Plan-Sub Work (UDSPRM4WA7)	191,595
Reliability	70060: 13.8kV Swgr Replacement - Pepco DC (UDSPRD8KD)	1,975,246
Reliability	70187: 4kv Substation Automation - DC (UDSPRD8H)	730,087
Reliability	70602: Batt & Chgr Replacement Distri. Subs. - DC (UDSPRD8ED)	237,833
Reliability	70762: Pepco DC - ACR/SF6 Control Install/Replace	251,617
Reliability	70897: URD Cable Pepco DC (UDLPRM4BCX)	2,353,802
Reliability	71012: Champlain - New 69kV Sub (DSPRD8AD17)	(1,262,439)
Reliability	71015: Champlain to L Street 34kV (UDLPRM4WA8)	1,820,455
Reliability	71119: Comprehensive Feeder Improvements - Pepco DC (UDLPRM63D)	10,615,303
Reliability	71213: DC Distributed RTU HMI Computer Replacement (UDSPRD8CR1)	841
Reliability	71222: DC- Ground Test Device Installation Program (UDSPRD8GTD)	659,460
Reliability	71426: Pepco DC CM Distribution Substation Capital	1,022,410
Reliability	71448: PEP DC DIST PLN SPL 21421 P3040 Prog Pole Repair & Replace	850,334
Reliability	71605: PEP DC DIST OH UG EMR SPL 21421 P10/P20 Repair and Replace	2,287,208
Reliability	71612: PEP DC DIST UG EMR SPL 21421 P10/P20 Repair and Replace	17,533,546
Reliability	71615: PEP DC DIST UG EMR CAP 21421 P1020 Replace Network Transformer	3,017,969
Reliability	71631: F St Sub Rebuild (UDSPLM717A)	262,740
Reliability	71721: Ft Lincoln Reliability Initiative - Pepco DC (UDLPRM4LRD)	430,230
Reliability	71731: G St 4kV Conversion (UDLPRGST1)	2,197,379
Reliability	71782: Georgetown : 4 to 13 kv Conver Phs 3-8 (UDLPRM8BT)	(61,917)
Reliability	71855: Harrison Sub: Construct New Sub (UDSPLNW2)	1,902,311
Reliability	71859: Harrison Sub: Extend New Dist Fdrs to 38 (UDLPLNW3)	220,172
Reliability	71864: Harvard Rebuild - Distribution Upgrade to 230/13kV, 210 MVA (UDSPRD8AD2)	16,381,539
Reliability	71870: Harvard 4kV Conversion - Pepco DC (UDLPRM8BY)	1,469,044
Reliability	72064: Install Smart Relays & Replace RTU's -DC (UDSPRD8SD)	323
Reliability	72251: MDO / CEMI Remediation - Pepco DC (UDLPRM4BQX)	251,499
Reliability	72268: Misc. Reliability Improvements - Pepco DC (UDLPRM4BA)	5,752,264
Reliability	72685: NERC Physical Security Pepco Dist Sub.- DC (UDSPRD8VD)	(3,060)
Reliability	72746: Pepco DC - Network RMS - Line	2,317,957
Reliability	72748: Pepco DC - Network RMS - Telecom	29,265
Reliability	72750: PEP DC DIST PLN CAP 21421 P30/40 Network Transf & Protector Replace (UDLP	387,151
Reliability	72810: North Capitol 4kV Conversion - Pepco DC (UDLPRM8BC)	2,813,022
Reliability	72851: Pepco O Street (sub 2) 2T (UDSPRD8OS2)	7,082
Reliability	72978: PILC REPLACEMENT PLANNED (UDLPRPLIC)	8,476,267
Reliability	72997: PEP DC DIST PLN CAP 21421 P3040 Pad Transformer Replace (UDLPRM4BO)	62,164
Reliability	73032: PEP DC DIST PLN CAP 21421 P3040 Deteriorated OH UG Equip, Wire, & Cable	63,262

Category	Description	2021 Actuals
Reliability	73042: Pumping Plant Upgrades - Pepco DC (UDLPRM9PD)	17,838
Reliability	73050: Pepco DC: Roof Replacements (UDSPRD8TD)	246,774
Reliability	73052: Pepco DC: Substation Ventilation (UDSPRD8LD)	707,804
Reliability	73053: 12th & Irving Area Plan - Pepco DC (UDLPRM4WA7)	11,604
Reliability	73054: Pepco DC: Add Sub Condition Monitoring Points (UDSPRD9D5)	220,180
Reliability	73055: Benning Area Plan - Pepco DC (UDLPRM4WA2)	1,262,225
Reliability	73179: Planned Rubber/Lead Secondary Replacement (UDLPRM4WA9)	2,726,971
Reliability	73250: Priority Feeder Improvements - Pepco DC (UDLPRM4BF)	3,684,726
Reliability	73332: Recloser Installations (ACR) - Pepco DC (UDLPRM4DJ)	968,721
Reliability	73368: Repl 69kV SCFF UG Supl-Georgetown, F St, 22nd St (UDLPRM5SG)	1,122,341
Reliability	73371: Repl Eng Generators Dist Sub: Pepco DC (UDSPRD8UD)	275,816
Reliability	73463: Retire for Downtown Resupply 34kV and 69kV for DC (UDLPRM4RDR)	32,028
Reliability	73696: NRL- Blue Plains DC Water Redundant 69kV Supply	657,658
Reliability	73698: Sta. C Replace RTU, breakers & Station Service (UDSPRD8SB)	22,907
Reliability	73762: Sub.168 Naval Research-Replace T1 & T2 Transformer (DSPRD8AD11)	1,464,956
Reliability	73781: Substation Improvements and Additions - DC (UDSPRD8AD)	2,230,993
Reliability	73932: 12th St 4kV Conversion - Pepco DC (UDLPRM8BU)	872,010
Reliability	74033: Van Ness SWGR Replacement (Dist Line) - Pepco DC (UDLPRM4WA1)	53,067
Reliability	74082: Waterfront Half-loop Extensions - Pepco DC (UDLPRM4BP1)	3,327,420
Reliability	74350: Pepco DC Fire Protection Distribution (UDSPRD8DC1)	16,057,339
Reliability	74352: FEP Physical Security - Pepco (DC): 22nd Street Sub 124 (UDSPRD	1,865
Reliability	74371: 69019 Potomac River Crossing Emergency Rebuild (UDLPRM4ER1)	3,548
Reliability	74590: DDOT DC South Capitol Street Bridge Conduit (UDLPLM7001)	26,221,589
Reliability	75093: NB Commercial Pepco DC	825,361
Reliability	75200: 17000 DC Billable Damage Claims Dist. Pepco DC CAPITAL 21440 416000	993,743
Reliability	75779:PEPCO DC DIST Benning T19 Replacement	5,984
Reliability	75782: PEPCO DC DIST Benning T18 Replacement	10,475
Reliability	77041: PEP DC P30/40 Network Transf & Protector Replace	9,313,305
Reliability	77201: PEP DC DIST OH PLN CAP P3040 Replace	194,377
Reliability	77204: PEP DC DIST UG PLN CAP P3040 Replace	(302,686)
Reliability	77475: PEP DC 69KV EMR CAP 21421 P1020 Cable Replace	284,201
Reliability	77613: Pepco DC North Capitol 4KV Conv. Supply Line Removal	18,914
Reliability	79302:PEPCO DC Dist Benning 69kV – 4 EPR Feeders	2,041
Reliability	86187: 17000 DC Billable Damage Claims Dist. Pepco DC EXPENSE 21440 416000	66,745
Reliability Total		**204,863,768**
Grand Total		**315,622,855**

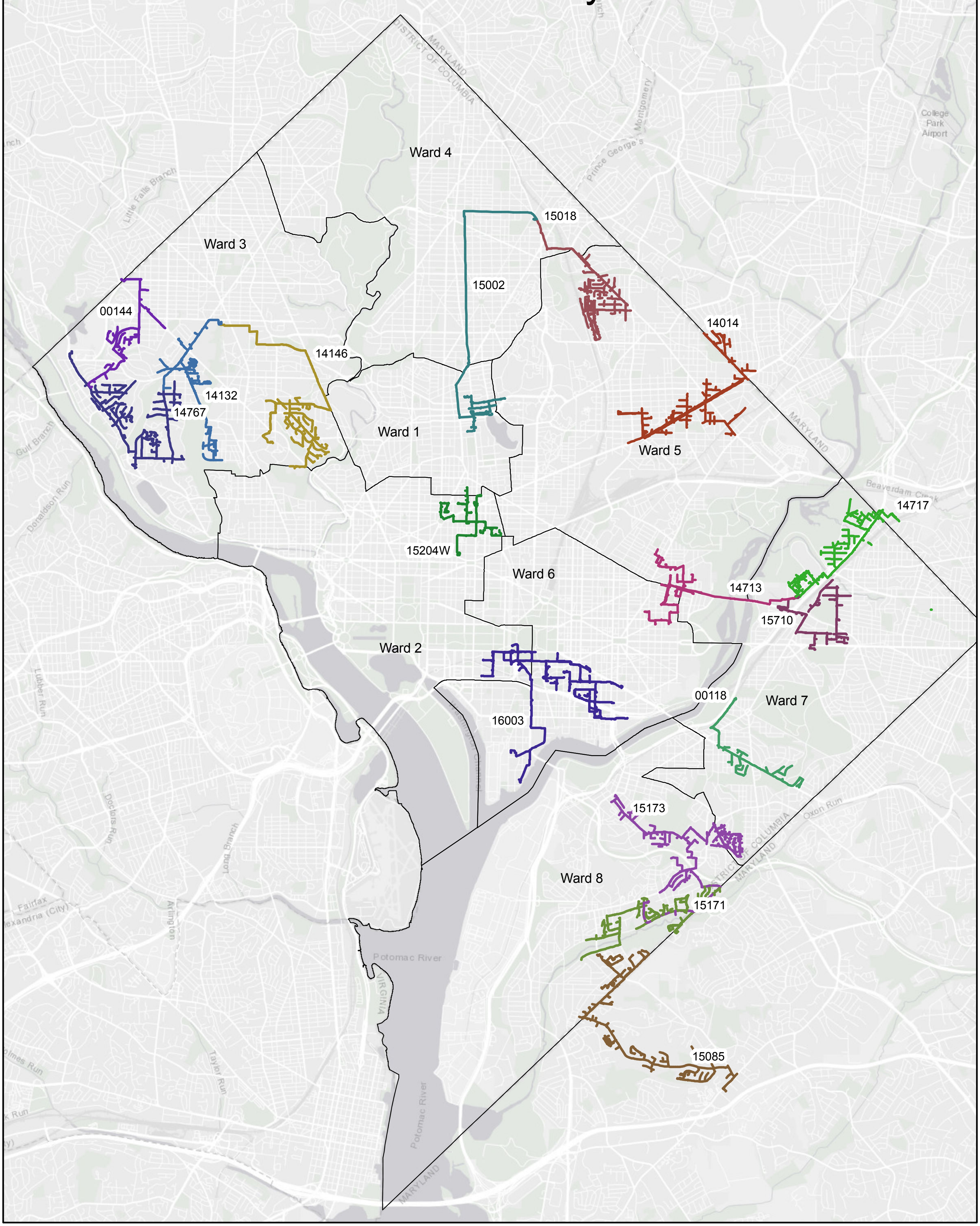
Category	ITN Name	2022 Budget
Customer	63698: PEPCO DC Parks at Walter Reed	3,332,923
Customer	64371: PEPCO DC: Clean River Tunnel proj	882,177
Customer	68911: PEPCO-DC Community Solar Distribution Line/Sub	496,888
Customer	68929: PEPCO-DC Community Solar Transmission Line or Sub	1,398
Customer	68933: PEPCO-DC large Customer interconnnections Distribution Line/Sub	369,023
Customer	68934: PEPCO-DC large Customer interconnections transmission Line/Sub	3,092
Customer	71214: DC Highway Relocations (UDLPCH0W)	2,820,711
Customer	71223: DC: Facility Relocations(Non-Highway) (UDLPCS3W)	199,119
Customer	71225: PEPCO DC New Load, Servs & St Lights, Non-Network (UDLPCS1W	843,250
Customer	72355: Meter Equipment DC (DLPCMR2DXX)	2,042,771
Customer	72359: Meter Install DC (UDLPCMR2DX)	1,712,917
Customer	75092: NB Residential Pepco DC	19,363,773
Customer	75093: NB Commercial Pepco DC	24,772,425
Customer	75095: PEPCO DC NB Network Commercial	17,395,183
Customer	75450: PEPCO DC Hill East, DC General	6,619
Customer	76382: PEPCO DC Streetcar Project Transmission	2,580,451
Customer Total		**76,822,720**
Load	62900: Pepco DC Alabama Ave. Sub 136 Feeder 15166 Battery Substation	2,954,588
Load	62935: Pepco DC Alabama Ave. Sub 136 Feeder 15166 Battery Distribution	126,475
Load	64195: Pepco DC Champlain Rebuild - 13 kV Champlain Load Transfers	23,195,328
Load	65194: Harvard Rebuild - 13 kV Harvard Re-Load Pepco DC	8,531,752
Load	66729: Pepco DC Northeast Sub. 212 East Network Group Push Pipe to Union Market	584,926
Load	68678: L. St Rebuild Distribution Work Pepco DC	287,138
Load	68972: PEPCO DC Georgetown National Mall NWA	81,712
Load	70096: 13kV Distribution Cutovers "F" St to "L" St DC (UDLPLM7W27)	4,161,956
Load	70251: 69kV Lines NRL Sub 168 to Blue Plains Sub 83 DC (UDLPRM8BB)	325,567
Load	70433: Alabama Ave Sub 136: Extend 7 Fdrs to Retire Anacostia (UDLPLWF1)	760,515
Load	70439: Anacostia: Convert 4 to 13kv Dist Line (UDLPLWF3)	248,361
Load	71411: Dist Feeder Load Relief - DC (UDLPLM7W)	1,526,262
Load	71630: F St Sub Rebuild (69kV) (UDSPLM718A)	1,997,722
Load	72004: Install 4th 230/69kV 224MVA transformer #12 at Benning (UDSPLM7	22,191
Load	72137: L St Sub Capacity Expansion Work (UDSPLM722A)	6,353,230
Load	72525: Mt Vernon Sq Sub: Construct 230/13kv Sub (UDSPLMV3)	20,150,532
Load	72527: Mt Vernon Sq Sub: Extend 3 Distribution Fdrs - Relieve S052 (UD	2,949,045
Load	72529: Mt Vernon Sq Sub: Extend LVAC (UDLPLMV1)	3,384,538
Load	72530: Mt Vernon Sq Sub: Extend Second LVAC - Transfer 20 MVA (UDLPLNJ1)	146,420
Load	73787: Substation Retirements-DC. (UDSPRD8RN)	535,912
Load	73839: Takoma to Sligo 69kV Line: Install Three 69kV Feeders (UDLPLM72	584,616
Load	73902: Transformer Load Management (TLM) Pep - DC (UDLPLM7W21)	852,087
Load	73918: Trinidad Sub 106 - Retire (UDSPRD8RO)	542,304
Load	74085: Waterfront Sub - Install 5th Transformer (UDSPLM7WF3)	11
Load	74087: Waterfront Sub-Extend Fdrs: Transfer HV, Metro, Distrib frm Sta	154,542
Load	77270: Pepco DC - Land for Ward 8 Substation	339,447
Load	77272: Pepco DC New Ward 8 Substation	228,758
Load Total		**81,025,935**
Reliability	62161: New Jersey Ave Reliability Initiative - Pepco DC	2,869,320
Reliability	62214: Pepco DC Plug Third Biennial Installs	830,188
Reliability	62219: Pepco DC DC PLUG FEEDER 14900	1,131,451
Reliability	62221: Pepco DC PLUG FEEDER 00368	2,838,197
Reliability	62222: Pepco DC DC PLUG FEEDER 14758	4,805,057
Reliability	62223: Pepco DC DC PLUG FEEDER 14007	2,819,528
Reliability	62224: Pepco DC DC PLUG FEEDER 15009	15,029
Reliability	63056: Pepco DC CM Non-emergency Dist Sub Cap	84,331
Reliability	63429: Pepco DC - ITE Air Circuit Breakers	384,062
Reliability	63507:PEPCO(DC) FEP Physical Security-Florida Ave	500,848
Reliability	63509:PEPCO(DC):FEP- Physical Security-Georgetown	555,641
Reliability	63510:PEPCO(DC): FEP- Physical Security-Northeast	609,687
Reliability	63511: PEPCO DC Dist FEP Physical Security: Southwest	1,950,736
Reliability	63560: Pepco DC DC Plug Feeder 14900 - Removal	86,553
Reliability	63628 Pepco DC Dist: Substation Infrastructure - DC	682,305
Reliability	63632: Pepco: DC- Storm Water Retention Credit	274,080
Reliability	63643: Pepco DC Dist: Drainage and Driveway Remediation	550,723

Category	ITN Name	2022 Budget
Reliability	63645: Pepco DC - UG SCADA Interrupter Install/Replace	2,138,609
Reliability	63647: Pepco DC - UG SCADA Interrupter Control Install/Replace	974,246
Reliability	63680: Pepco DC Dist: Buzzard 230/34kV Substation	4,892,607
Reliability	63914: Pepco DC - Navy Yard Sub 33: Retire Sub	22,560
Reliability	63926: Double Wood Pole Removals - Pepco DC	1,236,939
Reliability	64120:PEPCO(DC):Dist-Station Service Transformer Replacement Buckets	276,186
Reliability	64355: Pepco DC: Roof Replacements Distribution	495,605
Reliability	64357: Pepco DC: Sub Ventilation Distribution	633,393
Reliability	64365: Pepco DC: Sub Imprv. & add. Distribution	593,107
Reliability	65553: PEPCO DC: DIst- Benning Sub. 41 69kV GIS	12,534,887
Reliability	65555: PEPCO:DC-DIST:22nd Street, Sub. 124.T4	656,627
Reliability	65557 Pepco DC - Dist Benning T12 Install	80,118
Reliability	65582:PEPCO:DC Directional Overcurrent Relays	297,595
Reliability	66111: Pepco DC: Dist Flood Mitigation	275,297
Reliability	67259: PEPCO DC Termination Replacement Program- 69 kV DC	733,186
Reliability	67509: Pepco DC DC PLUG FEEDER 467	268,156
Reliability	67511: Pepco DC DC PLUG FEEDER 14767	2,250,893
Reliability	67513: Pepco DC DC PLUG FEEDER 15001	1,364,097
Reliability	67514: Pepco DC DC PLUG FEEDER 15021	723,118
Reliability	67519: Pepco DC DC PLUG FEEDER 14008	1,775,912
Reliability	67522: Pepco DC DC PLUG FEEDER 14093	2,424,769
Reliability	67523: Pepco DC DC PLUG FEEDER 118	825,885
Reliability	67524: Pepco DC DC PLUG FEEDER 14702	1,529,183
Reliability	67525: Pepco DC DC PLUG FEEDER 15166	1,787,654
Reliability	67526: Pepco DC DC PLUG FEEDER 15171	2,275,393
Reliability	67577: Georgetown 4kV Conversion (North Section) - Pepco DC	3,624,253
Reliability	68160: Disconnect Switch – DC Dist	156,792
Reliability	68165: Circuit Breaker – DC Dist	85,530
Reliability	68426: Pepco VA Dist - Spare Reactor/Transformer Purchase & #4 Install Sta C	195,521
Reliability	68523: PEPCO DC Harvard Spare Transformer	187,329
Reliability	68612: PEPCO DC L St T1 Replacement	74,113
Reliability	68613: PEPCO DC L St T2 Replacement	74,113
Reliability	68614: PEPCO DC L St. T3 Replacement	74,113
Reliability	68615: PEPCO DC L St T4 Replacement	74,113
Reliability	68756: Pepco Dist 22nd St., Switchgear replacement (DC)	359,317
Reliability	68761: Pepco Dist DC Surge Arrester Replacement - DC - Distribution	107,849
Reliability	68798: Pepco Trans DC - Buzzard (138kV), 14B, 11B & 13B, breaker (DC)	727,719
Reliability	68800: Pepco Trans DC Southwest 4B replacement	564,473
Reliability	68801: Pepco Trans - Benning 7 3C GCB	331
Reliability	68855: Tree Wire/Spacer Cable Installation - Pepco DC	197,776
Reliability	68861: Crossarm Replacements - Pepco DC	240,123
Reliability	68920: Unfused Lateral Program Pepco DC	136,721
Reliability	69096: PEPCO DC Florida T4	1,414,423
Reliability	70058: 12th Street Sub: Retire Sub DC (UDSPRD8RK)	200,004
Reliability	70060: 13.8kV Swgr Replacement - Pepco DC (UDSPRD8KD)	2,352,295
Reliability	70187: 4kv Substation Automation - DC (UDSPRD8H)	638,437
Reliability	70442: Animal Guards in Dist Subs: Pepco DC (UDSPRD8JD)	302,605
Reliability	70602: Batt & Chgr Replacement Distri. Subs. - DC (UDSPRD8ED)	210,956
Reliability	70897: URD Cable Pepco DC (UDLPRM4BCX)	4,129,470
Reliability	71012: Champlain - New 69kV Sub (DSPRD8AD17)	970,249
Reliability	71015: Champlain to L Street 34kV (UDLPRM4WA8)	16,883,604
Reliability	71119: Comprehensive Feeder Improvements - Pepco DC (UDLPRM63D)	2,608,759
Reliability	71222: DC- Ground Test Device Installation Program (UDSPRD8GTD)	102,140
Reliability	71417: Dist Sub Bushing Replacement: Pepco DC (UDSPRD8FD)	28,647
Reliability	71418: Dist Sub Bushing Replacement: Pepco DC (UDSPRD8FV)	35,554
Reliability	71426: Pepco DC CM Distribution Substation Capital	1,140,376
Reliability	71440: Distribution DC - HPFF System Cathodic Protection Program (UDLP	733,703
Reliability	71448: PEP DC DIST PLN SPL 21421 P3040 Prog Pole Repair & Replace	995,832
Reliability	71605: PEP DC DIST OH UG EMR SPL 21421 P10/P20 Repair and Replace	1,540,598
Reliability	71612: PEP DC DIST UG EMR SPL 21421 P10/P20 Repair and Replace	7,976,840
Reliability	71615: PEP DC DIST UG EMR CAP 21421 P1020 Replace Network Transformer	1,013,534
Reliability	71631: F St Sub Rebuild (UDSPLM717A)	1,315,313

Category	ITN Name	2022 Budget
Reliability	71640: FEP Physical Security - Pepco (DC): Buzzard Pt Sub B (TSPRD8VM01)	670,430
Reliability	71721: Ft Lincoln Reliability Initiative - Pepco DC (UDLPRM4LRD)	1,598,603
Reliability	71731: G St 4kV Conversion (UDLPRGST1)	12,362,182
Reliability	71864: Harvard Rebuild - Distribution Upgrade to 230/13kV, 210 MVA (UDSPRD8AD2)	13,132,479
Reliability	71987: Improve/Add Substation Enclosures (UDSPRD8D2)	2
Reliability	72251: MDO / CEMI Remediation - Pepco DC (UDLPRM4BQX)	513,696
Reliability	72268: Misc. Reliability Improvements - Pepco DC (UDLPRM4BA)	3,514,865
Reliability	72733: Navy Yard: Transfer to Waterfront Sub. 223 (UDLPLWF7)	6
Reliability	72746: Pepco DC - Network RMS - Line	6,090,008
Reliability	72811: North Capitol Sub: Retire Sub (UDSPRD8RJ)	171,917
Reliability	72978: PILC REPLACEMENT PLANNED (UDLPRPLIC)	6,887,050
Reliability	72997: PEP DC DIST PLN CAP 21421 P3040 Pad Transformer Replace (UDLPRM4BO)	396,458
Reliability	73032: PEP DC DIST PLN CAP 21421 P3040 Deteriorated OH UG Equip, Wire, & Cable	69,897
Reliability	73039: Pepco DC - Deteriorated Cap Bank Replacement (UDLPRM4S1)	1,276,193
Reliability	73042: Pumping Plant Upgrades - Pepco DC (UDLPRM9PD)	2,124,498
Reliability	73052: Pepco DC: Substation Ventilation (UDSPRD8LD)	397,944
Reliability	73179: Planned Rubber/Lead Secondary Replacement (UDLPRM4WA9)	7,641,060
Reliability	73250: Priority Feeder Improvements - Pepco DC (UDLPRM4BF)	2,285,462
Reliability	73332: Recloser Installations (ACR) - Pepco DC (UDLPRM4DJ)	322,232
Reliability	73348: Pepco DC - Regulator Control Install/Replace	71,479
Reliability	73368: Repl 69kV SCFF UG Supl-Georgetown, F St, 22nd St (UDLPRM5SG)	4,531,140
Reliability	73371: Repl Eng Generators Dist Sub: Pepco DC (UDSPRD8UD)	459,386
Reliability	73456: Retire Fort Carroll Sub. 130 (UDSPRD8SD3)	22,840
Reliability	73463: Retire for Downtown Resupply 34kV and 69kV for DC (UDLPRM4RDR)	16,218
Reliability	73651: TripSaver Installations - Pepco DC (UDLPRM4WJ)	83
Reliability	73696: NRL- Blue Plains DC Water Redundant 69kV Supply	116,699
Reliability	73698: Sta. C Replace RTU, breakers & Station Service (UDSPRD8SB)	56,425
Reliability	73932: 12th St 4kV Conversion - Pepco DC (UDLPRM8BU)	2,166,287
Reliability	74033: Van Ness SWGR Replacement (Dist Line) - Pepco DC (UDLPRM4WA1)	2,509,863
Reliability	74350: Pepco DC Fire Protection Distribution (UDSPRD8DC1)	1,850,786
Reliability	74590: DDOT DC South Capitol Street Bridge Conduit (UDLPLM7001)	5,751,994
Reliability	75391: Pepco DC Distribution Smart Fault Sensors	504,474
Reliability	75779:PEPCO DC DIST Benning T19 Replacement	186,915
Reliability	75782: PEPCO DC DIST Benning T18 Replacement	186,608
Reliability	77041: PEP DC P30/40 Network Transf & Protector Replace	5,122,764
Reliability	77049: Pepco DC DIST Porcelain Cutout Replacements	402,073
Reliability	77204: PEP DC DIST UG PLN CAP P3040 Replace	12,992
Reliability	77329: Pepco DC Fuse Box Replacements	1,103,769
Reliability	77475: PEP DC 69KV EMR CAP 21421 P1020 Cable Replace	1,636,393
Reliability	78623:Pepco DC Benning Sub 41 69kV Pipe Type Terminations Replacement	200,754
Reliability	86187: 17000 DC Billable Damage Claims Dist. Pepco DC EXPENSE 21440 416000	320
Reliability Total		**199,892,527**
Grand Total		**357,741,182**

ATTACHMENT C

District Of Columbia Priority Feeders 2022



ATTACHMENT D

Pepco 2021 Safety Merger Commitments

The following attachments reflect the Company's compliance with the merger commitment described in Order No. 18148 Attachment B at P 60, Safety:[1]

Exelon is committed to having all its utilities achieve and maintain first quartile performance in safety. Consistent therewith, Pepco will file annual reports on its safety performance and safety initiatives with the Commission as part of its Annual Consolidated Report and will also present this information to the PIWG. Pepco's reporting will include a report by Exelon on its existing safety and cybersecurity policies.

- Exelon Corporate Safety Policy
- Exelon Safety Update
- Pepco Transmission and Distribution Safety Incident rate, Including Edison Electric Institute (EEI) 2012-2021 Rankings
- Exelon Cyber-Security Statement

[1] In the Matter of the Joint Application of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC and New Special Purpose Entity, LLC for Authorization and Approval of Proposed Merger Transaction, Formal Case No. 1119, Order No. 18148, March 23, 2016, Attachment B at P 60

Exelon®

Dedicated to Safety

Corporate Policy: Safety

Policy Statement

Exelon Corporation will operate all aspects of its businesses in a manner that protects the safety and health of its employees, contractors, customers and the general public. We will foster a safety culture in which everyone believes and demonstrates that accidents, injuries and occupational illnesses are preventable and all employees understand their responsibility for maintaining a safe and healthful workplace. Further, each employee recognizes and accepts his/her right and obligation to question, stop and correct any unsafe conditions or behaviors.

Policy Intent

Exelon shall:

- Create a safety culture to achieve an accident, injury and occupational illness-free workplace;
- Comply with all applicable health and safety laws and regulations, industry and internal company standards, at a minimum;
- Integrate safety risk analysis into business planning, engineering design, and operating decisions, to develop and implement effective hazard control measures and safety performance improvement, engineering out hazards where feasible;
- Promote the value of employee empowerment in the prevention of injuries and illnesses, and maintain an open and honest dialogue with our employees on health and safety issues and performance; and
- Continually improve safety performance to become the safest electric and gas utility in the United States.

Implementation

This policy shall be implemented by establishing and maintaining:

- A corporate-wide safety program that will be integral to the Exelon Management Model based on external standards and best practices;
- Safety councils and committees, including the Exelon Operations Council, to encourage management sponsorship and employee involvement in injury and illness prevention;
- Annual objectives and targets for measuring and continually improving safety performance and recognition of top performing departments and individuals for safety is routine;
- An independent, corporate audit program and business unit self-assessments;
- Safety and health hazard evaluation programs including documented methods for controlling known safety and health hazards;
- Communications and Corrective Action Programs that facilitate the identification and resolution of safety related concerns;
- Training programs for employees and education programs for contractors on safety expectations and responsibilities;
- Employee and management personal accountability for following health and safety fundamentals and procedures; and
- Promote electricity and gas hazard awareness and accident prevention through public safety programs.

To anonymously report any safety concerns, employees or others working on behalf of Exelon can call the Exelon Helpline at 800.233.8442.

Exelon Safety Update

Exelon is committed to having all its utilities achieve and maintain first quartile performance in safety. As of the end of 2021, Pepco had a 17% reduction in OSHA recordable injuries, 36% reduction in Days Away Restricted Time Cases and the best safety performance post-merger.

Safety emphasis in 2021:

- Focused observation initiative implemented by leadership to ensure employee adherence to required COVID-19 PPE behaviors within field teams and crews.
- Alignment with other Exelon Utilities on screening strategy for employees working in high-density, critical infrastructure workspaces
- Developed shift work strategies that promote less employee interaction while maintaining necessary support levels.
- Participated with the other Exelon Utilities to continue to align safety best practices that were researched and benchmarked against Edison Electric Institute and American Gas Association utilities.
- Sustained Performance Assessment Programs by sharing incidents, lessons learned, and best practices across Exelon utilities through common communication channels.
- Continued the Ergonomic Coach program to provide Triage Support as needed in PHI overhead line school and field crews.
- PHI expanded driver training technologies and continues to leverage driver monitoring system.

Exelon has an established management model that governs key operational areas throughout the enterprise, including the safety function. The corporate Safety Policy, applicable to all Exelon operations, including Pepco Holdings and Pepco, establishes the framework for defining Exelon's industrial safety culture and sets expectations for continuously improving safety performance. It clearly sets expectations for each employee to take personal responsibility for his or her safety.

Underpinning the Safety Policy is the Corporate Industrial Safety Program, which delineates Exelon's requirements for the management of safety for the enterprise and which is based on recognized industry standards including BSI-OHSAS 18001, OSHA Voluntary Protection Program and ANSI Z10.

Detailed procedures (*e.g.*, Hazards Assessments) are maintained to affect the Safety Policy and programs, and they are routinely evaluated to ensure that best practices are utilized.

To ensure alignment and to facilitate learning, a Corporate Safety Council comprised of safety officers from each business addresses strategic safety issues, and a Corporate Safety Peer Group comprised of safety professionals and managers focuses on operational experience and use of best practices. Pepco is represented on both functions. In addition, the Exelon Utilities have a Safety Peer Group, with representation from each utility, who concentrate on improving safety performance in their specific operations.

As part of the safety performance oversight function, Exelon's enterprise-wide safety performance is reviewed at Quarterly Management Meetings (QMM) and a comprehensive review of the effectiveness of the safety policy and program is reviewed with the senior leadership team annually.

Further, the Exelon Environmental, Health & Safety Audit Program conducts independent assessments of the effectiveness of Exelon's compliance programs at a select number of locations annually. The results of the audits are reported to senior leadership, who have responsibility for affecting any corrective actions required.

Pepco Transmission and Distribution Incident Rate, Including Edison Electric Institute (EEI) Rankings

Year	Incident Rate	EEI Quartile Ranking
2012	1.89	Third Quartile
2013	1.79	Third Quartile
2014	1.52	Third Quartile
2015	1.68	Fourth Quartile
2016	2.16	Fourth Quartile
2017	1.51	Third Quartile
2018	1.20	Third Quartile
2019	1.05	Second Quartile
2020	0.94	Second Quartile
2021	0.82	First Quartile

Exelon Cyber-Security Statement

As one of the nation’s major critical infrastructure providers, Exelon recognizes that the safety, reliability and security of our systems and facilities are a top priority. The company utilizes a risk- based, intelligence-driven security approach to implementing a comprehensive set of cyber and physical security controls, in line with the National Institute of Standards and Technology’s (NIST) Cybersecurity Framework to effectively identify, protect, detect, respond to and recover from a spectrum of threats, mitigating the likelihood of successful attacks and their potential impacts. In addition, Exelon has implemented the mandatory regulatory requirements defined within the NERC CIP and NRC standards, ensuring further protection of cyber assets critical to the safe and reliable operation of the BES and Nuclear from cyber threats. Regulated critical cyber assets are isolated within restricted networks, segmented from the enterprise IT environment and the Internet, continuously monitored for malicious activity, and routinely evaluated for vulnerabilities.

ATTACHMENT E

pepco[SM]
AN EXELON COMPANY

Bill Sullivan
Vice President
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Services

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April 15, 2022

Ms. Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 G Street, N.W.
Suite 800
Washington, DC 20005

Re: <u>Pepco-DC Vegetation Management</u>

Dear Ms. Westbrook-Sedgwick:

In accordance with Order No. 19119, and Pepco's December 20, 2017, letter electing to adopt performance-based vegetation management reporting, I, Bill Sullivan, hereby verify that Pepco has in place a comprehensive vegetation management plan, which is fully implemented and was in place in 2021, and that its practices during 2021 conformed to the plan.

Sincerely,

Will Sull

Bill Sullivan
Vice President
Technical Services

ATTACHMENT F

I. Downtown Resupply Detailed plan and Scope of the Project:

The Downtown Resupply project will replace aging 34 kV and 69 kV supply feeders to the L Street, F Street, and Georgetown Substations. This work along with upgrades to the F Street Substation and extension of new 13 kV feeders will accommodate load transfers from I Street Substation as well as increasing sub-transmission supply capacity and providing reliability benefits to the District of Columbia by replacing aging infrastructure to reduce the number outages.

II. Downtown Resupply description of the reliability and resiliency benefits including the effects on global climate change and the District's public climate commitments:

As climate change accelerates, Pepco's electric system will face higher demands from the more frequent extreme weather events that could leave customers exposed to more frequent outages. As a company with significant assets and critical energy infrastructure in the District of Columbia and as a major employer, Pepco has a responsibility to create a reliable, resilient grid.

Pepco has taken several initiatives to enhance reliability and resilience, among them is replacing aging cables with new, more reliable, and environmentally friendly cable. In the year 2013, conducted a system-wide cable study to determine the age and condition of the self-contained cables in the Pepco Holdings service territory, including the District of Columbia. The result of the study showed that the existing cables to Champlain, "F" Street, "L" Street and Georgetown Substations need replacement because they are considered at-risk cables in the District.[1] The main drivers for the replacement of self-contained cables are system age, environmental concerns, capacity limitations, maintainability, material availability, and limited supply of skilled labor to work on the current cable.[2] For example, the existing supply lines from Potomac River Station C to Georgetown substation require monitoring of the pressure and hydraulic systems. Based on non-invasive inspections and testing of the alarm's gauges, Pepco personnel must regularly add fluid to those supply lines to maintain adequate pressure levels to keep supply lines in operation. The Downtown Resupply project will use dual-circuit duct banks with XLPE insulated cables. XLPE cables have significant operational and environmental benefits over previously used SCFF and HPPT cables, including lower capacitance, higher load-carrying capability, no need for insulating fluid, and lower maintenance costs.

In addition to the concern of aging infrastructure requiring the replacement of these cables, Downtown Resupply will continue to mitigate instances of single points of failure on our system. By having cables contained in a single point, the substation supplies are susceptible to damage, increasing the risk of losing power to the customers connected to a substation in which all the cables are in the same duct bank. Downtown Resupply mitigates single points of failure by dividing the feeders into two duct banks to supply various substations.

Moreover, the supplies to certain of the substations currently traverse the Potomac River. Replacing these cables as currently configured would require directional boring underneath the river, which would cause constructability and extensive environmental and permitting challenges. Instead, the Downtown Resupply project will avoid the environmental challenges and reduce the linear footage of duct banks required by using higher voltage cables to connect several of the substations, resulting in additional capacity.

The Downtown Resupply Plan removes the need for river crossing, retires aging infrastructure and increases capacity to mitigate the impacts of climate change on our electric grid.

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[1] Assessing, Maintaining & Replacing Fluid Filled Cable Systems at PEPCO
Source: (http://docplayer.net/18903366-Assessing-maintaining-replacing-fluid-filled-cable-systems-at-pepco.html)
[2] FC1144 Capital Grid OPC DR 5-1 Confidential Attachment

III. Downtown Resupply project schedule, current status, a budget, and any cost variances.

Updated Construction Schedule:

- L Street Substation: 2023-2025
- F Street Substation: 2025-2028
- I Street Substation: 2029-2030
- 69kV Supplies: 2023-2032
- 34kV Supplies: 2023-2025
- 13kV Supplies: 2019-2029

Current Status:

Pepco is retiring the 34 kV Transformer sources at the L Street Substation and replacing them with 69kV transformer sources. As a result of this change, some of the construction dates have changed.

Cost Estimate (provided in Formal Case No. 1144):

There are no changes to the cost estimate for the Downtown Resupply Project cost estimates as of April 15, 2022.

Items	Estimate Net (Lifecycle) ($)
13kV Distribution Cutovers "F" St to "L" St (UDLPLM7W27)	39,849,304
13kV Distribution Cutovers from "I" St to "F" St & "L" St (UDLPLM7W28)	32,434,952
Champlain to L Street 34kV (UDLPRM4WA8)	102,319,736
F St Sub Rebuild (69kV) (UDSPLM718A)	50,372,188
F St Sub Rebuild (UDSPLM717A)	33,581,458
L St Sub Capacity Expansion Work (UDSPLM722A)	4,011,558
Repl 69kV Self-Containd UG Supl-Georgetown,"F" St, 22nd St Subs (UDLPRM5SG)	177,223,136
Retire "I" St Sub (UDSPRD27RD)	2,081,496
Retirements for Downtown Resupply 34kV and 69kV for DC (UDLPRM4RDR)	35,522,470
Retirements for Downtown Resupply 34kV and 69kV for MD (UDLPRM4DRM)	1,309,199
Retirements for Downtown Resupply 34kV and 69kV for VA (UDLPRM4DRV)	13,322,712
Telecom - 22nd Street Sub (UDFPO22SS)	500,000
Telecom - Fiber for 34-69kV Resupply Champlain, L Street, F Street (UDFPOCL01)	500,000
Telecom - Georgetown Sub (UDFPOGS01)	500,000
Telecom - L Street Sub (UDFPOLS01)	500,000
Downtown Resupply Total	**494,028,210**

Accumulated Actual Costs through February 2022:

ITN	Major Projects	LTD thru Feb 2022 (minus AFUDC)
71015	Champlain to L Street 34kV	$ 3,197,486
71630	F St Sub Rebuild (69kV)	$ 866,090
71631	F St Sub Rebuild	$ 1,186,552
72137	L St Sub Capacity Expansion	$ 2,799,695
73368	Champlain to F St; Champlain Bypass; F St to Georgetown	$ 5,139,157
70096	13kV Distribution Cutovers "F" St to "L" St	$ 12,682,331
70097	13kV Distribution Cutovers from "I" St to "F" St & "L" St	$ -
Other	Other Projects (Retirement of I St and Telecom etc.)	$ 146,479
	Total	**$ 26,017,790**

ATTACHMENT G

Sub #	Location	DESIGNATION	General Condition	Date of Last PM	Outstanding Issues to be Remediated
126	12TH STREET	3 T	Increasing p.f. and high moisture in oil	4/25/2014	Monitoring until retirement
197	I Street	2 T	Major refurbishment planned - new bushings, pumps, gaskets and add online monitoring - to be completed Q1 2022	1/10/2015	Bushings, gaskets and pumps require replacement
41	BENNING	8 T	Slight increase in p.f., minor oil leaks; this type of unit is sucetible to through fault. Retire unit after addition/installation of 12T (currently in progress)	3/22/2016	N/A
42	Buzzard Point	13 T	Bushings and LTC motor replaced in 2018; acidic oil- will monitor until retirement	5/3/2016	Monitoring until retirement
2	O STREET	4 T	High mainteance costs - LTC maintenance on 2Y cycle; Critical station/load; 2025 targeted replacement	4/2/2017	N/A
42	Buzzard Point	4T	High maintenance costs; Unit near end of life	8/12/2017	Monitoring until retirement
10	FLORIDA AVE	4 T	Unit had bushings replaced and LTC overhauled in 2019; 2022 targeted replacement	9/11/2017	N/A
42	Buzzard Point	7T	Multiple cooling issues resolved with new pumps and fan motors	10/1/2017	Monitoring until retirement
42	Buzzard Point	3 T	Increasing p.f. in overall and bushings; unit operates at higher than normal temp; Load can be sustained without unit	11/29/2017	Monitoring until retirement
40	NORTH CAPITOL	3 T Retire Sub	Oil continues to be high in moisture and p.f. test results show slight increase. Station to be retired.	5/18/2018	N/A
42	Buzzard Point	12 T	Elavated moisture in oil; leakng barier board	6/21/2018	Monitoring until retirement
117	NINTH STREET	3 T	LTC is inoperable (fixed tap); multiple oil leaks and cooling issues; replacement parts are difficult to find	11/21/2018	N/A
52	TENTH STREET	3 T	LTC type has known issues; critical downtown station	12/3/2018	N/A
40	NORTH CAPITOL	4 T Retire Sub	Oil continues to be high in moisture and is also very acidic. Station to be retired.	11/1/2019	N/A
40	NORTH CAPITOL	1 T Retire Sub	Oil continues to be high in moisture and is also very acidic. Station to be retired.	10/14/2020	N/A
197	I Street	4 T	Major refurbishment completed - new bushings, pumps, gaskets and add online monitoring	5/1/2021	N/A
197	I Street	1 T	Major refurbishment completed - new bushings, pumps, gaskets and add online monitoring	5/12/2021	N/A
2	O STREET	2 T	High mainteance costs - LTC maintenance on 2Y cycle; Critical station/load; 2024 targeted replacement	8/13/2021	N/A

CERTIFICATE OF SERVICE

I hereby certify that a copy of Potomac Electric Power Company's 2022 Annual Consolidated Report was served this April 15, 2022 on all parties in Docket PEPACR and Formal Case No. 1119 by electronic mail.

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/s/ *Dennis P. Jamouneau*
Dennis P. Jamouneau

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO DCG DATA REQUEST NO. 5

QUESTION NO. 2
Provide all workpapers in Excel format with the formulae intact for the Company's 10-year Forecasted District of Columbia Loads (see Exhibit PEPCO (H)-1, Table 2: Forecasted District of Columbia Load by Ward, pages 19 -20).

RESPONSE:

Please see the Company's attachment labeled FC 1176 DCG DR 5-2 Attachment.

SPONSOR: Jaclyn Cantler

Forecasted District of Columbia Loads

Loads in Mega-Volt-Amperes (MVA)

Ward	Sub. Number	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Ward 1	**Sub. Number**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
	10	135.2	116.8	121.8	125.9	128.7	129.7	130.9	131.3	132.7	133.7
	13	4.9	35.6	87.0	87.1	87.9	88.3	88.1	88.2	88.0	88.2
	25	50.0	50.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Subtotal - Ward 1	**190.1**	**202.7**	**208.8**	**213.0**	**216.6**	**218.0**	**219.0**	**219.5**	**220.7**	**221.9**
											Avg. Trend = 1.73%
Ward 2	**Sub. Number**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
	2	144.2	144.9	145.4	145.7	145.8	145.8	145.8	145.8	145.8	145.8
	12	100.0	96.4	111.2	110.4	109.9	110.1	110.2	110.2	109.9	110.2
	18	111.4	116.5	118.6	123.5	126.8	129.8	130.0	129.9	130.1	130.0
	21	29.2	29.2	29.2	29.2	29.2	29.1	59.7	59.7	59.6	59.7
	52	142.3	127.8	127.9	127.8	127.5	127.8	127.7	127.6	127.7	127.8
	74	29.0	29.3	29.2	28.9	29.0	28.7	0.0	0.0	0.0	0.0
	124	80.2	80.5	80.6	80.9	80.9	80.8	80.9	80.9	81.2	80.9
	197	95.0	95.2	95.2	95.1	95.2	95.3	95.2	95.2	95.2	95.2
	Subtotal - Ward 2	**731.3**	**719.8**	**737.3**	**741.5**	**744.3**	**747.4**	**749.5**	**749.3**	**749.5**	**749.6**
											Avg. Trend = 0.27%
Ward 3	**Sub. Number**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
	38	34.9	35.9	36.2	36.3	36.3	36.3	36.3	36.3	36.3	36.3
	77	61.3	62.6	62.6	62.6	62.6	62.6	62.6	62.6	62.6	62.6
	93 (4.33kV)	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
	129	140.5	150.6	153.9	154.1	154.2	154.3	154.3	154.3	154.3	154.3
	145 (4.33kV)	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
	146 (4.33kV)	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
	Subtotal - Ward 3	**247.8**	**260.2**	**263.8**	**264.1**	**264.2**	**264.3**	**264.3**	**264.3**	**264.3**	**264.3**
											Avg. Trend = 0.72%
Ward 4	**Sub. Number**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
	27	33.4	33.8	33.8	33.8	33.7	33.6	33.7	33.7	33.8	33.7
	190	106.8	99.6	104.5	107.6	108.6	108.9	109.3	109.7	110.0	110.0
	Subtotal - Ward 4	**140.2**	**133.4**	**138.3**	**141.4**	**142.3**	**142.5**	**143.0**	**143.4**	**143.8**	**143.7**
											Avg. Trend = 0.27%

Forecasted District of Columbia Loads

Loads in Mega-Volt-Amperes (MVA)

	Sub. Number	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Ward 5	**Sub. Number**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
	133	101.5	104.5	105.8	102.0	106.8	113.3	113.3	113.3	113.3	121.4
	212	124.2	119.3	127.7	144.3	144.3	144.3	144.3	144.3	144.3	144.3
	Subtotal - Ward 5	**225.7**	**223.8**	**233.5**	**246.3**	**251.1**	**257.6**	**257.6**	**257.6**	**257.6**	**265.7**
										Avg. Trend =	1.83%
Ward 6	**Sub. Number**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
	Sta. 'B'	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	117	97.7	97.9	97.6	97.7	97.6	97.5	97.6	97.6	97.5	97.8
	161	101.6	103.9	98.4	99.8	84.3	84.4	68.2	68.1	68.2	68.2
	223	164.5	175.7	181.6	181.0	181.0	179.1	179.6	180.0	180.1	180.4
	230	0.0	38.7	46.4	46.4	64.4	64.4	84.4	84.4	84.4	84.4
	Subtotal - Ward 6	**363.8**	**416.2**	**424.0**	**424.9**	**427.3**	**425.4**	**429.8**	**430.1**	**430.2**	**430.8**
										Avg. Trend =	1.90%
Ward 7	**Sub. Number**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
	7	165.1	167.4	172.3	175.5	176.1	177.5	178.3	179.5	180.1	181.4
	Subtotal - Ward 7	**165.1**	**167.4**	**172.3**	**175.5**	**176.1**	**177.5**	**178.3**	**179.5**	**180.1**	**181.4**
										Avg. Trend =	1.05%
Ward 8	**Sub. Number**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
	8 (4.33 kV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	8 (13.8 kV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	136	120.4	126.2	134.3	139.9	141.5	141.4	142.5	142.2	142.1	141.8
	168	23.1	23.1	23.1	25.9	28.7	31.5	31.4	31.5	31.4	31.4
	Subtotal - Ward 8	**143.5**	**149.3**	**157.4**	**165.8**	**170.2**	**172.9**	**173.9**	**173.7**	**173.5**	**173.2**
										Avg. Trend =	2.11%
	DC TOTAL	**2207.5**	**2272.8**	**2335.4**	**2372.5**	**2392.1**	**2405.6**	**2415.4**	**2417.4**	**2419.7**	**2430.6**
										Avg. Trend =	1.08%

Notes: All substations supply 13.8kV of primary power unless otherwise noted.
Totals shown are the sum of undiversified peak loads and are not meant to be used as official Pepco system peak loads.
Totals shown include planned transfers, DERs, NWAs and known new business loads.

B.L. Clark
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _______ (I) – 2

DC CONSTRUCTION REPORT: PEPCO (I)-2

PEPCO(I)-2

DC Construction Report

No:	85
ITN Name:	74084: Waterfront Sub - Install 4th Transformer (UDSPLM7WF4)
	UDSPLM7WF4
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$1,034.82
2019_Budget_(000s):	$1,890.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	3/1/2018
Est. ISD	12/30/2019
Finish:	9/1/2022
Scope of Work:	Install 4th Transformer at Waterfront Sub. 223 and 18 MVAr of bus capacitors.
Justification:	Current firm capacity is 144MVA, whereas projected load by Summer 2019 is 147MVA. Unanticipated load on Waterfront sub. 223 is projected to cause 2% firm capacity overload. These loads include the radial 13.8kV feeders from Buzzard Point Sta. B used to energize Waterfront and the load that would remain on Waterfront Sub. 223 due to delay in project to convert "G" St. 4kV feeders to Southwest Sub. 18 13kV.
Alternative:	None
Reimbursable:	No
Related Circuit:	-
Related Substation:	WATERFRONT (223)

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 4

QUESTION NO. 73
Referencing ITN 74120 (Pepco H-2 Page 172 of 216) White Flint New Substation 69/13kV:

a. This project is entirely outside of the District. Please explain why this project is included in this rate case in the District.

b. If Pepco asserts this project should remain in this case:

    i. All presentations, minutes, memos, and emails regarding the Project Scoping Meeting.

    ii. All presentations, minutes, memos, and emails regarding the Asset Investment review.

    iii. All presentations, minutes, memos, and emails regarding the Project Concurrence.

    iv. Provide the current ten-year-forecast for all feeders and substations affected by this proposed project.

c. Provide all transmission costs to be allocated to the District.

d. Provide all distribution costs to be allocated to the District.

e. Provide all substation costs to be allocated to the District.

f. Provide peak load served in the District from the facilities proposed by this project.

RESPONSE:

a. This project consists of sub transmission and distribution components as described in H-2 Exhibit, page 172 of 216. The cost of the sub transmission components is recoverable in this rate case using the Average and Excess Non-coincident Peak Demand (AED-NCP) allocation method, as referenced at 4-74(a). The cost of the distribution components is not recoverable in this rate case.

   Currently, the Company does not have a cost breakdown to illustrate how the project's costs are being allocated between the sub transmission and distribution components. The Company will perform this breakdown and will file it as a supplemental response to this DR.

b -f. Refer to the Company's response to 4-73(a). The Company will revisit and respond to these subparts as part of the supplemental response for this DR.

SPONSOR: Jaclyn Cantler and Robert T. Leming

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 4

QUESTION NO. 73
Referencing ITN 74120 (Pepco H-2 Page 172 of 216) White Flint New Substation 69/13kV:

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b. If Pepco asserts this project should remain in this case:

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    ii. All presentations, minutes, memos, and emails regarding the Asset Investment review.

    iii. All presentations, minutes, memos, and emails regarding the Project Concurrence.

    iv. Provide the current ten-year-forecast for all feeders and substations affected by this proposed project.

c. Provide all transmission costs to be allocated to the District.

d. Provide all distribution costs to be allocated to the District.

e. Provide all substation costs to be allocated to the District.

f. Provide peak load served in the District from the facilities proposed by this project.

RESPONSE:

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   Currently, the Company does not have a cost breakdown to illustrate how the project's costs are being allocated between the sub transmission and distribution components. The Company will perform this breakdown and will file it as a supplemental response to this DR.

b -f. Refer to the Company's response to 4-73(a). The Company will revisit and respond to these subparts as part of the supplemental response for this DR.

SPONSOR: Jaclyn Cantler and Robert T. Leming

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 4

QUESTION NO. 72
Referencing ITN 72730 (Pepco H-2 Page 171 of 216) National Harbor Sub – New 69/13 Dist Sub:

a. This project is entirely outside of the District. Please explain why this project is included in this rate case in the District.

b. If Pepco asserts this project should remain in this case, provide:

    i. All presentations, minutes, memos, and emails regarding the Project Scoping Meeting.

    ii. All presentations, minutes, memos, and emails regarding the Asset Investment review.

    iii. All presentations, minutes, memos, and emails regarding the Project Concurrence.

    iv. Provide the current ten-year-forecast for all feeders and substations affected by this proposed project.

c. Provide all transmission costs to be allocated to the District.

d. Provide all distribution costs to be allocated to the District.

e. Provide all substation costs to be allocated to the District.

f. Provide peak load served in the District from the facilities proposed by this project.

RESPONSE:

a. This project was inadvertently tagged as sub transmission and should not be included in this rate case. The project is not going in service during the rate effective period of this MYP and has no impact on the revenue requirement.

b – f. Refer to response at subpart a.

SPONSOR: Jaclyn Cantler and Robert T. Leming

PUBLIC
Exhibit OPC (E)-14
Formal Case No. 1176

Confidential Materials Omitted

pepco.
An Exelon Company

Andrea H. Harper
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June 17, 2020

Ms. Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 G Street, N.W., Suite 800
Washington DC, 20005

Re: Formal Case No. 1144

Dear Ms. Westbrook-Sedgwick:

Enclosed please find Potomac Electric Power Company's report regarding its efforts to develop non-wires alternatives to defer construction of the new Ward 8 substation, in accordance with Paragraph 95 of Order No. 20274 in the above-referenced proceeding.

Please feel free to contact me if you have any questions regarding this matter.

Sincerely,

/s/ *Andrea H. Harper*

Andrea H. Harper

Enclosures

cc: All Parties of Record

Order No. 20274 at Paragraph 95: NWAs for Ward 8 Substation Deferral.

Pursuant to the Order No. 20274, Paragraph 95, directive for Pepco to "provide a preliminary assessment and implementation framework for battery energy storage deployment which may enable the new Substation deferral at Ward 8 (Alabama Avenue)," in the context of "demonstration projects which would integrating more NWAs throughout the electric distribution system," Pepco submits the following report regarding its efforts to develop NWAs to defer construction of the new Ward 8 substation.

Pepco strongly supports the District's clean energy and innovation goals and the actions taken by the Commission to advance those initiatives, including its directive regarding the use of non-wires alternatives ("NWAs") to defer the need for a new substation in Ward 8 to meet capacity needs currently forecasted for the 2029 timeframe. The Commission has indicated a clear and consistent interest in the development of NWAs in a series of Orders and subsequent directives, including: 1) for Pepco to report on its plans for battery storage at the New Mt. Vernon Substation,[1] 2) approval of the distribution system planning ("DSP") and NWA process ("DSP/NWA Process") and directive to report on an accelerated schedule for implementation in Order No. 20286,[2] and 3) a directive for Pepco to report on the development of NWA projects in Order No. 20364.[3]

NWAs, including utility-scale Distributed Energy Resources ("DERs"), will play an important role in meeting the District's clean energy and grid modernization goals. The load growth driving the need for a new Ward 8 substation provides the opportunity to explore using DERs—such as solar panels, battery storage, and demand response programs—for peak load reduction. As a result, these DER deployments will enable Pepco to develop operational experience and provide broader knowledge for its District of Columbia system in the use of DERs to manage capacity constraints, improve resiliency, and understand the overall impact on the functioning of the distribution system.

The capacity need in Ward 8 will require a substantial amount of peak load shaving to allow for deferral of the new Ward 8 substation. In response, Pepco recognizes that a portfolio of projects will be needed before 2029. The 2029-need date will allow Pepco to develop this portfolio over time and through a combination of solutions established through the DSP/NWA Process and demonstration projects outside of the DSP/NWA Process, both on its own and in partnership with third parties. Included herein is a discussion of the first two demonstration projects that will be implemented to help defer the Ward 8 substation as well as a discussion of how the DSP/NWA Process will be used to add other NWA solutions to the portfolio.

The projects that Pepco is currently evaluating leverage technological advancements and steady cost declines for both lithium-ion batteries ("LIB") and smart inverters.[4] Pepco will deploy these

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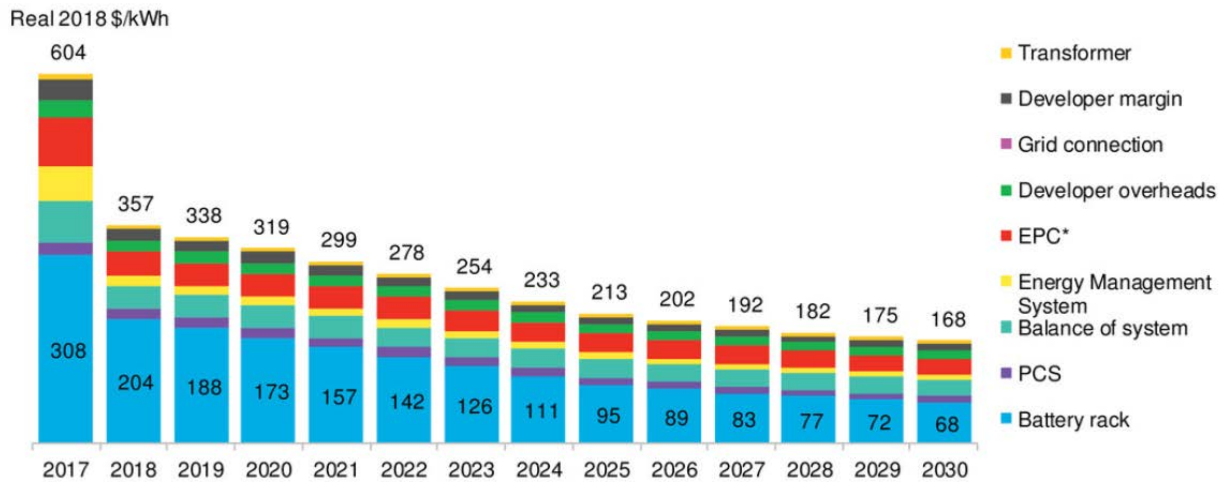
[1] *In the Matter of the Potomac Electric Power Company's Notice to Construct Two 230kV Underground Circuits from the Takoma Substation to the Rebuilt Harvard Substation, and from the Rebuilt Harvard Substation to the Rebuilt Champlain Substation (Capital Grid Project),* Formal Case No. 1144, Order No. 20274 (Dec. 20, 2019) at P 94.
[2] *In the Matter of the Investigation into Modernizing the Energy Delivery System for Increased Sustainability*, Formal Case No. 1130, Order No. 20286 (January 24, 2020) at P 38.
[3] *In the Matter of the Investigation into Modernizing the Energy Delivery System for Increased Sustainability*, Formal Case No. 1130, Order No. 20364 (June 6, 2020) at P 72 ("Order No. 20364").
[4] Available at https://about.bnef.com/blog/energy-storage-investments-boom-battery-costs-halve-next-decade/

technologies in a way that meets both the District's clean energy and innovation goals and provides benefits to ratepayers.

Figure 82: Capital costs for a nameplate 20MW/80MWh AC fully-installed energy storage system



Source: BloombergNEF Note: Excludes warranty costs, which are often paid annually rather than as part of the initial capital expenditure. These costs do not explicitly include any taxes, although due to a lack of transparency in the market, some may be unknowingly included. This is for a brownfield development so excludes grid connection costs. Includes a 10% EPC margin and developer margin set at 6%. Does not include salvage costs or project augmentation. See accompanying Excel for full breakdown.

The first demonstration project that Pepco will deploy will be a utility-owned 1- ("mega watt") MW, 3-hour battery.[5] This project will be deployed on an existing Pepco property at Congress Heights, avoiding costly property acquisition. It will serve both to help defer the Ward 8 substation and defer a feeder upgrade in the area. This demonstration project will provide important learnings regarding procurement, engineering design, construction and peak load shaving and deferral capabilities. Since the demonstration project is planned to be in-service in 2022, the learnings from this project will be important in informing future demonstration projects and NWA solutions selected through the DSP/NWA Process.

The second demonstration project, referenced in Order No. 20364,[6] involves a utility-owned battery and third party-owned generation. Pepco and the District Department of Energy and Environment are currently exploring a project demonstrating a "Solar Saturation Microgrid" design, which is undergoing evaluation to provide reliable, cost-effective peak reduction on the order of 1-to-2 MW. DOEE and Urban Ingenuity first presented this demonstration in the PowerPath DC Non-Wires Alternatives Working Group. This installation could be implemented by 2024, prior to the estimated 2029 need-date for capacity expansion in Ward 8. Installing the solar saturation microgrid well before the need date allows Pepco to perform simulated loading events to gain experience with using the microgrid as a load-shaving resource during peak loading

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5 Pepco discussed this battery project in the Capital Grid proceeding.
6 Order No. 20364 at PP 69-72.

periods. Positive results could lead to replication of the design at additional sites in Ward 8 and elsewhere in Pepco's service territory, contributing to further capacity expansion deferral and resiliency.

A Solar Saturation Microgrid enables residential neighborhoods, including single-family homes, to deploy saturation levels of rooftop solar, with participation of roughly 80% of the roofs in a given neighborhood. With the inclusion of smart inverters, centralized battery storage, enhanced communications, and a microgrid controller with dedicated software, the usual limitations on solar hosting capacity would not apply. The same battery storage assets would also enable dispatchable load reductions at hours of peak demand, alleviating stress on the local feeders and substation. The same assets could also enable microgrid islanding during broader grid outages, providing additional resiliency to a given community.

Finally, Pepco will address the capacity need requiring the Ward 8 substation through the DSP/NWA Process. As the forecasted 2029 need date is far enough out in time, Pepco will be able to address this capacity constraint through the DSP/NWA Process on an iterative basis, incrementally adding to the portfolio of NWA solutions over time to defer the forecasted Ward 8 substation-need date. Similar to the demonstration projects, the learnings from each of the DSP/NWA Process-selected solutions will inform future projects.

Continued evolution of existing regulations around contracting with third parties for DER deployment and operations and other emergent issues will require Commission action to carry out these innovative approaches. For example, an independent operator of solar and storage assets could contract with Pepco for peak demand reduction services that would be obligated at peak loading periods in Ward 8 via a long-term agreement that could be added to rate base and earn a return. Moreover, Pepco will evaluate potential NWA solutions submitted in the DSP/NWA Process through a benefits-cost analysis ("BCA") methodology.[7] Because the BCA requires a wires solution against which to compare the cost of any NWA solution, Pepco will be required to complete the design for the substation. In order to be able to properly recover for that design, Pepco will require Commission action specifically allowing for capital recovery of the design.

Pepco will continue to explore these and other avenues to expand the development of DERs and NWAs in the District and will file a follow-up to this report regarding the Company's progress deploying battery storage in Ward 8 and in implementing the NWA/DSP process.

[7] Pepco will report the details of this methodology in the September filing directed by Order No. 20364.

CERTIFICATE OF SERVICE

I hereby certify that a copy of Potomac Electric Power Company's Report was sent to all parties on this June 17, 2020 by electronic mail to:

Ms. Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
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Washington, DC 20005
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/s/ Andrea H. Harper
Andrea H. Harper

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 8

QUESTION NO. 5
Reference Pepco (H)-2 at page 2, “Project 62900 and 62935”.

a. Please provide all project authorization documents, workpapers and analysis conducted for the proposed Alabama Avenue Substation Battery Storage Project.

b. What other resiliency benefits does the Company intend to use the batter storage project before besides peak load reduction?

RESPONSE:

a. Please see the Company attachment FC1176 OPC DR 8-5 Confidential Attachment. Additionally, please note that this project intends to fulfill the commitment made in the Capital Grid Notice of Construction, per Order No. 20274, paragraph 94-95.

b. The Company anticipates using the battery storage project to mitigate voltage drop violations during peak load conditions and using the capabilities of the battery to augment emergency transfers in response to storms.

SPONSOR: Jaclyn Cantler

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 4

QUESTION NO. 9
Provide an updated version of Attachment A to Pepco's Response to OPC Data Request 7- 53 in Formal Case No. 1150.

RESPONSE:

Please refer to the attachment labeled: FC 1176 OPC DR 4-9.

SPONSOR: Jaclyn Cantler

Potomac Electric Power Company
Capacity Planning

Prospective New Business Summary - 2021 Histories

Type	
C-Comml	SF - Single Family
G - Govt	TH - Townhouses
	A - Apartments

FC 1176
OPC DR 4-9
Attachment
Page1 of 12

Dwg. No: 03-21/22-03 | Substation Name: **Northeast** | No. 212 | Date: **12/08/23**

Feeder	PNB No.	Customer Name (Address Optional)	Type	Total Load (No. of Units)	2020	2021	2022	2023	2024	2025	2026	Projected I.S. Date		Comments
Distribution														
15461														
15462														
	3486275	301 Florida Ave.	R/A	71k sq ft. / 60 units			300	300				2021		Under Construction as of September 2021
	3502213	476 K ST NW	C	17850 Sft	200							2020		Completed and in service as of September 2021
	3548951	72 Florida Ave. NE		Storage facility	300	300						2020		Completed in 2020. Leasing started March 2020
	16640854	1634 N. Capitol St. NW		Rest. Plus 27 unit apartment			360							Tentative in-service March 1, 2022
	WO#17031931	1515 N. Capitol St. NE	A	139 Units			200	200						Tentative in-service March 1, 2022
		Total Distribution PNB Load			**500**	**300**	**860**	**500**	**0**	**0**	**0**			
H.T. North Group														
15457														
15458														
15459														
15458														
15459														
		Total H. T. North Group PNB Load												
Sub. 212 Southeast (Future East Network Group)														
15481														
15482														
15483	3	Union Market (S. Bldg) Edens	C/A	550 KW					200	200	100	2022		Nothing yet as of 1/21/2020
15484	4	Union Market (N. Bldg) Edens	C	1,600 KW					1000	600		2022		Nothing yet as of 1/21/2020
15485	5	1270 & 1280 4th St. NE - Edens	C/A	29k sqf retail/430 Units			600	600	300			2022		Leasing as of September 2021
15486	6	The Highline @ Union Market	C/A	9k sqf retail/315 Units		400	400	200				2021		Completed as of September 2021. Leasing up
		320 Florida Ave. NE												
	7	5th st. South	C	300KW					400	100	100	2022		Nothing yet as of 1/21/2020
	8	400 Florida Ave.	C/A	805.5 KW					406	400		2021		Planned. Nothing as of September 2021
	9	1300 4th st. ne (Shapiro North)	C/A	847.5 KW		400	448					2021		Leasing as of september 2021
	10	Marice Parking Lot (N)	C/A	1,200 KW					600	600		2022		Nothing yet as of 1/21/2020
	11	Marice BLDG	C/A	1,100 KW			600	500				2022		Under construction as of September 2021 - Completing the skelleton
	12	300 & 350 Morse ST.	C/A	3,500 KW		1000	1000	1000	500			2022		Leasing as of september 2021
	13	Gallaudet Parcel 1	C/A	900 KW					500	400		2022		Nothing yet as of 1/21/2020
	14	Gallaudet Parcel 2	C/A	700 KW					400	300		2022		Nothing yet as of 1/21/2020
	15	Gallaudet Parcel 3	C/A	3,800 KW				1000	1000	1000	800	2022		Nothing yet as of 1/21/2020
	16	1271 5th St.	C/A	600 KW					300	300		2022		Nothing yet as of 1/21/2020
	17	500 Morse ST.	C/A	1,100 KW		600	500					2021		Leasing as of september 2021
	18	Gallaudet Parcel 4	C/A	3,200 KW					1000	1000	1200	2023		Nothing yet as of 1/21/2020

Potomac Electric Power Company
Capacity Planning

Prospective New Business Summary - 2021 Histories

Type	
C-Comml	SF - Single Family
G - Govt	TH - Townhouses
	A - Apartments

FC 1176
OPC DR 4-9
Attachment
Page2 of 12

Dwg. No: 03-21/22-03		Substation Name: **Northeast**			No. 212	Date:						**12/08/23**			
Feeder	PNB No.	Customer Name (Address Optional)		Type	Total Load (No. of Units)	2020	2021	2022	2023	2024	2025	2026	Projected I.S. Date		Comments
	19	300 & 350 Morse ST.		C/A	3,100 KW				1000	1000	1100		2023		Under construction as of September 2021 - Building the skelleton
	Total East Network Group PNB Load					**0**	**2400**	**3548**	**4300**	**7606**	**6000**	**2200**			

Potomac Electric Power Company
Capacity Planning

Prospective New Business Summary - 2021 Histories

Type		
C-Comml	SF - Single Family	
G - Govt	TH - Townhouses	
	A - Apartments	

FC 1176
OPC DR 4-9
Attachment
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Dwg. No: 03-21/22-03 | Substation Name: **Northeast** | No. 212 | Date: **12/08/23**

Feeder	PNB No.	Customer Name (Address Optional)	Type	Total Load (No. of Units)	2020	2021	2022	2023	2024	2025	2026	Projected I.S. Date		Comments
West LVAC Grop														
15475	3533453	227 Harry Thomas Way	R/A	335 Units		500	800	500				2021		Completed as of September 2021
15476				10k sft restaurant										
15477				90k sft garage										
15478				45k sft common space										
15479														
15480	3534031	Eckington Yards - West	R/A	457Units		500	1000	100				2021		Completed as of September 2021 - Selling/leasing
				70k sft restaurant										
		Eckington Yards - East	R/A	228Units		500	500					2021		Completed as of September 2021 - Selling/leasing
				1.6k sft restaurant										
				50k sft garage										
	3577055	601 K ST. NW	Hotel	220 rooms		300						2020		Completed in 2020
	Total West LVAC Group PNB Load				**0**	**1800**	**2300**	**600**		**0**	**0**		**0**	
Southwest LVAC Group														
15451														
	N/A	401 K St. NW	A	800				400	300			2023/4		Old building still up…. Nothing as of 9/2021 per urban turf
	3456780	501 K St. NW	C	550k Sq Ft		500	500					2021		Completed as of September 2021
		888 New Jersey Av NW	A	104 Units			200					2021		Under Construction as of September 2021
		801 3rd St. NW	A	273 Units		200	300					2020		Planned - nothing yet as of September 2021
		1112 First St. NW	A			400	400					6/1/2021		Under construction as fo September 2021
		Sursum Corda Community												
	SR#05012266	333 G St. NW	A/R	420 uits + retail		400	500					6/1/2021		Under construction as of September 2021
	SR# 05065545	925 5TH ST NW	A/R	47 units + 19k sft restaurant		200						8/27/2021		Use Fdrs 15451 and 15453 - Under Construction as of 9/2021
	SR# 16959213	300 K ST NW	A/R	302 units + 7k sft ret.+79k comm.			300	300				1/31/2022		Use Fdrs 15451 and 15454 - Under Construction as of 9/2021
		Total 15451 Load			**0**	**1700**	**2200**	**700**	**300**	**0**	**0**			
15452														
	N/A	401 K St. NW	A	800				400	300			2023/4		Old building still up…. Nothing as of 9/2021 per urban turf
		801 3rd St. NW	A	273 Units		200	300					2020		Planned - nothing yet as of September 2021
		Hotel	H	270 Units		200	200					6/1/2021		Completed and in service as of September 2021
		317 K ST. NW												

Potomac Electric Power Company
Capacity Planning

Prospective New Business Summary - 2021 Histories

Type	
C-Comml	SF - Single Family
G - Govt	TH - Townhouses
	A - Apartments

FC 1176
OPC DR 4-9
Attachment
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Dwg. No: 03-21/22-03	Substation Name:	Northeast			No. 212	Date:							12/08/23		
Feeder	PNB No.	Customer Name (Address Optional)		Type	Total Load (No. of Units)	2020	2021	2022	2023	2024	2025	2026	Projected I.S. Date		Comments
		Total 15452 Load				**0**	**400**	**500**	**400**	**300**	**0**	**0**			
15453	N/A	401 K St. NW		A	800				400	300			2023/4		Old building still up…. Nothing as of 9/2021 per urban turf
		615 H St. & 616 I St. NW		A/R	81 units/5.5k Sft Rest.81 units/5.5k Sft Rest.			300	250					7/20	Has not broken ground yet as of 9/2021 - Planned status per urban turf
					7k sft retail/ 23k sft office										
		Hotel		H	270 Units		200	200					6/1/2021		Completed and in service as of September 2021
		317 K ST. NW													
	SR#05012266	333 G St. NW		A/R	420 uits + retail		400	500					6/1/2021		Under construction as of September 2021
		1112 First St. NW		A			400	400					6/1/2021		Under construction as fo September 2021
		Sursum Corda Community													
	SR# 05065545	925 5TH ST NW		A/R	47 units + 19k sft restaurant		200						8/27/2021		Use Fdrs 15451 and 15453 - Under Construction as of 9/2021
		Total 15453 Load				**0**	**1200**	**1400**	**650**	**300**	**0**	**0**			
15454															
	N/A	401 K St. NW		A	800				400	300			2023/4		Old building still up…. Nothing as of 9/2021 per urban turf
	3456780	501 K St. NW		C	550k Sq Ft		500	500					2021		Completed as of September 2021
		888 New Jersey Av NW		A	104 Units		200						2021		Under Construction as of September 2021
		575 3rd St. NW		C	32k sft		100						6/1/2021		Completed as of September 2021
		Museum													
		1112 First St. NW		A			400	400					6/1/2021		Under construction as fo September 2021
		Sursum Corda Community													
		615 H St. & 616 I St. NW		A/R	81 units/5.5k Sft Rest.81 units/5.5k Sft Rest.			300	250					7/20	Has not broken ground yet as of 9/2021 - Planned status per urban turf
					7k sft retail/ 23k sft office										
	SR# 16959213	300 K ST NW		A/R	302 units + 7k sft ret.+79k comm.			300	300				1/31/2022		Use Fdrs 15451 and 15454 - Under Construction as of 9/2021
		Total 15454 Load				**0**	**1200**	**1500**	**950**	**300**	**0**	**0**			

Potomac Electric Power Company
Capacity Planning

Prospective New Business Summary - 2021 Histories

Type	
C-Comml	SF - Single Family
G - Govt	TH - Townhouses
	A - Apartments

FC 1176
OPC DR 4-9
Attachment
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Dwg. No: 03-21/22-03 | Substation Name: **Northeast** | No. 212 | Date: **12/08/23**

Feeder	PNB No.	Customer Name (Address Optional)	Type	Total Load (No. of Units)	2020	2021	2022	2023	2024	2025	2026	Projected I.S. Date	Comments
15455													
	N/A	401 K St. NW	A	800				400	300			2023/4	Old building still up…. Nothing as of 9/2021 per urban turf
		575 3rd St. NW	C	32k sft		100						6/1/2021	Completed as of September 2021
		Museum											
		Total 15455 Load			**0**	**100**	**0**	**400**	**300**	**0**	**0**		
15456													
	N/A	401 K St. NW	A	800				400	300			2023/4	Old building still up…. Nothing as of 9/2021 per urban turf
	3456780	501 K St. NW	C	550k Sq Ft		500	500					2021	Completed as of September 2021
		888 New Jersey Av NW	A	104 Units		200						2021	Under Construction as of September 2021
		1112 First St. NW	A			400	400					6/1/2021	Under construction as fo September 2021
		Sursum Corda Community											
		Total 15456 Load			**0**	**1100**	**900**	**400**	**300**	**0**	**0**		
	Total Southwest LVAC Group PNB Load				**0**	**5700**	**6500**	**3500**	**1800**	**0**	**0**		
Southeast Spot Network Group													
15463		1300 4th St. NE	A/C	134 Units/ 32sft commercial/12k sft retail		300	200						Leasing as of September 2021
	From Benning Sub. 7	1200 3rd st. NE	R/C	45k sft retail/650 units			200	200	200				Under construction as of September 2021
		Central Armature		200 hotel rooms									
	WO#15661948	300 Morse Bldg A1	A/C	451 units/15k sftRetail	200	200						6/2020	Leasing as of September 2021
		35 New York Ave.	H	75 Units					100	100		Uncertain	Still uncertain when it will happen as of Feb 5 2020
		40 New York Ave.	A	99 Units			100	100				6/1/2020	Under construction as of September 2021
		7 New York Ave.	A	116 Units				100	100			4/22/2022	Received from Ronnie November 12, 2021
	WO#16470452	1201 1st st. ne		8 superchargers sta.			200					10/1/2021	2 cabinets feeder 4 chargers - each cabinet is rated for 387 kW
	3473814	The Wilkes Company	C/A	370,377 sq ft 401 Units			300	274				2020	Under Construction as of September 2021
		300 M St., NE											Total 2,297kW
	WO#15662076	340 Morse St. NE	C/A	260 units, 75k sftgarage, 7k sq ft restaurant			200	200				March 20, 2022	Received from Ronnie October 18, 2021
	WO#15667707	360 Morse St. NE	A	159 units, 6k sq ft restaurant				100	100			October 20, 2022	Received from Ronnie January 4, 2022
	WO 17157724	1133 North Capitol St NE	A	438 Units				200	200			June 1 2023	Received from Jason Pane November 2, 2021
Total	**15463**				**200**	**500**	**1200**	**1174**	**700**	**100**	**0**		
15464													

Potomac Electric Power Company
Capacity Planning

Prospective New Business Summary - 2021 Histories

Type	SF - Single Family	FC 1176
C-Comml	TH - Townhouses	OPC DR 4-9
G - Govt	A - Apartments	Attachment ~~Page6 of 12~~

Dwg. No: 03-21/22-03 | Substation Name: **Northeast** | No. 212 | Date: **12/08/23**

Feeder	PNB No.	Customer Name (Address Optional)	Type	Total Load (No. of Units)	2020	2021	2022	2023	2024	2025	2026	Projected I.S. Date		Comments
		35 New York Ave.	H	75 Units					100	100		Uncertain		Still uncertain when it will happen as of Feb 5 2020
		40 New York Ave.	A	99 Units			100	100				6/1/2020		Under construction as of September 2021
	N/A	Union Place Phase II	A	1.0 MVA From Benning	100	100						2020		Completed as of 1/21/2020 but not fully occupied
		200 K St., NE	525 units											Total 1,000kW (2019)
	WO#15661948	300 Morse Bldg A1	A/C	451 units/15k sftRetail	200	200						6/2020		Leasing as of September 2021
	WO#15667675	350 Morse Bldg C1	O/C	218ksft office/9k sft Rest	500	400						6/2020		Leasing as of September 2021
				9k sft Storage/amenities										
	From Benning Sub. 7	1200 3rd st. NE	R/C	45k sft retail/650 units			200	200	200					Under construction as of September 2021
		Central Armature		200 hotel rooms										
		1300 4th St. NE	A/C	134 Units/ 32sft commercial/12k sft retail		300	200					2020		Leasing as of September 2021
	WO 16435987	55 H St. NW	A/R	158 units/ 1950 sft retail				300	200	200		11/1/2022		Estimated completion Summer 2022
	3473814	The Wilkes Company	C/A	370,377 sq ft 401 Units			300	274				2020		Under Construction as of September 2021
		300 M St., NE												Total 2,297kW
Total	**15464**				**800**	**1000**	**800**	**874**	**500**	**300**	**0**			
15465														
	N/A	Union Place Phase II	A	1.0 MVA From Benning	100	100						2020		Completed as of 1/21/2020 but not fully occupied
		200 K St., NE	525 units											Total 1,000kW (2019)
	WO#15667675	350 Morse Bldg C1	O/C	218ksft office/9k sft Rest	500	400						6/2020		Leasing as of September 2021
				9k sft Storage/amenities										
		1109 Congress St. NE	A/R									2019		Currently on NJ Ave. radial per distribution Eng. Decision (300kW)
			62 Units											
	Going to Push-pipe	300 Morse St. NE	A/R	50nits/4500 sf retail	200							6/1/2020		Leasing as of September 2021
	WO 16435987	55 H St. NW	A/R	158 units/ 1950 sft retail				300	200	200		11/1/2022		Estimated completion Summer 2022
	From Benning Sub. 7	1200 3rd st. NE	R/C	45k sft retail/650 units			200	200	200					Under construction as of September 2021
		Central Armature		200 hotel rooms										
	WO#15970065	500 Penn St. NE	R/C	300 units- 22ksft rest.			200	200	200				2021	Under Construction as of September 2021
				13kft. Common area										
	From Sub. 133 network	Edens Realty	A/R	465 units/29k sft retail	400	300							2019	Completed - not fully occupied as of 1/21/2020
		1270 4th st. NE												
	WO#16382666	1329 5th Street, NE	A/R	300 units/23k sft retail				300	300				2022	Class of service submitted Jan 2, 2020. I. S. 2022
		Union Market												
	WO#16470452	1201 1st st. ne		8 superchargers sta.			200					10/1/2021		2 cabinets feeder 4 chargers - each cabinet is rated for 387 kW
		7 New York Ave.	A	116 Units				100	100			4/22/2022		Received from Ronnie November 12, 2021

Potomac Electric Power Company
Capacity Planning

Prospective New Business Summary - 2021 Histories

Type	SF - Single Family
C-Comml	TH - Townhouses
G - Govt	A - Apartments

Dwg. No: 03-21/22-03		Substation Name: Northeast			No. 212	Date:							12/08/23		
Feeder	PNB No.	Customer Name (Address Optional)		Type	Total Load (No. of Units)	2020	2021	2022	2023	2024	2025	2026	Projected I.S. Date	Comments	
Total	**15465**					**1200**	**800**	**600**	**1100**	**1000**	**200**	**0**			

Potomac Electric Power Company
Capacity Planning

Prospective New Business Summary - 2021 Histories

Type	SF - Single Family
C-Comml	TH - Townhouses
G - Govt	A - Apartments

Dwg. No: 03-21/22-03		Substation Name: Northeast			No. 212	Date:							12/08/23		
Feeder	PNB No.	Customer Name (Address Optional)		Type	Total Load (No. of Units)	2020	2021	2022	2023	2024	2025	2026	Projected I.S. Date		Comments
15466															
	N/A	Union Place Phase II		A	1.0 MVA From Benning	100	100						2020		Completed as of 1/21/2020 but not fully occupied
		200 K St., NE		525 units											Total 1,000kW (2019)
	From Benning Sub. 7	1200 3rd st. NE		R/C	45k sft retail/650 units			200	200	200					Under construction as of September 2021
		Central Armature			200 hotel rooms										
		1109 Congress St. NE		A/R									2019		Currently on NJ Ave. radial per distribution Eng. Decision (200kW)
				62 Units											
	WO#15661948	300 Morse Bldg A1		A/C	451 units/15k sftRetail	200	200						6/2020		Leasing as of September 2021
	3572159	1300 4th ST NE		R/A	12k sft retail; 134 Units		200	100						2020	Leasing as of September 2021
		Great Gulf Union													
	WO#15662076	340 Morse St. NE		C/A	260 units, 75k sftgarage, 7k sq ft restaurant			200	200				March 20, 2022		Received from Ronnie October 18, 2021
	WO#15667707	360 Morse St. NE		A	159 units, 6k sq ft restaurant				100	100			October 20, 2022		Received from Ronnie January 4, 2022
	WO 18226884	1323 4th St NE		C/O/R	3k sft retail, 13.5k office, 5k sq ft restaurant				50	100			January 19 2023		Received from Jason Pane November 2, 2021
	WO 17157724	1133 North Capitol St NE		A	438 Units				200	200			June 1 2023		Received from Jason Pane November 2, 2021
Total	**15466**					**300**	**500**	**500**	**750**	**600**	**0**	**0**			
15467															
	N/A	Union Place Phase II		A	1.0 MVA From Benning	100	100						2020		Completed as of 1/21/2020 but not fully occupied
		200 K St., NE		525 units											Total 1,000kW (2019)
	From Benning Sub. 7	1200 3rd st. NE		R/C	45k sft retail/650 units			200	200	200					Under construction as of September 2021
		Central Armature			200 hotel rooms										
	3473814	The Wilkes Company		C/A	370,377 sq ft 401 Units			300	274				2020		Under Construction as of September 2021
		300 M St., NE													Total 2,297kW
	WO#15661948	300 Morse Bldg A1		A/C	451 units/15k sftRetail	200	200						6/2020		Leasing as of September 2021
	3572159	1300 4th St. NE		A/C	134 Units/ 32sft commercial/12k sft retail		300	200							Leasing as of September 2021
	WO#15662076	340 Morse St. NE		C/A	260 units, 75k sftgarage, 7k sq ft restaurant			200	200				March 20, 2022		Received from Ronnie October 18, 2021
	WO 17157724	1133 North Capitol St NE		A	438 Units				200	200			June 1 2023		Received from Jason Pane November 2, 2021
	WO 18226884	1323 4th St NE		C/O/R	3k sft retail, 13.5k office, 5k sq ft restaurant				50	100			January 19 2023		Received from Jason Pane November 2, 2021
Total	**15467**					**300**	**600**	**900**	**924**	**500**	**0**	**0**			
15468															
	N/A	Union Place Phase II		A	1.0 MVA From Benning	100	100						2020		Completed as of 1/21/2020 but not fully occupied
		200 K St., NE		525 units											Total 1,000kW (2019)
	300 Morse St. NE	**Going to Push-pipe**		A/R	50nits/4500 sf retail	200							6/1/2020		Leasing as of September 2021

Potomac Electric Power Company
Capacity Planning

Prospective New Business Summary - 2021 Histories

Type	SF - Single Family	FC 1176
C-Comml	TH - Townhouses	OPC DR 4-9
G - Govt	A - Apartments	Attachment
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Dwg. No: 03-21/22-03 | Substation Name: **Northeast** | No. 212 | Date: **12/08/23**

Feeder	PNB No.	Customer Name (Address Optional)		Type	Total Load (No. of Units)	2020	2021	2022	2023	2024	2025	2026	Projected I.S. Date		Comments
	3473814	The Wilkes Company		C/A	370,377 sq ft 401 Units			300	274				2020		Under Construction as of September 2021
		300 M St., NE													Total 2,297kW
	WO#15970065	500 Penn St. NE		R/C	300 units- 22ksft rest.			200	200	200				2021	Under Construction as of September 2021
					13kft. Common area										
	From Sub. 133 network	Edens Realty		A/R	465 units/29k sft retail	400	300							2019	Completed - not fully occupied as of 1/21/2020
		1270 4th st. NE													
	WO#15667675	350 Morse Bldg C1		O/C	218ksft office/9k sft Rest	500	400						6/2020		Leasing as of September 2021
					9k sft Storage/amenities										
	WO#16382666	1329 5th Street, NE		A/R	300 units/23k sft retail				300	300				2022	Class of service submitted Jan 2, 2020. I. S. 2022
		Union Market													
	WO#16470452	1201 1st st. ne			8 superchargers sta.			200					10/1/2021		2 cabinets feeder 4 chargers - each cabinet is rated for 387 kW
Total	**15468**					**1200**	**800**	**700**	**774**	**500**	**0**	**0**			
Total Southeast Spot Group PNB Load						**4000**	**4200**	**4700**	**5596**	**3800**	**600**	**0**			

Potomac Electric Power Company
Capacity Planning

Prospective New Business Summary - 2021 Histories

Type	
C-Comml	SF - Single Family
G - Govt	TH - Townhouses
	A - Apartments

FC 1176
OPC DR 4-9
Attachment
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Dwg. No: 03-21/22-03 | Substation Name: **Northeast** | No. 212 | Date: **12/08/23**

Feeder	PNB No.	Customer Name (Address Optional)		Type	Total Load (No. of Units)	2020	2021	2022	2023	2024	2025	2026	Projected I.S. Date		Comments
South Spot Network Group															
15469	3508651/3508652/3508650	1250 1st St. NE/ 50 Patteson		R/C	208 Units/544713 Sf Mix					600	700		2021		Still in Planning Phase as of 1/21/2020
		and 51 NSt. NE													
	16029307	1150 1st Street NE		R/C	500 units/10.5k sf retail					300	300		2021		Revised Class of service approved 6/29/2020 - Planning Phase
					87.6k sft common space										
	N/A	301 & 331 N Street- NE		C/R/H	350 units/27k sqt retail	300	300								Leasing as of September 2021
					25k sqf office/175 rooms										Total 3.0 MVA Fdrs. 15469, 70, 71, 73, & 74
	3326521	Storey Park		C/R	350k sqft office			300	200				2021		Under construction as of September 2021
		1005 1st St. NE			65k retail/300 apt.										Use Fdrs. 15469, 15470, 15471, 15472
	N/A	44 M St. NE		A	285 Units					200	200		2024		PNB received from JB February 14 2022 - I.S. by 2024
	N/A	88 M St. NE		C/R	315k Sft					100	200		2024		PNB received from JB February 14 2022 - I.S. by 2024
		45 L St. NE		C/R		300	700						2019		Completed but not occupied as of 1/21/2020
	SR#04907217	1222 First St. NE		H	290 Units		100	200					2020		Under construction as of September 2021
	6151159 & 16060944	101 New York Ave. NE		A/C	314 units		500	400					2021		Almost completed as of September 2021
		1 Florida Ave. NE		A/C	648 units/13k sf restaur.					300	400		2021		Preconstruction/Planning Phase as of September 2021
		60 Florida Ave. NE		Office	1275k sft				600	600	700		2023		Prelimary Plan provided by JB 10/29/20
Total	**15469**					**600**	**1600**	**900**	**800**	**2100**	**2500**	**0**			
15470	N/A	301 & 331 N Street- NE		C/R/H	350 units/27k sqt retail	300	300								Leasing as of September 2021
					25k sqf office/175 rooms										Total 3.0 MVA Fdrs. 15469, 70, 71, 73, & 74
	3326521	Storey Park		C/R	350k sqft office			300	200				2021		Under construction as of September 2021
		1005 1st St. NE			65k retail/300 apt.										Use Fdrs. 15469, 15470, 15471, 15472
		1 Florida Ave. NE		A/C	648 units/13k sf restaur.					300	400		2021		Preconstruction/Planning Phase as of September 2021
		1324 N. Capitol St. NW		A	35 Units		100						2020		Under construction as of September 2021
		60 Florida Ave. NE		Office	1275k sft				600	600	700		2023		Prelimary Plan provided by JB 10/29/20
Total	**15470**					**300**	**400**	**300**	**800**	**900**	**1100**	**0**			
15471	3326521	Storey Park		C/R	350k sqft office			300	200				2021		Under construction as of September 2021
		1005 1st St. NE			65k retail/300 apt.										Use Fdrs. 15469, 15470, 15471, 15472
	N/A	301 & 331 N Street- NE		C/R/H	350 units/27k sqt retail	300	300								Leasing as of September 2021
					25k sqf office/175 rooms										Total 3.0 MVA Fdrs. 15469, 70, 71, 73, & 74
		45 L St. NE		C/R		300	700						2019		Completed but not occupied as of 1/21/2020
Total	**15471**					**600**	**1000**	**300**	**200**	**0**	**0**	**0**			

Potomac Electric Power Company
Capacity Planning

Prospective New Business Summary - 2021 Histories

Type	
C-Comml	SF - Single Family
	TH - Townhouses
G - Govt	A - Apartments

FC 1176
OPC DR 4-9
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Dwg. No: 03-21/22-03 | Substation Name: **Northeast** | No. 212 | Date: **12/08/23**

Feeder	PNB No.	Customer Name (Address Optional)	Type	Total Load (No. of Units)	2020	2021	2022	2023	2024	2025	2026	Projected I.S. Date	Comments
15472	3326521	Storey Park	C/R	350k sqft office			300	200				2021	Under construction as of September 2021
		1005 1st St. NE		65k retail/300 apt.									Use Fdrs. 15469, 15470, 15471, 15472
	3508651/3508652/3508650	1250 1st St. NE/ 50 Patteson	R/C	208 Units/544713 Sf Mix					600	700		2021	Still in Planning Phase as of 1/21/2020
		and 51 NSt. NE											
	N/A	44 M St. NE	A	285 Units					200	200		2024	PNB received from JB February 14 2022 - I.S. by 2024
	N/A	88 M St. NE	C/R	315k Sft					100	200		2024	PNB received from JB February 14 2022 - I.S. by 2024
		45 L St. NE	C/R		300	700						2019	Completed but not occupied as of 1/21/2020
	6151159 & 16060944	101 New York Ave. NE	A/C	314 units		500	400					2021	Almost completed as of September 2021
	16029307	1150 1st Street NE	R/C	500 units/10.5k sf retail					300	300		2021	Revised Class of service approved 6/29/2020 - Planning Phase
				87.6k sft common space									
		60 Florida Ave. NE	Office	1275k sft				600	600	700		2023	Prelimary Plan provided by JB 10/29/20
Total	**15472**				**300**	**1200**	**700**	**800**	**1800**	**2100**	**0**		
15473													
	N/A	301 & 331 N Street- NE	C/R/H	350 units/27k sqt retail	300	300							Leasing as of September 2021
				25k sqf office/175 rooms									Total 3.0 MVA Fdrs. 15469, 70, 71, 73, & 74
	3508651/3508652/3508650	1250 1st St. NE/ 50 Patteson	R/C	208 Units/544713 Sf Mix					600	700		2021	Still in Planning Phase as of 1/21/2020
		and 51 NSt. NE											
	N/A	44 M St. NE	A	285 Units					200	200		2024	PNB received from JB February 14 2022 - I.S. by 2024
	N/A	88 M St. NE	C/R	315k Sft					100	200		2024	PNB received from JB February 14 2022 - I.S. by 2024
		1 Florida Ave. NE	A/C	648 units/13k sf restaur.					300	400		2021	Preconstruction/Planning Phase as of September 2021
		1324 N. Capitol St. NW	A	34 Units		100						2020	Under construction as of September 2021
		60 Florida Ave. NE	Office	1275k sft				600	600	700		2023	Prelimary Plan provided by JB 10/29/20
Total	**15473**				**300**	**400**	**0**	**600**	**1800**	**2200**	**0**		
15474													
	N/A	301 & 331 N Street- NE	C/R/H	350 units/27k sqt retail	300	300							Leasing as of September 2021
				25k sqf office/175 rooms									Total 3.0 MVA Fdrs. 15469, 70, 71, 73, & 74
	SR#04907217	1222 First St. NE	H	290 Units		100	200					2020	Under construction as of September 2021
	16029307	1150 1st Street NE	R/C	500 units/10.5k sf retail					300	300		2021	Revised Class of service approved 6/29/2020 - Planning Phase
				87.6k sft common space									
Total	**15474**				**300**	**400**	**200**	**0**	**300**	**300**			
Total South Spot Group PNB Load					**2400**	**5000**	**2400**	**3200**	**6900**	**8200**	**0**		

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Potomac Electric Power Company
Capacity Planning

Prospective New Business Summary - 2021 Histories

Type	SF - Single Family	FC 1176
C-Comml	TH - Townhouses	OPC DR 4-9
G - Govt	A - Apartments	Attachment
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Dwg. No: 03-21/22-03		Substation Name:	**Northeast**		No. 212	Date:							**12/08/23**		
Feeder	PNB No.	Customer Name (Address Optional)		Type	Total Load (No. of Units)	2020	2021	2022	2023	2024	2025	2026	Projected I.S. Date	Comments	
		Total Station PNB Load				**6900**	**17600**	**18008**	**17096**	**20106**	**14800**	**2200**			

pepco
An Exelon Company

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PUBLIC

March 19, 2020

Ms. Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 G Street, N.W., Suite 800
Washington DC, 20005

Re: Formal Case No. 1144

Dear Ms. Westbrook-Sedgwick:

On August 9, 2019, the Public Service Commission of the District of Columbia issued Order No. 20203 approving Phase 1 of the Capital Grid Project. Pursuant to Order No. 20203, Pepco is filing the public portion of its 90-day compliance filing, which includes the 1) Substation diagram; 2) Compliance Media Plan; and 3) CBE Tracking Template. Portions of this filing contain Critical Infrastructure Information (CII) and are being withheld due to delivery restrictions related to COVID-19. Pepco will file the CII portions of this filing under separate cover when it can resume in-person deliveries.

Please contact me if you have any further questions.

Sincerely,

Andrea H. Harper

Andrea H. Harper

Enclosures
cc: All Parties of Record

A. Order No. 20285 at Paragraph 94: Battery Storage at the Mt. Vernon Substation.

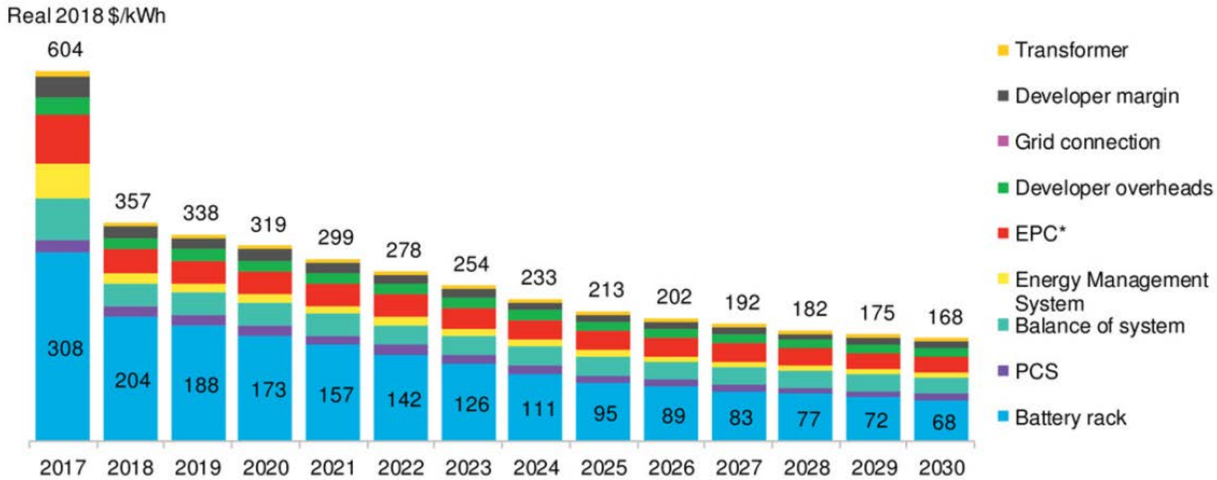
Pursuant to the Order No. 20285, Paragraph 94, directive for Pepco to file its "plan and implementation details for battery energy storage, including the physical location and expansion possibilities of the proposed battery storage at Mt. Vernon Substation," Pepco submits the following regarding its efforts to best use battery storage to defer a fourth transformer at the Mt. Vernon Substation.

Pepco fully supports and is committed to fulfilling the Commission's directive regarding battery storage to defer a fourth transformer at the Mt. Vernon Substation. Pepco agrees that exploring non-wires alternatives ("NWAs"), such as utility-scale Distributed Energy Resources ("DERs"), will be vital to meeting the District's clean energy goals. This project will give Pepco the opportunity to explore using battery storage for peak load shaving in a controlled environment, thereby developing Pepco's operational experience with using large-scale storage on its system to manage capacity constraints.

Pepco is still designing the substation and, thus, the design of the bay in which the battery will be housed as well as the design of the battery itself are not complete. Pepco's continues to evaluate battery size and design as substation design moves forward. At present, as reported Pepco's Formal Case No. 1144 Reply Comments,[1] the 600 square foot fourth transformer bay[2] is being evaluated to contain the 1 MW, three-hour battery as well as the HVAC and fire protection equipment necessary to operate a utility-scale battery inside a critical substation. This installation is currently planned for 2024. Pepco is also exploring the possibility that a larger battery may be deployed, if the installation occurs after 2024 but prior to the estimated 2027 need-date for the fourth transformer. Installing the battery prior to the need date would still allow Pepco to perform simulated loading events to gain experience with using the battery as a load-shaving resource during peak loadings. However, installing it later than the currently planned 2024 installation would allow Pepco to take advantage of technological advancements and also reduce the degradation of its capacity that will occur from repeated use of the battery prior to the need to use the battery for deferral purposes.Much like any new technology, lithium-ion battery ("LIB") technology is rapidly evolving, with the price per kWh steadily declining.[3]

[1] Reply Comments at 17.
[2] See Confidential Attachment A.
[3] Available at https://about.bnef.com/blog/energy-storage-investments-boom-battery-costs-halve-next-decade/

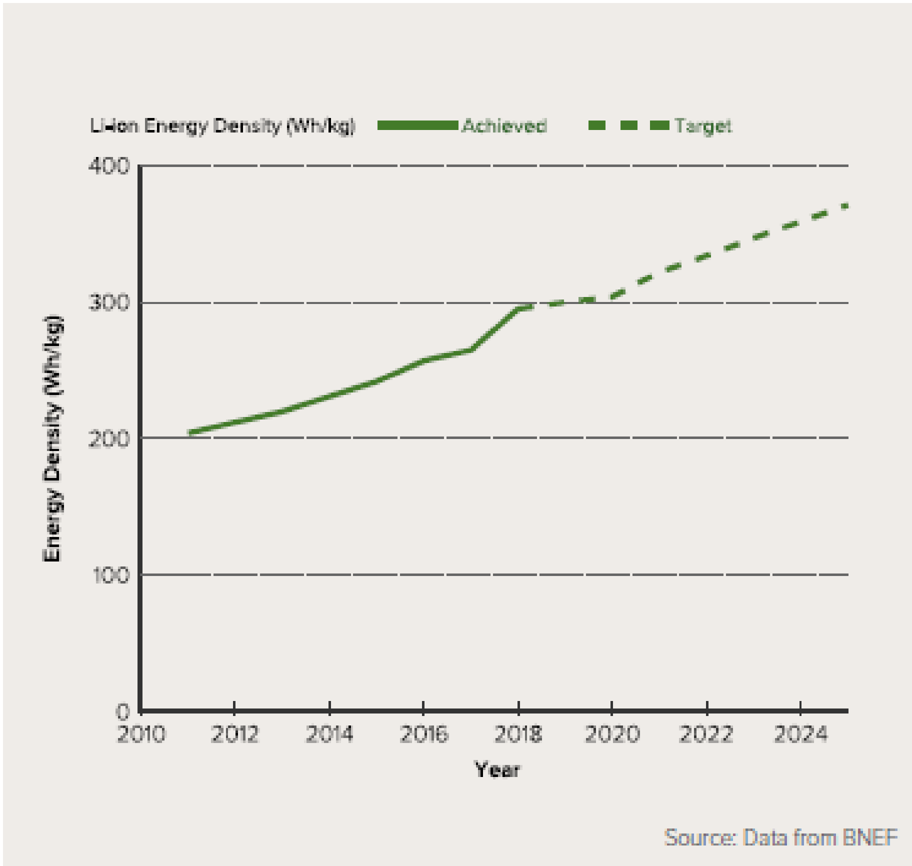
Figure 82: Capital costs for a nameplate 20MW/80MWh AC fully-installed energy storage system



Source: BloombergNEF Note: Excludes warranty costs, which are often paid annually rather than as part of the initial capital expenditure. These costs do not explicitly include any taxes, although due to a lack of transparency in the market, some may be unknowingly included. This is for a brownfield development so excludes grid connection costs. Includes a 10% EPC margin and developer margin set at 6%. Does not include salvage costs or project augmentation. See accompanying Excel for full breakdown.

Further, as illustrated in the figure below, LIB energy density - the amount of electricity that can be stored in the same size battery - is projected to steadily increase and is likely to continue to improve as research and design of electric vehicles continues.[4]

[4] Available at https://rmi.org/insight/breakthrough-batteries/



Because of these factors, as well as the expected degradation of the battery caused by repeated discharge, Pepco is currently performing a feasibility study that will inform its decision about the timing of installation of the battery and its independent HVAC and fire protection. Pepco's ultimate goal is to defer the need for the fourth transformer as long as practicable, and Pepo will assess the options with that goal in mind and report back to the Commission.

Pepco also has the ability to expand the battery storage project to an area outside of the planned structure of the new Mt. Vernon Substation. Specifically, the immediate area adjacent to the Mt. Vernon Substation will be used during construction as a staging area and could be used for battery storage after construction. However, post-construction, any use of this space to house expanded battery storage would require approval from the Board of Zoning Adjustment ("BZA"). Pepco will continue to explore this and other avenues to expand the implementation of DERs and NWAs in the District.

B. Order No. 20274 Attachment A: Magnetic Field Mitigation

The Commission directed "Pepco to provide calculations of magnetic field strength based on final substation designs" for the Mt. Vernon Substation. The Commission further "to provide any site-specific mitigation plans for reducing the magnetic fields from underground transmission XLPE (solid dielectric) cables." Finally, Pepco is directed "to provide the study results of their evaluation on the expected levels of magnetic fields associated with the proposed Capital Grid project as described in June 29, 2018 Notice of Construction, Appendix M Environmental Impact Study."

1. Calculations of Magnetic Field Strength Based on Final Mt. Vernon Substation Final Design

Calculations of the magnetic field strength associated with the Mt. Vernon Substation will be prepared within three months of the completion of the Mt. Vernon Substation Final Design, which is currently scheduled for September 4, 2020. Pepco will provide the magnetic field strength estimates after that date.

2. Mitigation Plans for Reducing the Magnetic Fields from Underground Transmission XLPE (Solid Dielectric) Cables

Regarding the mitigation of magnetic field resulting from underground transmission solid dielectric cables, these lines connecting to substations are very weak sources of magnetic fields above ground. The electric field is totally blocked by the coverings of the underground transmission lines and the earth itself. Although the magnetic field from underground lines is not similarly blocked by the ground cover, the placement of the conductors close together in conduits results in a significant reduction in the magnetic field and causes the magnetic field to diminish more quickly with distance so that even a few feet away from the lines field levels often fall to background levels. For these reasons, the opportunity for the underground lines to contribute to residential EMF is non-existent (electric fields) or vanishingly small (magnetic fields).

C. Order No. 20274 Attachment A: Communication Plan

The Commission directed that any Customer Outreach and Engagement Plan should include, at a minimum:

1. A detailed description and timetable of notice(s) to affected consumers of impending construction;

2. A plan of customer communications, such as bill inserts, newspaper ads, website postings;

3. An interactive dedicated website or project map related to the project which residents can access for project information;

4. A community liaison who consumers can contact with issues or complaints related to the project and who will be responsible for coordinating community outreach;

5. A hotline that consumers can contact to log complaints, which shall be responded to with 24 hours of receipt; and

6. A method of tracking consumer complaints related to the project, and periodic reporting and discussion of such complaints and their resolution to the Commission and the Office of the Peoples Counsel.

Please see Attachment B for the Communications Plan as updated for Order No. 20274.

D. Order No. 20274 Attachment A: Economic Opportunities

The Commission directed Pepco "to develop a plan with percentage goals and timelines associated with CBE contracting and hiring of local residents for the Capital Grid Project Construction."

In the Sept. 8, 2019 90-Day Compliance Filing to Order No. 20203, Pepco stated:

> Pepco will be hiring a compliance contractor to track resident hiring for the Capital Grid Project. The compliance contractor will be responsible for gathering, tracking and working with internal teams and the contractors to validate FTE reporting data inputs from contractor time and headcount reports. This data will be captured in Pepco's internal sourcing system that will also be used to collect CBE contractor data in an effort to streamline the process. Data will be then be compiled to produce the quarterly and annual CBE and local hiring reports that will be submitted to the Commission. Pepco historically has not tracked local contractor hiring and is still in the process of setting up its program and defining appropriate goals for its contractors. Pepco is in the process of contacting its contractors regarding their current and expected levels of District hiring and will use that data to help inform appropriate percentage goals.
>
> Once appropriate goals are set based on discussions with its contractors, Pepco will create a template for tracking and both the goals and the template will be shared with the Commission.

Pepco has completed the template (see Attachment C). Further, Pepco has implemented a secure data portal for intake of supplier hiring data. The first test of this data intake was performed from February 3 to February 24, 2020 for the January reporting period. The second test was performed March 2 to March 13, 2020 for the February reporting period. A total of 19 Capital Grid Project suppliers were queried. The range of responses were as follows:

Performance Period	January 2020	February 2020
Open to vendors to enter information in to SMART GEP	February 3-24	March 2-13
Total # of suppliers	19	11
Suppliers Responded	11	7
Suppliers with Questions	8	1
Suppliers failed to respond	8	4
% of DC residents on project	Data not available	12%
Total # of employee's vs DC residents	Data not available	8/1

To clarify the reporting requirement and improve the response rate, Pepco will add residency tracking into supplier Key Performance Indicator discussions, continue to highlight an opening screen message explaining the steps to reporting and results of non-compliance, and hold a conference call with the Capital Grid Project suppliers on the residency tracking requirement.

As a further follow-up, Pepco conducted a survey of Capital Grid suppliers asking what percentage of their total contingent they would agree is a reasonable initial goal regarding District resident hiring for the Capital Grid Project. The survey results indicate suppliers believe an initial goal of 25% of their workforce executing the Capital Grid work being District residents was attainable. Based on this data Pepco intends to use 25% as the starting point for its supplier District resident hiring and expects to be able to increase that amount incrementally on an annual basis, based on market conditions, through its contract award system.

The results of this reporting will be included in Pepco's Diverse Supplier Reports.

E. Order No. 20274 Attachment A: Construction Reporting to the Commission

The Commission directed Pepco to "provide an updated construction timeline for the major components of the Capital Grid Project." Pepco submits the following update to the construction timeline. Pepco notes that Gantt Charts will also be provided starting on April 15 as part of the quarterly Capital Grid Project reporting requirements.

Submission	Mt. Vernon Substation
30% - Civil	6/6/2018
60% - Civil	10/19/2018
90% - Civil	6/30/2020
IFC – Civil	9/4/2020
30% -Electrical/Layout/Str	6/6/2018
60% - Electrical/Layout/Str	10/20/2018
90% - Electrical/Layout/Str	6/4/2020
IFC - Electrical/Layout/Str	9/4/2020
30% - P&C	6/5/2018
60% - P&C Complete	8/17/2020
90% - P&C Complete	2/24/2021
IFC - P&C	4/9/2021

F. Order No. 20274 at Attachment A: Permits.

The Commission directed Pepco to provide it with the following when available:

a. Copies of all permits and/or instruments approving or authorizing work activities prior to the commencement of activities within 30 days of obtaining each permit or authorization;

b. Two calendar days' notice prior to conducting any work in areas identified as potentially contaminated; and

c. A report on all safety and environmental violations to human health and/or the environment within twenty-four (24) hours of receipt of a citation by any relevant governmental agency.

There has been no change to the permit matrix since Pepco's Nov. 7, 2019 Order No. 20203 90-Day Compliance filing in this docket.

MOUNT VERNON SUBSTATION MITIGATION PLAN

tb&a

pepco
An Exelon Company

DRAFT March 2020

INTRODUCTION

The Capital Grid project is a forward-looking plan that promotes enhanced reliability and will strengthen the District's energy grid. Along with a 10-mile transmission line, the project includes upgrading three substations in the District and Maryland and building a new substation to serve the Mt. Vernon community and its projected rapid growth and development.

The Mount Vernon Substation will be constructed at 1st and K Street NW in an area where there are currently more than 18,000 residential units and over 10 million square feet of completed and/or planned retail and office space. This continuous growth in Mount Vernon Triangle, Northwest One, Shaw, NoMa, and surrounding areas will overload the current system without the addition of a new substation to meet this area's growing demands.

The Mount Vernon Substation will be enclosed and housed in a building that fits the aesthetics of the surrounding area. While the substation will provide long-term benefits to customers, it involves substantial work and construction will have various impacts on the surrounding area. Until construction begins, we will use this property as a staging area. We expect to start construction in 2020 and to complete it by 2023. It is important to mitigate the concerns that are directly associated with the impacted stakeholders.

This Mount Vernon Substation Mitigation Summary serves as a tool to minimize the construction impacts as much as possible through an effective mitigation process that is built around proactive communication, education, transparency, responsiveness and collaboration.

APPROACH

Staying in front of the information curve, maintaining consistent communication with stakeholders surrounding the Mount Vernon Substation will be critical to the success of the project. We will continue to engage the identified stakeholders including:

- Meeting with stakeholders prior to the start of construction
- Keeping stakeholders regularly apprised of construction activity including anticipated impacts throughout the life of the project
- Notify stakeholders of any community meetings and encourage their attendance
- Promote project and safety awareness
- Build advocacy and trust by being a reliable, consistent and accessible source of information
- Track and respond to constituents' issues and concerns and collaborate with the contractor and/or appropriate agencies to assist with responses

IDENTIFICATION OF STAKEHOLDER GROUPS

We have identified the stakeholder groups that will be directly impacted by the construction of the Mt. Vernon Substation. Proactive communication with all stakeholder groups is critical to the success of the project. The delivery of clear consistent messaging to educate stakeholders on the purpose and need for the project, along with construction impacts will be used to ensure all stakeholder groups are informed and proactively updated on all activity.

CAPITALGRID
BUILDING TOMORROW'S ENERGY GRID TODAY

CAPITAL GRID PROJECT BENEFITS

The Capital Grid project provides many long-term benefits to our customers across the Capital region.

Enhanced Service
- New infrastructure that will reduce the strain on surrounding areas, improving service for customers

Stronger System
- Enhancements that will lessen the impact and speed recovery from storms and other emergencies

Added Capacity
- A more robust energy grid to handle energy needs, as the District experiences rapid residential and commercial development

Economic Support
- Increased opportunities for minority, women, veteran and disabled local businesses and contractors to support project work as we energize the diverse, local communities where we live and work

STAKEHOLDER GROUPS

- Residents
- Health Care Centers
- Schools/Libraries/ Recreation Centers
- Businesses
- Churches
- Multi-Modal Users
- Developers
- Government Agencies and Utilities
- City Officials
- Emergency Responders

CONSTRUCTION CONCERNS AND TASKS

We have identified the common stakeholder concerns. The following outlines the concerns and the tasks assigned to mitigate these concerns. The catchment area that would be most directly impacted by the Mount Vernon Substation construction falls within and in close proximity to the surrounding streets.

	PROPERTY ADDRESS			
Mount Vernon Substation (Catchment Area)	**Start**	**Finish**	**Zip Code**	**ANC**
L St. NW	100 (Unit Block)	1	20001	ANC 6E
1st St. NW	1150	850	20001	ANC 6E
New Jersey Ave. NW	1130	900	20001	ANC 6D
K St. NW	200	20	20001	ANC 6C
I St. NW	19 (Unit Block)	19	20001	ANC 6E
Pierce St. NW	170	124	20001	ANC 6E
First Terrace NW	1136	1159	20001	ANC 6E
1st Pl. NW	82 (Unit Block)	2	20001	ANC 6D

RESIDENTS (MULTI-UNITS)	CONCERNS
The Carmel Plaza Apartments - 200 K St. NW **The SeVerna** - 1001 1st St. NW **The SeVerna on K** - 43 K St. NW **Golden Rule Plaza** - 1050 New Jersey Ave. NW **Golden Rule Apartments** - 901 New Jersey Ave. NW **Sibley Plaza Public Housing** - 1140 North Capitol St. NW **Plaza West Apartments** - 307 K St. NW **Residential Dwellings** - 1st and Pierce St.	• Vibration • Trash/Specialized Services • Noise • Special Accommodations • Sidewalk/Road Closures • Traffic • Deliveries • Environmental • Parking and Driveway Access
HEALTH CARE CENTERS	**CONCERNS**
Providence Health System Perry Family Health Center - 128 M St. NW, #050 **Unique Rehabilitation & Health Center** - 901 1st St. NW	• Vibration • Trash/Specialized Services • Noise • Special Accommodations • Sidewalk/Road Closures • Traffic • Deliveries • Environmental • Accessibility
SCHOOLS/LIBRARIES/RECREATION CENTERS	**CONCERNS**
Walker Jones Education Campus - 1125 New Jersey Ave. NW **Northwest One Neighborhood Library** - 155 L St. NW **Infant Toddler Preschool** - 1135 New Jersey Ave. NW **Gonzaga College High School** - 19 I St. NW **UDC CCC** - 801 North Capitol St. NE **RH Terrell Recreation Center** - 155 L St. NW	• Vibration • Trash/Specialized Services • Noise • Special Accommodations • Sidewalk/Road Closures • Traffic • Deliveries • Environmental • Accessibility

BUSINESSES	CONCERNS
Colonial Garage - 90 K St. NW **Franklin Parking Lot** - 33 K St. NW **Walmart** - 99 H St. NW **Starbucks** - 99 H St. NW	• Trash/Specialized Services • Special Accommodations • Sidewalk/Road Closures • Traffic • Deliveries • Accessibility
CHURCHES	**CONCERNS**
Southern Baptist Church - 134 L St. NW **Holy Redeemer Catholic Church** - 206 New York Ave. NW **Bible Way Church** - 1100 New Jersey Ave. NW **Second Baptist Church** - 816 3rd St. NW **St. Aloysius Church** - 19 I St. NW	• Trash/Specialized Services • Special Accommodations • Sidewalk/Road Closures • Traffic • Deliveries • Accessibility
MULTI-MODAL USERS	**CONCERNS**
Bus Stop 1 - New York Ave./New Jersey Ave. **Bus Stop 2** - New Jersey Ave./Pierce St. **Bus Stop 3** - K St./New Jersey Ave. **Bus Stop 4** - K St./1st St **Pedestrians** **Bicyclists**	• Special Accommodations • Sidewalk/Road Closures • Traffic • Accessibility
DEVELOPERS	**CONCERNS**
Toll Brothers (Sursum Corda) - 1st and K St. NW **MRP/CSG Urban (Northwest One)** - North Capitol St. and K St. NW **Dantes Partners (Capitol Vista)** - 810 New Jersey Ave. NW **Property Group Partners (Capital Crossing)**	• Sidewalk/Road Closures • Traffic • Accessibility
ADDITIONAL HIGHLIGHTS	**CONCERNS**
K St. Farm - 111 K St. NW, Washington, DC 20001 **Farm at Walker Jones** - 111 K St. NW	• Sidewalk/Road Closures • Traffic • Accessibility

CONCERNS	TASKS
Vibration	• Conduct pre-construction video surveys • Continue to monitor and communicate with stakeholders experiencing concerns • Identify causes of vibration and coordinate solutions with contractor • Determine if vibration monitoring device is necessary
Trash/Specialized Services	• Survey construction area to identify pre-existing pick-up locations • Work with DPW and any private companies to create alternate pick-up locations during construction • Special consideration for private and bulk trash • Inform community of any changes and encourage container labeling • Monitor ongoing trash pick ups
Parking	• Survey and document parking challenges along route, identifying street cleaning hours/days. • Align Survey with MOT • Schedule routine field observations for quality controls • Coordinate with DDOT to temporarily adjust parking restrictions when needed based on MOT • Work with Capital Grid project team to provide off site parking options and/or shuttle service if needed
Special Accommodations	• Identify metro access users and other private transportation services by researching and contacting appropriate contacts to relocate pick-up and drop off locations. • Identify if there are any ADA parking restrictions and potential relocation options during construction. • Identify handicapped parking spots within the catchment area • Consider ADA access to apartment buildings and provide alternate access during construction
Parking and Driveway Access	• Survey and document parking challenges along route, identifying street cleaning hours/days. • Align Survey with MOT • Schedule routine field observations for quality controls • Coordinate with DDOT to temporarily adjust parking restrictions when needed based on MOT • Work with Capital Grid project team to provide off site parking options and/or shuttle service if needed
Accessibility	• Do field surveys of access points (especially for health centers) and coordinate with construction team to ensure they are never blocked
Environmental (Dust)	• Create dust and debris containment solutions that may include: Covering bare soil, keeping roads damp, applying dust retarding products, restricting earthmoving tasks during extremely windy conditions • Monitor the impacts during field visits

CONCERNS	TASKS
Noise	• Identify source of noise concern • Attempt to employ noise quieting methods such as: Haul roads, detours, temporary barriers and strategic storage areas to shield • Ensure Stakeholders are aware of construction hours • Field visits to monitor noise levels
Deliveries	• Identify potentially impacted stakeholders to document delivery schedules and coordinate relocation during construction or alternatives to ensure deliveries are made • Notify major delivery companies of construction (UPS, USPS, Amazon, FedEx, DHL) • If needed, work with DDOT to establish temporary delivery zones
Sidewalk/Road Closures	• Proactively notify the community of lane and sidewalk closures • Provide clear and strategically placed signage • Provide timeline for closures • Review and understand MOT and coordinate with DDOT on detours • Communicate with WMATA and transportation services to relocate bus stops if needed • Provide secure and safe options for ingress and egress
Traffic	• Keep interactive map updated • Work with DDOT on detours and traffic advisories • Deploy traffic control officers/flaggers if needed
Pedestrian Safety	• Provide signage and barriers to direct pedestrians safely around the work zone as required in the MOT • Work with the contractor to minimize uneven pathways during construction • Provide safe access to residences and establishments • Use traffic control officers to direct pedestrians, if needed. • Document traffic calming measures to ensure replacement once construction completed

ATTACHMENT C

Project Name: CAPITAL GRID
REPORTING PERIOD: October 2019 - December 2019
CALENDAR YEAR QUARTER: 4th

(A) LINE #	(B) PRIME VENDORS	(C) PRODUCT/SERVICES	(D) CONTRACT No.	(E) CBE Goal	District Hiring Goal	(F) TOTAL ($) SPEND	(G) TOTAL ($) CBE SPEND	(H) TOTAL ($) NON CBE SPEND	(I) PERCENTAGE OF CBE (%) SPEND
1		**Champlain Sub Rebuild /Materials**	X	8%	X%				X%
2		**Harvard Sub Rebuild /Construction**	X	20%	X%				X%
3		**Harvard Sub Rebuild/Construction**	X	20%	X%				X%
4		**Harvard Sub Rebuild /Materials**	X	8%	X%				X%
5		**Harvard Sub Rebuild/Engineering**	X	8%	X%				X%
				TOTALS					X%
	TIER II - Subcontractors (Diverse & Nondiverse)								
	CBE subcontractor	Materials	X	8%	X%				
	CBE subcontractor	Construction	X	20%	X%				
	CBE subcontractor	Engineering	X	8%	X%				
	CBE subcontractor	Materials	X	8%	X%				
	CBE subcontractor	Construction	X	20%	X%				
	CBE subcontractor	Engineering	X	8%	X%				
	CBE subcontractor	Materials	X	8%	X%				
						TOTALS	X%	X%	X%

CERTIFICATE OF SERVICE

I hereby certify that a copy of Potomac Electric Power Company's 90 Compliance Filing was sent to all parties on this March 19, 2020 by electronic mail:.

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Exelon Utilities

Baltimore Gas and Electric Company

Delmarva Power & Light Company

Potomac Electric Power Company

Maryland Energy Storage Pilot Program

PJM Emerging Technology Forum

January 11, 2020

January 11, 2020

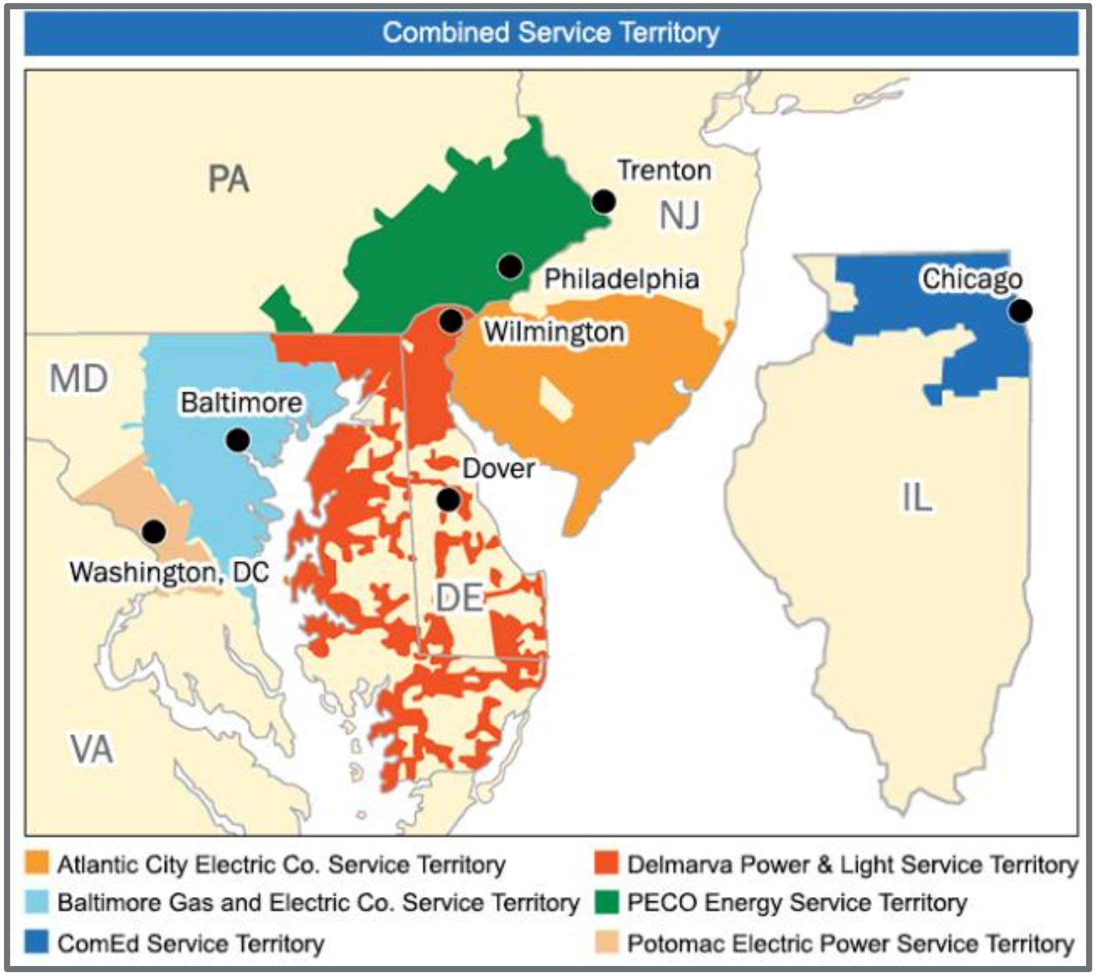
Agenda

1. About Exelon
2. Value Streams
3. Overview of MD Legislation and MD Pilot
4. Overview of Pilot Projects
   a. Fairhaven
   b. Chesapeake Beach
   c. Oxon Hill
   d. Silver Spring
   e. Ocean City
   f. Elk Neck
5. Next Steps

Exelon.

About Exelon

- Fortune 100
- 33,400 Employees
- 10M Electric and Natural Gas Utility Customers
- Utility Operations in 6 states
- 6 Utilities
  - Atlantic City Electric
  - BGE
  - ComEd
  - Delmarva Power
  - PECO
  - Pepco



Battery Energy Storage System Benefits

State Policy Goals

- Environmental Objectives
- Electric Vehicle support
- Green House Gas Reductions
- Economic Development
- Land Use

Utility Goals

- Deferral Opportunities
- Hosting Capacity
- Operational Flexibility
- Resiliency
- Reliability
- Service Quality (Voltage/Harmonics)
- Electrification
- Learnings
- PJM Market Participation

Customers Goals

- Resiliency
- Reliability
- Cost Savings
- Market Research
- Innovation
- DER Integration

Legislation and Policy

- Senate Bill 573/House Bill 650 was signed into Law May 13, 2019 and the Commission Order was released on June 1, 2019
- All MD Investor-Owned Utilities ("IOU") required to submit 2 pilots.
- One of the two projects for each utility must be third-party owned.
- Total aggregated program size is 5-10 MW with a minimum of 15 MWh
- Reporting to the Commission annually until 2025.

Models	BTM[1] / FTM[2]	Owner	Grid Reliability Control	Wholesale or Other Application Control
1. Utility Only	FTM	Utility	Utility	Utility
2. Utility and 3rd Party Operation	FTM	Utility	Utility	3rd Party
3. 3rd Party Ownership	Either	3rd Party	Utility contract with 3rd Party	3rd Party
4. Virtual Power Plant (VPP)	BTM	Customer or 3rd Party	Utility or contract with 3rd Party Aggregator	3rd Party, Customer(s) or Utility Aggregation

[1] "BTM" or behind the meter indicates that the storage system is placed behind the customer's revenue style meter

[2] "FTM" or front of the meter indicates that the storage system is in front of the customer's meter or that there is no revenue style meter on site

Maryland Exelon Utility Projects

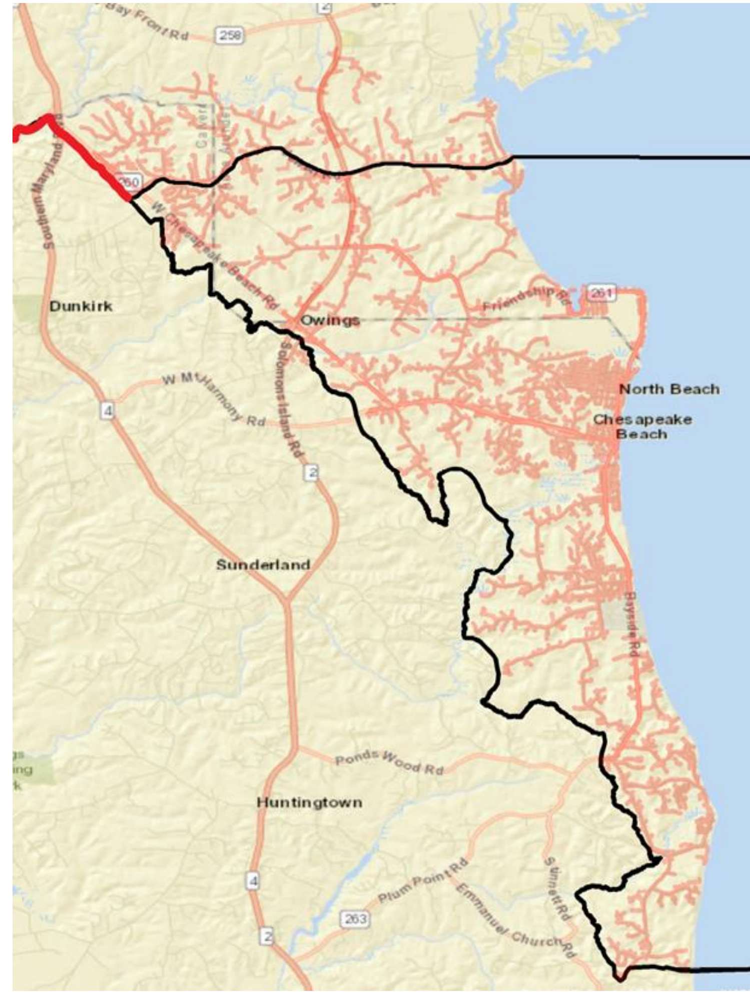
Project Summary

	Delmarva Power		PEPCO		BGE		
Project Description	Elk Neck, Maryland Project	Ocean City, Maryland Project	National Harbor/ Livingston Road Project	Montgomery County Electric Bus Depot Project	Chesapeake Beach Project	BESS at Fairhaven Substation Project	Total
Capacity	0.5 MW	1.0 MW	1.0 MW	1.0 MW	1.0 MW	2.5 MW	7.0 MW
Guaranteed End of Life Usable Capacity	1.5 MWh	3.0 MWh	3.0 MWh	3.0 MWh	1.5MWh	4.0 MWh	16.0 MWh
Initial Usable Capacity	2.2 MWh	3.6 MWh	4.3 MWh	4.3 MWh	2.0 MWh	7.1 MWh	23.5 MWh
Model 1: Utility Owned and Utility Operated		X				X	2
Model 2: Utility Owned and Third Party Operated			X				1
Model 3: Third Party Owned and Third Party Operated				X	X		2
Model 4: Virtual Power Plant	X						1

Pepco Holdings
An Exelon Company

BGE Identified Area of Need

- BGE reviewed all identified overloads system-wide and compared the costs of a BESS install vs. a traditional project
- Marriott Hill 34 kV post-contingency winter overload showed best opportunity for avoidance of traditional distribution system investment (10 miles of undergrounding)
- Area serves more than 9,000 customers via three substations and ten 13 kV feeders
- Provides opportunity for BGE to leverage two systems working in tandem:
  - Unique learning opportunity
  - Backup benefits from having multiple storage units (e.g., minimize maintenance down time, enhance storm resiliency)
- No utility real property acquisition required; adequate space for third-party project siting



BGE BESS at Fairhaven Project

Category	Project Information
Required Capacity for Grid Reliability through the 10-year project term	2.5 MW/4.0 MWh
Initial Usable Capacity	2.5 MW/7.1 MWh
Business Model	Model 1: Utility Only; BGE operates for grid reliability and in PJM markets, Front-of-the-Meter (FTM)
Project Developer	ABB/Hitachi is the proposed developer
Energy Storage Technology	Lithium-Ion BESS
Primary Application	Grid reliability/distribution infrastructure avoidance
Primary Operation	BESS will provide discharge capacity during winter peak load conditions; BGE will communicate a kW interval signal to the BESS Control system
Secondary Application	PJM Wholesale Market Services (Frequency Regulation)
Primary Location	Fairhaven Substation in Southern Anne Arundel County

BGE Chesapeake Beach Project

Category	Project Information
Required Capacity for Grid Reliability through the 10-year project term	1.0 MW/1.5 MWh
Initial Usable Capacity	1.0 MW/2.0 MWh
Business Model	Model 3: Third-Party Ownership that is Front-of-the-Meter (FTM)
Project Developer	Ameresco is the proposed developer/owner/operator
Energy Storage Technology	Lithium-Ion BESS
Primary Application	Grid reliability/distribution infrastructure avoidance
Primary Operation	BESS will provide discharge capacity during winter peak load conditions; BGE will communicate a kW interval signal to the BESS Control system up to 10 times in a year
Secondary Application	PJM Wholesale Market Services
Primary Location(s)	Multiple locations identified in Northern Calvert County

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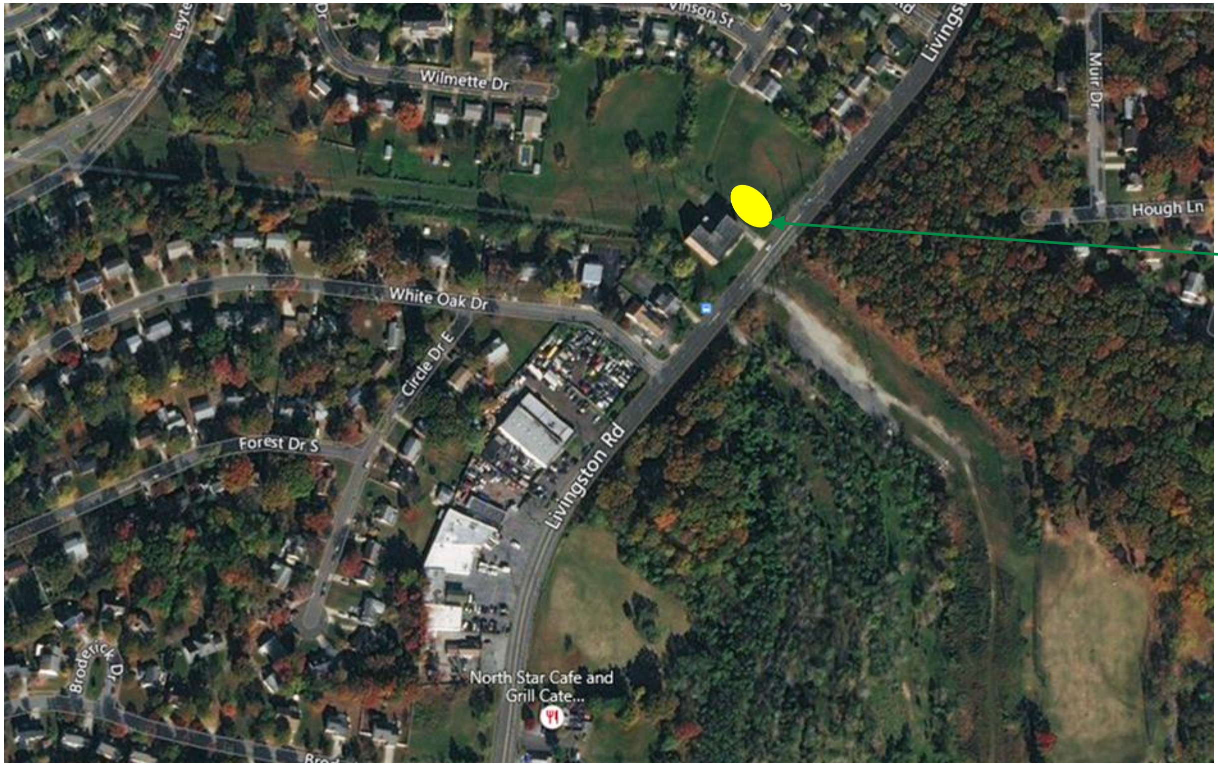
National Harbor Project Utility Owned/Third Party Operated Model



Battery Energy Storage

National Harbor Project: Located in Oxon Hill, Maryland

- Defer construction of a planned Pepco substation
- Peak shaving and grid emergencies
- PJM market participation opportunity – utility/third party revenue sharing
- Expected future expansion of battery storage at site – either utility owned or third party owned

National Harbor Project Summary

Project Category	Project Information
Size	1.0 MW/3.0 MWh
Business Model	Utility Owned/Third Party Operated
Energy Storage Owner	Pepco
Energy Storage - Wholesale Operations	A.F. Mensah (Minority Owned African American Firm)
Project Developer	A.F. Mensah (Minority Owned African American Firm)
Energy Storage Technology	Lithium Iron Phosphate (LFP)
Primary Application	Peak Shaving, Grid Reliability
Secondary Application	PJM Market
Location	Livingston Road, Oxon Hill, MD

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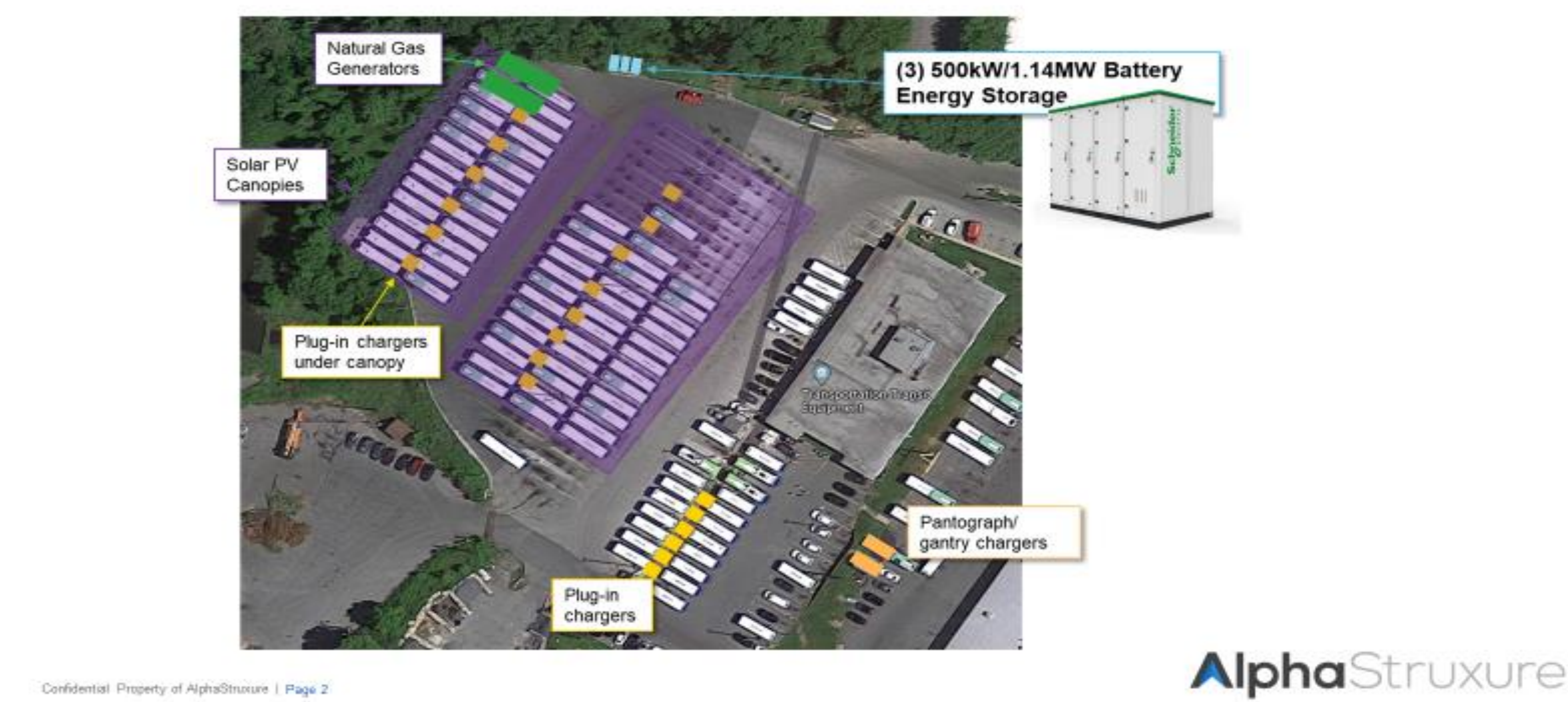
Bus Depot Project -- Third Party Owned/Third Party Operated

Draft Site Overview



Montgomery County Electric Transit Bus Depot: Silver Spring, Maryland

- Avoid construction of new Pepco distribution feeder
- Support regional grid reliability
- Support electric transit bus charging during normal grid conditions and grid outages
- Rely primarily on energy from planned photovoltaic array to charge battery

Exelon

Electric Bus Depot Project Summary

Project Category	Project Information
Size	1.0 MW/3.0 MWh
Business Model	Third Party Owned/Third Party Operated
Energy Storage Owner/Operator	AlphaStruxure
Project Developer	AlphaStruxure
Energy Storage Technology	Nickle Metal Chloride Lithium-Ion
Primary Application	Peak Shaving, Grid Reliability
Secondary Application	Customer side demand management. Charging during outages. Microgrid integration with photovoltaic array
Location	Brookville Road, Silver Spring, MD (Montgomery County)

Ocean City Project -- Utility Owned/Utility Operated Model

Ocean City Project: Beach-front Resort Community on a Barrier Island in the Atlantic Ocean

- Reliability improvement support for Automatic Sectionalizing and Restoration (ASR) Scheme
- Resiliency improvement by providing back-up support for adjacent county library and regional electricity grid (increasing storm risk resulting from climate change)
- PJM market participation opportunity
- Selected vendor: Mesa Veterans Power (Service-Disabled Veteran-Owned Firm)

Ocean City Project Summary

Project Category	Project Information
Size	1.0 MW/3.0 MWh
Business Model	Utility Owned/Utility Operated
Energy Storage Owner/Operator	Delmarva Power
Project Developer	MESA Veterans Power (Service-Disabled Veteran-Owned Firm)
Energy Storage Technology	Nickle Manganese Cobalt Lithium Ion
Primary Application	Peak Shaving, Grid Reliability, Resiliency
Secondary Application	PJM Wholesale Market
Location	Ocean City, MD (Worcester County)

Elk Neck Project -- Virtual Power Plant Business Model

Elk Neck Project: Residential community located in Cecil County on an isolated peninsula in the Chesapeake Bay

- First Exelon Utility Virtual Power Plant and first PJM Market Virtual Power Plant

Reliability/Resiliency Opportunity:

- 300 + residential customers south of Elk Neck State Park fed by a four-mile radial feeder
- Unique Virtual Power Plant Project
- Experienced vendor selection – Sunverge Energy, Inc.

Exelon

Elk Neck Project Summary

Project Category	Project Information
Size	0.5 MW/1.5 MWh
Business Model	Virtual Power Plant (VPP) - Aggregated Residential Storage Program
No of Customers in the VPP Program	110 Residential Customers
Energy Storage Developer/Owner	Sunverge Energy, Inc
Energy Storage - Wholesale Operations	PJM Virtual Power Plant Pilot
Energy Storage Technology	LG Electronics 5kW/19.6 kWh
Primary Application	Grid Reliability & Backup Power
Secondary Application	DER-Integration/Possible PJM Market Participation
Location	Elk Neck Peninsula, Cecil County, Maryland

Next Steps

1. Execute contracts with vendors
2. Respond to Commission requirements for emissions modeling, decommissioning and safety
3. Continue to take steps to participate in the PJM market
4. Complete integration plan for utility operation of batteries for grid support
5. Continue to investigate other opportunities for storage

Projects associated with the modified Downtown Resupply Plan which should not be included in the Multi-Year Rate Plan.

		$s in '000s			
Number	**ITN Name**	**2023B**	**2024B**	**2025B**	**2026B**
11	68678: L. St Rebuild Distribution Work	$ 269	$ 1,109	$ -	$ -
16	72137: L St Sub Capacity Expansion Work	$ 4,449	$ 10,966	$ 3,314	$ -
152	80130: Pepco DC Buzzard to F Street	$ 270	$ 1,695	$ 2,439	$ 1,548
153	80425: Pepco DC F Street to Georgetown	$ 852	$ 1,334	$ 99	$ -
154	80427: Pepco Champlain to L Street 69kV	$ 1,179	$ 2,333	$ 10,065	$ 23,782
155	80740: Pepco DC Champlain to F Street	$ 1,482	$ 877	$ -	$ -
213	68612: Pepco DC L St T1 Replacement	$ 746	$ 81	$ 83	$ 84
214	68613: Pepco DC L St T2 Replacement	$ 714	$ 89	$ 89	$ 92
215	68614: Pepco DC L St T3 Replacement	$ 192	$ 97	$ 97	$ 2,806
216	68615: Pepco DC L St T4 Replacement	$ 197	$ 105	$ 2,341	$ 39
236	71630: F St Sub Rebuild (69kV) (UDSPLM718A)	$ 709	$ 4,239	$ 3,669	$ 1,799
237	71631: F St Sub Rebuild (UDSPLM717A)	$ 540	$ 2,996	$ 2,648	$ 1,441
299	73368: Champlain Bypass	$ 1,790.19	$ 5,699.99	$ 1,034.35	$ 761.17
306	71012: Champlain - New 69kV Sub (DSPRD8AD17)	$ 831.01	$ 1,341.16	$ 5,788.36	$ 17,646.81
	Total	**$ 14,220.86**	**$ 32,960.87**	**$ 31,667.71**	**$ 49,997.73**

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Andrea H. Harper
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February 4, 2020

Ms. Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 G Street, N.W., Suite 800
Washington DC, 20005

Re: Formal Case No. 1144

Dear Ms. Westbrook-Sedgwick:

On August 9, 2019, the Public Service Commission of the District of Columbia issued Order No. 20203 approving Phase 1 of the Capital Grid Project. In its order, at Paragraph 46, the Commission directed Pepco "to provide a draft format for the Annual Report for review and approval by the Commission within 180 days of the date of the Order." Pursuant to Order No. 20203, Pepco is filing its 180-day compliance filing, which includes its proposed draft format for the Annual Report.

Please contact me if you have any further questions.

Sincerely,

Andrea H. Harper

Enclosures

cc: All Parties of Record

FC 1144
Capital Grid - Downtown Resupply Project
Annual Report

Attachment [X] to Annual Consolidated Report

Downtown Resupply Description (updated, if appropriate):

The Downtown Resupply project will replace aging 34 kV and 69 kV supply feeders to the L Street, F Street, Georgetown, and 22nd Street Substations. This work along with upgrades to the F Street Substation and extension of new 13 kV feeders will accommodate load transfers from I Street Substation as well as increasing sub-transmission supply capacity and providing reliability benefits to the District of Columbia.

Explanation of Significant changes to Project:

[ ]

Cost Estimate (provided in Formal Case No. 1144):

Items	Estimate Net (Lifecycle) ($)
Downtown Resupply	494,028,210
13kV Distribution Cutovers "F" St to "L" St (UDLPLM7W27)	39,849,304
13kV Distribution Cutovers from "I" St to "F" St & "L" St (UDLPLM7W28)	32,434,952
Champlain to L Street 34kV (UDLPRM4WA8)	102,319,736
F St Sub Rebuild (69kV) (UDSPLM718A)	50,372,188
F St Sub Rebuild (UDSPLM717A)	33,581,458
L St Sub Capacity Expansion Work (UDSPLM722A)	4,011,558
Repl 69kV Self-Containd UG Supl-Georgetown,"F" St, 22nd St Subs (UDLPRM5SG)	177,223,136
Retire "I" St Sub (UDSPRD27RD)	2,081,496
Retirements for Downtown Resupply 34kV and 69kV for DC (UDLPRM4RDR)	35,522,470
Retirements for Downtown Resupply 34kV and 69kV for MD (UDLPRM4DRM)	1,309,199
Retirements for Downtown Resupply 34kV and 69kV for VA (UDLPRM4DRV)	13,322,712
Telecom - 22nd Street Sub (UDFPO22SS)	500,000
Telecom - Fiber for 34-69kV Resupply Champlain, L Street, F Street (UDFPOCL01)	500,000

Telecom - Georgetown Sub (UDFPOGS01)	500,000
Telecom - L Street Sub (UDFPOLS01)	500,000

Current Cost Estimate (As of xx/xx/2020):

[ ]

Construction Schedule (provided in Formal Case No. 1144):

L Street Substation: 2020-2021
F Street Substation: 2022-2026
I Street Substation: 2026-2028
69kV Supplies: 2019-2028
34kV Supplies: 2019-2028
13kV Supplies: 2019-2027

Updated Construction Schedule (as of xx/xx/2020):

[ ]

CERTIFICATE OF SERVICE

I hereby certify that a copy of Potomac Electric Power Company's 180 Day Compliance Filing was sent to all parties on this February 4, 2020 by electronic mail, first-class, postage prepaid, or hand delivery.

Ms. Brinda Westbrook-Sedgwick
Commission Secretary
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Andrea H. Harper
Andrea H. Harper

PUBLIC
Exhibit OPC (E)-22
Formal Case No. 1176

Confidential Materials Omitted

PUBLIC
Exhibit OPC (E)-23
Formal Case No. 1176

Confidential Materials Omitted

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 11

QUESTION NO. 3
Referencing the Company's Traditional Test Year Compliance filing, will project 70096: 13kV Distribution Cutovers "F" St to "L" St (exhibit Pepco (H)-2 page 11 of 216) be completed within the test year?

a. Provide documentation demonstrating the completion of the project.

RESPONSE:

No portion of this project will be completed within the test year.

a. No documentation can be provided at this time as the project is still on-going.

SPONSOR: Jaclyn Cantler

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 11

QUESTION NO. 4
Referencing the Company's Traditional Test Year Compliance filing, will project 80906: Pepco DDOT Bridge 78 Relocation - 69kV pipe type (exhibit Pepco (H)-2 page 41 of 216) be completed within the test year?

a. Provide documentation demonstrating the completion of the project.

RESPONSE:

No portion of this project will be completed within the test year.

a. No documentation can be provided at this time as the project is still on-going.

SPONSOR: Jaclyn Cantler

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Andrea H. Harper
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June 29, 2018

Ms. Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission of the District of Columbia
1325 G Street, N.W.
Suite 800
Washington, D.C. 20005

Re: Formal Case Nos. 1130 and 1144

Dear Ms. Westbrook-Sedgwick:

Enclosed please find Potomac Electric Power Company's Reply Comments in the referenced proceedings.

Please contact me if you have any further questions.

Sincerely,

Andrea H. Harper

Andrea H. Harper

Enclosures

cc: All Parties of Record

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

IN THE MATTER OF	)	
	)	
THE POTOMAC ELECTRIC POWER	)	
COMPANY'S NOTICE TO CONSTRUCT	)	
TWO 230 KVUNDERGROUND CIRCUITS	)	
FROM THE TAKOMA SUBSTATION	)	
TO THE REBUILT HARVARD	)	**Formal Case No. 1144**
SUBSTATION AND FROM THE REBUILT	)	
HARVARD SUBSTATION TO THE	)	
REBUILT CHAMPLAIN SUBSTATION	)	
(CAPITAL GRID PROJECT)	)	
	)	
AND	)	
	)	
IN THE MATTER OF	)	
	)	
THE INVESTIGATION INTO	)	
MODERNIZING THE ENERGY DELIVERY	)	**Formal Case No. 1130**
SYSTEM FOR INCREASED	)	
SUSTAINABILITY	)	

<u>REPLY COMMENTS OF POTOMAC ELECTRIC POWER COMPANY</u>

Pursuant to Order Nos. 19274[1] and 19313,[2] Potomac Electric Power Company ("Pepco") respectfully files its reply ("Reply Comments") to the comments filed by the District Department of Energy and Environment ("DOEE"), including the study prepared by Synapse Energy Economics, Inc. ("Synapse") on <u>Alternatives to Building a New Mt. Vernon Substation in</u>

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1 *In the Matter of the Potomac Electric Power Company's Notice to Construct Two Underground Circuits from the Takoma Substation to the Rebuilt Harvard Substation and from the Rebuilt Harvard Substation to the Rebuilt Champlain Substation (Capital Grid Project)*, Formal Case No. 1144, Order No. 19274 (Feb. 14, 2018) ("Order No. 19274").

2 *In the Matter of the Potomac Electric Power Company's Notice to Construct Two Underground Circuits from the Takoma Substation to the Rebuilt Harvard Substation and from the Rebuilt Harvard Substation to the Rebuilt Champlain Substation (Capital Grid Project)*, Formal Case No. 1144, Order No. 19313 (Apr. 5, 2018) ("Order No. 19313").

Washington, DC ("Synapse Study"), filed with the Public Service Commission of the District of Columbia ("Commission") on January 29, 2018 ("DOEE Comments").

I. BACKGROUND

On May 10, 2017, Pepco filed with the Public Service Commission of the District of Columbia ("Commission") a Notice of Construction for construction of two 230 kV underground circuits from the Takoma Substation in Takoma Park, Maryland to the rebuilt Harvard Substation and from the rebuilt Harvard Substation to the rebuilt Champlain Substation as well as upgrading aging substation infrastructure ("NOC-1"). Pursuant to its authority under Chapter 21 of the District of Columbia Municipal Regulations, the Commission issued a Notice *sua sponte* opening an investigation into the reasonableness, safety, and need for the underground transmission lines and the substations in NOC-1 on May 24, 2017, noting that "Pepco has provided, with its NOC, the information the Commission requires when initiating an investigation pursuant to Chapter 21 of Title 15 of the D.C. Municipal Regulations."[3] The Commission set comments and reply comments on NOC-1 for 90 and 120 days, respectively, after the Notice was published in the D.C. Register.[4] On September 7, 2017, the Commission issued Order No. 19085 *sua sponte* extending the comment period to November 29, 2017 and the reply comment period to January 2, 2018.[5] Various participants filed comments on NOC-1. On

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3 *In the Matter of the Potomac Electric Power Company's Notice to Construct Two 230 kV Underground Circuits from the Takoma Substation to the Rebuilt Harvard Substation and from the Rebuilt Harvard Substation to the Rebuilt Champlain Substation (Capital Grid Project)*, FC 1144, Public Notice (May 24, 2017) ("Notice").

4 Notice at P 3.

5 *In the Matter of the Potomac Electric Power Company's Notice to Construct Two 230 kV Underground Circuits from the Takoma Substation to the Rebuilt Harvard Substation and from the Rebuilt Harvard Substation to the Rebuilt Champlain Substation (Capital Grid Project)*, FC 1144, Order No. 19085 (Sept. 7, 2017) ("Order No. 19085").

January 2, 2018, the Commission *sua sponte* extended the date for reply comments to February 1, 2018,[6] and Pepco responded to the comments on February 1, 2018.

On January 29, 2018, DOEE filed in Formal Case No. 1130 comments that included the Synapse Study. On February 14, 2018, the Commission issued Order No. 19274 which, *inter alia*, directed Pepco to respond to the Synapse Study in Formal Case No. 1144.[7] Pepco responds to the Synapse Study and the DOEE Comments herein.

I. Executive Summary

It is a dynamic time in the District of Columbia and in the energy industry. A transformation toward a clean energy future throughout the country is underway, and the District of Columbia is a leader in bringing about this change. Pepco is making the necessary investments to enable this and deliver on our promise to provide safe, reliable, affordable and sustainable energy to all customers.

Over the past several years, Pepco has invested in modernizing the electric grid in the District of Columbia, using innovative technologies that have resulted in top-decile reliability for customers. At the same time, these investments are making the grid smarter, more dynamic and better able to integrate distributed energy resources ("DER"), such as rooftop solar, electric vehicles ("EV"), energy storage as well as facilitating demand response ("DR") and greater energy efficiency ("EE").

Pepco has the privilege to serve the District of Columbia and its residents and businesses, which have been so progressive and forward thinking when it comes to advancing and adopting energy innovation and combatting climate change. Pepco takes its role in facilitating and

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[6] *In the Matter of the Potomac Electric Power Company's Notice to Construct Two 230 kV Underground Circuits from the Takoma Substation to the Rebuilt Harvard Substation and from the Rebuilt Harvard Substation to the Rebuilt Champlain Substation (Capital Grid Project)*, FC 1144, Third Public Notice (Dec. 29, 2017).

[7] Order No. 19274 at P 18, Attachment A.

enabling this new, clean energy future seriously—a future that is more decarbonized, more distributed, more digitized and more connected. At the same time, Pepco understands the awesome responsibility it has serving the District of Columbia. It is important that Pepco invest to harden the grid to make it more resilient in the face of climate change and evolving threats, both physical and cyber-related. Pepco has made, and is proposing to make, these investments in system hardening and redundancy so that when extreme events occur, such as the storms of this past winter, it does not take a serious toll on the District of Columbia.

As Pepco engages in grid planning, it continuously asks a series of questions related to what the implication of all these new innovations and technologies are for the electric grid and for customers. What investment is needed to seamlessly connect and integrate these innovative technologies to the grid? What investment is needed to ensure high-levels of reliability for all customers in the face of incredible load growth in various pockets throughout the District of Columbia? What are the types of redundancies that are needed to maintain the integrity of the system in the face of extreme events? What investment is needed to facilitate further de-carbonization of the electric system? And, how can Pepco best balance these investment needs with the need to maintain overall system affordability?

This type of planning process led Pepco to determine that the Capital Grid Project is a critical part of ongoing efforts to improve and modernize the electric grid. It will deliver value to customers by increasing resiliency and reliability, allowing for greater interconnection of DER and creating the foundation for a clean energy future. The Capital Grid Project, for which Pepco is seeking approval, is a long-term plan that efficiently addresses multiple system needs: aging infrastructure, load growth, networking the transmission system for redundancy, enabling the deployment and integration of zero-carbon technologies and providing for the growing penetration of DER. The project, which will run from February 2019 through June 2026, involves rebuilding two existing substations (Harvard and Champlain Substations), constructing approximately 10 miles of underground transmission lines and constructing a new substation (Mt. Vernon Substation) in the District of Columbia. At the same time, Pepco is seeking authorization to pull the cable through the conduit authorized for installation in Order No. 18254 to allow it to convert the Waterfront Substation to a 230 kV substation.

Throughout the planning of the Capital Grid Project, Pepco was very cognizant of the cost of the investment and intent on ensuring that customers will receive the value they deserve. It is important to keep affordability front and center. Customers will pay the bill, so the affordability of these investments is as important as enabling the future energy platform and maintaining high levels of reliability. Pepco evaluated many different alternatives to the Capital Grid Project and found that the Capital Grid Project, as proposed, resulted in the greatest value to District of Columbia customers, addressing the myriad of system needs, cost-effectively, while continuing to increase the capacity and capability of the system to advance and enable a clean energy future.

These innovative technologies and services that are available to customers, such as rooftop solar, EV charging and storage rely on the grid to be enabled. The grid needs to be more connected and more resilient than it has ever been. The grid must be better able to safely and reliably interconnect the increasing number and variety of DER that make the clean energy future a reality.

For these reasons, the Capital Grid Project is necessary, reasonable and safe, providing for increasing levels of flexibility and resiliency, and should be approved as proposed.

As Pepco evaluated the electric grid within the District of Columbia, it identified several areas that require additional attention and investment. Two of the substations and the supply lines to those substations necessary to supply reliable electricity to District of Columbia homes and businesses are aged and in need of replacement. It will also improve the reliability of certain radial distribution feeders in the service area. In addition, rapid load growth forecasted in the Mt. Vernon Triangle, NoMa, Capitol Crossing, and Northwest One areas in the District of Columbia cannot be supported by the current infrastructure and necessitate construction of a new substation. Moreover, although the current radial configuration of the District of Columbia transmission system has been adequate to reliably serve the load in the District of Columbia, it is susceptible to low probability high impact events. If an extreme event were to impact any one of the four transmission pathways, customers within the District of Columbia could be without power for extended periods of time. Finally, investment is necessary to upgrade and enhance the existing infrastructure in the District of Columbia to be able to deliver on the District's aggressive Renewable Energy Portfolio Standard ("RPS") goals and sustainability requirements and to meet the modernization expectations of the District, the Commission and customers.

Importantly, the Capital Grid Project also will support system modernization in a number of ways. Part of Pepco's modernization process includes incorporating DER on the distribution system and deferring wires investments with non-wires solutions. Pepco is actively exploring alternative solutions to defer wires investments in a manner that will safely, reliably, and economically manage increasing loads. Pepco's approach is first to look for small-scale projects that would allow for quick remediation should the alternative solution cause unforeseeable negative impacts on any component of the system. Pepco has identified a deferral project as part of the Capital Grid Project that will increase Pepco's understanding of the responsible deferral of wires solutions through use of DER on the distribution system. As part of the Capital Grid Project, Pepco is proposing to install a storage unit in the Mt. Vernon Substation that will allow it to defer the fourth transformer. Because only three of the transformers in the Mt. Vernon Substation are needed by 2023, the storage battery will be used to gain an understanding of the impacts of storage on the distribution system and to defer the fourth transformer when the transformer would otherwise be needed.

The Capital Grid Project also will increase the hosting capacity within the District of Columbia and increase the ability to safely and reliably interconnect DER to Pepco's distribution system.

Finally, in addition to the reliability, resiliency, and sustainability benefits, the project results in an increase in economic activity associated with professional services required to construct the facilities, benefitting the District of Columbia and generating increased opportunities for minority, women, veteran and disabled local businesses and contractors to support the project. For example, the labor income for the District of Columbia associated with the Capital Grid Project is estimated at $63,440,708 and the GDP benefit is estimated at $85,685,724.

By contrast, the Synapse Study offers flawed analyses and cannot be relied upon as a non-wires solution that can defer the Mt. Vernon Substation. The study has failed to identify the extent of the need that its purported non-wires solution is planned to defer, thereby placing at risk the reliable service of 7,400 residential customers and 270 commercial customers, a total of over 100 MVA of load. The Synapse Study makes overly optimistic assumptions about peak load reductions that can be gained from EE and DR, assumptions that are unsupported by the realities of the District of Columbia and the study's own evidence. The Synapse Study further bases its analysis and conclusions on an incorrect identification of the customers and areas that will be served by the Mt. Vernon Substation, resulting in proposed solutions that are not tailored to the realities of the system and would leave customers at undue risk. The study cannot be relied upon to present an alternative to the Mt. Vernon Substation and should be rejected.

The Mt. Vernon Substation is an important part of a forward-looking plan that will strengthen the Capital area energy grid over the long term, promoting enhanced reliability and resiliency while creating smarter energy infrastructure to accommodate new growth and enable the clean energy future. The Capital Grid Project is necessary, reasonable and safe and delivers on Pepco's responsibility to provide safe, reliable, and affordable and sustainable energy to District of Columbia customers and communities.

II. Response

A. Pepco Is Committed to Adding New, Innovative Technologies and Alternative Solutions, including DER, to Its System in a Manner that Allows It to Provide Safe and Reliable Service

The use of non-wires solutions to defer traditional wires investment is an important advancement in the distribution of electricity in the District of Columbia. As with other innovative technologies, Pepco is committed to this advancement and is actively looking for opportunities to use non-wires solutions to defer wires solutions for load projects on its system. In moving forward with non-wires solutions and other innovative technologies, Pepco must ensure the safe and reliable distribution of electricity to its customers. Taking into consideration the unique characteristics of the District of Columbia and its distribution system, Pepco is looking for deferral projects that will allow customers to enjoy the benefits of the alternative solutions while assuring that Pepco can continue to provide safe and reliable service.

Delivering state-of-the-art innovation and modernization of the electric grid to benefit customers is inherent in the public utility responsibilities of Pepco, and Pepco's investments to date have created the reliable electric delivery system that powers the District of Columbia. When Pepco makes planning decisions about its system, it examines available technologies and makes the necessary upgrades in a way that continues to modernize the system and maintain reliability for all customers. Pepco's distribution system of today is more advanced than the system was even a few years ago and far more advanced than decades ago. These innovations made in the normal course of operations, while often imperceptible to many external stakeholders, have significantly extended system capabilities over time and are creating the modern grid required to support increased deployment of DER and viable alternatives to traditional capital investment. At the forefront when Pepco makes these planning decisions are both the cost to of the investments to customers and Pepco's obligation to provide customers reliable service.

Pepco continues to develop its distribution system through state-of-the-art investments. The integration of advanced metering infrastructure ("AMI") technology and resulting data into Pepco's load forecasting and planning processes for DER, new information technology upgrades to expand support for Community Renewable Energy Facilities, and DER-related deployment of smart inverters are examples of more recent system innovations that support the deployment of DER[8] and improve the Pepco customer experience. The Company has provided customers access to detailed hourly energy use data and the ability to share that data with selected developers. Pepco was among the first utilities in the country to adopt the White House Green

[8] *See In the Matter of the Investigation In Modernizing the Energy Delivery System for Increased Sustainability*, Comments of Potomac Electric Power Company, Formal Case No. 1130 (Apr. 10, 2017) ("Pepco MEDSIS Staff Report Comments") at 2-3 (providing examples of actions by Pepco in modernizing the electric distribution system).

Button Initiative, which allows customers to access their detailed hourly energy consumption data and the ability to share that data with energy suppliers. Resource Advisor (for the DC Benchmarking Mandate) allows building owners to see their entire building data in aggregate. The "Request Customer Usage" tool on Pepco's website provides secure access for contractors to obtain authorization to access and download customer energy usage data, allowing contractors to more accurately assess customer DER system requirements through the use of historical usage information that is requested and accessed electronically. Residential customers can access MyAccount on the Pepco webpage or sign a paper release, which can be uploaded to the Request Customer Usage module. Finally, CEO (Chief Energy Officer) is an online tool enabling the larger NEM customers who cannot access data via My Account to see their usage.

Pepco also provides on its website state-of-the-art tools for customers interested in connecting DER to Pepco's system. Pepco provides WattPlan, an online service to help customers estimate the potential electricity generation and savings based on their specific rooftop characteristics, historical usage, current rates, and available rebates and credits. Customers are able to create a personal estimate, view side-by-side comparison of financing options and learn more about the interconnection process. Pepco also makes available a Hosting Capacity Map that provides data that customers can use to determine if solar or other DER can be accommodated at their home and developers can use to help size or site large projects. The Company provides an interactive cross-border feeder map to help customers identify potential project locations in Maryland that may be eligible for Solar Renewable Energy Credits ("SRECs") in the District of Columbia, the first of its kind in the industry. Pepco hosts a Restricted Circuit Map that provides information regarding circuits that are no longer accepting additional DER installations, without distribution system upgrades, because the feeder has reached the DER threshold after which violations of voltage operating limits or other dangerous conditions may occur.[9] An Acceptable Inverters List is posted on the website that provides a list of inverters that meet the applicable standards to be used on Pepco's distribution system. Finally, Pepco provides a Solar Heat Map in an effort to provide more information to customers regarding the amount of solar generation that is currently installed and pending install on circuits. The map is color-coded and can be filtered to display the active projects only, pending queued projects only, or the combination of active and pending queued projects. The user is able to put the cursor over the feeder and see the actual amounts of solar (installed or pending queued or both) and any circuit restrictions.

Pepco also has offered numerous demand response and energy efficiency and conservation programs, including time-of-use rates, electric demand charges, residential air conditioning cycling programs, non-residential demand response programs, and numerous residential energy efficiency and conservation programs.[10]

Underlying every decision that Pepco makes to modernize its distribution system, however, is recognition of its obligation to provide its customers safe and reliable electric service. As the local electric utility, Pepco is charged with making investments in the electric distribution system, which it owns and operates, to improve reliability and customer satisfaction. Those investments—for which Pepco is always accountable to the Commission and ultimately its customers—must address the short- and long-term needs of an electric system infrastructure while also being prudent, safe and reliable.

[9] There are currently no restricted circuits in the District of Columbia.

[10] The mix of programs Pepco is permitted to offer at any time is dependent upon Commission and legislative authorizations.

Pepco incorporates any new technology into its system in a manner that allows for adequate testing and learning in anticipation of a broader rollout after the technology is proven on Pepco's District of Columbia distribution system. By taking this approach, Pepco is able to incorporate new technologies without degrading safety, reliability or customer satisfaction. Deployment of non-wires solutions is no different.

With clear "line of sight" of day-to-day, system-wide utility operations, Pepco is in the best position to leverage existing utility infrastructure to control costs and ensure both continued focus on the essential safety and reliability of core distribution system operation and the introduction of new technologies and other functionality that are appropriately delivered by the local electric distribution company. Moreover, it is Pepco—not Synapse, DOEE or any other entity—that people will turn to if the superior reliability that they currently experience begins to falter. Pepco is actively exploring non-wires deferral projects in a manner that will safely and reliably manage increasing loads. Taking into consideration the unique characteristics of the District of Columbia and its distribution system, Pepco is looking in the District of Columbia first for smaller-scale projects that would allow for quick remediation should the alternative solution cause unforeseeable negative impacts on any component of the system. In other jurisdictions, Pepco Holdings has been able to identify larger-scale non-wires deferral projects, such as a substation supplied by overhead lines. Given the dense urban load, the lack of space for siting batteries necessary to reliably support the low voltage alternating current ("LVAC") network groups and other unique systems in the District of Columbia, large deferral projects are more difficult to identify in the District of Columbia. In all cases, Pepco projects for which non-wires solutions may be considered are based on demonstrable current or forecasted needs that are often driven by load growth. Any proposed non-wires solution must consistently deliver a level of reliability commensurate with the initially-identified traditional solution.

Pepco has identified such a project in the District of Columbia. As part of its Capital Grid Project application, Pepco is proposing a project that will defer a significant investment in the Mt. Vernon Substation and can be used to pave the way to prudently implement larger-scale deferrals in the future. As discussed in more detail below, the Mt. Vernon Substation will be built as a standard 210 MVA substation. The forecasted need for the Mt. Vernon Substation is only for 140 MVA of the 210 MVA by 2023. The final 70 MVA will be provided by the addition of the fourth transformer, which currently is forecasted to be needed some time after 2028. Pepco proposes to use a non-wires solution (battery energy storage) to defer the need for the fourth Mt. Vernon Substation transformer as a deferral project, accomplishing Pepco's need for 140 MVA by 2023 and allowing Pepco, stakeholders and customers to enjoy the benefits of a non-wires solution on a scale that will continue to deliver reliability commensurate with the installation of the transformer it is deferring. During the period between which the battery is installed and the deferral of the transformer becomes necessary, Pepco is able to use the battery to create scenarios that will increase learning about using non-wires solutions within the downtown distribution system. Pepco is also actively evaluating other battery energy storage projects in the District of Columbia and in its other jurisdictions that would provide valuable learning regarding how to use battery energy storage in lieu of wires solutions in a manner that would ensure safe and reliable electric service to Pepco's customers. As previously discussed, Pepco has identified an opportunity to defer a substation supplied by overhead lines in Maryland using battery storage and continues to look at other potential options.

B. Mt. Vernon Substation is Necessary to Ensure Reliable Electric Service to District of Columbia Customers

While the safe and reliable deferral of future substations in the District of Columbia using alternative solutions may be on the horizon, Mt. Vernon Substation is necessary now. The proposed Mt. Vernon Substation—which currently has an in-service date of 2023—will be a high-capacity, permanent 230 kV/13 kV substation that initially will provide 140 MVA of firm capacity, with ultimate firm capacity of 210 MVA. This substation is needed to provide load relief to the Northeast Sub. 212 Southwest LVAC Network Feeder Group, the New Jersey Ave. Sub. 161 South LVAC Network Feeder Group, the Northeast Substation, and the Tenth Street Substation. These distribution capabilities have been previously expanded to their maximum capacity and would otherwise be overloaded or near full capacity as early as 2023 if the Mt. Vernon Substation were not constructed.

The cause of the initial overload is the rapid and dynamic load growth that is currently occurring and forecasted to occur in the Mt. Vernon Triangle, NoMa, Capitol Crossing, and Northwest One areas. Many of the areas that have recently been parking lots or empty buildings with minimal load requirements are being developed into high-load, multi-unit buildings. For example, the parking lot in Figure 1, located at North Capitol Street, NW and K Street, NW, is one block from the site of the proposed Mt. Vernon Substation and will be developed by MRP as part of the larger Northwest One revitalization area. The MRP development will consist of approximately 56,500 square feet of retail and over 800 residential units (rendering in Figure 1).

Figure 1

Transforming a parking lot or low load building into a mixed-use development, such as Northwest One, results in a significant amount of load being added to the distribution system. In the case of the MRP buildings, the development will add 2.8 MVA of load to the system.

The increase in load is studied and quantified for planning purposes and results first in a determination of how much load is being added—and where it is planned to be added—through

Prospective New Businesses ("PNBs") and, second, how the expected PNBs will affect future system needs. Using data from requests for electric service, various real estate development reports, various media sources, and Pepco site visits, a summary of all the recently completed, in progress, and planned construction projects was assembled for these areas using the parameters and assumptions that are part of Pepco's short- and long-term load forecasting process. For load-driven projects, such as the Mt. Vernon Substation, the Capacity Planning group reassesses the status of the PNBs every year. To the extent that the PNBs are behind schedule and the load is not materializing in the timeframe originally forecasted, Pepco will adjust the in-service date of load-driven projects based on the most recent assessment of the forecasted load. In the 2018 annual assessment, for example, the Mt. Vernon Substation in-service date was pushed back from 2022 to 2023 because the PNBs were behind schedule. This annual assessment process ensures that Pepco does not construct a load project before it is necessary. The annual assessment—which includes the assessment of impact of DER interconnected with the distribution system—is the reason that Pepco filed the original Notice of Construction for only the Harvard and Champlain Substations, allowing Pepco to continue to assess the need date for the Mt. Vernon Substation.[11] There is a point, however, at which further reassessments would jeopardize the project due to the lead time for approval, permitting and construction of the project. According to the most current annual assessment, Pepco will reach this point with the Mt. Vernon Substation in 2019.

The Mt. Vernon Triangle, NoMa, Capitol Crossing, and Northwest One areas (currently served by Florida Avenue Substation, New Jersey Avenue Substation, Northeast Substation and

[11] By excluding the Mt. Vernon Substation, Pepco had more time to understand the positive impacts of DER and was able to wait until the load materialized in the area where the Mt. Vernon Substation would need to be built. Pepco has, since at least 2013, laid the groundwork to explain that the Mt. Vernon Substation would be needed in the future. Pepco is formally proposing construction of the Mt. Vernon Substation for the first time in this NOC.

Tenth Street Substation) are and will be experiencing significant new growth, with approximately 126 MW of load from 132 new developments scheduled to be added over the next ten years. Table 1 shows the number of apartment units, hotel units, retail square footage and office square footage that are being added to the area to be served by the Mt. Vernon Substation starting in 2023. The load that each of the current substations will serve is also provided.

Table 1[12]

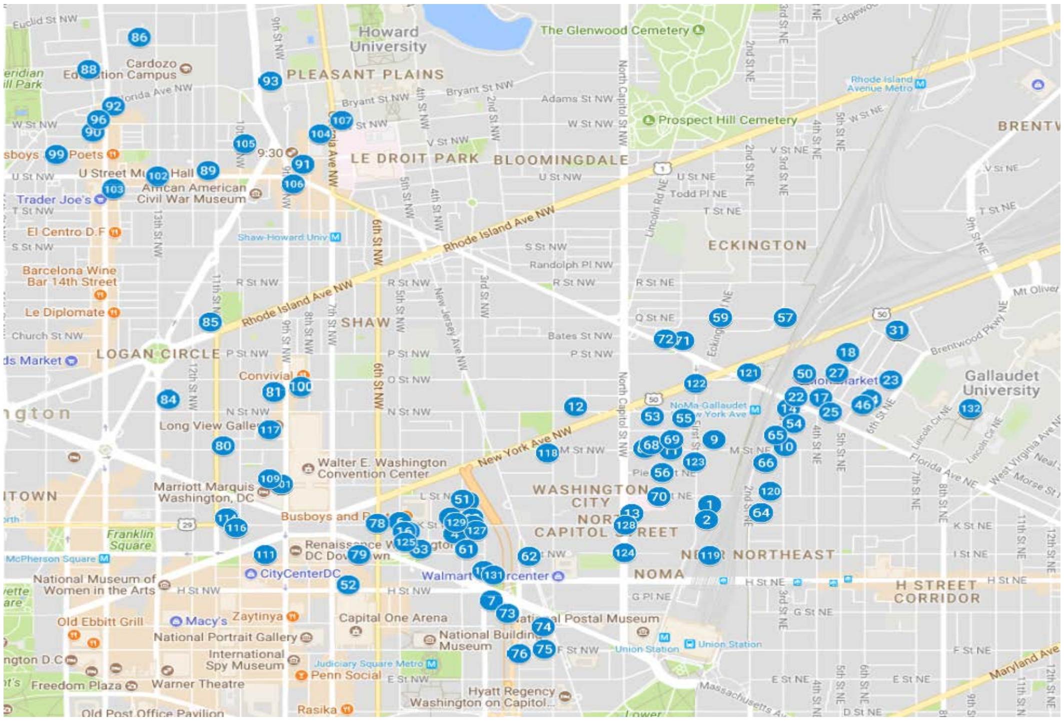
Substation/Feeder Group	Number of Apartments	Number of Hotel Rooms	Retail Sq. Ft.	Office Sq. Ft.	New Load (MW)
Florida Ave. Sub	1,799	0	214,500	0	7
New Jersey Ave. Sub. 161	918	0	219,000	399,000	5*
Northeast Sub. 212	14,520	1,311	2,240,558	6,139,000	102*
Tenth Street Sub. 52	811	1,061	111,800	1,080,000	12*
TOTAL	**18,048**	**2,372**	**2,785,858**	**7,618,000**	**126***

* 11 MW are partially in service and have been removed from Table 1.

Figure 2 shows where the new development is occurring. The specific developments and development details are provided in Attachment A.

[12] Note that the above information is based on the best information available to date. Developers frequently alter the use and scope of their future developments as market conditions warrant.

Figure 2



As demonstrated in Attachment A, PNBs in this area are projected to increase load rapidly, with over 102 MW being added by 2023 and another 24 MW forecasted by 2027. All of this new load is developing around the Florida Ave., New Jersey Ave., the Northeast, and the Tenth Street Substations, the areas that the Mt. Vernon Substation is designed to serve.

Table 2 below shows the forecasted load for the Northeast Sub. 212 Southwest LVAC Network Feeder Group, the New Jersey Sub. 161 South LVAC Network Feeder Group, the Northeast Substation, and the Tenth Street Substation in years 2023-2027 without construction of the Mt. Vernon Substation. The result of all of the additional load growth is that the current configuration of Northeast Sub. 212 Southwest LVAC Network Feeder Group will overload by approximately 5% in 2023 without sufficient capacity at any current feeder group and without enough feeder positions to extend new feeder groups from other substations to take the load. The surrounding feeder groups and substations will also be nearing 100% of capacity in 2023.

The New Jersey Sub. 161 South LVAC Network Feeder Group will be at 99% capacity, the Northeast Substation is at 96% capacity, and the Tenth St. Substation is at 94% capacity in 2023.

The New Jersey Sub. 161 South LVAC Network Feeder Group is predicted to reach 99% of its group firm capacity in 2020 and will continue at 99%/100% through 2024 after which the entire feeder group will overload. Individual feeders within an LVAC network group typically overload at lower levels of firm capacity than the feeder group as a whole under N-1 contingency scenarios. During the five years that the New Jersey Sub. 161 South LVAC Network Feeder Group is operating at 99%/100%, because load is not perfectly balanced across the feeders, individual feeders will likely overload. Even if none of the individual feeders were to overload, however, operating the feeder group at this high loading for this sustained period increases the risk of damaging individual feeders in the group and exposing the customers supplied by this group to long-term outages. This prolonged overstressing of the feeder group places customers at risk of outages.

For these reasons, Pepco typically initiates a construction project to reduce the total group load when the feeder group load exceeds approximately 95% of group firm capacity in order to avoid the overstressing of individual feeders in that group. Temporary emergency operating actions can usually be taken in the field to reduce individual feeder loads within a group but doing so exposes individual customers to additional risk of an outage by reducing the number of feeders supplying them during the emergency. When Pepco planned the Mt. Vernon Substation, it planned for the substation to relieve the load from the New Jersey Avenue Sub. 161 South Network Feeder Group. Pepco determined that it could tolerate the risk to the network group until the Mt. Vernon Substation was constructed, knowing that the new substation would reduce the group load and the individual feeder loads. With the in-service date of 2023 for the Mt.

Vernon Substation, this risk will have already been tolerated for three summer peak periods. Any further toleration of this risk is not in the best interest of the customers served.

Table 2

		Northeast Sub. Southwest LVAC Firm Capacity: 50MVA			
	2023[13]	**2024**	**2025**	**2026**	**2027**
LVAC Loading (MVA)	52.7	56.1	57.3	59.2	59.9
Load over Capacity (MVA)	2.7	6.1	7.3	9.2	9.9
Firm Capacity Overload	5%	12%	15%	18%	20%
		New Jersey Sub. South LVAC Firm Capacity: 47.5MVA			
	2023	**2024**	**2025**	**2026**	**2027**
Loading (MVA)	47.2	47.2	47.7	48.2	48.7
Load over Capacity (MVA)	0	0	0.2	0.7	1.2
Firm Capacity Overload	0%	0%	.004%	1%	3%
		Northeast Substation Firm Capacity: 214MVA			
	2023	**2024**	**2025**	**2026**	**2027**
Loading (MVA)	204.8	213.6	218.2	223.4	227.5
Load over Capacity (MVA)	0	0	4.2	9.4	13.5
Firm Capacity Overload	0%	0%	2%	4%	6%
		Tenth St. Substation Firm Capacity: 204VA			
	2023	**2024**	**2025**	**2026**	**2027**
Loading (MVA)	191.4	192.3	193.7	194.2	194.7
Percentage of Firm Capacity	94%	94%	95%	95%	95%

Under the current configuration, the significant load growth occurring in the Mt. Vernon Triangle, NoMa, Capitol Crossing, and Northwest One areas will increasingly stress the existing substations and network groups every year, expanding the overloading conditions to other feeder groups and substations starting in 2025. By 2025, the Northeast Sub. 212 Southwest LVAC

[13] The most recent annual assessment of PNBs indicated that the in-service date for the Mt. Vernon Substation should be moved to 2023 and that the load growth will result in a larger overload in the year that the substation is needed. The overload on the Northeast Sub. 212 Southwest LVAC Network Feeder Group increased from the 2.2 MVA in 2022, as identified in the Synapse Study, to 2.7 MVA in 2023.

Network Feeder Group will be overloaded by approximately 7.3 MVA. The New Jersey Sub. 161 South LVAC Network Feeder Group, which will have operated at 99%/100% capacity for the previous five years, will be overloaded by 0.2 MVA, Northeast Substation will be overloaded by 4.2 MVA, and the Tenth Street Substation will be at 95% capacity. By 2027, the Northeast Sub. 212 Southwest LVAC Network Feeder Group will be overloaded by 9.9 MVA, the New Jersey Sub. 161 South LVAC Network Feeder Group will be overloaded by 1.2 MVA, the Northeast Substation will be overloaded by 13.5 MVA, and the Tenth Street Substation will be at 95% capacity. Without the Mt. Vernon Substation, there is limited ability to transfer load off the Northeast Sub. 212 Southwest LVAC Network Feeder Group or the New Jersey Sub. 161 South LVAC Network Feeder Group to the surrounding feeder groups or substations should emergency load shedding be required, for example if an alternative used to defer the Mt. Vernon Substation were to fail. Because of the lead time necessary for construction of the Mt. Vernon Substation, constructing the substation on an emergency basis would not be an option.

Moreover, the current load forecasts do not incorporate load growth due to rapid growth in the electric vehicle ("EV") sector. Pepco, the District and other stakeholders are actively seeking to invigorate the EV market. The District has legislation to increase the level of public charging in the District of Columbia.[14] Further, the MEDSIS proceeding has a focus on EVs, including a proposal that Pepco will be filing this summer after significant stakeholder input and collaboration. Should the legislation and an EV program through MEDSIS be implemented, EV charging will add significant load in specific areas around the city. Given its location and the new development in the areas, there are likely to be charging stations in the area served by the Mt. Vernon Substation. If the Mt. Vernon Substation is constructed as proposed, it would be

[14] D.C. Pub. Law L22-0078.

able to serve the load that EV charging would require. If an alternative solution is used based on current forecasts and the forecasts change due to the growth of the EV market, there is no guarantee that a solution that is focused on shaving a particular level of current load could reliably serve the area.

The Mt. Vernon Substation will prevent the overload and overstress conditions by providing a reliable and safe substation to which much of the load can be transferred. As shown in Table 3 below, with the Mt. Vernon Substation relieving the surrounding substations and feeder groups, all of the overload and overstress conditions are mitigated, leaving additional firm capacity at all of the substations and on all of the LVAC network groups to allow for future scheduled load transfers, emergency load transfers, and future load growth.

Table 3

		Northeast Sub. Southwest LVAC Firm Capacity: 50MVA			
	2023	**2024**	**2025**	**2026**	**2027**
LVAC Loading (MVA)	12.7	16.1	17.3	19.2	19.9
Remaining Firm Capacity (MVA)	37.3	33.9	32.7	30.8	30.1
		New Jersey Sub. South LVAC Firm Capacity: 47.5MVA			
	2023	**2024**	**2025**	**2026**	**2027**
LVAC Loading (MVA)	27.2	27.2	27.7	28.2	28.7
Remaining Firm Capacity (MVA)	20.3	20.3	19.8	19.3	18.8
		Northeast Substation Firm Capacity: 214MVA			
	2023	**2024**	**2025**	**2026**	**2027**
Loading (MVA)	167.2	176	180.6	185.8	189.9
Remaining Firm Capacity (MVA)	46.8	38	33.4	28.2	24.1
		Tenth St. Substation Firm Capacity: 204VA			
	2023	**2024**	**2025**	**2026**	**2027**
Loading (MVA)	174.7	175.6	177	177.5	178
Remaining Firm Capacity (MVA)	29.3	28.4	27	26.5	26
		Mt. Vernon Substation Firm Capacity: 140MVA			
	2023	**2024**	**2025**	**2026**	**2027**
Loading (MVA)	56.7	76.7	84.4	84.4	84.4
Remaining Firm Capacity (MVA)	83.3	63.3	55.6	55.6	55.6

The Mt. Vernon Substation is reasonable and necessary to provide safe and reliable service to the distribution customers it will serve. In this instance, the traditional wires solution of a substation is the only alternative. Pepco does not yet have adequate evidence that non-wires solutions can provide a safe and reliable solution to the system need that the Mt. Vernon Substation will address. Pepco should not be using as its first deferral project on the complex

District of Columbia distribution system an alternative solution that attempts to defer the entire Mt. Vernon Substation, a component of the system that has a long lead time for design and construction and, as further discussed below, is complicated by its interdependency with the LVAC network groups and other underground systems in the District of Columbia. Instead, Pepco should be allowed to begin with smaller projects that would allow Pepco to remedy any failure quickly with a proven wires-based alternative. District of Columbia customers deserve solutions that can continue to provide the same level of safe and reliable service that is currently being provided through traditional wires-based solutions and the Commission should demand nothing less. An unreliable alternative to the Mt. Vernon Substation would unnecessarily place 7,400 residential and 270 commercial customers, representing 100.1 MVA of load at risk of extended outages.[15]

C. The Synapse Study Does Not Recognize the Full Extent of the Need for the Mt. Vernon Substation, Resulting in Solutions that Will Present Unacceptable Reliability Risks to Customers

The Synapse Study misidentifies significant fundamental facts relating to the need for the Mt. Vernon Substation. The failure to correctly understand the need results in a proposed "solution" that significantly understates the amount of capacity required to supply the customers impacted by the deferral of the substation. As a result, the Synapse Study's proposal to defer the construction of the Mt. Vernon Substation will subject customers to an unacceptably high risk of degraded service reliability.

Because the Synapse Study does not account for the nature of the District of Columbia LVAC system or the basic facts underlying Pepco's load forecast, it has created a "solution" that

[15] These are the customers and customer loads on the Northeast Sub. 212 Southwest LVAC Network Feeder Group and the New Jersey Sub. 161 South LVAC Network Feeder Group.

would not allow Pepco to safely serve its customers under peak conditions and would unnecessarily place 7,400 residential and 270 commercial customers, representing 100.1 MVA of load, at unreasonable risk of extended outages. According to the Synapse Study, shaving 2.2 MVA in 2022[16] off of the Northeast Sub. 212 Southwest LVAC Network Feeder Group will safely relieve the overload conditions and will allow Pepco to defer the Mt. Vernon Substation for one year.[17] However, the Synapse Study has oversimplified the load reduction requirements to defer the Mt. Vernon Substation.

First, the Northeast Sub. 212 Southwest LVAC Network Feeder Group overload is not the only driver for the Mt. Vernon Substation. As discussed above, while the New Jersey Sub. 161 South LVAC Network Feeder Group will not overload until 2025, it will have been overstressed for three years by 2023. Operating the feeder group at this high loading for a sustained period increases the risk of damaging individual feeders in the group and exposing the customers supplied by this group to the impact of long-term outages. This overstressing was planned to be relieved by the Mt. Vernon Substation in 2023. Should the Mt. Vernon Substation be deferred, the non-wires solution would also need to relieve the load on the New Jersey Sub. 161 South LVAC Network Feeder Group.

Second, the Synapse Study's assumptions regarding load relief on the Northeast Sub. 212 Southwest LVAC Network Feeder Group are wrong as well. To understand why the Synapse Study's assumptions are wrong, it is important first to understand what the Northeast Sub. 212 Southwest LVAC Network Feeder Group is, how it operates in outage conditions and how Pepco must plan to ensure safe and reliable service to customers. Pepco plans its LVAC network

16 Because the 2018 PNB assessment moved the in-service date to 2023, the overload is 2.7 MVA in 2023. The remainder of the discussion in this response will refer to the 2.7 MVA in 2023 rather than the 2.2 MVA in 2022.
17 Synapse Study at 49.

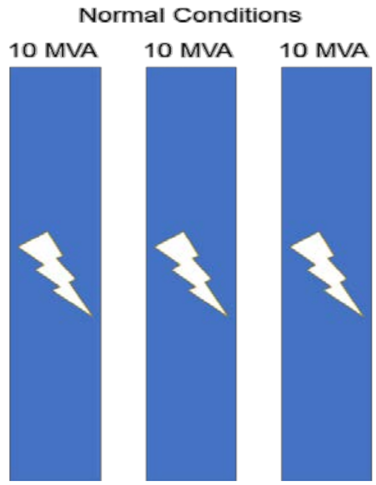
distribution system for an N-1 design contingency conditions,[18] meaning that if one feeder in a network group experiences an outage, the load normally supplied by that feeder is redistributed among the remaining feeders and those feeders must be able to carry the additional load. During an N-1 contingency (outage) on an LVAC network group, an entire feeder experiencing the outage and its associated transformers are removed from service. Because this LVAC network group consists of six (6) interconnected feeders, the load from the feeder experiencing an outage is carried by the remaining five (5) feeders in the LVAC network group and adjacent transformers.

The 2.7 MVA firm capacity overload described above in 2023 is under normal conditions. That means that if nothing is done to change the current configuration, there will be an overload of 2.7 MVA on the Northeast Sub. 212 Southwest LVAC Network Feeder Group when all 6 feeders are in operation. Under an N-1 contingency for a six feeder LVAC network group, such as the Northeast Sub. 212 Southwest LVAC Network Feeder Group or the New Jersey Sub. 161 South LVAC Network Feeder Group, the remaining five feeders in the LVAC feeder group must be able to carry the load from the feeder experiencing the outage. Thus, the load that Pepco must actually plan for is significantly higher.

A simple illustrative example helps make clear why this is the case. In this example, in a 3-feeder LVAC network feeder group each feeder has a maximum capacity under normal conditions of 9 MVA, and a maximum capacity under emergency (N-1) conditions of 10 MVA. Figure 3 assumes a 3 MVA overload under normal conditions that is spread equally across all three feeders, thus each feeder is currently carrying 10 MVA of load.

[18] Pepco Distribution System Planning and Design Criteria Section IV(C)(3): "The distribution system will be developed so that it can be operated at all load levels without interruption of load for the following unscheduled contingencies: . . . (c) The loss of a single circuit in a network feeder group or a high voltage customer vault with two or more supply feeders. (Exception - where the customer has failed to install recommended equipment)."

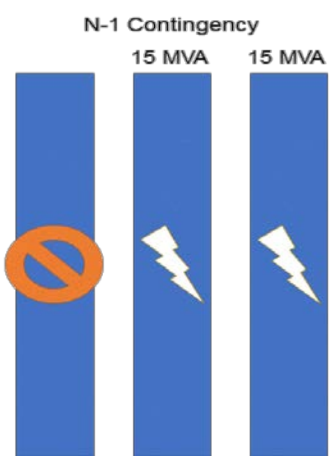
Figure 3



Under an N-1 contingency, one of the three feeders is lost. Figure 4 shows (through three different examples) that the 10 MVA from the feeder experiencing the outage is the redistributed to the two remaining feeders.

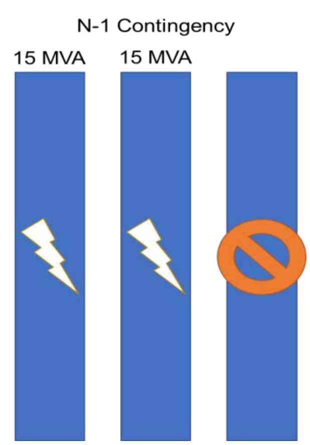
Figure 4

Example 1



Example 2

Example 3



Under an N-1 contingency, the overload is measured against the emergency rating, which in this example, is 10 MVA. Thus, when planning for an N-1 contingency, instead of planning for a 3 MVA overload, the feeder group must be able to accommodate a 10 MVA overload. If Pepco planned only for the 3 MVA overload, the entire feeder group would suffer an outage if any single feeder suffered an outage. In addition, because planning must account for each of the three N-1 contingency examples above, if using, for example, batteries in lieu of a substation, there would need to be a battery on each of the 3 feeders in the LVAC network group, and the batteries on the LVAC network group would need to cover the entire 15 MVA load above the emergency loading that would occur in an N-1 contingency.

Looking back at the real-life situation on the Northeast Sub. 212 Southwest LVAC Network Feeder Group, under normal conditions the feeder group will experience an overload of 2.7 MVA in 2023. Unlike the simple example, in the real-world load is not balanced perfectly across the six feeders. It may be that the entire 2.7 MVA overload is on a single feeder. Should that feeder experience an outage, the load that the other feeders must support would be even higher. Thus, if using DER in lieu of a substation, Pepco would have to deploy DER (*e.g.*, batteries) or other demand reduction over all of the feeders in the network group in a manner that would successfully relieve the potential overloads under any of the possible N-1 conditions. Because of the uncertainty about which contingency scenario might occur, the total amount of DER or other load reduction deployed would have to be greater than the sum of the load exceeding capacity (2.7 MVA). Under real-world conditions, if DER were used to defer the Mt. Vernon Substation, it would need to cover between 13.3 MVA and 17.3 MVA, depending on the portfolio used to defer the substation.

The assumption in the Synapse Study that by shaving 2.7 MVA of load in 2023 Pepco could defer the Mt. Vernon Substation and provide safe and reliable service to its customers is incorrect, resulting in a deferral solution that would jeopardize reliable distribution service for the customers on the Northeast Sub. 212 Southwest LVAC Network Feeder Group and the New Jersey Sub. 161 South LVAC Network Feeder Group. And, as explained above, because Pepco requires 3-4 years of construction after all permits and approvals are received to build a project the size of the Mt. Vernon Substation, the consequences could be amplified exponentially should the chosen alternative solution fail and the Mt. Vernon Substation be required to provide safe and reliable service to the customers on the two LVAC network groups and the two substations that the Mt. Vernon Substation is being constructed to relieve. Without the Mt. Vernon Substation, the increased stress on the Northeast Sub. 212 Southwest LVAC Network Group and the New Jersey Sub. 161 South LVAC Network Feeder Group in an N-1 contingency under peak loading conditions could result in a cascading failure in which one overloaded feeder fails and its load is carried by the remaining feeders in the network group which, in turn, overloads the remaining feeders and results in the loss of all six feeders comprising each of the Northeast Sub. 212 Southwest LVAC Network Feeder Group and the New Jersey Sub. 161 South LVAC Network Feeder Group. This catastrophic failure would result in extended outages for the entire Northeast Sub. 212 Southwest LVAC Network Feeder Group's approximately 6,700 residential and 150 commercial customers, representing 52.7 MVA of load, and the New Jersey Sub. 161 South LVAC Network Feeder Group's entire 700 residential customers and 120 commercial customers (including Union Station and certain federal government buildings), representing 47.2 MVA of load.

The Synapse Study has defined the problem incorrectly and, in doing so, the study's solution is inadequate. Moreover, the Synapse Study and the DOEE Comments fail to discuss the consequences should the proposed alternative solution fail to provide reliable service to District of Columbia customers and how such a circumstance would be addressed. The study's proposed solution creates unreasonable risk to customers and should be rejected.

D. The Synapse Study Contains Significant Additional Errors, Unrealistic Assumptions, and Technical Flaws that Further Undermine Its Credibility

As discussed previously, Pepco's choice to build the Mt. Vernon Substation is based on its responsibility to ensure the reliable delivery of electricity to residential and commercial customers in the District of Columbia, and the substation is a proven means to fulfill to that obligation. But, unlike the certainty provided by a proven solution such as the construction of a substation, there is significant uncertainty about the viability of the alternatives that the Synapse Study proposes that Pepco rely upon as a possible solution to the system needs. This is especially concerning given that an uncertain solution places at risk the reliability of electric service to thousands of customers. In addition to the problems with the Synapse Study discussed previously, the Synapse Study contains significant additional errors, unrealistic assumptions, and technical flaws. These problems lead to an overly optimistic portrayal of the Synapse Study's recommendations, further undermining the study's credibility. In short, while Pepco has proposed a proven solution after careful consideration and examination of its distribution system, the Synapse Study relies upon overly optimistic and, in many cases, flawed assumptions regarding uncertain alternatives that would place undue risk on the reliability of electric service for District of Columbia customers.

1. The Synapse Study Bases Its Analysis and Conclusions on an Incorrect Identification of the Customers and Areas that Will Be Served by the Mt. Vernon Substation, Resulting in Proposed Solutions that Are Not Tailored to the Realities of the System and Would Leave Customers at Undue Risk.

The Synapse Study bases its analysis and conclusions on an inaccurate identification of customers being served by the Mt. Vernon Substation—the Northeast Sub. 212 Southwest LVAC Network Feeder Group, the New Jersey Ave. Sub. 161 LVAC Network Feeder Group, the Northeast Substation 212, and the Tenth Street Substation 52. This is critically important, because the first step in distribution planning is to identify the specific geographic regions, the expected mix of customers and the forecasted electric loads that will be affected by any project under consideration. In the absence of this information, adequate distribution planning cannot occur, including evaluation of a potential new substation or the possible use of non-wires alternatives.

The Synapse Study identifies the Northeast Sub. 212 Southwest Network Feeder Group as the key peak load that must be reduced to defer the Mt. Vernon Substation. Table 4 represents the buildings on which the Synapse Study based its analysis of the Northeast Sub. 212 Southwest LVAC Network Feeder Group and shows the inaccurate assumptions made in the study. The four buildings that are crossed out are not served by the Northeast Sub. 212 Southwest LVAC Network Feeder Group.

Table 4

Address	Size (sq. ft.)	Load in peak hour (kW)
~~**441 G St. NW (GAO)**~~	~~1,935,500~~	~~6,342~~
~~**Gallery Place**~~	~~590,688~~	~~2,228~~
425 Massachusetts Ave NW	605,405	1,902
~~**600 5th St. NW**~~	~~423,710~~	~~1,388~~
450 Massachusetts Ave. NW	407,710	1,335
461 H St. NW	197,648	1,325
425 I St. NW	399,371	1,309
700 Sixth St. NW	306,459	971
455 Massachusetts Ave. NW	247,330	784
770 5th St. NW	233,968	766
811 4th St. NW	208,767	609
~~**401 F St. NW**~~	~~197,094~~	~~644~~
777 6th St. NW	196,997	624
599 Massachusetts Ave. NW	172,236	428
500 H St., NW	120,000	309
251 H St. NW	93,877	298
301 Massachusetts Ave. NW	68,989	201

The Synapse Study has misidentified 10,602 kW of the total 21,165 kW—or 50%—of the existing load that it assumed would be served by the Northeast Sub. 212 Southwest LVAC Network Feeder Group when creating its proposal for deferring the Mt. Vernon Substation.

The Synapse Study's failure to correctly identify the applicable customer base is evident throughout the study. In its Figure 1, the study purports to represent the "approximate location of substations and portions of the electric grid discussed in [the] report." However, the areas circled are supplied primarily by Northeast Sub. 212 Southeast LVAC and the South Spot Network Feeder Groups, neither of which is the subject of the study. Further, the Synapse Study's assertion that the Northeast Substation serves three load areas is incorrect.[19] In fact, the substation serves six load areas: the Southwest LVAC Network Feeder Group, the West Network Feeder Group, the Southeast Spot Network Feeder Group, the South Spot Network Feeder Group, the North High Voltage Group, and a two radial distribution feeder system. The study also incorrectly asserts that

> [t]he SW Network Group serves the area to the east and north of the Verizon Center, with a number of office buildings (including the U.S. General Accountability Office) and large apartment buildings. This area bridges between the Penn Quarter and NoMa. Capital Crossing, a 2.2 million sq. ft. five-building development, is under construction now and slated to be completed by 2022 on the eastern edge of this area; it's not clear whether this load would be served by the SW Network Group, radial service from #212, or a different substation altogether. Figure 5 shows the approximate route of the wires in the SW Network Group in red.[20]

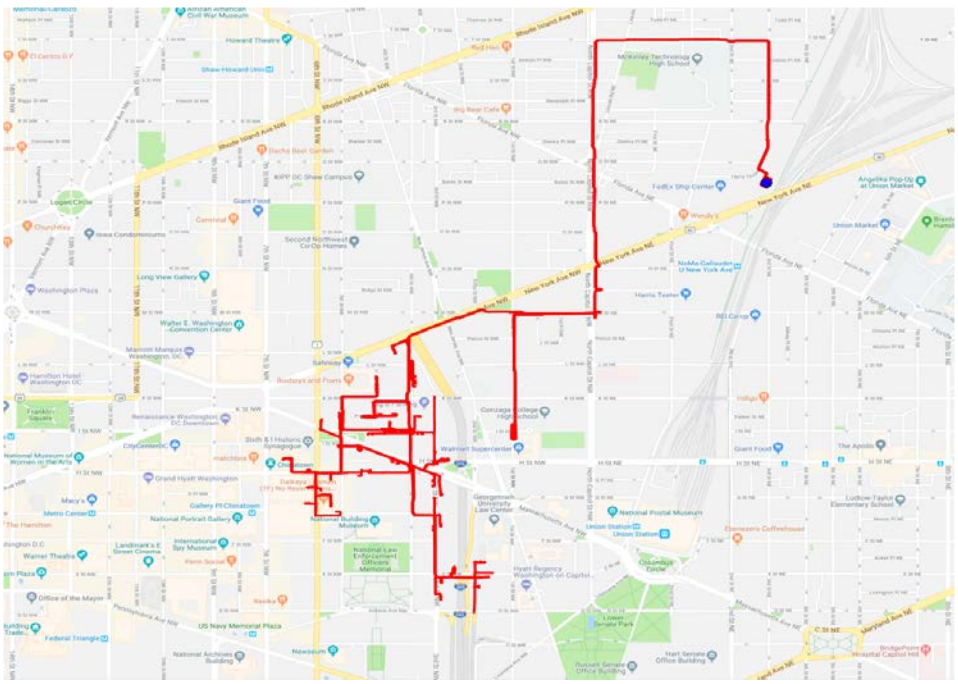
The U.S. General Accountability Office is supplied by the New Jersey Ave. Sub. 161 West High Voltage Feeder Group not the Northeast Sub. 212 Southwest LVAC Network Feeder Group. In addition, while the Capitol Crossing building with an address of 250 Massachusetts Ave., NW will be supplied by the Northeast Sub. 212 Southwest LVAC Network Feeder Group, all other

[19] Synapse Study at 7.
[20] *Id.*

buildings on the Capitol Crossing property will be supplied by New Jersey Ave. Sub. 161 South LVAC Network Feeder Group.

Moreover, the Synapse Study's Figure 5 does not represent the area covered by the Northeast Sub. 212 Southwest LVAC Network Feeder Group.[21] Instead, Figure 5 below shows an accurate depiction of the area covered by the Northeast Sub. 212 Southwest LVAC Network Feeder Group.[22]

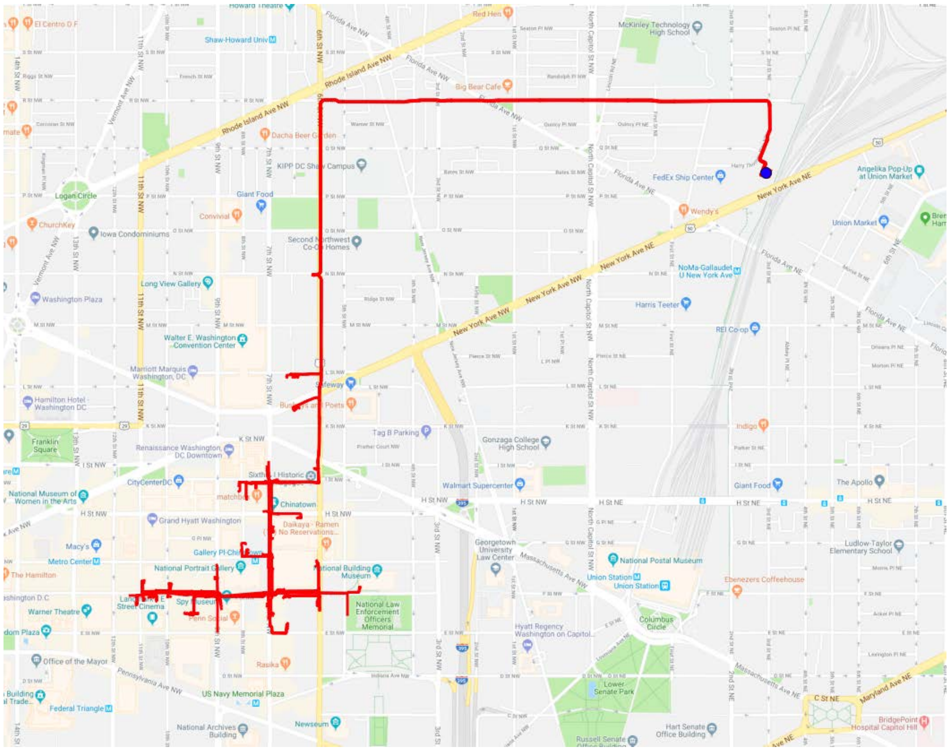
Figure 5



Furthermore, the Synapse Study's Figure 6 represents an inaccurate understanding of the Northeast Sub. 212 West Network Feeder Group.[23] Figure 6 below provides an accurate depiction of the Northeast Substation 212 West Network Feeder Group.[24]

21 Synapse Study at 8.
22 A larger version of the map is included in Attachment B.
23 Synapse Study at 10.
24 A larger version of the map is included in Attachment B.

Figure 6



The Synapse Study misidentifies the supply for the NoMa area as the "#212 radial network."[25] Instead, the NoMa area is supplied by the Northeast Sub. 212 Southeast LVAC Network Feeder Group and Northeast Sub. 212 South Spot Network Feeder Group.

The Synapse Study has not identified the significant expected load growth attributable to the Union Market Development that is currently underway and estimated to have a load of 19 MW by 2023 (with an additional 1.4 MW in 2024) and the potential development of the air rights over the train tracks near Union Station (Burnham Place) with a total load expectation of approximately 15 MW. The list of large buildings in the Synapse Study's Table 3 are not nor will be served by the radial feeders.[26] Instead, these buildings will be supplied by either the Northeast Sub. 212 Southeast LVAC or South Spot Network Feeder Groups. Finally, the

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25 Synapse Study at 11.

26 *Id.* at 12.

Synapse Study contends that "[n]o major buildings have been constructed in this area since 2009, although a few building permits have been granted, presumably for renovations or other work."[27] As Attachment A makes clear, significant development has been and continues to be undertaken in the area since 2009.

In sum, the Synapse Study bases its analysis and conclusions about potential deferral solutions on a flawed understanding of the distribution system that would be impacted by its recommendations. As a result, the Synapse Study's proposed alternatives to the Mt. Vernon Substation are not tailored to the realities of the system and would leave electric distribution customers at undue risk.

2. The Synapse Study's Assessments of the Potential for Peak Load Reductions from Demand Response Ignore Risks and Are Unsupported.

The Synapse Study relies heavily on demand-side measures in its purported alternatives to the Mt. Vernon Substation. Demand-side measures include all customer actions that take place on the customer side of Pepco's electricity meters. One such demand-side measure upon which the Synapse Study relies heavily is demand response. The Synapse Study projects that the existing buildings on the Northeast Sub. 212 Southwest LVAC Network Feeder Group could provide 4.4 MW of demand response[28] and contends that more than 8.3 MW of additional demand response from new buildings could be expected if Pepco's load forecast for unknown future buildings is correct.[29] However, in developing these estimates, and when developing potential demand response adoption patterns that are founded on this alleged potential,[30] the

[27] Synapse Study at 18, para. 3.6
[28] *Id.* at 40.
[29] *Id.* at 40-41.
[30] *Id.* at 48-52.

Synapse Study ignores realities about the timing, management, and other limitations of implementing demand response measures in the District of Columbia. Further, even putting these realities aside, a deeper look at the Synapse Study's own evidence used to support its estimates of potential savings shows that this evidence does not support these estimates. The reliability of the electric service of thousands of District of Columbia Customers should not be put at risk based on unsupported assumptions about demand reductions that might be achieved.

Real-World Limitations on Demand Response

The Synapse Study has failed to consider real-world timing, management, and other limitations that must be factored into any solution that is purporting to provide safe and reliable service to the District of Columbia.

Customer participation in demand response programs is voluntary in the District of Columbia and is largely dependent on several factors including economics, convenience, and altruistic motivations. Customers choose which measures to install and manage. To be most effective, demand response would need to be accompanied by the appropriate incentives, such as those provided through dynamic pricing program. There is currently no dynamic pricing in the District of Columbia, and Pepco currently is not allowed to expand its residential Direct Load Control ("DLC") program.[31] A successful deferral through demand response would require the time to (1) get dynamic pricing approved to provide the proper incentives to voluntarily join the program and ramp up adoption and (2) receive approval to expand the DLC program, have the ability to target the area that Mt. Vernon Substation would serve, and recruit new participants from that area to the program. In its various conceptions of multiple megawatts of demand

[31] At this time Pepco operates a residential direct load control program in the District of Columbia that reduces residential air conditioning demand by cycling residential central air conditioners or residential central heat pump compressors by an installed smart thermostat or outdoor cycling switch.

response being achieved over just a few years,[32] the Synapse Study fails to explain how, in the absence of these critical programs or program expansions, this demand response can be achieved and how Pepco can rely on it being achieved as a system reliability solution.

Further undermining the assumption that demand response benefits will immediately materialize is the fact that Pepco must receive Commission approval before it implements or expands demand response programs, a process that can be lengthy and must be initiated several years in advance of when load reduction capability is needed. By way of example, Pepco sought approval of its existing residential DLC program through a filing made initially on March 3, 2009 (Formal Case No. 1070) and subsequently denied on January 20, 2010. Pepco submitted an updated proposal on June 15, 2011 (Formal Case No. 1086) that was approved by the Commission on November 3, 2011.[33] The approval order required an educational plan to be filed with the Commission within 30 days prior to the program implementation. The education plan was approved on March 2, 2012.[34]

The timing involved in regulatory approval is particularly relevant because the Synapse Study relies on a residential dynamic pricing program in Worcester, Massachusetts to support its deferral alternatives. The study's reliance on the results of a dynamic pricing program in Massachusetts ignores the fact that there is currently no dynamic pricing program in the District of Columbia. Pepco has previously proposed two dynamic pricing programs in the District of Columbia, both of which were rejected after lengthy regulatory proceedings. The history of dynamic pricing proposals in the District of Columbia and the length of time it took to obtain approval, implement and fully ramp up the DLC program undermines the notion that a dynamic

32 Synapse Study at 48-52.
33 Order No. 16602 at 18.
34 Order No. 16720 at 10.

pricing program will be available in a timeframe or at a level that could be relied upon in lieu of a substation to ensure reliable electric service for customers in the District of Columbia.

Even after Pepco gains regulatory approval to implement a new program—in the case of dynamic pricing—or expand a program—in the case of the DLC program, it takes time to implement the program and to recruit participants to the program. For example, in the case of the DLC program, the Company immediately began to implement the program, select and enter into vendor contracts, design marketing materials and campaigns, make billing system modifications, train staff, and recruit participants. Load reduction capability began during the summer of 2013, approximately 1.5 years after Commission approval. The full program buildout was achieved by the summer of 2015, two years after implementation.

Moreover, customers who participate in any demand response program or activities in the District of Columbia do so voluntarily. Participants may drop out of demand response programs or opt to participate or not in demand response activities at any time. The more frequent the demand response reductions are activated, the greater the inconvenience experienced by customers, resulting in higher program attrition. Therefore, during periods when reductions are needed over numerous hours and days to shave peak load, reduction capability may be more limited.

To the extent that third parties are running demand response programs, Pepco has no authority to activate them. Therefore, these programs or initiatives may not be available during times of electricity supply constraints and cannot be relied upon to defer a substation. Moreover, the Commission would have to approve and fund any contractual relationships with third-party curtailment service providers.[35]

Finally, Pepco is concerned about putting the District of Columbia in a situation in which a timely solution (the Mt. Vernon Substation) to satisfy the system needs is rejected in favor of a solution that would require a subset of customers to adopt a time-of-use rate structure and demand response program whether or not they want that type of service. By building the Mt. Vernon Substation, this type of customer fairness issue can be avoided.

Specific Issues Regarding Non-Residential Demand Response Programs

Non-residential customer demand response programs in the District of Columbia are offered by competitive third-party curtailment service providers or by customers who participate directly in the PJM wholesale demand response market. The total estimated peak demand reduction capability of the program is approximately 168 MW, or approximately 0.8% of the Pepco District of Columbia capacity obligation for PJM Delivery Year 2017/2018. Approximately 1.5 MW, or 0.9%, of this reduction capability is currently located in the area that will be served by Mt. Vernon Substation, which is a heavily commercial load-dominated area. However, Pepco has no control over any of these load reductions, therefore the reductions may not be available when needed to shave the peak load.

Non-residential load reduction capability would be a necessary component of any demand response alternative to the Mt. Vernon Substation. According to PJM data, approximately 78 MW of third-party non-residential demand response existed in the District of Columbia during the PJM 2017/2018 Delivery Year. The total number of non-residential participants was 329, who provided an average reduction capability of 237 kW each. This

[35] The Company has previously established contracts with third-party curtailment service providers in Maryland for Pepco and its affiliate Delmarva Power with mixed success. Maryland Public Service Commission Case No. 9149. Also, Pepco's utility affiliate, Atlantic City Electric Company, established similar contracts in New Jersey.

capability represented approximately 3.5% of the total capacity obligation of the District of Columbia for the delivery year.

Finally, recent changes to the PJM capacity market require that capacity resources provide capacity throughout the entire calendar year to help ensure adequate electricity supply reliability. This limits the wholesale market revenue available to support utility or third-party demand response programs.

The Synapse Study's Demand Response Assumptions Are Not Supported by the Study's Own Evidence

Even if all of the real-world limitations of demand response in the District of Columbia could somehow instantly be overcome, a deeper look at the Synapse Study's own evidence used to support its estimates of the potential peak demand reductions that could be achieved from demand response reveals that it does not support the study's estimates.

To further understand how the Synapse Study's own evidence does not support its assumptions about potential peak demand reductions from demand response, the two categories of the Synapse Study's postulated demand response potential—large commercial buildings (Mt. Vernon large commercial DR program) and multifamily buildings (Mt. Vernon multifamily DR program)[36]—must be addressed separately.

With regard to demand response from large commercial buildings, the Synapse Study assumes that 50% of the large commercial buildings participate in demand response programs and that each of these participating buildings is able to reduce its peak demand by 58%-64%.[37] The study further assumes that this roughly 60% peak demand reduction per participating

[36] Synapse Study at 36-37.
[37] *Id.* at 40. See also the Synapse workpaper, "J. Mt. Vernon Buildings NWA Analysis.xlsx" provided as part of the District of Columbia Government's (DCG) Responses to the First Set of Data Requests from the Potomac Electric Power Company (Pepco).

building is achieved if an incentive payment of $150/kW-year is offered.[38] The Synapse Study supports this assumption by referencing elasticity values from results of demand response programs in California, presented in a study for the Pennsylvania Public Utility Commission.[39]

While the Synapse Study claims that this data supports its assumption of roughly 60% peak demand reductions for participating customers, close inspection of the report it references reveals that no such support exists. The California data used in the Pennsylvania report pertained to much lower incentive payments and resultant peak demand reductions and does not provide any empirical evidence of peak demand reductions anywhere close to the 58%-64% values that the Synapse Study asserts could be achieved. Specifically, the payment ranges used to calculate the elasticities in the Pennsylvania report ranged from $4.50/kW-year to $79.17/kW-year, implying resultant peak demand reductions of roughly 1% to 30%, nowhere close to the 58%-64% peak demand reductions assumed by the Synapse Study.[40]

The Synapse Study further attempts to justify its forecasted peak demand savings from large commercial demand response by stating that Orange & Rockland Utilities, Inc. ("O&R") achieved roughly 60% peak demand reductions from a large commercial demand response program in 2016.[41] While this may be true, the O&R report on this program indicates that the participation rate was less than 10%,[42] nowhere close to the 50% participation rate that the

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[38] Synapse Study at 39.

[39] *Id.*, which references "Demand Response Potential for Pennsylvania," GDS Associates, Inc., February 25, 2015. See also page 73 of this referenced study, which explains that its elasticity estimates are based on data for non-residential demand response programs in California.

[40] "Demand Response Potential for Pennsylvania," GDS Associates, Inc., February 25, 2015, pp. 73-75. The Synapse Study applies the elasticities for "Day-Ahead" and "Day-Of" demand response products.

[41] Synapse Study at 40.

[42] See "Orange & Rockland Utilities, Inc. Annual Report on Program Performance and Cost Effectiveness of Dynamic Load Management Programs," December 1, 2016. An 8.7 MW peak demand reduction was achieved via the Commercial System Relief Program (p. 10), and an 18.9 MW peak demand reduction was achieved via the Distribution Load Relief Program (p. 16), for a total peak demand reduction of 27.6 MW. In comparison, average monthly peak demands (which would be lower than annual peak demands) are an order of magnitude higher. For example, Exhibit_EFP-1, Schedule 4, Page 2 of 5 of "electric-filing-exhibits-volume-1" from O&R's "2018 Electric

Synapse Study asserts Pepco can rely on achieving with a 60% average peak demand reduction from participating customers. Rather than supporting the Synapse Study's assumptions regarding the potential for demand response savings from commercial buildings, the O&R report indicates that those assumptions are highly inflated.

The Synapse Study's forecasted peak demand reductions for multifamily buildings are similarly unsupported by the evidence that the study presents. Specifically, the Synapse Study's recommendation to defer the construction of the Mt. Vernon Substation is based in part on the potential for peak demand reductions from its envisioned "Multifamily DR program," which is a largely unspecified plan to pursue demand response measures for the multifamily buildings on the Northeast Sub. 212 Southwest LVAC Network Feeder Group.[43] The study assumes that 70% of the customers residing in multifamily buildings on the Northeast Sub. 212 Southwest LVAC Network Feeder Group will reduce their peak demands by 25% on average,[44] "mainly based on the performance of the residential demand response pilot program implemented by National Grid in Massachusetts, along with data for a few other pilot programs."[45] However, the Synapse Study's assumptions for the Northeast Sub. 212 Southwest LVAC Network Feeder Group are not consistent with the National Grid pilot program's results, and the results of the "few other pilot programs" similarly do not support the Synapse Study's assumptions.

First, the National Grid pilot program was able to achieve a high customer participation rate, consistent with the Synapse Study's 70% participation rate assumption for the Northeast Sub. 212 Southwest LVAC Network Feeder Group, only because it was an opt-out dynamic rate

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Rate Case Filing," found at https://www.oru.com/en/ny-rates-tariffs, shows that average monthly peak demand for non-residential is 6,700/12=558 MW, while as another point of comparison the average monthly peak demand for just Total Primary is 2,711/12=226 MW.

43 Synapse Study at 37.

44 *Id.*

45 *Id.* at 38.

pilot program. The National Grid pilot program entailed installing an AMI meter and providing the necessary price signals for demand reduction by imposing dynamic pricing rates[46] on every customer in the pilot area unless the customer affirmatively opted out of the program.[47] To reach the 70% participation rate assumed by the Synapse Study in the District of Columbia, Pepco would have to impose upon customers a similar opt-out dynamic pricing structure. Evidence from the National Grid pilot program's "Final Evaluation Report,"[48] upon which the Synapse Study relies for its 70% customer participation assumption, supports the inability to achieve a customer participation rate anywhere close to 70% without this opt-out feature. The National Grid report samples 19 different opt-in dynamic rate pilot programs, and the customer participation rates for those opt-in programs are only between 5% and 40%.[49] While the Synapse Study's assumed customer participation rate, therefore, is clearly dependent upon an opt-out demand response program and the associated necessary dynamic pricing structure, no such structure is currently in place in the District of Columbia, and Pepco cannot unilaterally impose such a structure on customers. Instead, Pepco would have to create such a program and propose it to the Commission for approval.

Second, even if an opt-out demand response program were imposed on all multifamily buildings on the Northeast Sub. 212 Southwest LVAC Network Feeder Group, the Synapse Study's assumption of an average 25% peak demand reduction per participating customer is far higher than the levels achieved in the National Grid pilot program. In the first year of the

46 Customers who did not affirmatively opt out of the program were placed on a "Critical Peak Pricing" rate, which is a combination of a time-of-use rate with critical peak pricing, unless they proactively selected a "Peak Time Rebate" rate.

47 "National Grid Smart Energy Solutions Pilot – Final Evaluation Report," Navigant, May 5, 2017, at 2-4.

48 *Id.*

49 *Id.* at 95.

National Grid pilot program, the total demand savings was only 3.9% for all residential[50] participants averaged across the 20 announced "Peak Events" of each summer.[51] In the second year, it was only 7.2%.[52]

The Synapse Study overlooks these facts and instead focuses on the peak demand reductions of a very small percentage of participating customers in the National Grid pilot program to support its 25% average peak demand reduction assumption, stating that

> [t]he participants with the advanced thermostats under Level 3 and Level 4 technology packages both reduced a similar level of peak load ranging from about 22 percent to 30 percent peak load…An evaluation study of National Grid's pilot program also reviewed peak load impacts from other programs. It found a similar level of impacts from demand response programs that offered Wi-Fi enabled thermostats, ranging from 25 percent to 35 percent average peak load reductions. Thus, we assumed a 25 percent reduction for our study.[53]

The Synapse Study is correct that the participants in the National Grid pilot program with the most advanced technology packages were able to reduce their peak demands by 22% to 30%. However, less than 3% of the customers in this pilot program elected to have these technology packages installed at their premises,[54] despite the fact that these technology packages were offered for free[55] and despite "heavy promotion of the technologies."[56] The overwhelming majority of the customers who participated in the pilot program had much lower peak demand reductions. The reductions were low despite the fact that participants were provided a web portal

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[50] "National Grid Smart Energy Solutions Pilot – Final Evaluation Report," Navigant, May 5, 2017, p. 8 ("The impact findings in this report are primarily focused on residential customers. Commercial customers were a very small portion of the Pilot participants and outcomes were explored for them to the extent possible based on the constraints of the small sample").

[51] *Id.*

[52] *Id.*

[53] Synapse Study at 38.

[54] "National Grid Smart Energy Solutions Pilot – Final Evaluation Report," Navigant, May 5, 2017, at 43, 53.

[55] *Id*. at 39-40, 93.

[56] *Id*. at 93.

that produced information about their personal electric use,[57] and they received notifications prior to days with expected high demands in which they were afforded opportunities to save extraordinary amounts of money by reducing their demands.[58]

In addition, the level of activity and the peak demand reduction percentages in the pilot program were even lower for renters than for customers in general.[59] Because there are existing and new apartment complexes on the Northeast Sub. 212 Southwest LVAC Network Feeder Group, this could also have an impact on the reductions realized under the Synapse Study's proposed alternatives.[60] As noted in the "Final Evaluation Report" for the National Grid pilot program, "[t]he lower savings for renters as compared to other customers likely stems from the particular challenges renters face in conserving electricity. For example, renters may or may not pay their own electric bill and they often have to get landlord permission for many conservation activities (such as buying new appliances)."[61]

The Synapse Study's 25% demand reduction assumption also is not supported by the "data for a few other pilot programs."[62] In referencing those other pilot programs, the study states that "[the 'Final Evaluation Report' for the National Grid pilot program] found a similar level of impacts from demand response programs that offered Wi-Fi enabled thermostats, ranging from 25 percent to 35 percent average peak load reductions."[63] However, that report only addresses peak demand savings levels achieved in other programs for the set of customers who have adopted advanced technologies and/or are the most active in managing their

57 Synapse Study at 6-7.
58 *Id*. at 7.
59 *Id*. at 53, 71.
60 *See*, *e.g.*, Attachment A for apartment complexes that are existing or in construction on the Northeast Sub. 212 Southwest Network Feeder Group.
61 "National Grid Smart Energy Solutions Pilot – Final Evaluation Report," Navigant, May 5, 2017, at 71.
62 Synapse Study at 38.
63 *Id.* at 38

demands.[64] The peak demand savings levels for other, less active customers are not addressed. Consequently, the Synapse Study's references to these other programs does not support its assumption that 70% of the customers residing in multifamily buildings in the Northeast Sub. 212 Southwest Network Feeder Group will reduce their peak demands by 25% on average.

The Synapse Study's conclusions regarding the demand reductions achieved from demand response are unsupported and overstated and should be rejected.

3. *The Synapse Study's Assessment of the Potential for Peak Load Reductions from Energy Efficiency Contains Significant Flaws that Cast Serious Doubt about the Synapse Study's Conclusions.*

The Synapse Study also relies heavily on energy efficiency measures as a critical part of its purported alternatives to the Mt. Vernon Substation.[65] To develop its demand reduction estimates from energy efficiency, the Synapse Study uses a bottom-up approach. The study first identifies the peak loads of the existing buildings and the projections for new buildings in the Northeast Sub. 212 Southwest LVAC Network Feeder Group. It then classifies these buildings, as "mixed-use," "office," "hotel," or "multifamily"[66] and applies a mix of end uses (*e.g.*, cooling, lighting, refrigeration, electronics) for each building classification.[67] As the final step to determine the estimated peak demand response reduction that could be achieved from energy efficiency, the Synapse Study applies the average percentage reductions from energy efficiency measures depicted in a 2015 Pennsylvania energy efficiency study ("Pennsylvania Study") to all of the buildings the Synapse Study assumes to be served by the Northeast Sub. 212 Southwest

[64] "National Grid Smart Energy Solutions Pilot – Final Evaluation Report," Navigant, May 5, 2017, pp. 10-11, 60-61, 125.
[65] Synapse Study at 2-32, 48-52.
[66] Synapse Study at 22, 29.
[67] *Id.* at 22-23.

Network Feeder Group.[68] This methodology results in the Synapse Study's estimates for potential peak demand reductions from energy efficiency of 3.4 MW from existing buildings and another 3.4 MW from new buildings.[69]

As is the case with the Synapse Study's estimates of the potential for peak demand reduction from demand response, the Synapse Study's assessment of the viability of energy efficiency contains significant flaws that invalidate its estimates of the potential for energy efficiency to satisfy the distribution system need. In developing its estimates of the potential for peak demand from energy efficiency, the Synapse Study ignores realities about the management, participation, and other limitations of implementing energy efficiency measures. Further, even putting these realities aside, a deeper look at the Synapse Study's analysis to support its estimates shows that these estimates have no validity. Significantly, the Synapse Study shows a fundamental misunderstanding of Pepco's planning process that severely undermines its energy efficiency demand reduction assumptions. The reliability of the electric services of thousands of District of Columbia Customers should not be put at risk based on an unsubstantiated hope that inadequately supported and inflated assumptions about demand reductions that could be achieved through energy efficiency.

<u>Real-World Limitations on Energy Efficiency</u>

Energy efficiency and conservation programs in the District of Columbia are currently provided by the District of Columbia Sustainable Energy Utility ("SEU"). Pepco is a member of the oversight board of the SEU but has no ability to control the types of energy efficiency and

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[68] Synapse Study at 25. See also Synapse workpaper "J. Mt. Vernon Buildings NWA Analysis.xlsx" provided as part of the District of Columbia Government's (DCG) Responses to the First Set of Data Requests from the Potomac Electric Power Company (Pepco).

[69] *Id.* at 28-29. This source shows an estimate of 3.3 MW from existing buildings, but the Synapse workpaper "J. Mt. Vernon Buildings NWA Analysis.xlsx" provided as part of the District of Columbia Government's (DCG) Responses to the First Set of Data Requests from the Potomac Electric Power Company (Pepco), shows an estimated value of 3.4 MW.

conservation programs established, reduction targets, and/or geographic reduction targets. This eliminates Pepco's ability to directly reduce load within the geographic area that will be served by the new Mt. Vernon Substation.

Furthermore, customer participation in energy efficiency and conservation programs is voluntary. Customers choose which measures to install and manage. Customer participation is largely dependent on several factors including economics, convenience, and altruistic motivations, and the Synapse Study ignores important considerations along these lines.

Voluntary energy efficiency programs will require multiple years to recruit sufficient participation. Any new energy efficiency and conservation program implementation typically requires considerable time before any significant energy and demand savings can be achieved. For example, Pepco filed for approval of new District of Columbia energy efficiency and conservation programs on April 4, 2007 in Formal Case No. 1056. The Commission approved several of Pepco's program proposals on December 18, 2008 through Order No. 1539 in Formal Case No. 945 but required Pepco to submit of a work plan prior to program implementation. On March 12, 2009, through Order No. 15219, the Commission approved the Company's work plan and permitted program implementation to commence. Pepco subsequently launched its residential energy efficiency and conservation programs during July 2009 and its non-residential programs during August 2009. The total required time for program implementation of these programs was 27 months. After one year of program operation, the Pepco programs provided 18,600 MWh of annual energy savings and 2.6 MW of peak demand reductions throughout the District of Columbia.[70]

[70] Note that on June 15, 2010 the City Council reallocated available funding from the Sustainable Energy Trust Fund to other governmental programs and, therefore, the funding for Pepco's energy efficiency programs ceased on September 30, 2010.

Pepco has significant experience with the implementation of energy efficiency and conservation programs in the District of Columbia, and it currently offers numerous programs in Maryland. Critical program elements include: design, staffing, implementation, marketing, and evaluation. Any energy efficiency programs targeted at reducing electric energy and demand in the area of the District served by the Mt. Vernon Substation would require a minimum lead time of 12 to 24 months after program approval prior to providing meaningful electricity savings that would need to be evaluated and verified.

In Pepco's experience implementing energy efficiency projects in Maryland through the EmPOWER Maryland program, the average total building lighting retrofit project for an office building or condominium building similar to those identified in the Synapse Study, full retrofit projects for similar facilities take 6-8 months from application pre-approval to final commissioning. The 6-8 months does not include the significant engineering analysis and planning that takes place prior to an application being approved. The time required calls into question the feasibility of the time frame the Synapse Study believes peak load savings will be realized. At no point in its analysis does the Synapse Study address the average length of a project or the circumstances that impact when a facility could be accessed and/or upgraded. Furthermore, after one year of operation with a full suite of energy efficiency and renewables programs, the DC SEU was able to achieve only 24,000 MWh of annual savings and 3.6 MW of peak demand savings throughout the entire District of Columbia system.

<u>The Synapse Study's Energy Efficiency Assertions Are Not Supported by Its Own Evidence</u>

Even if all of the real-world limitations of energy efficiency implementation could be instantly overcome, a deeper look at the Synapse Study's analysis to support its estimates of the potential for energy efficiency shows that these estimates have no validity, resulting in grossly overstated estimates of any such potential. Most significant among the flawed assumptions is that there is abundant potential for energy efficiency measures in new buildings. Pepco's peak load forecast already assumes that new buildings have energy efficiency measures incorporated into the designs, meaning that these buildings already are assumed to undertake substantial energy efficiency and conservation efforts. That the energy efficiency gains are already incorporated into the load forecasts negates any non-negligible additional potential for energy efficiency to reduce peak demands.[71] This effectively invalidates the Synapse Study's estimate of 3.4 MW of demand reduction from additional energy efficiency measures in new buildings for the area served by the Mt. Vernon Substation.

Similarly, the Synapse Study overlooks the fact that five of the existing buildings in the Northeast Sub. 212 Southwest LVAC Network Feeder Group are already LEED-certified, as well as an additional two buildings that Synapse identifies in the study that would not be served by the feeder group: 425 Eye, 700 6th St NW, 455 Massachusetts Ave, 777 6th St NW, 132- Hampton Inn, T43- Jackson Graham Building (not in area), and the National Building Museum (not in area). Accounting for this fact alone reduces the Synapse Study's estimate for incremental peak demand reductions from energy efficiency in existing buildings from 3.4 MW to 2.4 MW. Furthermore, one other building, Madrigal Lofts, already has LED lighting installed in its common spaces, which further reduces the potential for incremental peak demand reductions from energy efficiency. Additionally, there are two other buildings that are not LEED certified but are not included in the Northeast Sub. 212 Southwest LVAC Network Feeder Group: the GAO building and Gallery Place. Removing these two irrelevant buildings further

[71] Research conducted by the New Buildings Institute (NBI) concluded that LEED buildings in the United States generally save 25 to 30 percent energy usage over conventional buildings.

reduces the MW savings from EE according to the Synapse Study's model to less than 1 MW of demand reduction potential from energy efficiency.

The flaws in the Synapse Study's analysis of the potential for peak demand reductions from energy efficiency in existing buildings are not just limited to the fact that the Synapse Study ignores that the potential for incremental reductions is heavily mitigated by the reality that many buildings already have taken advantage of energy efficiency measures. The Synapse Study also overstates the savings potential from each existing building that has not yet installed significant energy efficiency measures. In creating a general estimate of peak demand savings from energy efficiency programs in existing buildings, the Synapse Study assumes that all of the existing buildings implement retrofit measures and half of the existing buildings implement replace on burnout ("ROB") measures.[72] However, in any energy efficiency project, each measure installed will be *either* a ROB measure or a retrofit measure. No measure will ever be both ROB *and* retrofit. Consequently, the Synapse Study significantly overestimates the potential for peak demand savings from any given existing building.

Moreover, the Synapse Study's estimates of potential peak demand reductions from energy efficiency in existing multifamily buildings may be particularly overstated. Specifically, in the calculation of peak savings from retrofit projects for lighting in multifamily buildings, the Synapse Study uses peak savings estimates for ROB lighting projects in multifamily buildings because it does not have data for peak savings estimates for retrofit lighting projects in multifamily buildings.[73] In offices and hotels, ROB lighting projects have higher peak savings,

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[72] Synapse Study at 26. *See also* Synapse Study workpaper "J. Mt. Vernon Buildings NWA Analysis.xlsx" provided as part of the District of Columbia Government's (DCG) Responses to the First Set of Data Requests from the Potomac Electric Power Company (Pepco).

[73] Synapse Study workpaper "J. Mt. Vernon Buildings NWA Analysis.xlsx" provided as part of the District of Columbia Government's (DCG) Responses to the First Set of Data Requests from the Potomac Electric Power Company (Pepco).

on average, than retrofit lighting projects; thus, to the extent that this relationship also applies for multifamily buildings, the Synapse Study's substitution of ROB data for retrofit data likely results in overestimated multifamily lighting savings.

The Synapse Study also does not distinguish owner-occupied multifamily condominium properties from renter-occupied multifamily properties, an important distinction for achieving any level of peak demand savings from voluntary energy efficiency. While the end-use load profiles for these two types of buildings are likely similar, access to individual units requires individual owner consent for owner-occupied buildings whereas access to individual dwelling units in rental properties can be negotiated with the property management company. Assuming the savings identified in the six multifamily buildings is whole building (not just common area retrofits), this calls into question the actual feasible savings potential in a timely manner from a practical implementation perspective.

In addition, the Synapse Study uses the most optimistic assumptions regarding the percentage of lighting in building end use. The Synapse Study presents two sources that provide end-use consumption breakdowns, Greenlink and CBECS/EIA NEMS Building Data.[74] For its lighting percentages, the study uses Greenlink as its source, which estimates that lighting represents higher percentages of building end use. Since lighting provides the greatest opportunity for peak demand reduction savings, the Synapse Study's treatment may result in a high estimate of potential savings. Finally, for both retrofit and ROB projects, to develop its peak savings estimates from lighting, cooling, and refrigeration (but not electronics) in multifamily buildings, the Synapse Study averages multifamily and hotel peak savings data

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[74] Synapse Study at 22, referencing "The Potential for Demand-Side Resources in the District of Columbia," Greenlink, October 5, 2016 and "Annual Energy Outlook 2015," EIA, April 2015. See also Synapse workpaper "J. Mt. Vernon Buildings NWA Analysis.xlsx" provided as part of the District of Columbia Government's (DCG) Responses to the First Set of Data Requests from the Potomac Electric Power Company (Pepco).

applicable to PECO.[75] The study purports to include hotel data to account for savings associated with common areas in multifamily buildings (*e.g.*, office, laundry, swimming pool, fitness room). However, this treatment is not adequately justified, and it has the effect of raising the Synapse Study's savings estimates for multifamily buildings.

Moreover, the Synapse Study bases its peak demand savings and cost estimates on very limited data about actual energy efficiency measures, calling into question the reliability of these estimates. For each combination of building type (mixed-use, office, hotel, or multifamily), end-use (cooling, lighting, refrigeration, or electronics), and project type (retrofit, ROB, or new construction), the Synapse Study computes average peak savings and costs (in $/kW) of energy efficiency measures based on data from a 2015 GDS energy efficiency potential study for Pennsylvania.[76] In particular, the Synapse Study examines only project savings and cost data corresponding to PECO, as the study contends that PECO's customer characteristics are more comparable than other utilities in Pennsylvania because PECO covers a metropolitan area similar to the District of Columbia.[77] For many combinations of building type, end-use, and project type (*e.g.*, office, cooling, ROB), there are only a few comparable, cost-effective measures in PECO from the GDS EE potential study for Pennsylvania.[78] Moreover, measures examined in the GDS study vary drastically in size and scope, so the Synapse Study's simple averages of percent savings and $/kW costs may be skewed.

75 Synapse Study workpaper "J. Mt. Vernon Buildings NWA Analysis.xlsx" provided as part of the District of Columbia Government's (DCG) Responses to the First Set of Data Requests from the Potomac Electric Power Company (Pepco).

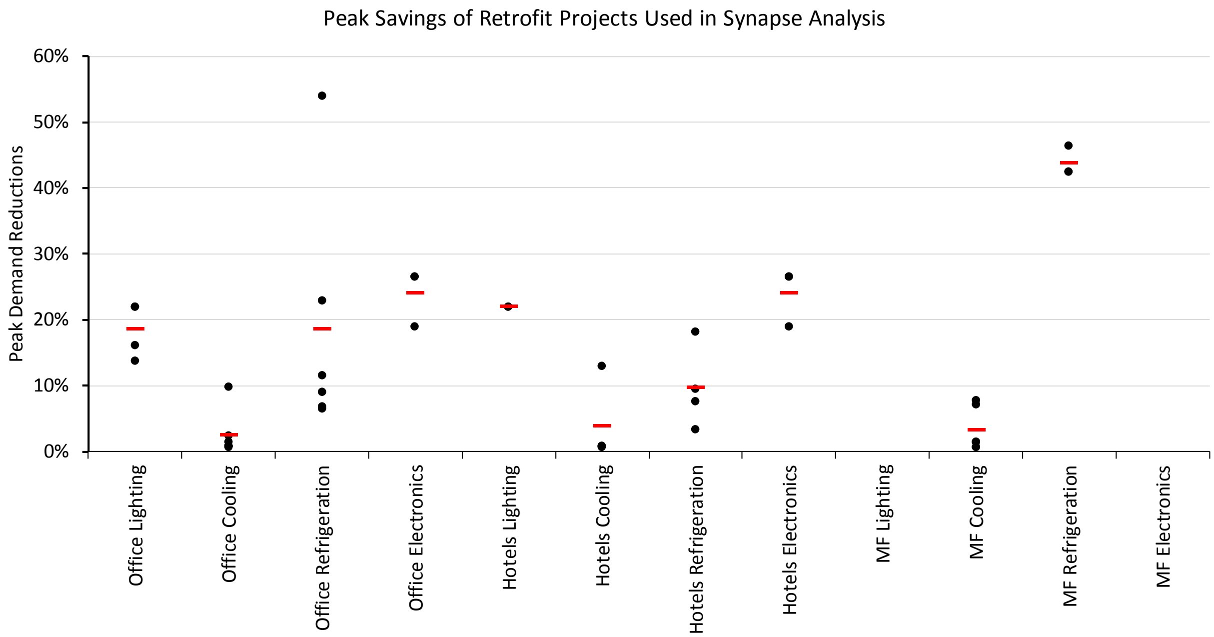
76 Synapse Study at 25, referencing "Energy Efficiency Potential Study for Pennsylvania," GDS Associates et al., February 2015. See also Synapse workpaper "J. Mt. Vernon Buildings NWA Analysis.xlsx" provided as part of the District of Columbia Government's (DCG) Responses to the First Set of Data Requests from the Potomac Electric Power Company (Pepco).

77 *Id.* at 25-26.

78 Synapse Study workpaper "J. Mt. Vernon Buildings NWA Analysis.xlsx" provided as part of the District of Columbia Government's (DCG) Responses to the First Set of Data Requests from the Potomac Electric Power Company (Pepco).

Figure 7 depicts the wide range of peak demand reductions achieved by various retrofit measures, using the data from the 2015 GDS energy efficiency potential study for Pennsylvania. In the figure, each black dot represents a different energy efficiency measure, and the dots in a given column show the distribution of peak demand reductions from that type of measure. Figure 7 provides two insights. First, the Synapse Study bases its estimates on very little data. Second, there is wide variability in the percentage demand reductions achieved by a particular type of energy efficiency measure. As the orange markers on Figure 7 indicate, the Synapse Study simply assumes that, for a given type of energy efficiency measure, any measure of that type would achieve a percentage demand reduction equal to the average percentage demand reduction across the distribution of the points represented by the empirical data. As the black dots show, however, there are relatively few data points for any given type of energy efficiency measure, and the savings distribution across the points is often quite wide. By ignoring this uncertainty about the peak demand reductions from energy efficiency, the Synapse Study does not adequately represent the risks associated with its recommendation to rely on energy efficiency programs to satisfy distribution system needs.

Figure 7



Furthermore, all of this data reflects peak demand reductions from energy efficiency measures in Philadelphia rather than the District of Columbia. Energy savings data specific to the District of Columbia are inherently more accurate than data from Philadelphia due to a variety of factors that include: building characteristic (size, age, etc.), weather conditions, commercial activities, demographics, and regional codes and standards. Table 5 provides a comparison of some key factors for Philadelphia versus the District of Columbia. Because the DCSEU is part of DOEE, the Synapse Study should have ample access to District of Columbia energy efficiency and conservation program savings estimates and should have used District of Columbia data as the basis to forecast saving estimates in the District of Columbia.[79]

[79] Pepco also has detailed energy efficiency and conservation savings estimates from its existing programs in Maryland.

Table 5

Factors	**Philadelphia**	**District of Columbia**
Weather Conditions[80]	HDD: 3,064 CDD: 2,226	HDD: 2,380 CDD: 2,763
Average Height of Highest 5 Buildings	860 Feet	242 Feet
City Population	1,567,872	681,170

Given the uncertainty surrounding the Synapse Study's claimed potential peak demand reductions from energy efficiency, it is not surprising that the Synapse Study's estimates of the peak demand reduction per building are not supported by Pepco's experience with energy efficiency initiatives. Specifically, a study of Pepco Maryland's applicable EmPOWER programs shows that the demand reductions achieved per building are much lower than the Synapse Study assumes. The applicable EmPOWER programs had 573 participants in 2017, resulting in an aggregate peak demand reduction of 8.37 MW. The average project in these programs reduced peak load by 14 kW (with approximately 90% of the savings from lighting retrofits), a value less than one tenth of the 203 kW per building peak demand reduction assumed by the Synapse Study for the Northeast Sub. 212 Southwest LVAC Network Feeder Group. Furthermore, the applicable EmPOWER participants each were large buildings, as none of these buildings had a peak load of less than 100 kW. While the applicable EmPOWER buildings are not an exact proxy for the buildings in the Northeast Sub. 212 Southwest LVAC Network Feeder Group, the large gap between actual demand reductions demonstrated in the EmPOWER results and the Synapse Study's assumed demand reductions casts further doubt on the demand reductions that the study hopes that Pepco could achieve.

80 2017 weather data sources from Weather Data Depot.

Table 6 shows a representative sample of average completed jobs in Pepco Maryland prescriptive/existing buildings recently. While these are not intended to represent a ceiling of energy efficiency potential, they do show what comprises a typical significant retrofit on large buildings. While these per-job savings are greater than 14kW, in all but one case they are dramatically lower than the 203 kW projection from the Synapse Study.

Table 6

Program Type	Existing Buildings	Existing Buildings	Existing Buildings	Custom	Existing Buildings	Existing Buildings
Project Name	Lighting Fixtures & Controls	Lighting Fixtures & Controls	Lighting Fixtures & Controls	Custom Window Film	Chillers	Lighting Fixtures & Controls
Year Built	2005	1997	1980	2004	unknown	1959
Square Footage	289,912	860 spaces	56,127	138,240	750,000	176,653
Building Type	R&D Manufacturing & Office	Parking Lot / Parking Garage	Office	Office	Office	Office
Total Timeline (months)	15	7	14	22	21	15
Completion Incentive Total	$55,380	$21,625	$64,990	$42,907	$50,691	$274,580
Completion Savings kW	60	27	42	26	58	197
Completion Savings kWh	299,422	194,447	147,532	153,239	223,573	440,040
Project Information	Installation of 1,017 LED retrofit kits	Installation of 80 LED panels and 40 LED parking area pole fixtures	Installation of 118 PAR & A LED lamps, 654 LED panels, 152 TLED Type C, 17 LED parking lot pole fixtures, PACE Financing	Installation of silver window film on portions of south, east and west exposure glazing	Installation of (2) 700 ton water cooled centrifugal chillers rated at 0.525 kW/ton full load and 0.334 IPLV	Installation of 1,492 LED Panels, 2,915 LED Strip retrofit kits

Finally, designed savings from projects often vary significantly from realized savings. A 2015 study from the Lawrence Berkeley National Laboratory indicated that actual energy usage deviates from planned savings by approximately 20% on average. Variation in actual building performance makes it very difficult to assess energy savings potential. A separate study that investigated the actual performance of designated high performance buildings (HPBs), such as LEED certification in the United States and comparable certifications in Europe and China, found little evidence that proves that specific measure installations actually yield significant realized energy savings. The study "conclude[s] that no single factor determines the actual energy performance of HPBs, and adding multiple efficient technologies does not necessarily improve building energy performance; therefore, an integrated design approach that takes account of climate, technology, occupant behavior, and operations and maintenance practices should be implemented to maximize energy savings in HPBs." The investigators looked at different mixes of technologies installed and factored for size, weather, and other potentially impactful variables, and importantly concluded "that stacking or simply adding more technologies does not lead to low energy use." The HPBs that consistently achieved superior performance had highly integrated design processes that considered the occupants' preferences and the building's unique usage needs, and took into consideration the behavioral components of energy savings.

The Synapse Study's conclusions regarding demand reductions achieved from energy efficiency are unsupported and overstated and should be rejected.

4. *The Synapse Study's Assessment of the Local Rooftop Solar Potential is Highly Problematic.*

The Synapse Study initially estimates a potential of 5 MW of rooftop solar photovoltaic ("PV") generation in the area served by Northeast Substation 212, including a potential for 2 MW of rooftop solar PV generation on buildings on the Northeast Sub. 212 Southwest LVAC Network Feeder Group.[81] To develop this estimate, the Synapse Study applies an assumption that 20% of total rooftop space is available for solar PV systems. The 20% value is calculated based on a study of a sample of non-residential buildings in the District of Columbia that already have installed solar PV systems.[82] The Synapse Study then applies its estimate of 0.125 kW/m^2, as sourced from the International Renewable Energy Agency, for the solar-capacity-to-rooftop-area ratio. The Synapse Study uses the solar-capacity-to-rooftop-area ratio to calculate the 5

[81] Synapse Study at 34.
[82] *Id.* at 34, footnote 25, referring to "Distributed Solar in the District of Columbia," p. 93; "C. DC DG PV model - Mt Vernon Technical Potential.xlsx", "RoofAvailabilityCheck" and "MtVernonAnalysis" tabs

MW of rooftop solar PV potential in the area served by Northeast Substation, including the 2 MW of rooftop solar PV potential on buildings in the Northeast Sub. 212 Southwest LVAC Network Feeder Group.[83] The Synapse Study notes that historic building and federal ownership issues may complicate deployment in the Northeast Sub. 212 Southwest LVAC Network Feeder Group, resulting in a reduction from 2 MW of solar PV capacity potential to 1 MW of solar PV capacity potential.[84] The study also assumes a 25% peak coincidence factor for solar PV with respect to times of system congestion for which the Mt. Vernon Substation otherwise would be needed.[85] Finally, in its development of portfolios for deferral, the Synapse Study directly includes solar PV only in its portfolio designed to defer the substation construction indefinitely. Here, the Synapse Study assumes that the full 1 MW of solar PV capacity potential in the Northeast Sub. 212 Southwest LVAC Network Feeder Group is utilized, reducing the peak load by 1 MW x 25% = 0.25 MW.[86]

The Synapse Study's assessment is highly problematic. First, the study's assumption that 20% of total rooftop space is available for solar PV systems is based on a small sample size of only 13 buildings and, therefore, is very uncertain.[87] Moreover, the Synapse Study does not derate the solar PV potential for economic viability but, instead, assumes that the entire estimated technical potential is utilized. This is particularly puzzling because Synapse did apply derations to account for economic viability as part of a similar analysis in Synapse's Distributed Solar in the District of Columbia report, to which the Synapse Study refers. The Distributed

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83 Synapse Study at 34, footnote 25, referring to "Distributed Solar in the District of Columbia," p. 98; "C. DC DG PV model - Mt Vernon Technical Potential.xlsx", "MtVernonAnalysis" tab

84 *Id.* at 34.

85 *Id.* at 35.

86 *Id.* at 50.

87 Synapse Study workpaper "C. DC DG PV model - Mt Vernon Technical Potential.xlsx" provided as part of the District of Columbia Government's (DCG) Responses to the First Set of Data Requests from the Potomac Electric Power Company (Pepco).

Solar in the District of Columbia report assumed an economic deration factor of 26% as its reference case for non-residential buildings.[88] Applying that value to the Synapse Study's final estimate of 1 MW of solar PV potential on the Northeast Sub. 212 Southwest LVAC Network Feeder Group would reduce the estimate to 0.26 MW, a value that is roughly one quarter of amount assumed in the portfolio for the substation deferral. Furthermore, the Distributed Solar in the District of Columbia report indicated that the economic deration factor would decline from 26% to virtually zero if the payback period for a solar PV facility were to extend to 10 years, indicating large uncertainty about the true economic potential and adoption rate.[89] Finally, the 26% value was labeled the "ultimate adoption potential," emphasizing that there is no guarantee that such adoption could be achieved by the time that the Mt. Vernon Substation otherwise would be needed.[90]

There are additional flaws in the study's solar PV analysis. The Synapse Study fails to address the possibility that some buildings already may have solar PV systems, thereby further reducing the solar PV potential. Finally, the study does not account for the fact that solar PV is an intermittent resource that cannot be guaranteed to generate 25% of its maximum output throughout the duration of any period in which it is needed to reduce congestion that otherwise would be remedied by the construction of the Mt. Vernon Substation. The Synapse Study's conclusions regarding solar PV availability are flawed and overstated and should be rejected.

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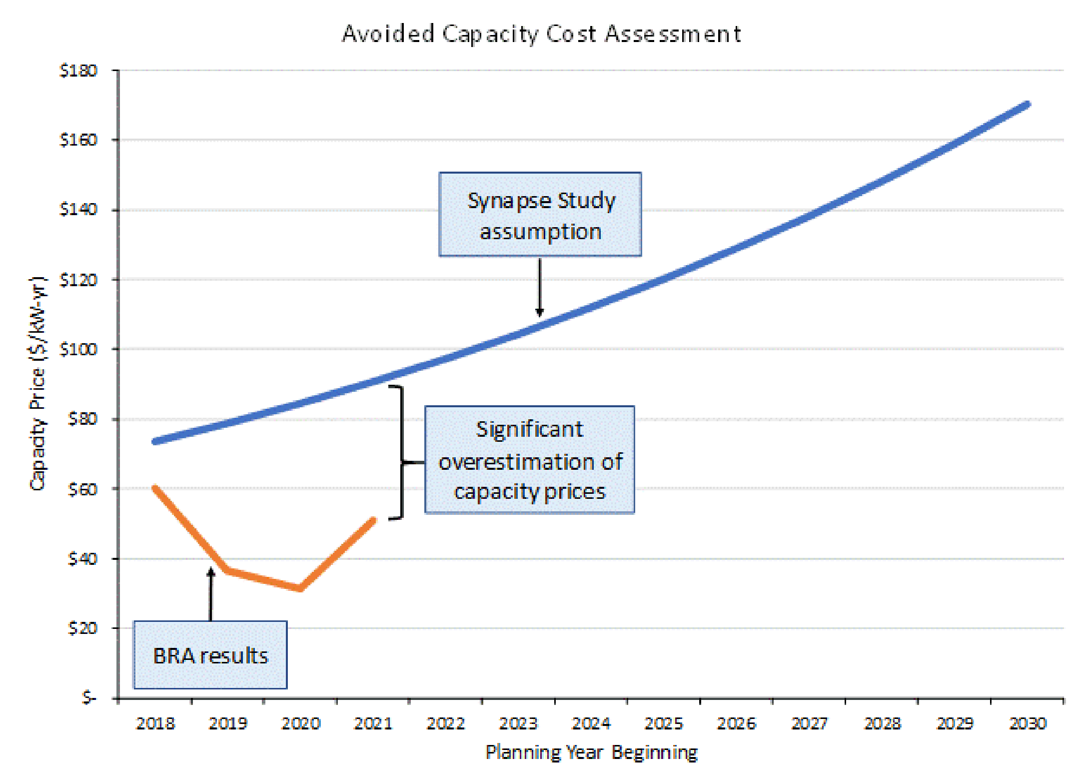
[88] "Distributed Solar in the District of Columbia," Synapse Energy Economics, Inc., April 12, 2017, at 104.
[89] *Id.*
[90] *Id.*

5. *The Synapse Study's Forecasted Avoided Costs of Capacity and Energy from Its Recommended Solutions Are Significantly Overstated.*

The Synapse Study's recommended alternatives are based on implementing projects that would avoid costs of capacity and energy by either reducing electricity demand (*e.g.*, demand response, energy efficiency) or increasing electricity generation (*e.g.*, rooftop solar).[91] Thus, the Synapse Study also relies upon these avoided costs as additional sources of value to justify its proposed alternatives to the Mt. Vernon Substation. However, a simple look at the markets for capacity and energy shows that the Synapse Study's estimates of avoided generation capacity and energy costs are substantially overstated.[92] Specifically, the following figure compares the Synapse Study's "Avoided Generation Capacity ($/kW-yr)" values with actual market clearing prices for generation capacity from PJM's Base Residual Auctions ("BRA"), which establish the actual compensation that resources can be provided for capacity.[93] As Figure 8 shows, the Synapse Study's assumptions for the value of avoided capacity are much higher than actual BRA results.

[91] Synapse Study at 32-33.
[92] *Id.* at 33.
[93] The overwhelming majority of generation capacity in PJM is priced through PJM's Base Residual Auctions.

Figure 8



Similarly, as shown in the Figure 9, the Synapse Study's "Avoided Energy ($/MWh)" values are much higher than forward market prices. [94]

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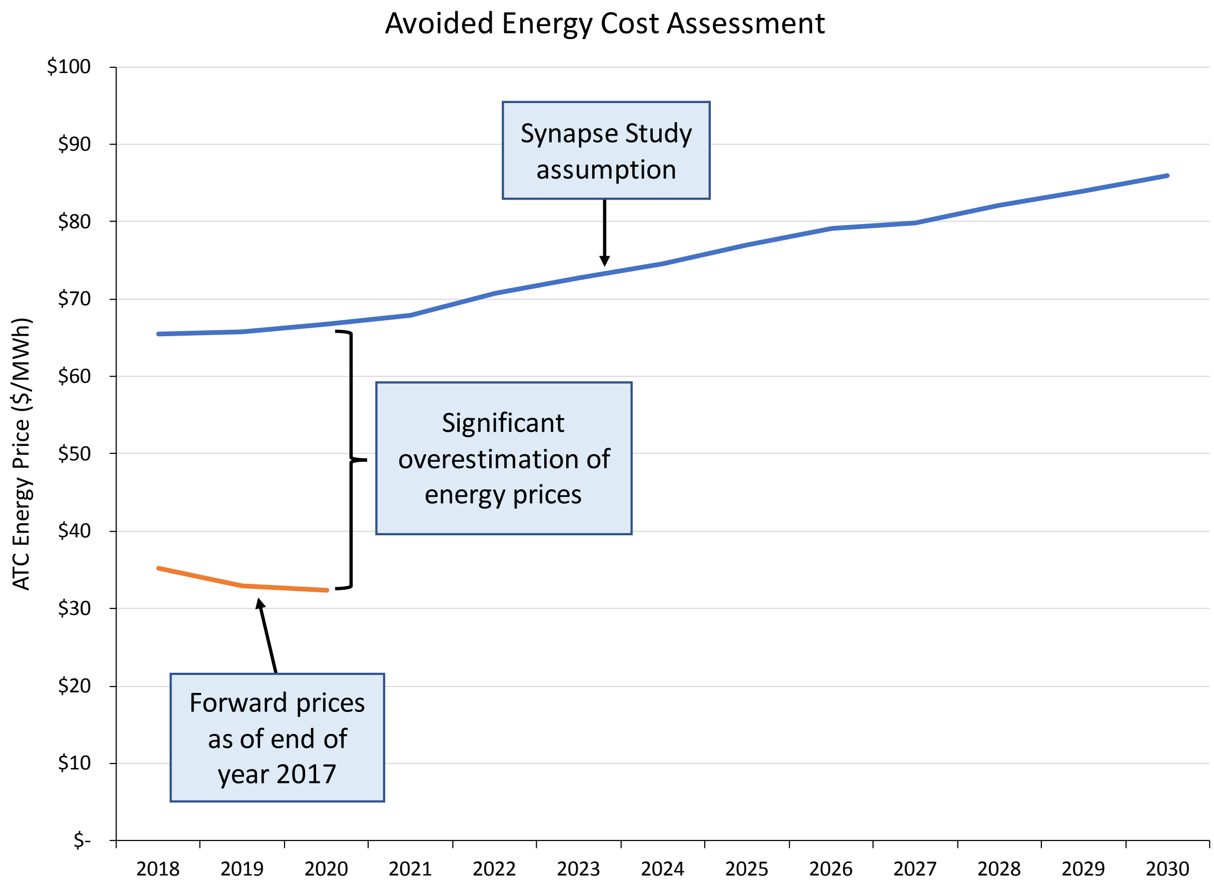
94 Forward prices reflect NYMEX forward prices for PJM Western Hub as of December 28, 2017, provided by Ventyx / Energy Velocity, plus a locational basis to the PEPCO Zone based on 2017 hourly locational marginal prices provided by Ventyx / Energy Velocity.

Figure 9



The Synapse Study's inflated estimates of the avoided capacity and energy costs paint an overly optimistic picture of the economics of its proposed alternatives to the Mt. Vernon Substation and should be rejected.

6. *The Synapse Study's Calculations of the Present Values of Substation Deferral Overstate the Actual Value to Residents of the District of Columbia.*

Since the Synapse Study's main goal is to defer the construction of the Mt. Vernon Substation, the value of deferring the substation is of critical importance. The deferral value estimate presented in the Synapse Study is derived by comparing the present value of the forecasted revenue requirements paid by customers if the substation is constructed as proposed by Pepco with the revenue requirements if the substation is deferred.[95] Given the time value of money, delaying the costs to customers could have value. However, the Synapse Study has made substantial oversights in performing its calculations, which inflate its estimate of the value of substation deferral. Most notably, a substantial portion of the substation costs that must be covered by customers are the property taxes associated with the substation, which Pepco must pay. The Synapse Study assumes a property tax rate of 5.0% without support for its assumption but with a comment in its supporting workpaper that asks, "What value should we use?"[96] In reality, District of Columbia commercial and industrial real property tax rates are in the range of 1.65%-1.85%,[97] and the personal property rate is generally 3.4%.[98] Lowering the tax rate assumption accordingly would commensurately lower the assumed value of deferring the substation. Furthermore, while these property taxes represent a cost to District of Columbia residents, they also represent a cash inflow to the District of Columbia to provide valuable services to District of Columbia residents. As such, treating property taxes as a cost to residents without recognizing the value that they provide in the form of incremental services to residents inflates the value of substation deferral. Specifically, if the value of the services is treated as a one-for-one value, the present values of substation deferral as calculated by Synapse are reduced by almost 40%.[99] Furthermore, the Synapse Study's analysis of deferral value is based on an erroneous corporate income tax rate of 35%, ignoring the fact that the corporate income tax rate

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95 Synapse Study at 19-22.

96 Synapse Study workpaper "A. MtVS cost benefit no storage revised (1).xlsx" provided as part of the District of Columbia Government's (DCG) Responses to the First Set of Data Requests from the Potomac Electric Power Company (Pepco).

97 https://otr.cfo.dc.gov/page/real-property-tax-rates

98 https://otr.cfo.dc.gov/sites/default/files/dc/sites/otr/publication/attachments/2019_FP-31%20Booklet_4.25.18.pdf

99 Synapse Study workpaper "A. MtVS cost benefit no storage revised (1).xlsx" provided as part of the District of Columbia Government's (DCG) Responses to the First Set of Data Requests from the Potomac Electric Power Company (Pepco).

has been cut to 21% per federal legislation passed in 2017. The Synapse Study's calculations of value are overstated and should be rejected.

7. *The Synapse Study Misrepresents the Load Forecasts.*

The Synapse Study inappropriately compares actual load to Pepco's load forecasts to suggest that Pepco's load forecasts for the impacted substations and feeder groups were flawed. The section in the Synapse Study entitled "Pepco's Load Forecast" shows an understanding of how and why Pepco forecasts load as it does.[100] Nevertheless, the Synapse Study compares the load forecasts to actual load as if the load forecasts were intended to predict the actual load. The comparison is misleading and should be ignored.

To understand why the study's comparisons are misleading, it is important to understand Pepco's planning process. Pepco's methodological planning approach allows the distribution system to handle peak conditions and, thus, enables Pepco to reliably serve customers in the District of Columbia when those conditions occur. The customer demand in the District of Columbia peaks during the summer, and peak customer demand generally is what drives capacity modifications or additions to the distribution system. Accordingly, Pepco uses the year with the highest summer system peak demand in the last ten years for developing a base load for each feeder, substation transformer and substation from which it forecasts future load, which typically corresponds to the highest temperature during non-holiday weekdays over the same period. This 90/10 approach is used to ensure that the distribution system is capable of providing reliable service to District of Columbia customers during the most extreme summer weather likely to be experienced over a ten-year period.

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[100] Synapse Study at 14.

Complementing Pepco's 90/10 approach is its "bottom-up" method of developing a load forecast: the load is first forecasted at the distribution feeder level, and then the expected load of all the feeders supplied by a given substation in each year of the forecast is summed to determine the corresponding substation peak load for each year of the forecast. Because the load of feeders supplied by a given substation may not peak at the same time (non-coincident feeder peak load), an adjustment to the total of the feeder peak loads in each year of the forecast may be necessary to avoid inflating the expected transformer and substation peak load (feeder coincident peak load). Pepco's load forecasting methodology accounts for expected increases and, where applicable, decreases in future loads, as well as load transfers and other factors that affect the distribution system's capacity. Load forecasts are performed on a short- and long-term basis.

The Synapse Study misuses Pepco's load forecasting data to imply that Pepco's load forecasts are flawed. First, the Synapse Study implies that Pepco's actual loads have not reached the levels projected by Pepco. In Figures 2, 4, and 7, the Synapse Study provides a series of graphs showing the actual load for certain substations and five years of Pepco's 90/10 forecasts. The study then suggests that because the forecasted capacity is higher than the actual loads experienced, that the load forecasts must be incorrect or the methodology faulty. The comparison inappropriately suggests that the purpose of the load forecast was to predict what actual load would be in those years and that the forecast failed to predict the actual loads. However, Pepco's load forecasting and planning process does not predict the actual load that will actually be experienced in future years under normal circumstances. Instead, Pepco forecasts to ensure that the distribution system is capable of providing reliable service to District of Columbia customers during the most extreme summer weather likely to be experienced over a ten-year period. The 90/10 data will always be greater than the actuals unless the actuals being compared are for the 90/10 year that serves as the basis for the forecast.

Then, the Synapse Study claims that "the fact that each [load] forecast [in Figure 10] has been lower than the last indicates that new loads have not been arriving as quickly as initially thought."[101] In fact, when looking at Figure 10, it is clear that the load forecasts for 2014-2016 are relatively similar and even 2013 is not significantly higher. It is only the 2017 load forecast that is noticeably lower. As Pepco has reported, 2017 was the first load forecast that fully incorporated DER impact into the load forecast, resulting in cumulative load reductions of approximately 14% of the total load on the Northeast Sub. 212 Southwest LVAC Network Feeder Group. The Synapse Study's assertion is incorrect.

Finally, the Synapse Study relies on Greenlink's data—the same data that the Synapse Study admits "did not target the specific circuits" and which Pepco demonstrated above identifies the wrong customer base for the Northeast Sub. 212 Southwest LVAC Network Group—as a basis for comparison with Pepco's forecasted load. The Synapse Study adds to the Greenlink data two buildings (GAO and Capitol Crossing) which, as discussed above, are not on the Northeast Sub. 212 Southwest LVAC Network Group (either in whole or in part). Because it does not have the energy-to-square foot relationship for GAO, the Synapse Study assumes the same relationship as the Metro headquarters at 600 5th St., NW. It uses the Greenlink load that is modeled on "typical" weather (which it does not define) and compares it to Pepco's load forecast under 90/10 conditions. Finally, the study concludes that the Synapse Study has "no reasonable theories to explain the rest of the more than 20 MVA of growth that Pepco projects in the area by

101 Synapse Study at 16.

2024," implying that Pepco's load forecasted are flawed and overstated.[102] In reality, the Synapse Study has misidentified customer base, compared dissimilar load, and created Frankenstein-like load assumptions that conveniently support to the study's preferred implication that the load forecasts are overstated on the Northeast Sub. 212 Southwest LVAC Network Group.

E. MEDSIS Funding Should Not Be Significantly Depleted by a Single Project that Is not Well Founded

The possible scope of projects that can be piloted through MEDSIS is wide ranging. The Commission anticipated that the MEDSIS funding would accommodate this wide range of technologies:

> Generally, the scope of this proceeding is to identify technologies and policies that can modernize our energy delivery system for increased sustainability and make the system more reliable, efficient, cost effective and interactive . . . an examination of new technologies that will impact the delivery of energy in the District including but not limited to energy storage, distributed energy resources, electric vehicles, microgrids and the integration of identified enabling technologies.[103]

As demonstrated above, the proposed projects that DOEE and the Synapse Study have put forward are only conceptual and have not been thoroughly thought through and substantiated with reliable data. Spending $10 million on proposals that are not well formulated risks wasting half of the MEDSIS funds on projects that will produce no actual learning. More significantly, funding this project would place the electric distribution service of thousands of District of Columbia customers at risk. Finally, DOEE is requesting that almost half of the MEDSIS funding be applied/directed to one project consisting only of energy efficiency and demand

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[102] Synapse Study at 17.
[103] Order No. 17912 at P 5.

response solutions that DOEE claims will defer a substation for one and two years. None of the technologies identified in Order No. 17912 for examination as part of MEDSIS will be included in DOEE's project. Applying $10 million of the $21.55 million to the projects in the Synapse Study would leave only $11.55 million to pilot all of these new technologies. In addition, a portion of that $11.55 million will be used to pay the consultants in charge of the working group and the RFP processes. In the end, only a fraction of the MEDSIS funding will be used on the types of projects the Commission intended.

The more reasonable approach would be to use the MEDSIS funds for a variety of smaller pilot projects that use a variety of technologies. The learning from these pilot projects will be instrumental integrating the technologies into the modernized grid in the normal course of business. It also aligns with Pepco's approach to integrating new technology into its distribution system.

F. A Working Group Targeting Mt. Vernon Would Cause Reliability Concerns

Order No. 19274 directed Pepco to file a Notice of Construction that includes both the reliability projects that are part of the Capital Grid Project (Harvard and Champlain Substations) and the load project (Mt. Vernon Substation), which Pepco has filed contemporaneously with these Reply Comments. If the Commission were to act on the DOEE Comments' requests to defer the construction of the Mt. Vernon Substation for two years and to convene a working group to look at alternative solutions, the Commission would be deferring the reliability projects (Harvard and Champlain Substations) as well. The Harvard and Champlain Substations cannot be deferred for almost three years (two years of working group time and additional time to rule on the combined Notice of Construction) without reliability impacts to customers. Pepco originally structured the two Notices of Construction to allow it to move forward with the reliability projects (the Harvard and Champlain Substations) and allow assessment of DER impact on the load project (the Mt. Vernon Substation). Order No. 19274 directed Pepco to file one Notice of Construction containing the Harvard, Champlain, and Mt. Vernon Substations and associated transmission. Moreover, as demonstrated in the Notice of Construction being filed concurrently, the Mt. Vernon Substation is necessary in 2023. The RFP for MEDSIS has properly focused the working group on reviewing non-wires solutions more broadly and not as a replacement for any particular project. The Notice of Construction approval process should move forward in parallel with the working group focused on non-wires alternatives.

III. CONCLUSION

Pepco appreciates the opportunity to complete the record with its Reply Comments. For the reasons described above, the DOEE Comments and the Synapse Study should be rejected.

Respectfully submitted,
Potomac Electric Power Company

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June 29, 2018

ATTACHMENT A

Final Attachment A to Synapse Study Response - Final Mt Vernon Substation PNB List.xlsx

updated as of 6/6/18

ID	Development Name	Development Address	Customer Name	Building Type	Delivery Year	Known Sq. Ft	Known # of Units	Substation Name/N0	Feeder Type	Total Load	Estimated Number of Apts (assume avg apt = 1,000 sq ft)	Estimated Number of Hotel Rooms (assume avg room = 350 sq ft)	Estimated Retail Sq Ft	Estimated Office Sq Ft	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
96	Lumen	2200 14th St NW		Residential		18,000		Florida Ave Sub 10	Network	**0.1**	18.00				0.1									
93	907 Barry Place	907 Barry Pl NW		Residential		319,000		Florida Ave Sub 11	Network	**1.0**	319.00					0.5	0.5							
90	Martha's Table	2122 14th St NW		Residential		122,335	233	Florida Ave Sub 12	Network	**0.4**	122.34						0.2	0.2						
94	Elysium 14	1925 14th St NW		Residential		56,000	109	Florida Ave Sub 13	Network	**0.2**	56.00				0.2									
91	2030 Eighth St	2030 8th St NW		Residential		62,000	238	Florida Ave Sub 14	Network	**0.2**	62.00				0.2									
92	2221 14th St	2221 14th St NW		Residential		30,000		Florida Ave Sub 15	Network	**0.1**	30.00				0.1									
99	V Street Residences	15th & V St NW		Residential		95,000	43	Florida Ave Sub 16	Network	**0.3**	95.00				0.3									
89	2002 11th St NW	2002 11th St NW		Residential		30,000		Florida Ave Sub 17	Network	**0.1**	30.00						0.1							
103	Elysium 14	1925 14th St NW		Retail		12,300	58	Florida Ave Sub 18	Network	**0.1**			12,300		0.1									
87	13th & U	1300 u St NW		Residential		135,000	165	Florida Ave Sub 19	Network	**0.4**	135.00				0.2	0.2								
86	1309-1315 Clifton Street	1309-1315 Clifton St NW		Residential		170,000	128	Florida Ave Sub 20	Network	**0.5**	170.00					0.3	0.2							
88	1412 Chapin St	1412 Chapin St NW		Residential		30,000	31	Florida Ave Sub 21	Network	**0.1**	30.00					0.1								
106	The Shay & The Hatton	8th & 9th St & Florida Ave		Retail		26,000		Florida Ave Sub 22	Network	**0.2**			26,000			0.2								
98	The Shay & The Hatton	8th & 9th St & Florida Ave		Residential		242,000		Florida Ave Sub 23	Network	**0.7**	242.00				0.4	0.3								
104	Howard Town Center	2114 Georgia Ave NW		Retail		74,000		Florida Ave Sub 24	Network	**0.6**			74,000			0.3	0.3							
102	13th & U	1300 u St NW		Retail		15,200		Florida Ave Sub 25	Network	**0.1**			15,200		0.1									
95	Howard Town Center	2114 Georgia Ave NW		Residential		445,000		Florida Ave Sub 26	Network	**1.3**	445.00					0.7	0.3	0.3						
97	The Logic	2105 10th St NW		Residential		45,000		Florida Ave Sub 27	Network	**0.1**	45.00					0.1								
105	The Logic	2105 10th St NW		Retail		5,400		Florida Ave Sub 28	Network	**0.0**			5,400											
107	Howard U Interdisciplinary Research Bldg	2201 Georgia Ave		School		81,600		Florida Ave Sub 29	Network	**0.7**			81,600			0.7								
75	Capitol Crossing	201 F St NW	Capitol Crossing	Mixed Use	2020	268,000		New Jersey Sub 161	Network	**1.1**	214		53,600	-			0.6	0.5						
73	Capitol Crossing	200 Mass Ave NW	Capitol Crossing	Mixed Use	2018	414,170		New Jersey Sub 162	Network	**2.5**			15,000	399,000	1.3	0.6	0.6							
74	Capitol Crossing	200 G St NW	Capitol Crossing	Mixed Use	2020	159,000	150	New Jersey Sub 163	Network	**0.5**	150		9,000	-			0.3	0.2						
76	Capitol Crossing	200 F St NW	Capitol Crossing	Mixed Use	2020	692,000		New Jersey Sub 164	Network	**2.8**	554		138,400	-			1.4	0.7	0.7					
18	N. A.		Masseria	Restaurant	2017	3,000		New Jersey Sub 165	Radial	**0.0**	-		3,000	-										
132	Existing Florida Market Demo	Where Union Market is going			2020			New Jersey Sub 166	Radial 14786 & 14787	**-2.0**					-0.5	-1.0	-0.5							
38	Union Market		Gallaudet Parcel 2	Retail/Apartments	2020	61,043		Northeast Sub. 212	East Network	**0.3**	49		12,209	-					0.3					
39	Union Market		Gallaudet Parcel 2	Retail/Apartments	2021	61,043		Northeast Sub. 212	East Network	**0.3**	49		12,209	-					0.3					
20	Union Market		Union Market (N. Bldg) Edens	Retail	2018	313,440		Northeast Sub. 212	East Network	**2.7**	-		313,440	-			1.3	0.7	0.7					
26	Union Market		Shapiro North	Retail/Apartments	2019	89,215		Northeast Sub. 212	East Network	**0.4**	71		17,843	-				0.2	0.2					
27	Union Market		Shapiro North	Retail/Apartments	2020	89,215		Northeast Sub. 212	East Network	**0.4**	71		17,843	-				0.2	0.2					
21	Union Market	1270 4th St. NE - Edens	N. A.	Retail/Apartments	2018	384,300		Northeast Sub. 212	East Network	**1.6**	307		76,860	-		0.8	0.8							
35	Union Market	300 & 350 Morse ST.	N. A.	Retail/Apartments	2022	93,000		Northeast Sub. 212	East Network	**0.4**	74		18,600	-				0.2	0.2					
28	Union Market		Marice Parking Lot (N)	Retail/Apartments	2019	120,000		Northeast Sub. 212	East Network	**0.5**	96		24,000	-				0.3	0.2					
29	Union Market		Marice Parking Lot (N)	Retail/Apartments	2020	120,000		Northeast Sub. 212	East Network	**0.5**	96		24,000	-				0.3	0.2					
40	Union Market		Gallaudet Parcel 3	Retail/Apartments	2020	169,938		Northeast Sub. 212	East Network	**0.7**	136		33,988	-					0.3	0.4				
41	Union Market		Gallaudet Parcel 3	Retail/Apartments	2021	169,938		Northeast Sub. 212	East Network	**0.7**	136		33,988	-					0.3	0.4				
42	Union Market		Gallaudet Parcel 3	Retail/Apartments	2022	169,938		Northeast Sub. 212	East Network	**0.7**	136		33,988	-					0.3	0.4				
45	Union Market	500 Morse ST. NE	N. A.	Retail/Apartments	2020	97,000		Northeast Sub. 212	East Network	**0.4**	78		19,400	-					0.2	0.2				
46	Union Market	500 Morse ST. NE	N. A.	Retail/Apartments	2021	97,000		Northeast Sub. 212	East Network	**0.4**	78		19,400	-					0.2	0.2				
47	Union Market		Gallaudet Parcel 4	Retail/Apartments	2021	196,000		Northeast Sub. 212	East Network	**0.8**	157		39,200	-						0.4	0.4			
48	Union Market		Gallaudet Parcel 4	Retail/Apartments	2022	196,000		Northeast Sub. 212	East Network	**0.8**	157		39,200	-						0.4	0.4			
24	Union Market	400 Florida Ave.	N. A.	Retail/Apartments	2019	49,905		Northeast Sub. 212	East Network	**0.2**	40		9,981	-			0.2							
25	Union Market	400 Florida Ave.	N. A.	Retail/Apartments	2020	49,905		Northeast Sub. 212	East Network	**0.2**	40		9,981	-			0.2							
43	Union Market	1271 5th St. NE	N. A.	Retail/Apartments	2020	53,311		Northeast Sub. 212	East Network	**0.2**	43		10,662	-					0.2					
44	Union Market	1271 5th St. NE	N. A.	Retail/Apartments	2021	53,311		Northeast Sub. 212	East Network	**0.2**	43		10,662	-					0.2					
32	Union Market	300 & 350 Morse ST.	N. A.	Retail/Apartments	2019	200,000		Northeast Sub. 212	East Network	**0.8**	160		40,000	-				0.4	0.4					
33	Union Market	300 & 350 Morse ST.	N. A.	Retail/Apartments	2020	200,000		Northeast Sub. 212	East Network	**0.8**	160		40,000	-				0.4	0.4					
34	Union Market	300 & 350 Morse ST.	N. A.	Retail/Apartments	2021	200,000		Northeast Sub. 212	East Network	**0.8**	160		40,000	-				0.4	0.4					
36	Union Market		Gallaudet Parcel 1	Retail/Apartments	2020	78,390		Northeast Sub. 212	East Network	**0.3**	63		15,678	-					0.3					
37	Union Market		Gallaudet Parcel 1	Retail/Apartments	2021	78,390		Northeast Sub. 212	East Network	**0.3**	63		15,678	-					0.3					
23	Union Market	5th st. South	N. A.	Retail	2018	50,000		Northeast Sub. 212	East Network	**0.4**	-		50,000	-			0.2	0.2						
30	Union Market		Marice BLDG	Retail/Apartments	2019	153,500		Northeast Sub. 212	East Network	**0.6**	123		30,700	-				0.3	0.3					
31	Union Market		Marice BLDG	Retail/Apartments	2020	153,500		Northeast Sub. 212	East Network	**0.6**	123		30,700	-				0.3	0.3					
22	Union Market		The Highline @ Union Market	Retail/Apartments	2018	227,000		Northeast Sub. 212	East Network	**0.9**	182		45,400	-			0.5	0.4						
19	Union Market		Union Market (S. Bldg) Edens	Retail/Apartments	2018	178,571		Northeast Sub. 212	East Network	**0.7**	143		35,714	-		0.4	0.3							
49	Union Market	300 & 350 Morse ST. NE	N. A.	Retail/Apartments	2021	182,000		Northeast Sub. 212	East Network	**0.7**	146		36,400	-						0.4	0.3			
50	Union Market	300 & 350 Morse ST. NE	N. A.	Retail/Apartments	2022	182,000		Northeast Sub. 212	East Network	**0.7**	146		36,400	-						0.4	0.3			
17	The Edison @ Union Market		The Edison @ Union Market	Retail/Apartments	2017	183,430		Northeast Sub. 212	East Network	**0.8**	147		36,686	-	0.4	0.4								
15		470 K ST NW	N. A.	Retail	2017	17,850		Northeast Sub. 212	Radial	**0.2**	-		17,850	-	0.2									
16		476 K ST NW	N. A.	Retail	2017	17,850		Northeast Sub. 212	Radial	**0.2**	-		17,850	-	0.2									
13		1005 NORTH CAPITOL NE	North Capitol Commons	Residential	2017		124	Northeast Sub. 212	Radial	**0.4**	124.00		2,200	-	0.2	0.2								
14		301 Florida Ave.	N. A.	Residential	2018	71,000	56	Northeast Sub. 212	Radial	**0.2**	56.00		4,500	-			0.2							
12		57 N St. NW	N. A.	Residential	2017	28,400	114	Northeast Sub. 212	Radial	**0.3**	114.00		-	-		0.2	0.1							
71		72 Florida Ave. NE		Apartments	2021		182	Northeast Sub. 212	Radial	**0.5**	182		-					0.3	0.2					
119	Burnham Place	H St over Train Tracks		Mixed Use	2026/2027	3,000,000		Northeast Sub. 212	South Spot Ntwk	**14.7**	1,300	500	100,000	1,500,000							3.7	3.7	3.7	3.6
69		88 M St. NE		Office	2021	315,000		Northeast Sub. 212	South Spot Ntwk	**1.9**			8,000	299,000				1.0	0.5	0.4				
1		1005 First St, NE	Perseus/First Potomac Realty Trust	Hotel	2017		260	Northeast Sub. 212	South Spot Ntwk	**1.6**	278	260	27,000	-	0.8	0.4	0.4							
54		301 & 331 N Street- NE	N. A.	Office	2019	25,000		Northeast Sub. 212	South Spot Ntwk	**1.8**	350	175	27,000	25,000		0.9	0.5	0.4						
68		44 M St. NE		Apartments	2021		320	Northeast Sub. 212	South Spot Ntwk	**2.6**	320		24,000	234,000				1.3	0.7	0.6				
70		45 L St. NE		Office	2019	545,000		Northeast Sub. 212	South Spot Ntwk	**3.3**				545,000		1.7	0.8	0.8						
67		22 M St. NE		Retail/Apartments	2019	337,000	326	Northeast Sub. 212	South Spot Ntwk	**1.1**	320		13,000			0.5	0.6							
122	Capitol Point North	77 New York Ave NE		Office	2019	780,000		Northeast Sub. 212	South Spot Ntwk	**4.4**				732,000				2.2	1.1	1.1				
11		55 M St NE	Archstone	Residential	2017		438	Northeast Sub. 212	South Spot Ntwk	**0.0**	-		-	-										
123	1150 First St NE	1150 1st St NE	Tishman Speyer	Office	2021	350,000		Northeast Sub. 212	South Spot Ntwk	**2.1**				350,000					1.1	0.5	0.5			
9		140 M St. NE	N. A.	Apartments	2020		203	Northeast Sub. 212	South Spot Ntwk	**0.6**	203					0.3	0.3							
72		50 Florida Ave. NE		Apartments	2017	182,000	182	Northeast Sub. 212	South Spot Ntwk	**0.6**	182		7,500		0.3	0.3								
121	Washington Gateway Phase II	100 Florida Ave NE		Apartments	2021		372	Northeast Sub. 212	South Spot Ntwk	**1.1**	372							0.5	0.3	0.3				
120	NoMa Station	220 L St NE		Apartments	2021		62	Northeast Sub. 212	South Spot Ntwk	**0.2**	62		3,700					0.2						
55	Lacebark Alley	1250 1st St. NE/ 50 Patteson and 51 N St. NE	N.A.	Retail/Apartments	2019	544,713	220	Northeast Sub. 212	South Spot Ntwk	**3.3**	220		53,000	368,000			1.6	0.9	0.8					
56		61 Pierce St. NE	N.A.	Apartments	2017		203	Northeast Sub. 212	South Spot Ntwk	**0.6**	203				0.3	0.3								
10		300 M St NE	N. A.	Retail/Apartments	2018	771,377		Northeast Sub. 212	Southeast Spot Ntwk	**1.4**	425		10,000	-					0.7	0.4	0.3			
53		33 N St. NE	N. A.	Retail/Apartments	2018	350,010		Northeast Sub. 212	Southeast Spot Ntwk	**1.1**	346		4,200	-	0.6	0.5								
64		200 K St. NE	Union Place Phase II	Apartments	2018	525,000	525	Northeast Sub. 212	Southeast Spot Ntwk	**1.6**	525				0.8	0.4	0.4							
2		100 K St, NE	Archstone	Retail/Apartments	2018	224,000	222	Northeast Sub. 212	Southeast Spot Ntwk	**0.7**	222		2,000		0.3	0.4								
124	Union Square III	901 North Capitol St NE	Akridge	Office	2021	250,000		Northeast Sub. 212	Southeast Spot Ntwk	**1.5**				250,000				0.7	0.4	0.4				
65		1200 3rd St. NE	Central Armature	Retail/Apartments	2021	695,000	650	Northeast Sub. 212	Southeast Spot Ntwk	**2.8**	556		139,000					1.4	0.7	0.7				
66		201 M St. NE	REI	Retail	2017	38,000		Northeast Sub. 212	Southeast Spot Ntwk	**0.2**	30		7,600		0.2									
51		1035 4th St. nw	N. A.	Apartments	2018		see 307 K	Northeast Sub. 212	Southwest LVAC Network	**0.7**	223				0.4	0.3								
60		307 K St. nw	N.A.	Apartments	2018		223	Northeast Sub. 212	Southwest LVAC Network	**0.7**	223				0.4	0.3								
6		501 K St. NW	N. A.	Retail	2019	550,000		Northeast Sub. 212	Southwest LVAC Network	**3.4**	-		29,000	521,000			1.7	0.9	0.8					

Final Attachment A to Synapse Study Response - Final Mt Vernon Substation PNB List.xlsx

updated as of 6/6/18

ID	Development Name	Development Address	Customer Name	Building Type	Delivery Year	Known Sq. Ft	Known # of Units	Substation Name/N0	Feeder Type	Total Load	Estimated Number of Apts (assume avg apt = 1,000 sq ft)	Estimated Number of Hotel Rooms (assume avg room = 350 sq ft)	Estimated Retail Sq Ft	Estimated Office Sq Ft	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
3		401 K St. NW	N. A.	Apartments	2019		825	Northeast Sub. 212	Southwest LVAC Network	**2.5**	825							1.3	0.5	0.7				
4		400 K St. NW	N. A.	Retail/Apartments	2019	337,500		Northeast Sub. 212	Southwest LVAC Network	**1.1**	324		13,000	-		0.5	0.3	0.3						
118	Toll Brothers - Sursum Corda	1174 1st Pl. NW	Sursum Corda	Retail/Apartments	TBD possibly 2023	1,191,000	1150	Northeast Sub. 212	Southwest LVAC Network	**4.9**	953		238,200	-							2.5	1.2	1.2	
61		901 4th St. nw	N.A.	Office	2018	7,734		Northeast Sub. 212	Southwest LVAC Network	**0.7**			7,734	103,000	0.4	0.3								
7		250 Mass Ave. NW	Capitol Crossing	Mixed Use	2018	539,600		Northeast Sub. 212	Southwest LVAC Network	**3.4**	-		15,000	544,000		1.7	0.9	0.8						
5		1031 4th St. nw	N. A.	Apartments	2017		133	Northeast Sub. 212	Southwest LVAC Network	**0.4**	133				0.2	0.2								
79	600 Massachusetts Avenue	600 Mass Ave NW		Office	2017	200,000		Northeast Sub. 212	Southwest LVAC Network	**1.2**			-	200,000	0.6	0.3	0.3							
62		888 New Jersey Ave. nw	N.A.	Apartments	2021	104,000	104	Northeast Sub. 212	Southwest LVAC Network	**0.3**	104								0.3					
8		600 Mass Ave NW	N. A.	Retail	2017	10,000		Northeast Sub. 212	Southwest LVAC Network	**0.1**	-		10,000	-	0.1									
63		455 I St. NW	N.A.	Apartments	2017	88,000	88	Northeast Sub. 212	Southwest LVAC Network	**0.3**	88				0.3									
129	Lima Hotels	4th and K St NW	Lima Hotels	Hotel	2022		200	Northeast Sub. 212	Southwest LVAC Network	**0.4**		200								0.2	0.2			
130	The Cantata	801 3rd St NW	The Cantata	Apartments	2021		351	Northeast Sub. 212	Southwest LVAC Network	**1.0**	335									0.7	0.3			
126	300 K St NW	300 K St NW	The Wilkes Co.	Office	2021	246,000		Northeast Sub. 212	Southwest LVAC Network	**1.5**			12,700	233,000					0.7	0.4	0.4			
125	901 5th St NW	901 5th St NW	Peebles Corp	Hotel	2021		211	Northeast Sub. 212	Southwest LVAC Network	**0.5**	35	176	7,500						0.3	0.2				
127	950 3rd St NW	950 3rd St NW	The Wilkes Co.	Office	2021	118,000		Northeast Sub. 212	Southwest LVAC Network	**0.7**				118,000					0.4	0.3				
131	AIPAC	251 H St NW	AIPAC	Office	2021	72,000		Northeast Sub. 212	Southwest LVAC Network	**0.4**				72,000					0.2	0.2				
128	Northwest One (3 Buildings)	North Capitol and "K" Street / First Terrace	Northwest One	Retail/Apartments	2027		806	Northeast Sub. 212	Southwest LVAC Network	**1.4**	403		28,256										0.7	0.7
57	227 Harry Thomas Way	227 Harry Thomas Way	N.A.	Retail/Apartments	2020/21	390,000	335	Northeast Sub. 212	West LVAC Network	**1.4**	335		10,000	45,000			0.7	0.4	0.3					
58	Eckington Yards - West	Eckington Yards - West	N.A.	Retail/Apartments	2020/21	527,000	457	Northeast Sub. 212	West LVAC Network	**2.2**	422		105,400				1.1	0.6	0.5					
52		655 H St. NW	N. A.	Retail/Apartments	2017	93,200		Northeast Sub. 212	West LVAC Network	**0.4**	75		18,640	-	0.2	0.2								
59	Eckington Yards - East	Eckington Yards - East	N.A.	Retail/Apartments	2020/21	229,600	228	Northeast Sub. 212	West LVAC Network	**0.9**	184		45,920				0.5	0.4						
110	Conrad Hotel Retail at City Center	New York Ave & 10th St.		Retail	Late 2018	30,000		Tenth Street Sub 52	Network	**0.3**			30,000			0.3								
81	1322 9th St NW	1322 9th St NW		Residential	2020	19,000		Tenth Street Sub 53	Network	**0.1**	19.00						0.1							
100	1336 8th St NW	1336 8th St NW		Retail	2020	6,900		Tenth Street Sub 54	Network	**0.1**			6,900				0.1							
112	City Market at O	810 O Street NW	Four Points	Retail	2019	6,900		Tenth Street Sub 55	Network	**0.1**			6,900			0.1								
77	Columbia Place	901 L St NW		Hotel	2018	175,350	501	Tenth Street Sub 56	Network	**1.0**		501			0.5	0.5								
117	Blagden Alley Micro Apts.	Blagden Alley		Apartments	2020	123,000	123	Tenth Street Sub 57	Network	**0.4**	123						0.2	0.2						
108	Moxy Hotel	1011 K Street NW	Marriot International Inc.	Hotel	Late 2018	70,000	200	Tenth Street Sub 58	Network	**0.4**		200			0.2	0.2								
111	Conrad Hotel at City Center	New York Ave & 10th St.		Hotel	Late 2018	126,000	360	Tenth Street Sub 59	Network	**0.7**		360			0.4	0.3								
116	900 New York Ave	900 New York Ave	Goud Property Company	Retail	2020	35,000		Tenth Street Sub 60	Network	**0.3**			35,000				0.2	0.1						
113	City Market at O	810 O Street NW	Four Points	Apartments	2019	66,000	66	Tenth Street Sub 61	Network	**0.2**	66					0.1	0.1							
83	Columbia Place	901 L St NW		Residential	2018	200,000		Tenth Street Sub 62	Network	**0.6**	200.00				0.3	0.3								
84	Logan 13	1311 13th St NW		Residential	Late 2017	67,000		Tenth Street Sub 63	Network	**0.2**	67.00				0.2									
115	900 New York Ave	900 New York Ave	Goud Property Company	Office	2020	585,000		Tenth Street Sub 64	Network	**3.5**				585,000			1.7	0.9	0.9					
82	1336 8th St NW	1336 8th St NW		Residential	2020	70,000		Tenth Street Sub 65	Network	**0.2**	70.00						0.2							
80	10 Eleven	1011 M St NW		Residential	Late 2017	71,000		Tenth Street Sub 66	Network	**0.2**	71.00				0.2									
85	The Holm	1550 11th St NW		Residential	Late 2017	38,000		Tenth Street Sub 67	Network	**0.1**	38.00				0.1									
78	6th & K Street Office	6th & K St NW (1001 6th St NW)		Office	2020	550,000		Tenth Street Sub 68	Network	**3.2**			29,000	495,000			1.6	0.8	0.8					
114	City Market at O	880 P Street NW		Apartments	Late 2017	142,000	142	Tenth Street Sub 69	Network	**0.4**	142				0.2	0.2								
101	Columbia Place	901 L St NW		Retail	2018	4,000		Tenth Street Sub 70	Network	**0.0**			4,000											
109	The Lurgan	915 L St NW		Apartments	Spring 2018	15,000	15	Tenth Street Sub 71	Network	**0.0**	15													
										126.1	**18,048.3**	**2,372.0**	**2,785,857.8**	**7,618,000.0**	**11.5**	**16.4**	**22.1**	**22.6**	**19.3**	**10.3**	**9.3**	**4.9**	**5.6**	**4.3**

CERTIFICATE OF SERVICE

I hereby certify that a copy of Potomac Electric Power Company's Reply Comments was sent to all parties on this June 29, 2018 by electronic mail.

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POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 6

QUESTION NO. 24
Reference Pepco (H)-2, project 268, 294 (ITN 61976, 84541).
a) Please provide a description of the software and hardware investments included in the ADMS projects and the differences between project 268 and 294.
b) To the extent possible, provide the share of total costs for each of these software and hardware investments described in a).
c) Provide a list of management functions that the Company is seeking to enable/deploy with the ADMS investment.

RESPONSE:

a. For Project 268, an ADMS is installed in each operating company. Although functionality is equivalent, configuration is specific to each OpCo. This implementation will replace their existing SCADA and OMS software as well as hardware: servers, workstations, data acquisition equipment and network infrastructure.

   In Project 294, an evaluation will be performed to determine whether it would be beneficial to combine any of the instances created in Project 268 while assessing operational risk. The aim is to drive standardization of applications, configuration and use by the OpCos. In addition, there will be a hardware refresh and redesign taking into account platform size and performance where consolidation is adopted. New functionality to be introduced includes model based FLISR (Fault Location, Isolation and Service Restoration), Fault Location Analysis, and DER Output control and DER Visualization.

b. Please see FC1176 AOBA DR 7-25 Confidential Attachment NN.

c. The ADMS system includes the applications that enable Distribution Operators to monitor, manage and control the electrical grid. This enables operators to execute system switching to isolate equipment that needs to be taken out of service for repair, and to reconfigure the electrical system due to system conditions. It enables operators to understand system configuration and restore customers in the event of electrical outages.

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POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1176
RESPONSE TO OPC DATA REQUEST NO. 6

QUESTION NO. 10
Reference Direct Testimony of Cantler at p.7 "grid operations." Please describe the Company's activities related to voltage optimization as a part of grid operations:
a) What role does the Company believe voltage optimization plays in DER integration?
b) Please describe any existing and proposed investments in voltage optimization the Company intends to pursue.

RESPONSE:

a. Under certain conditions, DER can cause voltage along the feeder to rise outside of the upper band limit of acceptable voltage. A Voltage Optimization tactic is one element of a coordinated strategy that will increase the Company's ability to accept higher levels of DER on the Company's distribution system.

b. As part of the Company's ADMS platform (ADMS stage 2 / 3), the Company intends to develop a Voltage Optimization program. One element of that plan would be to include field voltage regulators and capacitors into the communications network and link these devices into the SCADA. That will allow a Voltage Optimization algorithm to fully control voltage throughout the distribution system.

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RESPONSE TO OPC DATA REQUEST NO. 6

QUESTION NO. 20

Reference Direct Testimony of Cantler at p.22 “The goal of the ADMS Project is to deploy foundational Distributed Energy Resource Management System (DERMS) capabilities - including DER Visualization, DER Estimation, DER Forecasting, and DER Monitoring & Control.”

a) Please describe all the functionalities and benefits that will be enabled by the ADMS deployment.

b) Please provide an implementation timeline for when the ADMS and DERMS functionalities will be deployed and available for use.

c) Does the Company intend to procure “digital twin” functionality as part of its ADMS procurement?

d) Where on the system does the Company expect DERMS control functionality to be deployed and how is this determined?

RESPONSE:

a. Please see the Company’s Attachment NN that was provided in response to AOBA DR 7-25 for a description of ADMS functionalities and benefits the project will enable.

b. The estimated date that ADMS and DERMS functionalities will be deployed and available for use is 2029.

c. The term “digital twin” is not a term that the ADMS project, or the software vendor is using to describe ADMS capabilities. The term “digital twin” can have various meanings so further clarification would be needed to provide a more specific answer about the functionality in question. However, ADMS does plan to include “Study Mode” models and analysis, as well as unbalanced load flow analysis both of which could be considered “Digital Twin” functionality. ADMS does not plan to include 3D geo-spatial modeling of assets if that is what is implied with “Digital Twin” functionality.

d. Given DERMS is scheduled for a future phase of ADMS implementation, the detailed functionality and capabilities have yet to be fully scoped or defined. As such, an evaluation of where DERMS functionality would reside in the organization has yet to be determined.

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RESPONSE TO OPC DATA REQUEST NO. 6

QUESTION NO. 21

Reference Direct Testimony of Cantler at p.44 "ADMS technology is designed to communicate and control future DER to mitigate those fluctuations and accommodate for such things as the continued integration of electric vehicle (EV) charging stations and rooftop solar."

a) Please describe the Company's approach to communicating and controlling future DER including including what sizes and types of DERs it intends to directly control.

b) Does the Company's ADMS approach consider DER control approaches that do not require direct control by the Company?

c) Does the Company intend to directly control small DER systems such as residential rooftop solar or individual EV charging stations?

RESPONSE:

a. Given DERMS is scheduled for a future phase of ADMS implementation, the detailed functionalities and capabilities, including the size and type of DERs, have yet to be fully scoped or defined.

b. The detailed design of ADMS stage 2 has not been performed. However, the intention is not to limit DER controls to only direct company owned controllers.

c. Please refer to response OPC DR 6-21(a). The Company's goal is to allow for greater DER adoption, while maintaining the reliability of the grid, and safety of public and company personnel. It is currently unclear as to what capabilities & measures would be required with small DERs, as their adoption increases into the future to ensure reliability and system performance.

SPONSOR: Jaclyn Cantler

CERTIFICATE OF SERVICE

Formal Case No. 1176, In the Matter of Pepco's Application for Approval to Increase Rates Through the Implementation of a Multiyear Rate Plan ("MYP"), also referred to as the "Climate Ready Pathway" for its Electric Distribution Service

I certify that on January 12, 2024, a public copy of the *Office of People's Counsel for the District of Columbia's Direct Testimony of OPC Witnesses, Exhibits OPC (A) – (E)* was served on the following parties of record by hand delivery, first class mail, postage prepaid or electronic mail:

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