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GOVERNMENT OF THE DISTRICT OF COLUMBIA
OFFICE OF THE ATTORNEY GENERAL

BRIAN L. SCHWALB
ATTORNEY GENERAL

Public Advocacy Division
Social Justice Section

April 5, 2023

Public Version

Ms. Brinda Westbrook-Sedgwick, Secretary
Public Service Commission
of the District of Columbia
1325 G Street, NW, Suite 800
Washington, DC 20005

Re: Formal Case No. 1130 – In the Matter of Modernizing the Energy Delivery System for Increased Sustainability
and
Formal Case No. 1167 – In the Matter of the Implementation of Electric and Natural Gas Climate Change Proposals

Dear Ms. Westbrook-Sedgwick:

On behalf of the District of Columbia Government, please find for filing in the above-captioned proceedings the enclosed public version of the Department of Energy and Environment's Strategic Electrification Roadmap for Buildings and Transportation in the District of Columbia. Please note that a confidential version of this document containing information alleged by Pepco to be Critical Infrastructure Information (CII) is being separately filed in Formal Case No. 1167 only.

Parties to Formal Case No. 1167 may obtain the confidential version upon confirmation to the undersigned that the party has executed a separate CII nondisclosure agreement with Pepco. Please note that Pepco's CII nondisclosure agreement is different than the prior confidentiality agreement parties may have executed with Pepco in Formal Case No. 1167.

If you have any questions regarding this filing, please contact the undersigned.

Sincerely,

BRIAN L. SCHWALB
Attorney General

By: *<u>/s/ Brian Caldwell</u>*
BRIAN CALDWELL
Assistant Attorney General

cc: Service List

The District of Columbia Department of Energy and Environment
Energy Administration

The Strategic Electrification Roadmap for Buildings and Transportation in the District of Columbia “RESILIENT, INNOVATIVE, AND AFFORDABLE ELECTRIFICATION”

for the Office of Energy Efficiency and Renewable Energy
U.S. Department of Energy

April 2023

Public Version

EXECUTIVE SUMMARY OF KEY FINDINGS AND CONCLUSIONS

The Strategic Electrification Roadmap for Buildings and Transportation (Roadmap) outlines the scope and scale of energy efficiency and electrification measures needed to meet the District of Columbia's climate targets as delineated in the Clean Energy DC Plan. The Roadmap is broken into several sequential Tasks:

- **Task 1: Building Electrification.** Task 1 quantifies the impact of building electrification on electricity demand. Task 1 modeled baseline, gradual, and accelerated electrification scenarios. In both the gradual and accelerated scenarios, which target 13% and 32% of the existing building stock respectively, there was no significant increase in overall peak demand.

- **Task 2: Light-Duty Vehicle Electrification and Bus Electrification.** Task 2 summarizes the results in electricity demand and charging infrastructure required to sustain the electrification in the transportation sector within the District through 2040. Task 2's assessment showed that the energy and charging infrastructure required to meet the future's vehicle electrification in the District can vary considerably by 2040. Nonetheless, the more electric vehicles (EV) on the road, the greater the need will be for electricity demand and charging infrastructure. The hourly-energy demand profiles of light-duty vehicles are likely to be determined by electricity rates and the smart tools available to optimize charging. Bus charging is expected to have a small impact on peak load, because most of the charging is done during periods of low demand.

- **Task 1 & 2: Combined Electrification Loads.** This section presents the combined loads for building and transportation electrification that the District may experience in 2032, by using the "worst-case" summer and winter peak days from building loads. None of the loads exceed the substation capacity, although they do approach the maximum in some cases. Electrification is nowhere near complete by 2032, so additional loads can be expected after 2032 which could, if unmitigated, result in the need to upgrade substations or build new substations. The time of greatest stress on the substations is 7AM on winter mornings. Because building electrification loads do not add substantially to summer peaks, no substation peak load exceeds 80 percent of its capacity in the summer.

- **Task 3: Grid Emissions Assessment.** Task 3 analyzes the greenhouse gas (GHG) impact of anticipated changes to the building and transportation sectors in the District. The analysis estimates that the evolution of the building fleet between today and 2032 will result in a 36-41% decrease in CO2 emissions, depending on the energy efficiency scenario. This decrease is largely due to a projected decrease in carbon intensity of electricity in PJM. By 2050, the electrical energy consumption for EV charging in the District will increase by up to 62 times the usage from 2019, which is up to 300 MWh per year. For a given load on the grid, the GHG impact can be reduced by shifting the usage to the times of lower marginal carbon intensity. For the future EV fleet, carbon emissions reductions of 3-12% can be expected on an annual basis through smart-charging with an emissions-optimal control scheme.

- **Task 4: Grid Analysis.** Task 4 assesses the expected infrastructure that the District's electric utility, Pepco, may need to implement in its network to support the projected increases in load due to building electrification and new EV charging. Pepco's system is expected to be able to accommodate the impacts of building and vehicle electrification, and the majority of the feeders analyzed were not expected to experience overloads, even when considering the summer ratings. However, 31 of the 371 feeders that were expected to receive increased loads were identified as candidates for potential overload, and a further review found that in a sample of 3 feeders selected within this group, two could have significant overloads that could be addressed with traditional "wires" solutions.

- **Task 5: Grid Impact Mitigation.** Task 5 evaluates non-wires alternatives (NWA) to meet increased grid electrical demand resulting from electrification. The analysis of NWA to the wires investments illustrates a number of conclusions that can inform grid planning in the District and elsewhere as the building and transportation sectors electrify and decarbonize:
    - Many feeders do not require investment for at least another decade.
    - Anticipation of future grid state is important for solution planning.
    - Distributed Energy Resources (DERs) could play a substantial role in wholesale markets as the grid shifts toward zero carbon supplies.
    - Cost estimates of traditional components and DERs have a large impact on relative economics.
    - Local resilience needs could shape investment patterns.

Conclusions

Pepco's grid is well positioned to handle projected electrification loads between now and 2032. Long-term planning including appropriate Benefit-Cost testing, integrated distribution system planning, and grid modernization efforts will be required for incorporating future loads.

INTRODUCTION

The Roadmap builds on the District of Columbia's comprehensive energy and climate plan, "Clean Energy DC" by identifying additional energy efficiency and electrification measures needed to meet the city's target for a 50% energy reduction by 2032. Currently, Clean Energy DC's energy use reduction pathway shows a 30% reduction – falling short of the 50% reduction goal.

A holistic and comprehensive picture of the required efficiency and electrification measures will inform and help stakeholders to coordinate on implementation strategies and development of new tools and programs. To accomplish this, this Roadmap includes 5 sequential and interrelated tasks:

- **Task 1: Building Electrification.** Task 1 quantifies the impact of building electrification on electricity demand by modeling baseline, gradual, and accelerated electrification scenarios.

- **Task 2: Light-Duty Vehicle Electrification and Bus Electrification.** Task 2 assesses the electricity demand and charging infrastructure required to sustain the electrification in the transportation sector within the District through 2040.

- **Task 1 & 2: Combined Electrification Loads.** This section combines building and transportation electrification loads for 2032.

- **Task 3: Grid Emissions Assessment.** Task 3 analyzes the greenhouse gas (GHG) impact of anticipated changes to the building and transportation sectors in the District.

- **Task 4: Grid Analysis.** Task 4 assesses the expected infrastructure that the District's electric utility, Pepco, may need to implement in its network to support the projected increases in load due to building electrification and new EV charging.

- **Task 5: Grid Impact Mitigation.** Task 5 evaluates non-wires alternatives (NWA) to meet increased grid electrical demand resulting from electrification.

BACKGROUND

The Clean Energy DC Plan provides a roadmap for the District to reduce GHG emissions within its jurisdiction by 50% below 2006 levels by 2032, while simultaneously increasing renewable energy and reducing energy consumption, putting the District on a viable path to achieve complete carbon neutrality by 2050.[1] Currently, as directed by Mayor Bowser, DOEE is in the process of developing a Carbon Neutrality Strategy,[2] which picks up where the Clean Energy DC Plan ends, with a consistent framework for decarbonization. Both the Clean Energy DC Plan and the Carbon Neutrality Strategy call for a significant shift away from natural gas use in the years prior to 2032 culminating in the eventual end to nearly all fossil fuel use by 2045:

> Achieving the District's 2032 GHG reduction target, or any future targets that are aligned with the Paris Agreement, will require a significant shift away from fossil fuels, including natural gas. Achieving its … GHG carbon neutral target will require the District to eliminate fossil fuel use.[3]

The Clean Energy DC plan emphasizes that the District must move away from fossil fuels in buildings, in particular natural gas, which is the dominant fuel source for heating in buildings after electricity:

> Energy, through extraction and consumption of fossil fuels, is the leading global source of GHG emissions. In the District, fossil fuels provide energy for electricity, for building heating and hot water through natural gas or fuel oils, and for motor vehicles. Because GHG emissions associated with fossil fuel combustion can continue to warm the climate for several hundred years after their release, phasing out fossil fuels from the District's energy supply (or "decarbonizing" the supply) will be essential to achieving its climate change goals.
>
> If a city is to transform its energy system, it must shift energy generation, distribution, and consumption away from fossil fuels and inefficient, fossil fuel-dependent systems and technologies, and instead embrace highly efficient use of renewable and zero-emission energy.

The District's primary strategy to achieve this reduction and gradual elimination of natural gas use is first to shift water and space heating and cooling functions to equipment that does not use fossil fuels:

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[1] The District of Columbia Climate and Energy Action Plan (hereinafter "Clean Energy DC") (August 2018), https://doee.dc.gov/sites/default/files/dc/sites/ddoe/page_content/attachments/Clean%20Energy%20DC%20-%20Full%20Report_0.pdf

[2] Climate Commitment Act of 2021. Available at: https://lims.dccouncil.gov/Legislation/B24-0267

[3] Clean Energy DC, p. 156.

> To achieve its 2032 GHG target, the District will clearly need to shift away from fossil fuels for buildings (natural gas and fuel oil) and transportation (gasoline and diesel) while simultaneously decarbonizing its electricity supply. For buildings, this will mean shifting to non-fossil fuel sources for heat and hot water.[4]
> ….
> Consequently, the District must transition away from equipment and technologies that currently depend on such fuels. The equipment used to heat and cool space and water in buildings is a key aspect of this transition.[5]

This transition means that natural gas heating systems in residential and commercial buildings, which can be electrified cost-effectively in many cases, must be converted to electric systems. It also means that new buildings must be designed for electric heating systems rather than those that require the onsite use of fossil fuels: "natural gas and other carbon-intensive heating furnaces can be switched to a low-carbon energy source such as a high-efficiency electricity-based heat pump."[6]

The reliance on electrification of space and water heating and light-duty vehicles as essential decarbonization measures in both the Clean Energy DC Plan and the 2050 Carbon Neutrality Strategy is strongly supported by leading authorities on climate change mitigation, such as the Intergovernmental Panel on Climate Change (IPCC), the Deep Decarbonization Pathway Project (DDPP), and the U.S. Mid-Century Strategy for Deep Decarbonization submitted in accordance with the Paris Agreement (see Appendix A for more details).

The Clean Energy DC Plan adopts the decarbonization framework developed in the DDPP report, which lays out "three fundamental changes" that must occur:

A. Demand: Highly efficient end use of energy in buildings, transportation, and industry
B. Supply: Decarbonization of electricity and other fuels
C. Fuel Switching: Switching of energy end uses to electricity and other low-carbon fuels [7]

[4] Id., p. 24.
[5] Id., p. 156.
[6] Id., p. 80.
[7] http://unsdsn.org/wp-content/uploads/2014/09/US-Deep-Decarbonization-Report.pdf.

1	2	3
Highly efficient end use of energy in buildings, transportation, and industry. The energy intensity of GDP must decline 70% by 2050, with final energy use reduced by 20% despite a forecast population increase of 40% and a 166% increase in GDP.	**Nearly complete decarbonization of electricity, and reduced carbon in other fuels.** The carbon intensity of electricity must be reduced by at least 97% or more by 2050.	**Electrification where possible and switching to lower-carbon fuels otherwise.** The share of end-use energy coming directly from electricity or fuels produced from electricity must increase from less than 20% in 2010 to over 50% in 2050, displacing fossil fuel combustion.

↑ **Box 2:** Box 2 Three pillars of decarbonization with long-term targets for the United States.[15]

These three imperatives, to be implemented sequentially, represent the primary GHG mitigation strategies for energy for the residential and commercial sectors. As an example, below is a summary of key measures identified in the DDPP report:

Strategy and Sector	Measures
Energy Efficiency Strategies	
Residential and commercial energy efficiency	• Highly efficient building shell required for all new buildings • New buildings require electric heat pump HVAC and water heating • Existing buildings retrofitted to electric HVAC and water heating • Near universal LED lighting in new and existing buildings
Industrial energy efficiency	• Improved process design and material efficiency • Improved motor efficiency • Improved capture and re-use of waste heat • Industry specific measures, such as direct reduction in iron and steel
Transportation energy efficiency	• Improved internal combustion engine efficiency • Electric drive trains for both battery and fuel cell vehicles (LDVs) • Materials improvement and weight reduction in both LDVs and freight

Fuel Switching Strategies	
Petroleum	• LDVs to hydrogen or electricity • HDVs to LNG, CNG, or hydrogen • Industrial sector petroleum uses electrified where possible, with the remainder switched to pipeline gas
Coal	• No coal without CCS used in power generation or industry by 2050 • Industrial sector coal uses switched to pipeline gas and electricity
Natural gas	• Low carbon energy sources replace most natural gas for power generation; non-CCS gas retained for balancing in some cases • Switch from gas to electricity in most residential and commercial energy use, including majority of space and water heating and cooking

*Table 6. Key Decarbonization Measures by Sector and Decarbonization Strategy

The District Government has already begun implementing the three pillars of deep decarbonization through following legislation and regulations:

Energy demand reduction: creation of DC SEU under the Clean and Affordable Energy Act; creation of the Building Energy Performance Standards (BEPS) and Utility Energy Efficiency and Demand Response programs under the Clean Energy DC Omnibus Amendment Act; and the Clean Energy DC Building Code Amendment Act of 2022 which requires a net-zero-energy standard for all new construction buildings beginning in 2027.[8]

Decarbonized electricity: 100% Renewable Portfolio Standards under the Clean Energy DC Omnibus Amendment Act and the Distributed Generation Amendment Act; the Commission's Order and approval of purchasing renewable electricity via long-term PPAs for Standard Offer Service (currently comprising 5% with an eye towards increasing the amount in future years).

Electrification: Building Energy Performance Standard, Net Zero Energy Code, Residential Electrification Studies including market analysis, cost-effectiveness analysis, DC SEU's Whole House Retrofit Pilot Project, Grid Modernization Pathway under Formal Case 1130, a proposal to perform Non-Pipe Safety Alternatives (i.e., electrification) for Washington Gas's proposed pipe replacement program.

In particular, studies and analyses are underway to inform a holistic strategy for implementing electrification in a manner that maximizes benefits to District residents and businesses and accelerates the District's GHG mitigation efforts:

Residential Electrification	Energy Efficiency	***Electrification Roadmap***
Market analysis	Building Energy/Carbon Std	***Location-based load analysis***
Incentives analysis	Net Zero Energy/Carbon Code	***Hourly emissions analysis***
Cost-effectiveness analysis		***Grid assessment***
Impact on LMI communities		***Non-wires mitigation strategies***

[8] D.C. Law 24-177. Clean Energy DC Building Code Amendment Act of 2022. Available at: https://code.dccouncil.gov/us/dc/council/laws/24-177.

OUTLINE OF THE ROADMAP

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TECHNICAL CONSULTANTS

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Task 2 (Transportation): Nelson Nygaard, Synapse Energy Economics
Task 1&2 (Combined Electrification Loads): Synapse Energy Economics
Task 3 (Grid Emissions): WattTime
Task 4 (Grid Assessment): Siemens
Task 5 (Grid Impact Mitigation): Synapse Energy Economics

TECHNICAL REVIEW & STAKEHOLDER BRIEFINGS

US Department of Energy, Office of Energy Efficiency and Renewable Energy
District of Columbia Public Service Commission
Office of People's Counsel
District Department of Transportation
Washington Metropolitan Area Transportation Authority
Metropolitan Washington Council of Governments
American Council for an Energy Efficient Economy
Regulatory Assistance Project
Institute for Market Transformation
Clean Grid Advisors

TECHNICAL ASSISTANCE

US Department of Energy, Office of Energy Efficiency and Renewable Energy
National Renewable Energy Laboratory
Oak Ridge National Laboratory

Potomac Electric Power Company

ROADMAP TASK 1: BUILDING ELECTRIFICATION

Introduction

According to the District's 2018 Greenhouse Gas Inventory, on-site fossil fuel use in buildings – primarily for space heating, domestic hot water production, and cooking – accounts for roughly 17%[9] of the District's total greenhouse gas emissions. Electrifying building systems, or using alternative low carbon fuel strategies when electrification is impractical, will help to significantly reduce the District's carbon footprint. On an annual basis, using an electric heat pump to produce 1 mmbtu of heating energy will result in roughly 70 lbs of carbon dioxide equivalent emissions (CO2e), compared to 140 lbs of CO2e for an efficient gas boiler.[10] By 2032, emissions could be as low as 30 lbs CO2e/mmbtu for efficient electric heat pump systems – roughly 80% less than gas boilers. Similarly, electric cooking appliances, which today are comparable to gas appliances in terms of emissions, could produce half the emissions of combustion-based systems.

While there are clear and demonstrable benefits to widespread electrification, there are also several challenges that need to be addressed. Not surprisingly, switching to electric systems will increase the total amount of electricity used by buildings, which may require capacity upgrades in certain areas of the District. Furthermore, older buildings, which currently rely on steam or high temperature hot water for heating, may need building envelope improvements to accommodate electric systems. There are also some building loads, such as high-temperature process loads in manufacturing and healthcare facilities, that are difficult to electrify and will require alternative, low carbon solutions.

The purpose of this Task is to quantify the impact of building electrification on grid electrical demand and determine whether combining electrification with energy efficiency retrofits will help the District achieve its energy reduction targets. The load estimates produced as part of this scope of work feed directly into subsequent Tasks and form the basis of this report's overall findings and recommendations.

Methodology and Assumptions

Integral relied on a three-step process to model aggregate building electricity use for each substation zone: (i) Identify building typologies, or building variants, that capture statistically significant variations in building energy use. (ii) Create calibrated energy models for each

---

[9] DC Carbon Neutrality Framework

[10] 85% efficient natural gas boiler compared to 300% efficiency for electric heat pump system, using 854 lbs CO_2e/MWh as the grid emissions factor with a 57% attribution rate for the District's Renewable Portfolio Standard.

typology. (iii) Aggregate the results of the typology energy models by substation zone, on an hourly basis.

Typology Development

Using a combination of linear regression and statistical clustering analysis, Integral identified 30 distinct building typologies in the District, based on building program, size, vintage, and energy use intensity. These typologies reflect statistically significant variations in building attributes and building energy use that exist across the District's Tax Assessor's data and energy benchmarking data, in addition to other datasets such as Residential Energy Consumption Survey (RECS) data. Figure 1 shows the distribution of energy use intensities for each typology.

Figure 1: Energy use intensity by typology

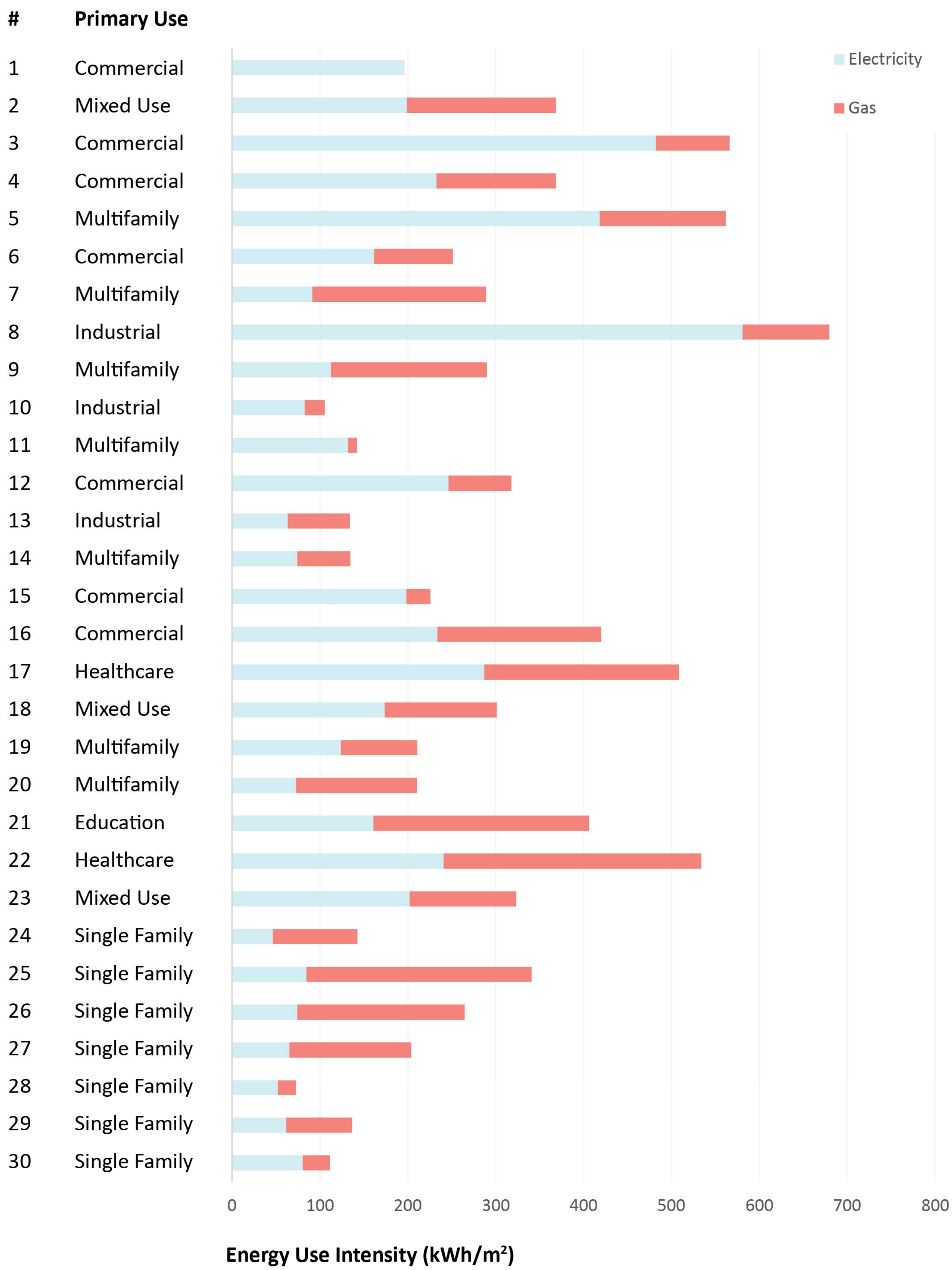


Figure 1 shows the distribution of EUIs for each typology. The energy use intensity values range from roughly 72 kwh/m^2 to 680 kwh/ m^2 (23-215 kbtu/ft^2), with varying intensities of electricity and gas use. [11] Based on Tax Assessor's Data[12], Integral classified each building in the District as one of these typologies, resulting in a map of typological distribution in the District (Figure 2), and estimated total annual energy use (Figure 3).

In addition, Integral estimated the future buildout in the District, by typology and location, for 2032 and 2050. Using data from the Office of Planning, we assumed that the District would grow by approximately 10% by 2032, and 26% by 2050[13]. We assumed that this growth would occur primary on vacant, infill lots, at the maximum floor-to-area ratio (FAR) allowed by current zoning regulations. Furthermore, we used a qualitative assessment of the zoning regulations to identify which typologies would exist in different areas of the District. Figure 4 summarizes this process, starting with the map of vacant lots (bottom) and ending with the size and type of building created in 2032, and 2050.

<u>Model Calibration</u>

To create a baseline model of hourly electricity use, Integral developed simple transient dynamic block energy models for each of the identified building typologies, calibrated against the annual electricity and gas use intensities. To calibrate the models, Integral used surrogate modeling techniques[14] to identify the appropriate set of input parameters – insulation values, equipment usage, system efficiencies, etc. – for each typology. This bottom-up approach to model calibration, where the model is configured based on what we know about expected energy performance, helps ensure that the assumptions about baseline performance are grounded in statistical reasoning.

The results of this calibration process are shown in Tables A.1 and A.2, in Appendix B. The input parameters represent typical performance characteristics that one might expect for each typology, or group of similar buildings, in the District.

[11] For the purposes of this analysis, fuel oil and natural gas were combined into a single "fuel use" value. Given the relatively small amount of fuel oil used in the District, this assumption does not have any material impact on the analysis or its findings.

[12] Common Ownership Lots, 2019.

[13] This represents an annual growth rate of 0.2-1.3% depending on program type.

[14] S Nagpal, C Mueller, A Aijazi, C Reinhart, A methodology for auto-calibrating urban building energy models using surrogate modeling techniques, Journal of Building Performance Simulation 12 (2018), 1-16

Figure 2: Typological distribution by building

Figure 3: Estimated annual energy use by building

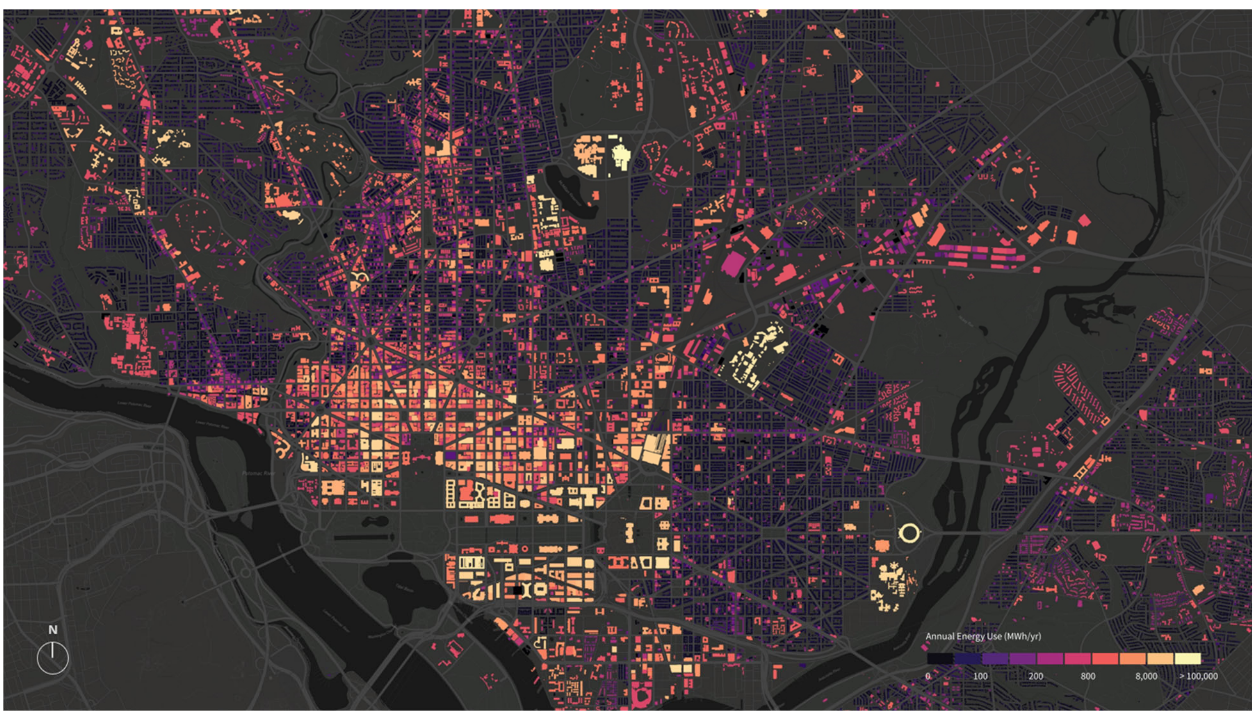
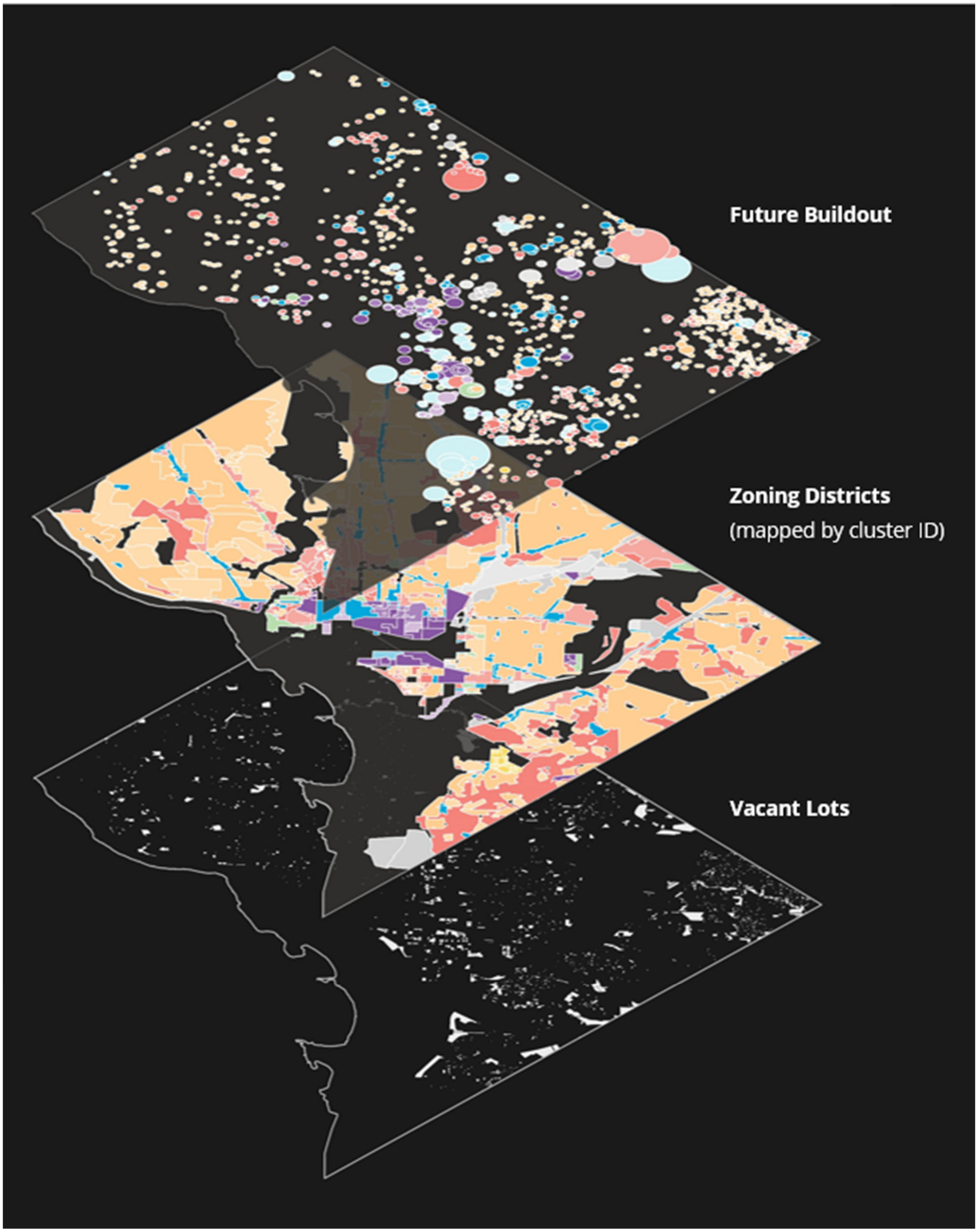


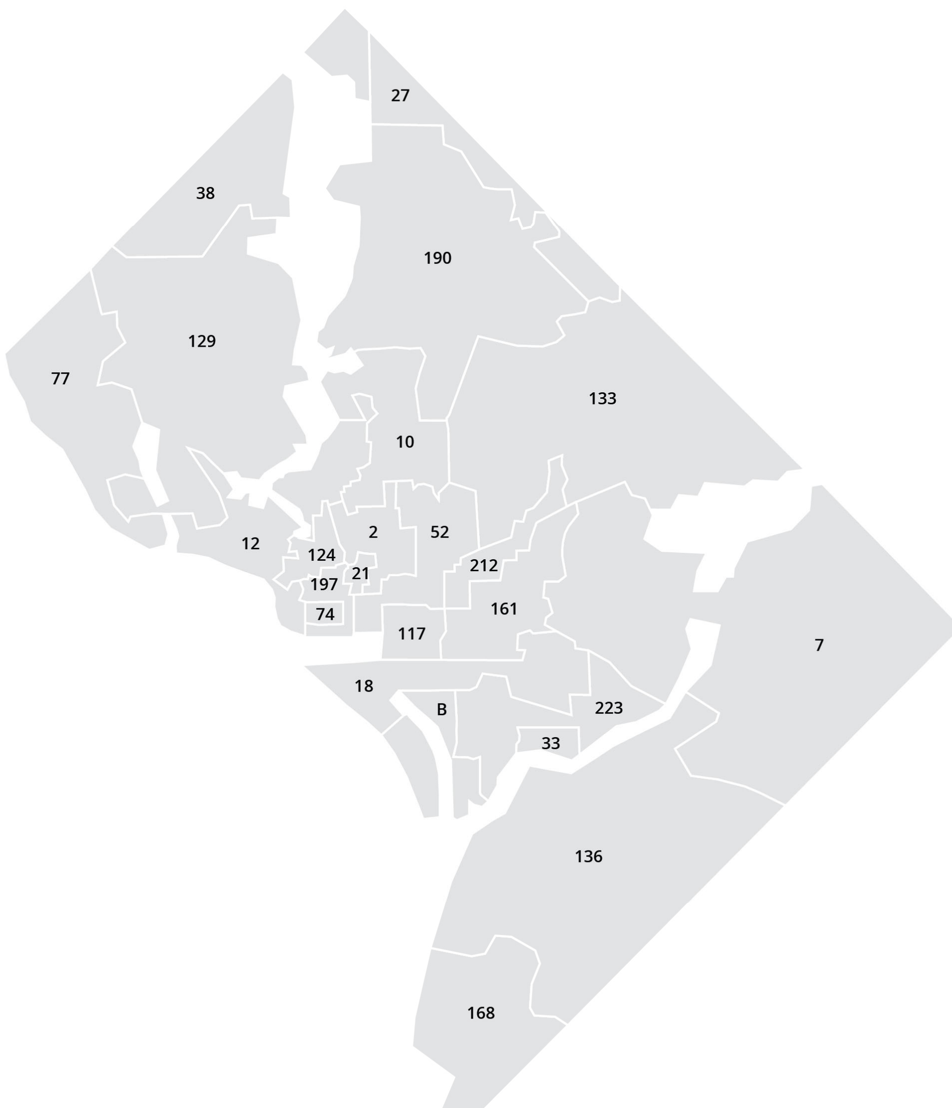
Figure 4: Diagram explaining process of estimating future growth



Aggregation By Substation Zone

Theoretically, we can use the calibrated typology energy models to estimate the performance of any single building in the District, using the building size and representative typology. However, the error associated with this type of estimate would be quite significant, since the typology models are designed to represent the average performance of a group of buildings. To decrease the statistical error in the results, the building level estimates are aggregated into larger areas. For the purposes of this analysis, the results are aggregated to the Pepco substation zones, which are shown in Figure 5 below.

Figure 5: Map showing substation zones



2032 Analysis

Integral analyzed 3 scenarios for each substation, exploring the impact of electrification and energy efficiency, targeting 2032. The following is a description of each scenario:

Baseline
This scenario represents the electricity use for each substation zone by 2032 with electrification for new buildings, but no policy for electrifying existing buildings. This scenario does not include any energy efficiency measures for existing buildings beyond what is currently required by law.

Scenario 1: Gradual Electrification Adoption
This scenario represents a gradual adoption of electric systems across the entire building stock. All new buildings would incorporate electric systems, and roughly 13% of existing buildings would be electrified by 2032. Furthermore, for this scenario we did not assume any additional energy efficiency retrofits for existing buildings beyond what is already required by law.

Scenario 2: Accelerated Electrification Adoption
This scenario represents an accelerated adoption of electric systems across the entire building stock. All new buildings would incorporate electric systems, and roughly 32% of existing buildings would be electrified by 2032. Furthermore, for this scenario we assumed that low- to no-cost efficiency improvements would be implemented alongside upgrades to electric systems.

Renewable Natural Gas
While electrification was the primary focus of this analysis, we did make some accommodations for alternative, low-carbon fuels in the District. Based on Synapse's testimony to the Public Service Commission of the District of Columbia in 2017 on behalf of the District Government,[15] the maximum local availability of renewable natural gas (RNG) is approximately 1 TBtu.[16] For the future electrification scenarios we assumed that the RNG would feed existing district heating systems – largely colleges and universities that have significant investments in district thermal systems. In reality, RNG may also feed industrial and healthcare facilities, though there is no specific accommodation for these types of buildings in this analysis.

The assumptions for each scenario are listed in Tables A.3-A.6 of Appendix B. The models were simulated using EnergyPlus, using default occupancy, lighting, and equipment schedules from DOE reference models.[17] Since the team did not have access to hourly metered data to

[15] In the Matter of the Merger of the AltaGasLtd. And WGL Holdings, Inc., Formal Case No. 1142 (2017) (testimony of Asa Hopkins)
[16] The share of the total amount of renewable natural gas produced in VA and MD, proportional to the population of DC.
[17] https://www.energycodes.gov/development/commercial/prototype_models

calibrate the typology models, the hourly electrical load data generated from this analysis should not be used for predictive purposes, but it is still valuable for understanding patterns, trends, and order-of-magnitude changes to peak demand.

Baseline

In the baseline scenario in 2032, as is currently the case, electricity demand has a seasonal spike in the summer for most substations, and daily peaks in the afternoon and early evening. Figures 6 and 7 show the electric load profiles for average days in each month of the year for two substations: substation 52 (primarily commercial) and substation 129 (primarily detached residential). These figures also show the range of electrical demand values that are experienced throughout the year. For the substation zones with more commercial properties, the peaks tend to coincide with afternoon cooling and equipment loads, whereas in substation zones with more residential properties, peak demand tends to fall in the early evening as residents return home after work.

With current building policies in place[18], total building-sector source energy use will be approximately 4% lower in 2032 than in 2006, after accounting for population growth and existing building replacements.[19] Table 1 below shows the reduction in site and source energy estimated between 2006 and 2032 in the baseline scenario.

Table 1: District-wide energy use in baseline scenario

Fuel	**2006 (est.)**	**2032 (Baseline)**	**Change**
Electricity (Site GWh)	10,349	9,989	(3%)
Fuel (Gas/Oil Site GWh)	6,902	6,581	(5%)
Total (Site GWh)	**17,251**	**16,570**	**(4%)**
Total (Source GWh)	**36,223**	**34,879**	**(4%)**

[18] Current policies include the Building Energy Performance Standard (BEPS) and the 2018 High Performance Building Code.
[19] DC Carbon Neutrality Framework model, produced by Integral in July 2019.

Figure 6: 2032 Baseline electric load profiles for substation 52.

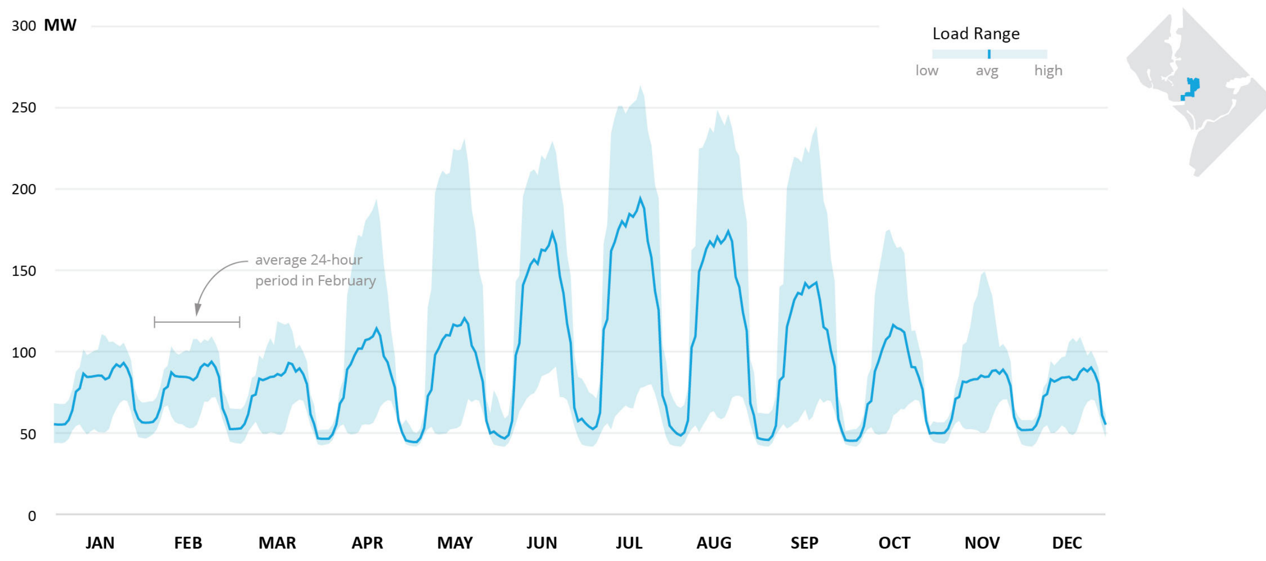
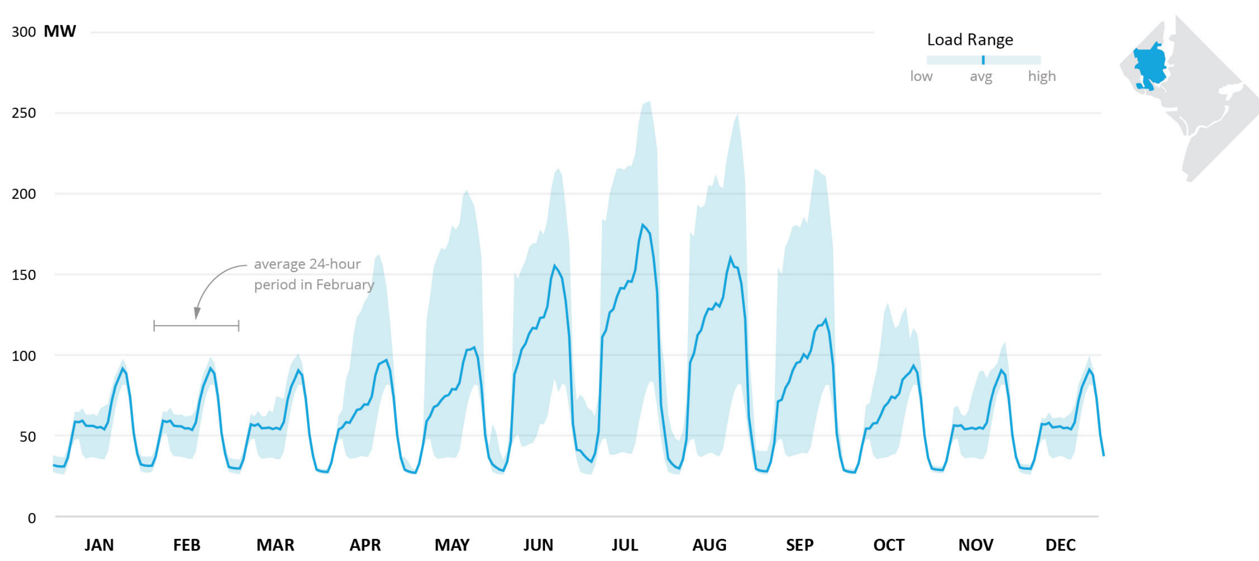


Figure 7: 2032 Baseline electric load profiles for substation 129.



Scenario 1

In this scenario, which represents a gradual adoption rate of electric systems targeting roughly 13% of existing buildings by 2032, peak electrical demand remains roughly at baseline levels during the summer but increases slightly in the winter – particularly during the morning and early evening hours when mechanical heating systems are active. In areas of the District where residential buildings predominate, wintertime peak demand could increase by as much as 25-30%, but it will not surpass current summertime peaks. Figure 9 shows the electrical demand for substation zone 129, which is composed almost entirely of residential buildings. Peak demand in the winter increases by approximately 25% compared to the baseline scenario, while the peak demand in summer remains roughly the same. In substation zone 52, which is composed predominately of commercial buildings, wintertime peak demand increased by roughly 14%, but is still below summertime peak levels.

Table 2: District-wide energy use in gradual electrification adoption scenario

Fuel	2006 (est.)	2032 Scenario 1	Change
Electricity (Site GWh)	10,349	10,442	1%
Fuel (Gas/Oil Site GWh)	6,902	5,742	(17%)
Total (Site GWh)	**17,251**	**16,184**	**(6%)**
Total (Source GWh)	**36,223**	**35,267**	**(3%)**

Table 3: District-wide peak electrical demand in baseline + electrification scenario

Fuel	2032 Baseline	2032 Baseline + Elec	Change
Peak Electrical Demand (MW)	3,650	3,673	(1%)

In Scenario 1, there is a slight (1%) increase in overall electricity use compared to 2006 levels, as well as a slight (1%) increase in overall district-wide peak demand. Due to increasing levels of building efficiency in the District and the relative efficiencies of heat pumps compared to gas equipment, total source energy would decrease by approximately 3% compared to 2006 levels.

Figure 8: 2032 Scenario 1 electric load profiles for substation 52.

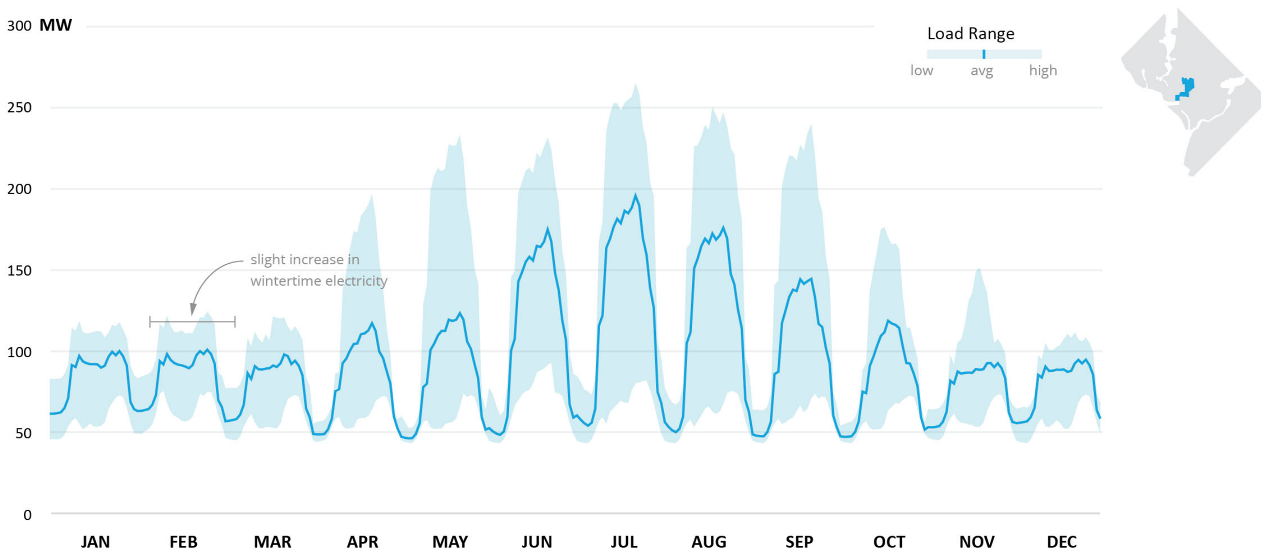
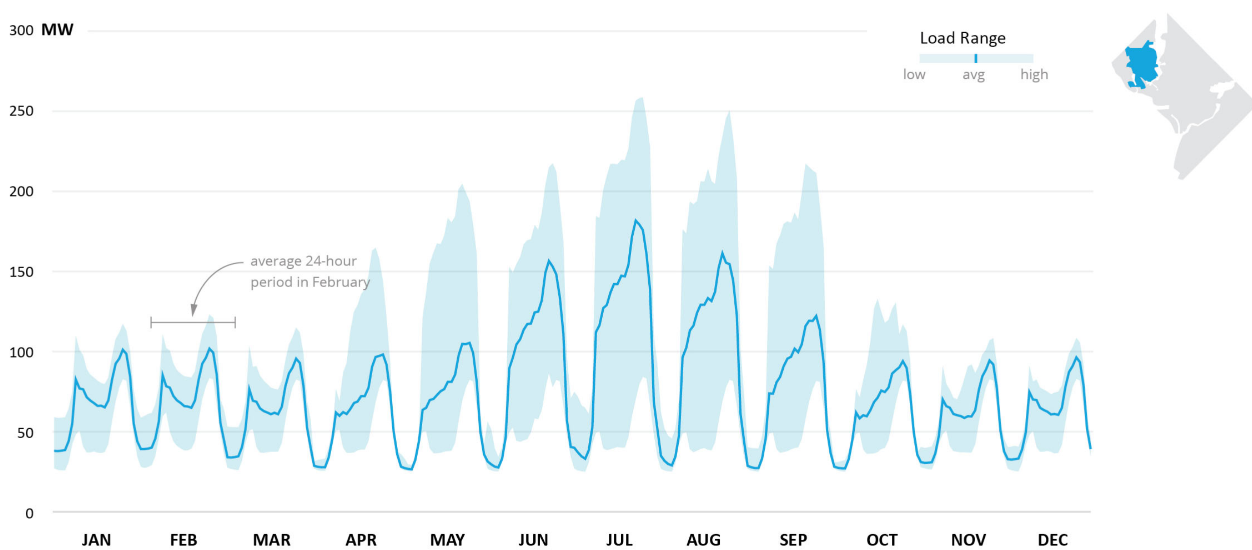


Figure 9: 2032 Scenario 1 electric load profiles for substation 129.



Scenario 2

In scenario 2, we combined accelerated electrification adoption rates with low- to no-cost energy efficiency improvements, targeting roughly 32% of the existing building stock by 2032. Examples of low- to no-cost efficiency improvements include:

1. Relamping (lighting upgrades)
2. Air sealing and building weatherstripping
3. Temperature setpoint adjustments
4. Passive heating/cooling strategies (shades, natural ventilation, etc.)

Compared to 2006 values, this scenario would result in a 3% increase in electricity use, but a 5% reduction in overall source energy. Similar to Scenario 1, wintertime peak electricity demand increases (25-45%), but does not surpass summertime peak demand. As a result of efficiency upgrades, the total peak demand decreases slightly, by roughly 2%.

Table 4: District-wide energy use in Scenario 2

Fuel	2006 (est.)	2032 Scenario 2	Change
Electricity (Site GWh)	10,349	10,654	3%
Fuel (Gas/Oil Site GWh)	6,902	4,499	(35%)
Total (Site GWh)	**17,251**	**15,153**	**(12%)**
Total (Source GWh)	**36,224**	**34,555**	**(5%)**

Table 5: District-wide peak electrical demand in Scenario 2

Fuel	2032 Baseline	2032 Scenario 2	Change
Peak Electrical Demand (MW)	3,650	3,581	(2%)

Figures 10 and 11 show the average day hourly electrical demand profile for Scenario 2 for two representative substation zones. Note the change in daily electricity profile in the winter for substation zone 129, which is composed primarily of residential buildings. Electricity demand peaks in the morning, and evening, coinciding with heating demand. This profile is most pronounced in areas that have more residential buildings.

Figure 10: 2032 Average day electric load profile, Scenario 2, substation 52.

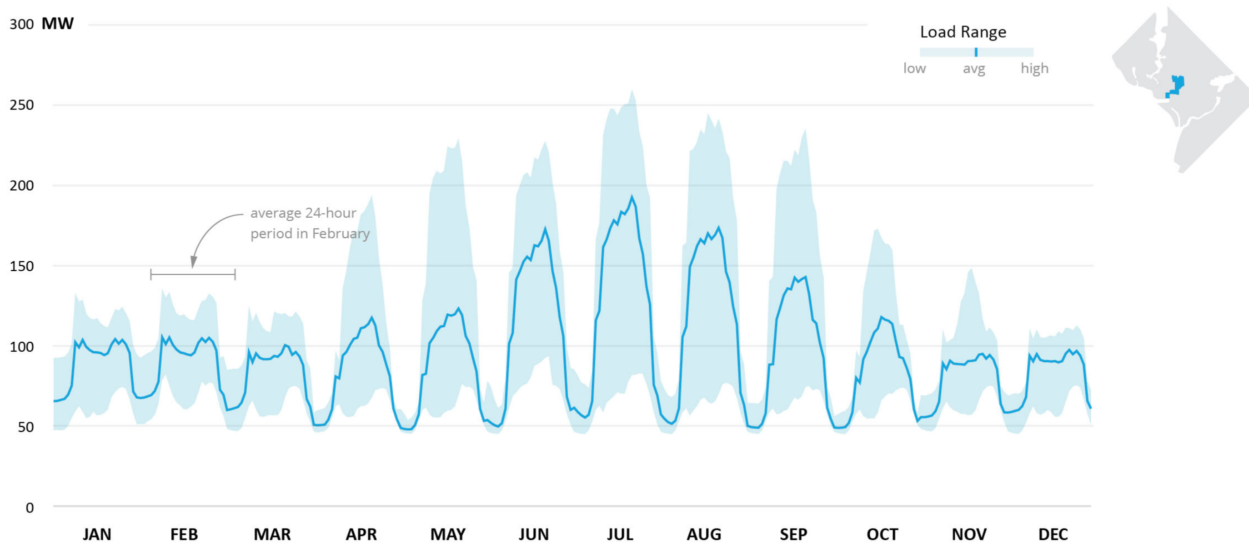
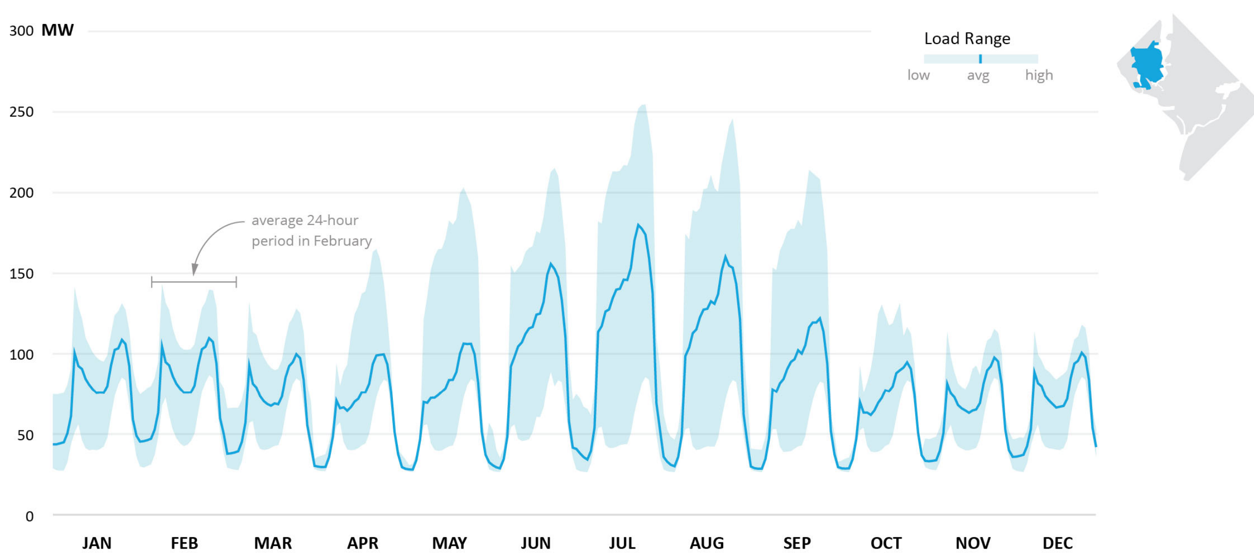


Figure 11: 2032 Average day electric load profile, Scenario 2, substation 129.



Findings

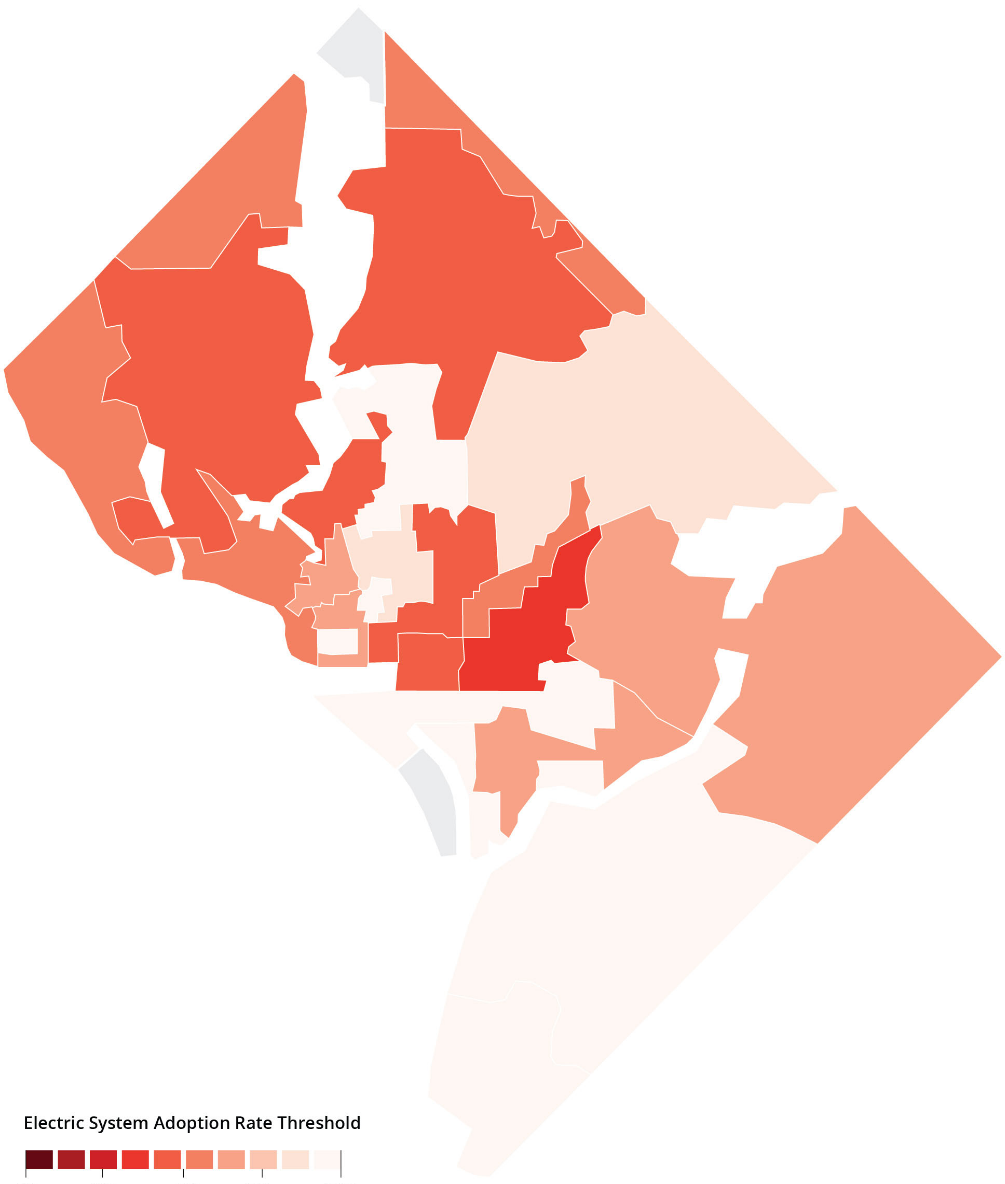
One of the primary concerns related to building electrification is the impact on electrical demand, particularly during the winter months when heating loads are highest. **Our analysis indicates that even in the accelerated electrification adoption scenario (Scenario 2), wintertime peak demand does not surpass current summertime peaks. This is true for all substation zones – even those composed primarily of residential buildings where the risk of high wintertime electric heating loads is greatest.** Beyond 2032, as the electrification adoption rate passes roughly 36%, wintertime electric loads will likely increase beyond current summertime peak levels, though that threshold varies by substation zone. Table 6 and Figure 12 show the critical thresholds for electric system conversions – the adoption rate at which the wintertime peak demand increases beyond the baseline 2032 summertime peak demand. It is worth noting, however, that most increases in peak demand can be mitigated through low- to no-cost efficiency upgrades. For some substation zones, even a 100% rate of electrification will not convert to a winter peak.

Table 6: Threshold adoption rates for electric system conversions

Substation Zone	Adoption Rate Threshold (winter Peak surpasses summer peak)
161	36%
52	44%
190	44%
117	48%
25	50%
129	50%
77	52%
12	54%
27	58%
38	58%
212	58%
7	62%
197	64%
124	68%
223	70%
2	80%
133	80%
10	90%

21	90%
33	90%
168	94%
136	96%
B	98%
18	100%
74	100%

Figure 12: Threshold adoption rates for electrification by substation zone



In terms of overall energy use reductions, electrification alone will not make a significant contribution to the District's goal of achieving a 50% energy use reduction by 2032. In the accelerated scenario (Scenario 2), the total site energy use reduction from the building sector is only 12%, with a 5% reduction in source energy. To achieve the 50% energy use reduction target by 2032, the District would need to combine widespread electrification with deep energy retrofits targeting more than 90% of existing buildings. This would ultimately reduce peak demand beyond what has been modeled in this analysis.

Conclusions

Our analysis indicates that increases to overall peak demand vary by substations zone and are largely dependent on the assumptions regarding electrification adoption rates.

We evaluated three scenarios as part of this analysis: a baseline scenario in 2032, a scenario that assumes a gradual adoption rate of electric building systems, and a scenario that assumes accelerated adoption rates. In both the gradual and accelerated scenarios, which target 13% and 32% of the existing building stock respectively, there was no significant increase in overall peak demand. Depending on the substation zone, increased wintertime electric demand only becomes an issue once the adoption rate surpasses 36%. In some instances, for substation zones that are predominately composed of commercial office buildings, electrification does not increase peak demand even when all buildings are electrified. Furthermore, our analysis indicates that low- to no-cost energy efficiency improvements could mitigate any significant increase to overall peak demand that result from building electrification.

ROADMAP TASK 2A: LIGHT-DUTY VEHICLE ELECTRIFICATION

Introduction

This section summarizes the results in energy demand and charging infrastructure required to sustain the electrification in the transportation sector within the District of Columbia through 2040. It also highlights critical assumptions and the methodology adopted to estimate the sector's potential electrification. Because of the wide range in possible vehicle electrification pathways, especially for light-duty vehicles, the analysis contains three different scenarios:

- Business as usual. This scenario represents a conservative trend where electrification rates remain relatively constant, and internal combustion engines are still most of the new vehicle sales by 2040.
- Gradual. This scenario represents a central trend where electrification rates take a significant uptake following the industry's forecasts of significantly increasing number of battery-electric vehicles over the next decades.
- Accelerated. This scenario represents a high-celling trend where electrification rates grow significantly faster than the industry's current forecasts. In this scenario, almost all new sales vehicles will be battery-electric vehicles (BEVs) by 2040.

For spatial comparison purposes across the different scenarios, this analysis provides the energy demand by substation zone for 2032 and 2040 with a common base year in 2019.

Methodology and Assumptions

Due to the different nature of light-duty vehicles and buses used in public transit, this assessment uses two approaches to estimate the sector's electrification and energy demand. The light-duty vehicle transition is primarily determined by:

- Current and future population and employment in the region
- Current and future travel demand in the region
- The cost evolution of battery electric vehicles (BEVs) relative to the internal combustion engine vehicles
- Access and deployment of charging infrastructure
- Other private and public incentives for the early adoption of BEVs.

Although it is also affected by the prices of battery-electric buses (BEBs), the transit sector electrification across many U.S. cities is influenced by sustainable transportation plans and regulatory efforts to set specific target timeframes for fleet electrification. In the District of

Columbia, the CleanEnergy DC Omnibus Amendment Act of 2018[20] requires that 100% of public buses use zero-emission technology by 2045. Following this regulation, the District Department of Transportation (DDOT) and the Washington Metropolitan Area Transit Authority (WMATA) are piloting BEBs and planning their introduction into their fleets. This provides a more solid starting point to estimate the future number of electric buses in the District and allows for a more straightforward modeling approach.

Figure 13 provides an overview of the methodology steps to forecast BEVs charging within the District and its associated energy demand. As observed, the methodology consists of three core steps related to Task 2. A brief description of each step is provided below.[21]

Initial travel demand. This step calculates Vehicle Miles Traveled (VMT) by vehicle type based on travel demand data at the traffic analysis zone-level provided by the Washington Metropolitan Council of Governments (MWCOG). This process also adjusts the auto travel demand to meet the 25% mode share target of active transportation in the Sustainable D.C. 2.0 plan by 2032.[22]

EV Technical Assessment. This step develops a fleet turnover module to future VMT generated by the existing fleet and the VMT generated by new vehicles entering the fleet in 2019-2040. Three different new BEV sales rates are used to forecast EV VMT resulting in three different scenarios (NAU, Gradual, and Accelerated). The EV penetration rates are a critical lever impacting the model's over results; therefore, it was important to include rates to showcase a range of future possibilities.

EV VMT Allocation. This step estimates the average hourly energy demand required to sustain the EV VMT calculated in the previous step. This process uses hourly load profiles for light-duty vehicles from the National Renewable Energy Laboratory (NREL). This step also assigns the annual total EV VMT during 2019-2040 back to traffic analysis zones for further consolidation into electric substations.

Input for Task 3. The hourly energy demand during a typical day in 2019, 2032, and 2040 under the BAU, Gradual and Accelerated scenarios serve as an input in Task 3 to estimate the hourly energy CO_2 emissions based on the electric grid composition.

[20] Law 22-257 - CleanEnergy DC Omnibus Amendment Act of 2018 < https://lims.dccouncil.us/Legislation/B22-0904>

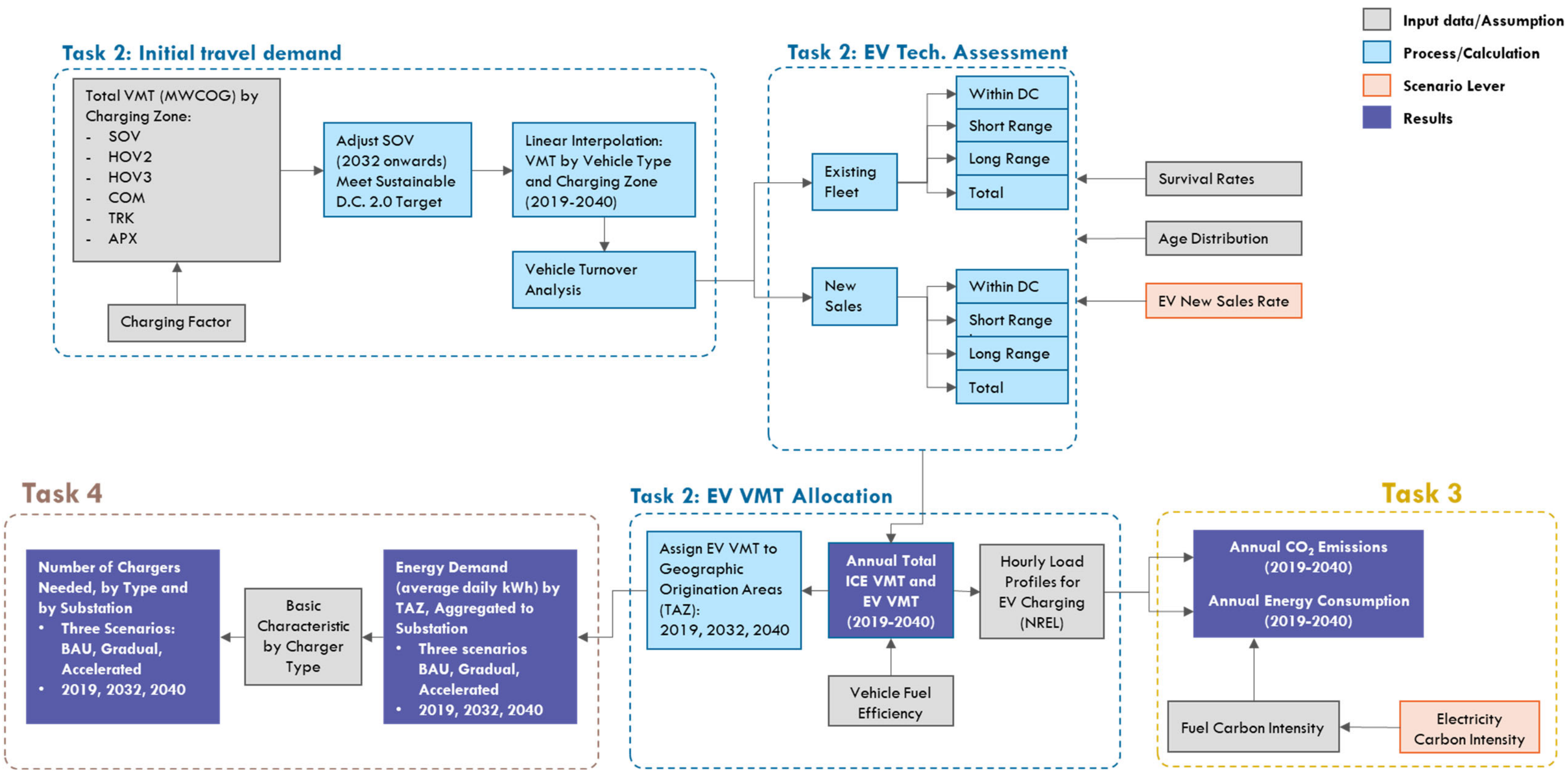
[21] See Appendix E.1 for more details on each step of this methodology.

[22] Sustainable D.C. 2.0 Plan, https://sustainable.dc.gov/sdc2

Input for Task 4. The average daily energy demand by electric substation in 2019, 2032, and 2040 under the BAU, Gradual and Accelerated scenarios serve to approximate the number of chargers required in each area of the District. This input is used in Task 4.

Detailed methodology and assumptions are included in Appendix C.

Figure 13 Methodology Overview for Light-Duty Vehicle Electrification



Maps and Demand Profiles

Figure 14 shows the geographic distribution of the energy demand in the BAU scenario in 2019. This is the common baseline not only for 2032 and 2040 BAU, but also for the Gradual and Accelerated scenarios. Most areas have an average daily energy demand below 1,000 kWh, with just the east part of the city and some neighborhoods (e.g. Forest Hill and Cleveland Park) west of Rock Creek Park slightly surpasses the 1,000 kWh mark. The average daily total energy demand in BAU 2019 is estimated at slightly above 13,000 kWh.

Figure 14 Energy Demand Map: 2019, BAU

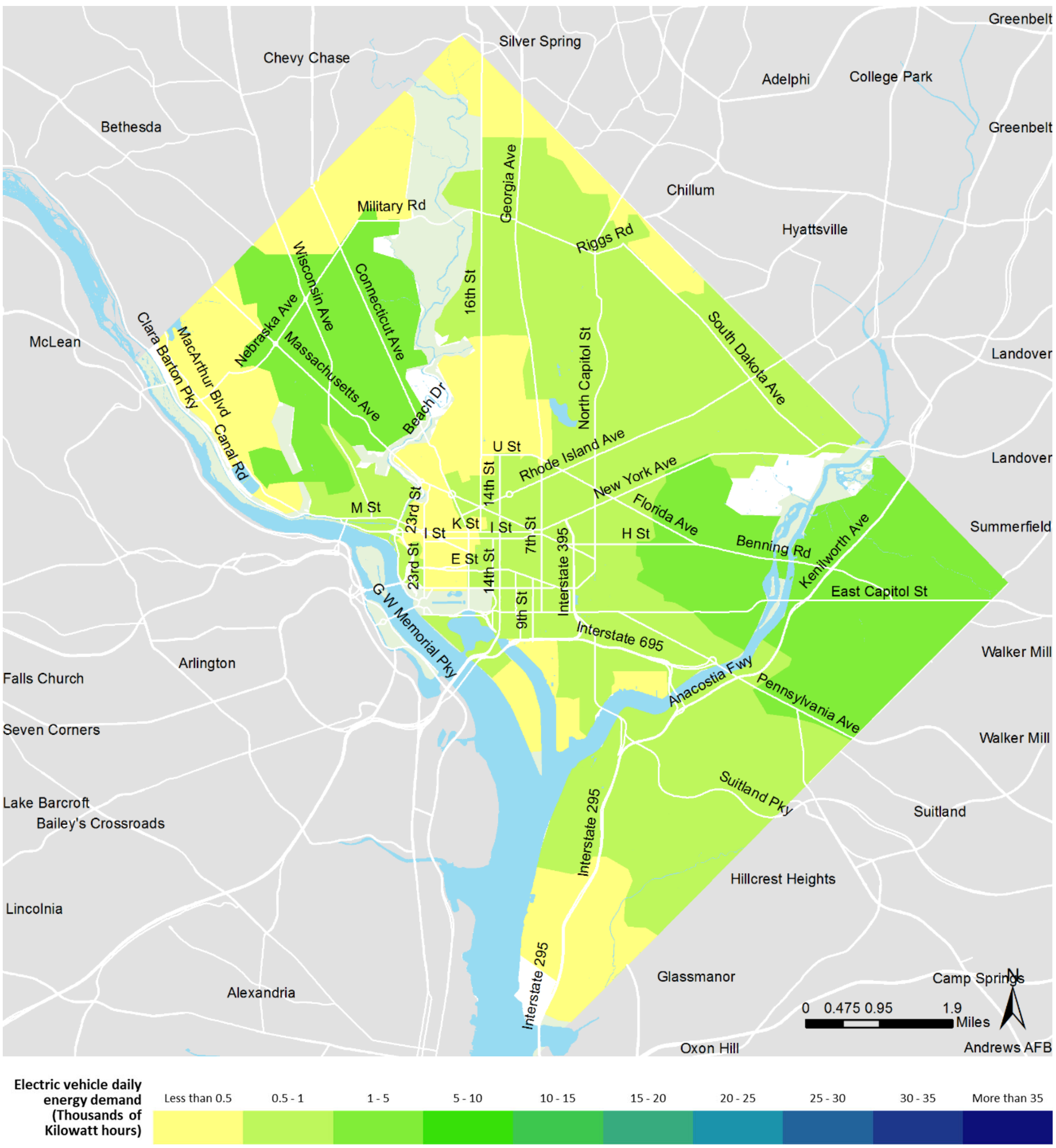


Figure 15 shows the geographic distribution of the energy demand in 2032 under the three scenarios modeled. The growth in the BAU scenario's energy demand is minimal compared to 2019 (Figure 14). All areas demand less than 5,000 kWh, and the total daily energy threefold to approximately 46,000 kWh compared to 2019. The Gradual and Accelerated scenarios show a significant uptake in the energy demand by 2032. In the Gradual scenario, most areas will draw 5,000-10,000 kWh daily, with the east and northwest parts of the city reaching close to 20,000 kWh. The total energy demand in the Gradual scenario goes up to 220,000 kWh. The Accelerated scenario shows the same geographical pattern, with some areas exceeding the 20,000 kWh daily mark, and with a total daily energy demand of approximately 280,000 kWh.

Figure 15 Energy Demand Maps: 2032

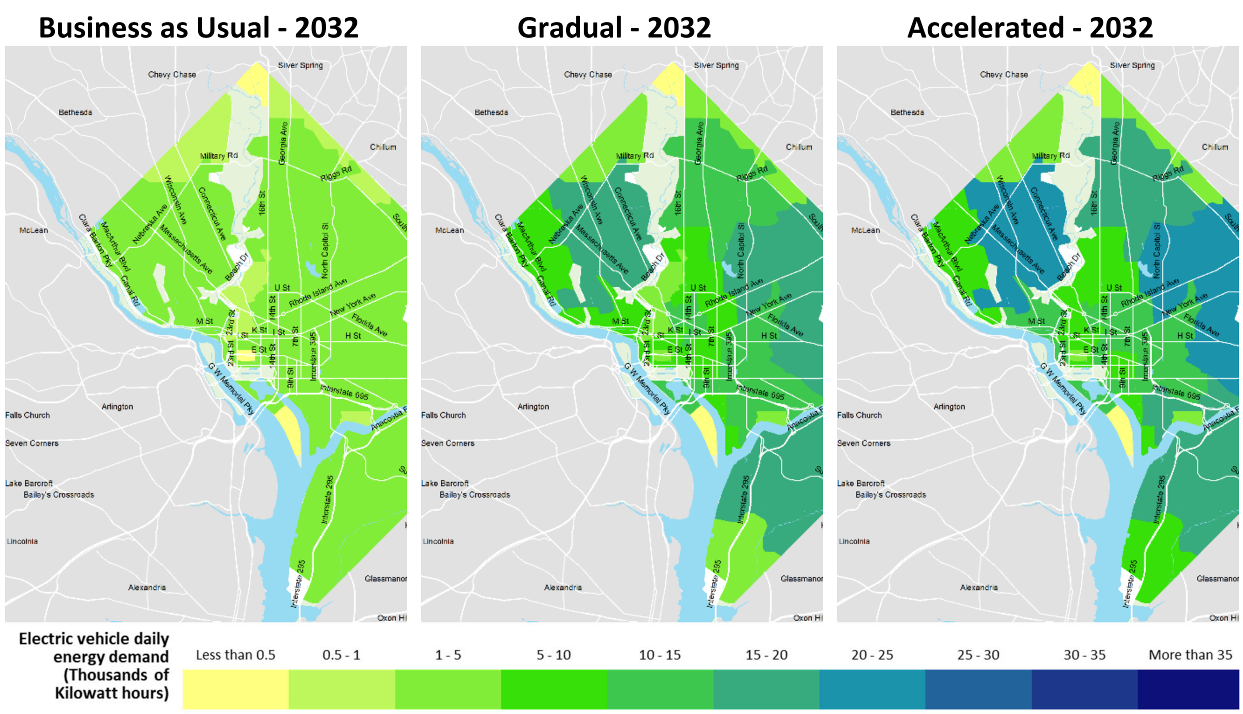
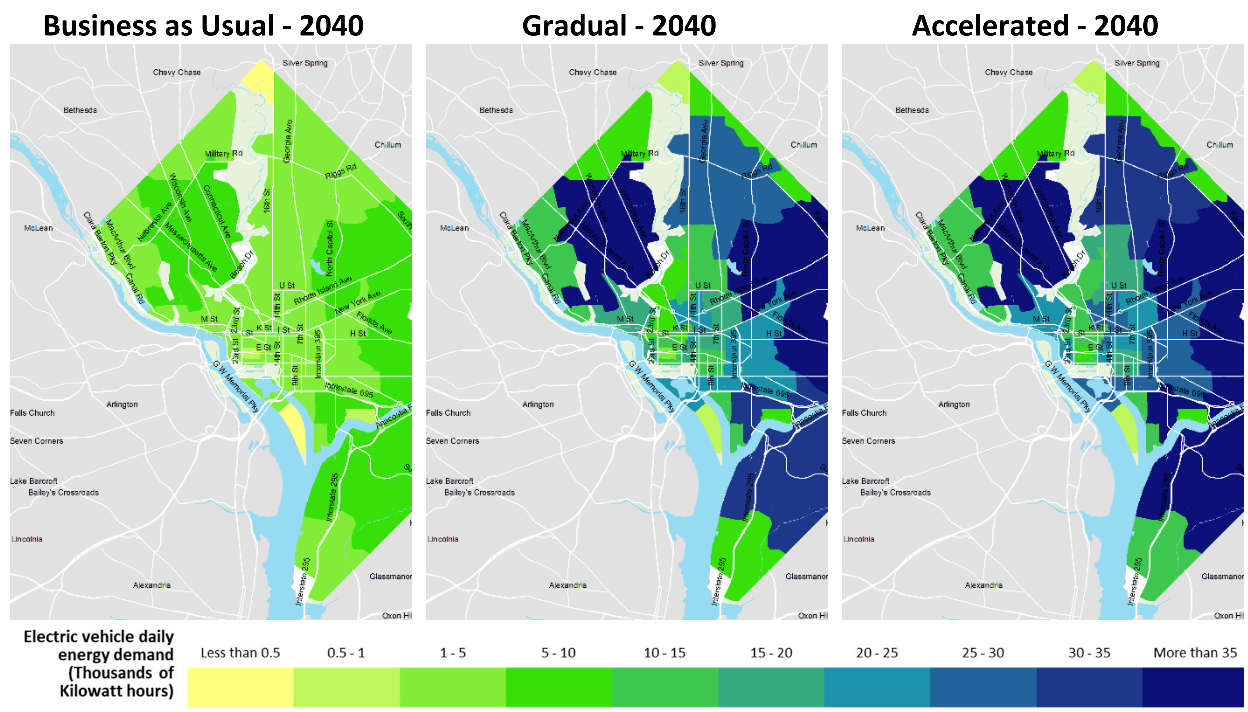


Figure 16 shows the geographic distribution of the energy demand in 2040 under the three scenarios modeled. The BAU scenario's total daily energy demand ascends to 75,000 kWh with no area requiring more than 10,000 kWh in a day. In the Gradual scenario, many areas will draw more than 10,000 kWh daily, with the east and northwest parts of the city reaching up to 40,000 kWh. The total energy demand in the Gradual scenario goes up to 450,000 kWh. The Accelerated scenario has some areas exceeding 40,000 kWh per day and total daily energy demand of approximately 570,000 kWh.

Figure 16 Energy Demand Maps: 2040



Analysis

Estimating the charging points needed to meet the daily energy demand under the different scenarios bears a significant amount of uncertainty. It will largely depend on the BEV user's charging behavior, the place they prefer to charge, and the evolution of different charging technologies' costs and capabilities. This analysis uses a common assumption across scenarios where most of the energy recharging occurs at home.[23] Figure 17 shows the average energy demand in kWh by electric substation by charger type. It is important to note the high variability across the different scenarios and within the same scenarios across substation areas.

Figure 17 Daily Energy Demand Summary, average kWh by electric substation

Year – Scenario	Metric by substation	Home (Level 1)	Workplace (Level 2)	Public Access (Level 2)	Public Access (DC Fast)
2019 - BAU	Average	198	24	228	47
	Range	7 - 419	1 - 52	8 - 483	2 - 99
2032 - BAU	Average	1,052	120	428	125
	Range	42 – 2,457	5 - 281	17 - 1000	5 - 291
2032 - Gradual	Average	5,624	643	1,371	538
	Range	223 – 12,906	26 – 1,477	54 – 3,146	21 – 1,235
2032 - Accelerated	Average	7,179	821	1,692	679
	Range	285 – 16,477	33 - 1885	67 – 3,883	27 – 1,557
2040 - BAU	Average	1,832	210	589	195
	Range	66 – 4,517	8 - 517	21 - 1452	7 - 481
2040 - Gradual	Average	11,601	1,327	2,603	1,078
	Range	426 – 27,948	49 - 3197	96 – 6,272	40 – 2,598
2040 - Accelerated	Average	14,853	1,699	3,274	1,372
	Range	546 – 35,784	62 – 4,094	120 – 7,888	50 – 3,306

[23] More specifically, this analysis assumes that 77% of the BEVs is delivered through home charging, 10% at workplace, 7% in Level 2 public charges and 6% at DC fast chargers during 2019-2025. For 2025-2040 the share of energy delivered changes to 71% at home, 8% at workplace, 15% at public level 2, and 6% at DC fast chargers. Source: The International Council on Clean Transportation, 2019. *Quantifying the Electric Vehicle Charging Infrastructure Gap Across U.S. Markets*. <https://theicct.org/sites/default/files/publications/US_charging_Gap_20190124.pdf>

Lastly, to obtain the number of chargers required in a given substation it was necessary to define charger characteristics and usage intensity. Each charger type set of assumptions are the following:[24]

- Home chargers have 1.3 kWh capacity. Typical charging time per vehicle is eight hours per day, and on average, only one vehicle uses the charger in a day.
- Workplace chargers have 4.95 kWh capacity. Typical charge time per vehicle is approximately three hours, and on average, 2.5 vehicles use the charger in a day.
- Public chargers have 4.95 kWh capacity. Typical charge time per vehicle is approximately one hour, and on average, seven vehicles use the charger in a day.
- DC fast chargers have 50 kWh capacity. Typical charge time per vehicle is approximately 20 minutes, and on average, 25 vehicles use the charger in a day.

The number of chargers by time is highly sensitive to these parameters. Figure 18 shows the average and range chargers by type in each substation under the three different scenarios. The number of fast chargers might seem unusually low. However, as BEVs become more common, it is expected that fast infrastructure is used similarly to today's gas stations, where several vehicles refuel for short periods in a given day.

Figure 18 Charger Stations Summary, number of charger points

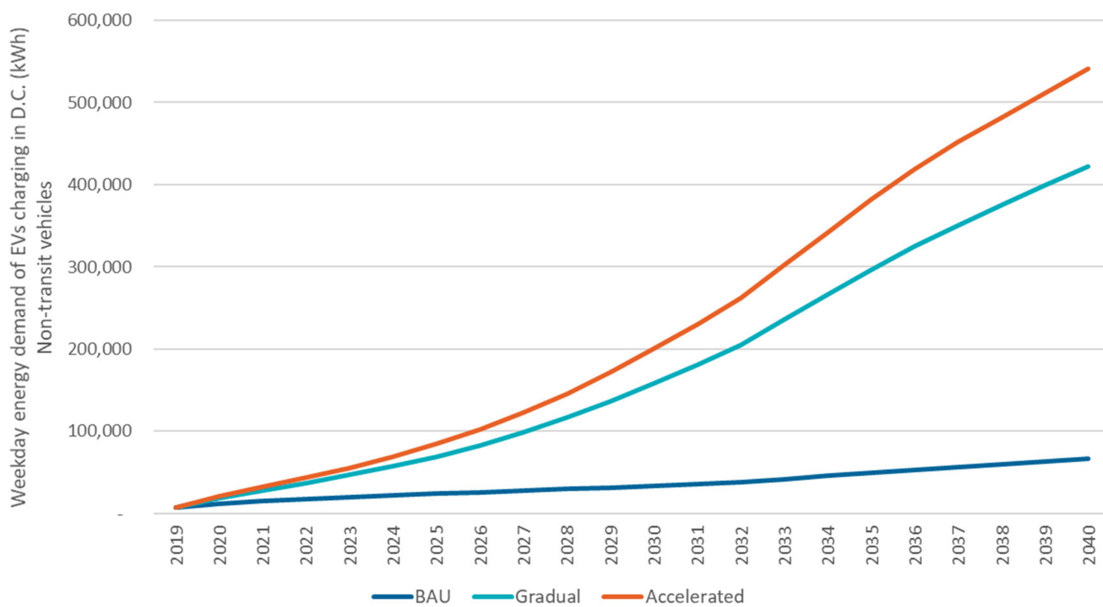
Year – Scenario	Metric by substation	Home (Level 1)	Workplace (Level 2)	Public Access (Level 2)	Public Access (DC Fast)
2019 - BAU	Average	19	1	6	0
	Range	1 - 40	0 - 1	0 - 12	0 - 0
2032 - BAU	Average	101	3	11	0
	Range	4 - 236	0 - 7	0 - 25	0 - 1
2032 - Gradual	Average	541	16	35	1
	Range	21 – 1,241	1 - 37	1 - 79	0 - 3
2032 - Accelerated	Average	690	21	43	2
	Range	27 – 1,584	1 - 48	2 - 98	0 - 4
2040 - BAU	Average	176	5	15	0
	Range	6 - 434	0 - 13	1 - 37	0 - 1
2040 - Gradual	Average	1,115	34	66	3
	Range	41 – 2,687	1 - 81	2 – 1,58	0 - 6
2040 - Accelerated	Average	1,428	43	83	3
	Range	52 – 3,441	2 – 1,03	3 – 199	0 - 8

[24] The International Council on Clean Transportation, 2019. *Quantifying the Electric Vehicle Charging Infrastructure Gap Across U.S. Markets*.

Findings

Figure 19 shows the average weekday energy demand by non-transit vehicles for 2019-2040. As observed, there is a significant difference between a conservative BAU scenario and the Gradual and Accelerated scenarios. The key takeaway is that a rapid uptake in the EV penetration rate will also increase the District's electricity demand and charging infrastructure.

Figure 19 Non-transit Energy Demand in Three Scenarios (2020-2040)



There is a more defined long-term direction in the transit bus segment set by the regulatory framework and transit agencies' commitment to transitioning to BEBs. Figure 20 shows that in 2040 the electricity demand will be the same; however, the scenarios highlight the significant difference that can occur during the transition years. For example, by 2030 there can be a 150,000 kWh difference between the BAU and Accelerated energy demand required by the transit sector, representing a difference of about 150%.

Figure 20 Transit energy demand

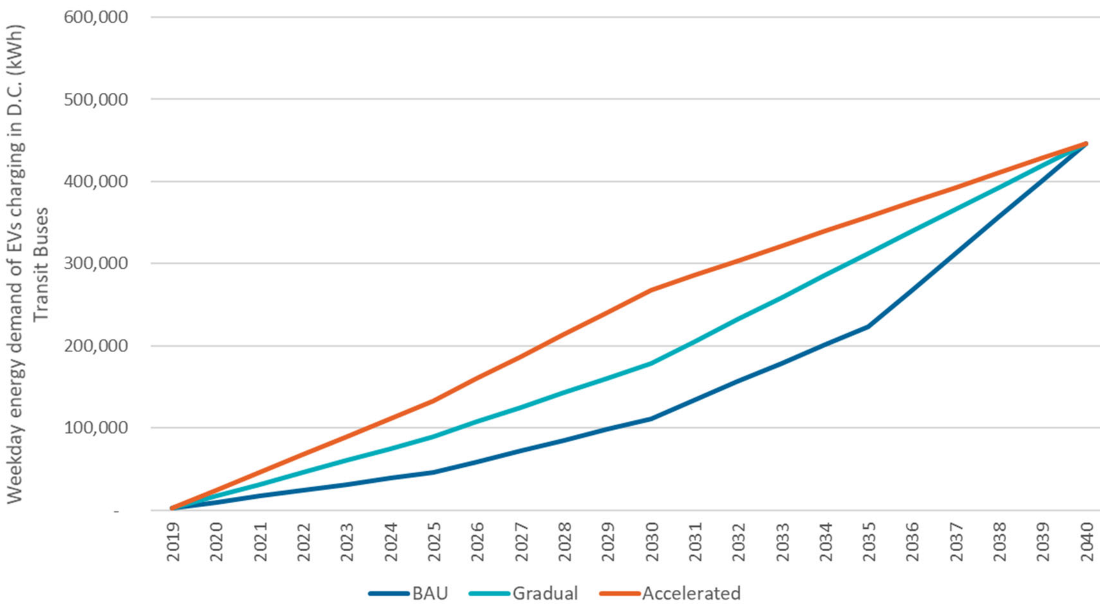
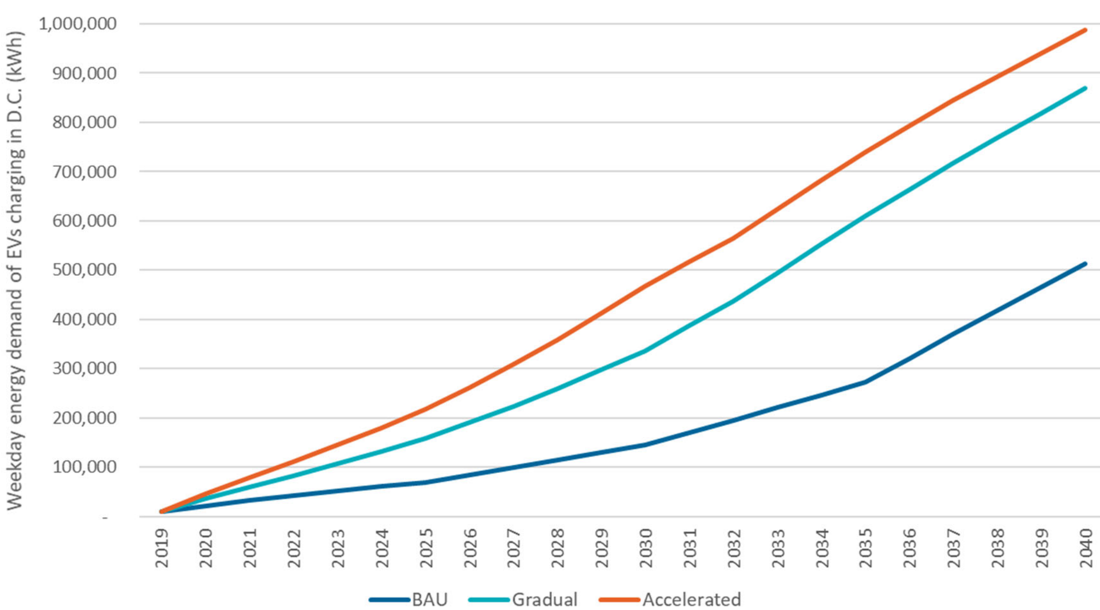


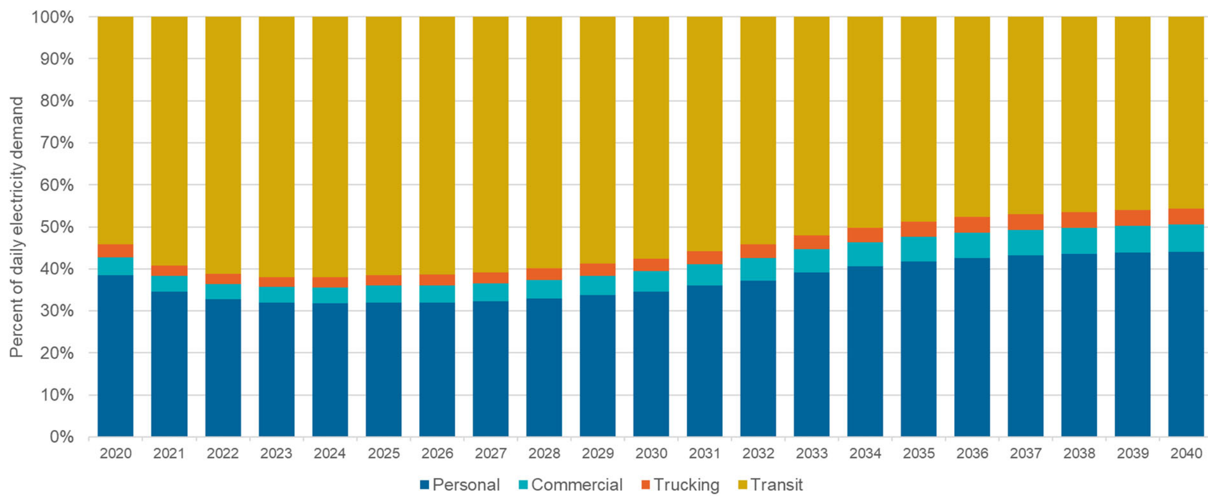
Figure 21 summarizes the energy demand in the non-transit and transit sectors. By 2040 the BAU represents about half of the energy needs of the Accelerated scenario. Noticeably, even under a high conservative BAU scenario for light-duty vehicles, there will be a significant increase in the total energy demand driven by the transit sector.

Figure 21 Total energy demand



Even in an accelerated scenario, the transit sector will account for the highest share of the energy demand during the next years, as represented in Figure 22.

Figure 22 Electricity demand share by Vehicle type: Accelerated Scenario



Conclusions

Task 2A's assessment showed that the energy and charging infrastructure required to meet the future's vehicle electrification in the District can vary considerably by 2040. Nonetheless, the more EVs on the road, the higher the electricity demand and charging infrastructure. In the Gradual scenario, representing a central scenario, the energy demand would reach approximately 900,000 kWh daily. This is almost twice the energy demand forecasted in the BAU scenario (500,000 kWh). The future electricity supply required to meet the vehicle electrification depends mainly on the following two aspects:

- The rate of new light-duty vehicle sales. Electric vehicles' cost, particularly batteries' cost evolution, will be the primary driver of new EV sales along with incentives and availability of charging points.
- The charging behavior of light-duty vehicle users. **<u>This analysis considered the latest evidence suggesting shorter EV trips will not require re-charging within the District.</u>** However, this can change depending on conditions such as electricity rates and availability of charging points.

The energy demand associated with the transit sector (approximately 430,000 kWh by 2040) is more certain due to the CleanEnergy DC Omnibus Amendment Act of 2018 requiring the electrification of transit fleets by 2045. It is recommended that the District Government work closely with the transit agencies to assess their energy demand's specific locations. The electricity to replenish buses will typically be drawn at the bus depots at nights, or along the route corridors if opportunity charging is implemented.

For the charging infrastructure forecast, the actual number of chargers needed will depend on the share of chargers by type. It is expected that as the EV adoption increases over time, home charging will be the primary type in the market. Additionally, the number of public charging infrastructure is significantly affected by the charger intensity of use. In other words, if more vehicles use a single public charging point throughout the day (by optimizing and strategically locating the chargers) fewer charging points will be required to provide the same amount of energy.

Lastly, the hourly-energy demand profiles are likely to be determined by electricity rates and the smart tools available to optimize charging. Task 3 demonstrate that hourly profiles are not only relevant to manage the grid demand but also to minimize CO_2 emissions.

TASK 2B: BUS ELECTRIFICATION

Our BEB charging analysis examines the impacts of bus electrification on the distribution system in the District. We developed an analysis of electric bus charging load using data from the Washington Metropolitan Area Transit Authority (WMATA), but this projection of bus adoption and charging strategies is a scenario developed for this project, not an official WMATA projection. This included estimating the annual penetration of EV buses in the District and developing an hourly charging profile. Our analysis modeled the impact of the EV Bus stock share increasing to 100% by 2045. Such a change would represent an increase from 0 EV buses in 2021 to approximately 1,600 EV buses in 2045 within the WMATA region. This assumption was based off a WMATA report which projected that:

- The WMATA bus fleet size of 1,593 will remain relatively constant through 2045[25]
- Approximately 25% of new buses purchased in the years 2024 through 2029 will be zero emission.[26]
- 100% new buses purchased from 2030 onwards will be zero-emission.[27, 28]

[25] WMATA Executive Committee. June 10, 2021. *Sustainability Vision and Principles and Metrobus Fleet Plan.* Available at: https://www.wmata.com/about/board/meetings/board-pdfs/upload/3A-Sustainability-Vision-Goals-and-Bus-Fleet.pdf p. 33

[26] WMATA Executive Committee p. 34

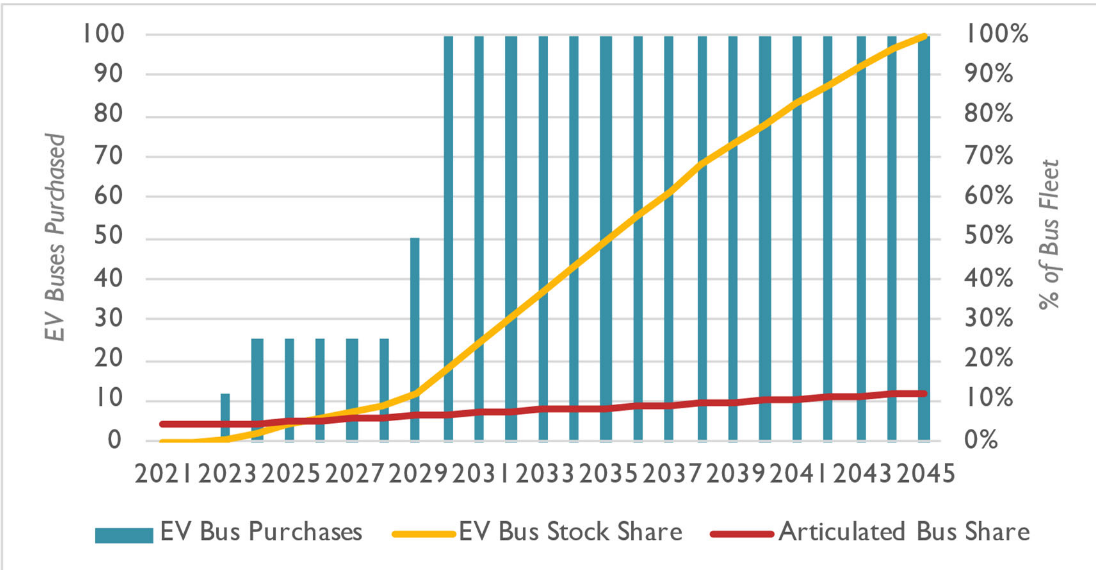
[27] WMATA Executive Committee p. 34

[28] We assumed that all the buses were electric in our analysis.

- The share of articulated buses grows from 4% to 12% over the period.[29]

Our assumptions for EV Bus Stock share are summarized in Figure 23 shown below.

Figure 23: Assumed Number and Percentage of EV Buses in WMATA's Fleet (2020-2045)



Based on these assumptions, by 2032, we estimated that the WMATA fleet would include 487 EV buses in the District, which would represent 30% of the total bus stock share.

As the penetration of EV buses increases, so will the amount of energy required to charge them. Our analysis assumed that the majority of charging will take place at the bus depots located within the District. The depot locations were sourced from a WMATA report released in June 2021 and are shown in Table 7.[30] Electric bus growth was modeled to remain proportional to the capacity at each depot. This means that the first three depots to be electrified (Shepherd Parkway, Northern, and Bladensburg) transition from fossil fuel powered buses to electric buses at the same rate in our analysis. By 2032, electric buses make up about 74 percent of their total bus capacity. The capacity and location of each depot included in our analysis is summarized in Table 7.

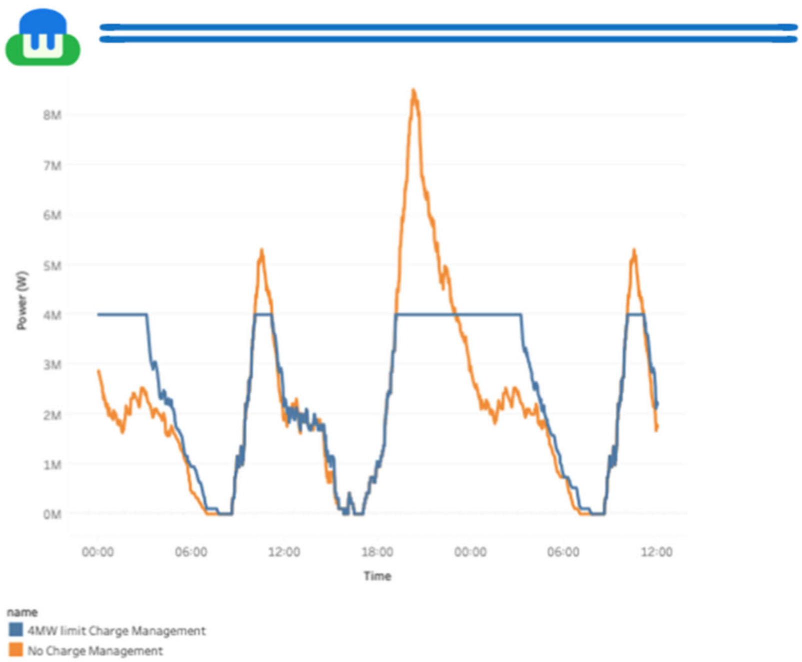
Table 7: Locations and Capacity of Bus Charging Depots

Garage	Address	Bus Capacity
Shepherd Parkway	2 DC Village Ln SW, Washington, DC 20032	223
Northern	4615 14th St NW, Washington, DC	150
Bladensburg	2250 26th St NE, Washington, DC 20018	250

[29] WMATA Executive Committee p. 33
[30] WMATA Executive Committee. p. 43

To inform our analysis of EV Bus Load, we reference a report completed by Wise Charging on electric bus charging in the District.[31] Using charging data from this report, we developed a 24-hour charging schedule, repeated over the course of the year. This charging schedule was extracted from the Wise charging report and is depicted below in Figure 24.

Figure 24: EV Bus Charging Schedule



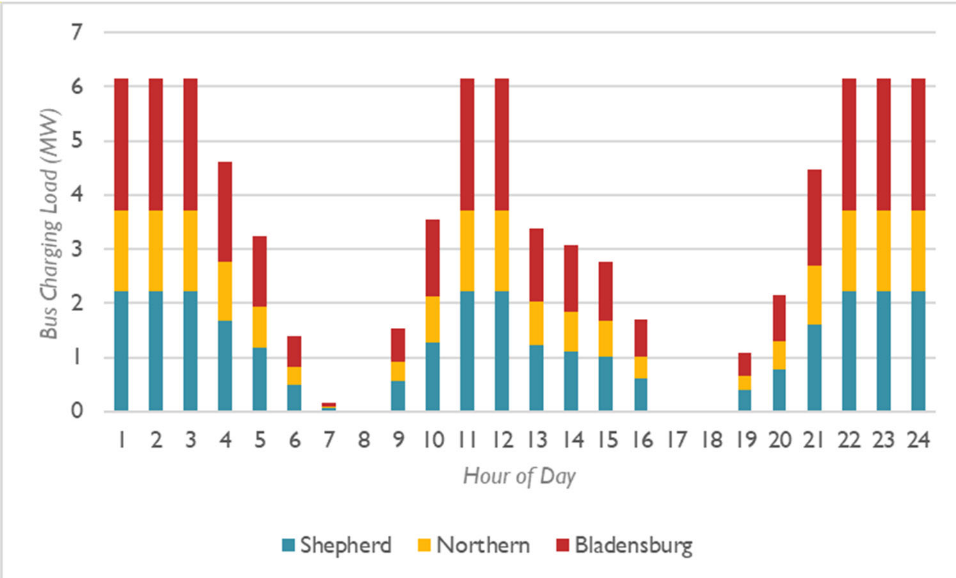
Source: Wise Charging on behalf of the Washington Metropolitan Area Transit Authority. August 2020. WMATA Northern Charging. p. 31

Figure 24 shows two charging schedules. The orange line represents a schedule with no charge management. Under this scenario, buses charging is less spread out, which increases peak demand to nearly 9 MW for the 150 buses modeled. Under the 4 MW limit scenario, depicted in by the blue line, charging is more spread out. Wise Charging recommended the second charging profile as a way for WMATA to save money. In particular, the second profile would help WMATA limit demand charges. The WMATA report notes that "Demand charges driven by peak power make up a substantial part of utility costs." It also notes that a single period of peak demand can set the demand charge being levied for the whole month, or even for the following 11 months.[32] By implementing the 4MW charge management limit, WMATA can save an

[31] Wise Charging on behalf of the Washington Metropolitan Area Transit Authority. August 2020. *WMATA Northern Charging*.
[32] Wise Charging p. 20

estimated $38,000 per month, at current rates, which would translate to $456,000 annually.[33] Hourly bus load, by depot, is summarized in Figure 25.

Figure 25: Charging Load Modeled for Shepherd, Northern, and Bladensburg. (2032)



<u>Overall, we found that bus charging had a small impact on peak load, because most of the charging was done during periods of low demand.</u> For example, during the winter, peak hours often occur in the morning (between 6 AM and 9 AM) and the evening (between 4 PM and 7 PM). As shown in Figure 25, bus charging load is either low or zero during these peak hours. By utilizing the strategic charging plan outlined by Wise, the District can decrease its peak energy usage, thereby avoiding unnecessary demand charges and minimizing costs associated with investment in new energy infrastructure.

33 Wise Charging P. 22

TASK 1 AND 2: COMBINED LOAD FORECAST

In this section we present the overall loads that our modeling indicates the District may experience in 2032, after accounting for load growth, energy efficiency, and electrification of many end uses, as described in the preceding sections.

Our overall strategy to develop projected loads was as follows:

1) Begin with the hourly load experienced on each of Pepco's substations on a winter and summer peak day in 2019.
2) Increase the load in all hours at a rate commensurate with Pepco's load forecast through 2029, and then extrapolate to 2032 using a compound annual growth rate approach.
    a. Pepco's Mt. Vernon substation comes online during this study period, and feeders and load are transferred to it. We developed a load for this substation by treating these feeders as though they had not been transferred, completing the same projection, and then transferring the final feeder loads to the new substation. This allowed us to avoid nonsensical growth rates resulting from load transfers rather than underlying growth in demand.
3) Add the hourly substation-level incremental electrification loads developed by Integral (buildings, **using the worst-case winter and summer load day**), Nelson\Nygaard (light duty electric vehicles), and Synapse (bus depots) to the 2032 base load.

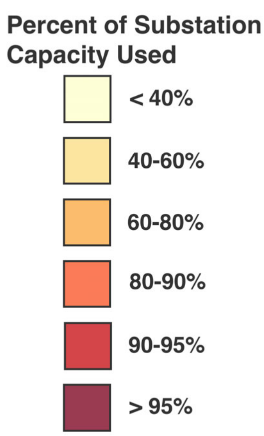
We then compared the hourly loads to the maximum load capacity for each substation. **None of the loads exceed the substation capacity, although they do approach the maximum in some cases.** Electrification is nowhere near complete by 2032, so additional loads can be expected after 2032 which could, if unmitigated, result in the need to upgrade substations or build new substations. (This need depends in part on the use of demand-side resources, which are the subject of Task 5 of this project.) In addition, the geographic distribution of load increases within the areas served by a given substation, and the capacity of existing feeders, could mean that substation investments are required on the distribution system to meet underlying growth combined with electrification loads, even if the substation load is not exceeded. This kind of feeder-level analysis is the subject of Tasks 4 and 5.

This analysis does not include the impact of distributed solar PV, which would reduce net loads during summer daylight times, particularly those with the highest loads which occur on hot sunny days. Because winter peak loads occur during relatively dark periods (including before sunrise), and snow may cover panels, the inclusion of solar PV would not affect our analysis of winter peaks, which are the driver for the reliability challenges that we are concerned with in this project.

Figure 27 presents the winter hourly results; the legend can be found in Figure 26. The color for each substation area reflects the fraction of the substation's capacity that is being used in each hour, with darker colors indicating higher utilization.[34] **<u>The time of greatest stress on the substations is 7AM on winter mornings.</u>** During this hour, substations 7 and 133 each exceed 95 percent of their capacity.

Figure 28 shows the same results, but for a summer peak day. **<u>Because building electrification loads do not add substantially to summer peaks (and in fact, more efficient equipment and building shell improvements consistent with District policies mitigate peak demand, according to Integral's analysis), no substation peak load exceeds 80 percent of its capacity in the summer.</u>**

Figure 26. Legend for Figure 27 and 28



[34] The substation map provided by Pepco did not include the area served by the new Mt. Vernon Substation. We have mapped it as a circle in the approximate location and shifted loads from the neighboring substations as projected by Pepco.

Figure 27. Modeled hourly load as a fraction of the capacity of each substation in the District of Columbia on a winter peak day in 2032

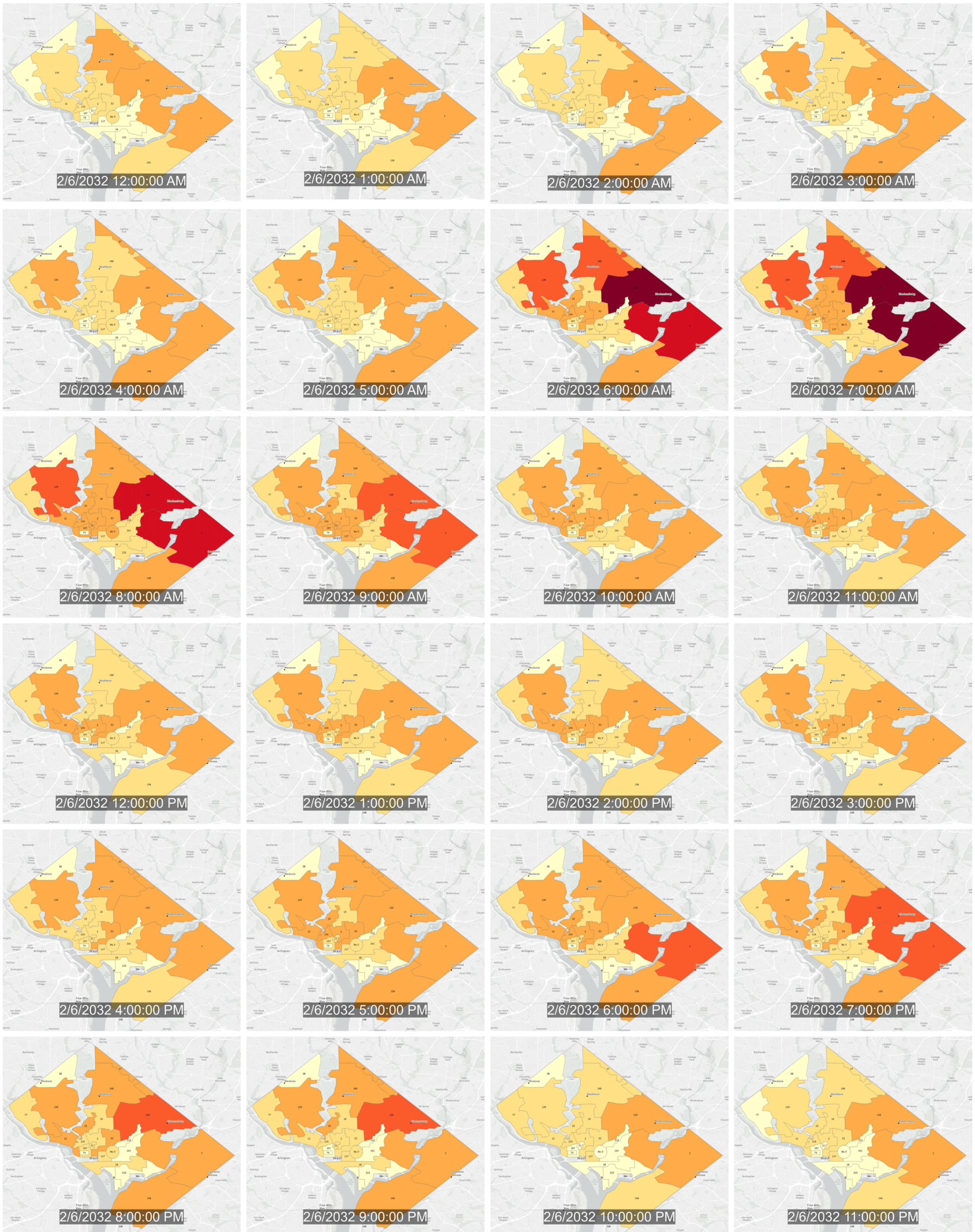
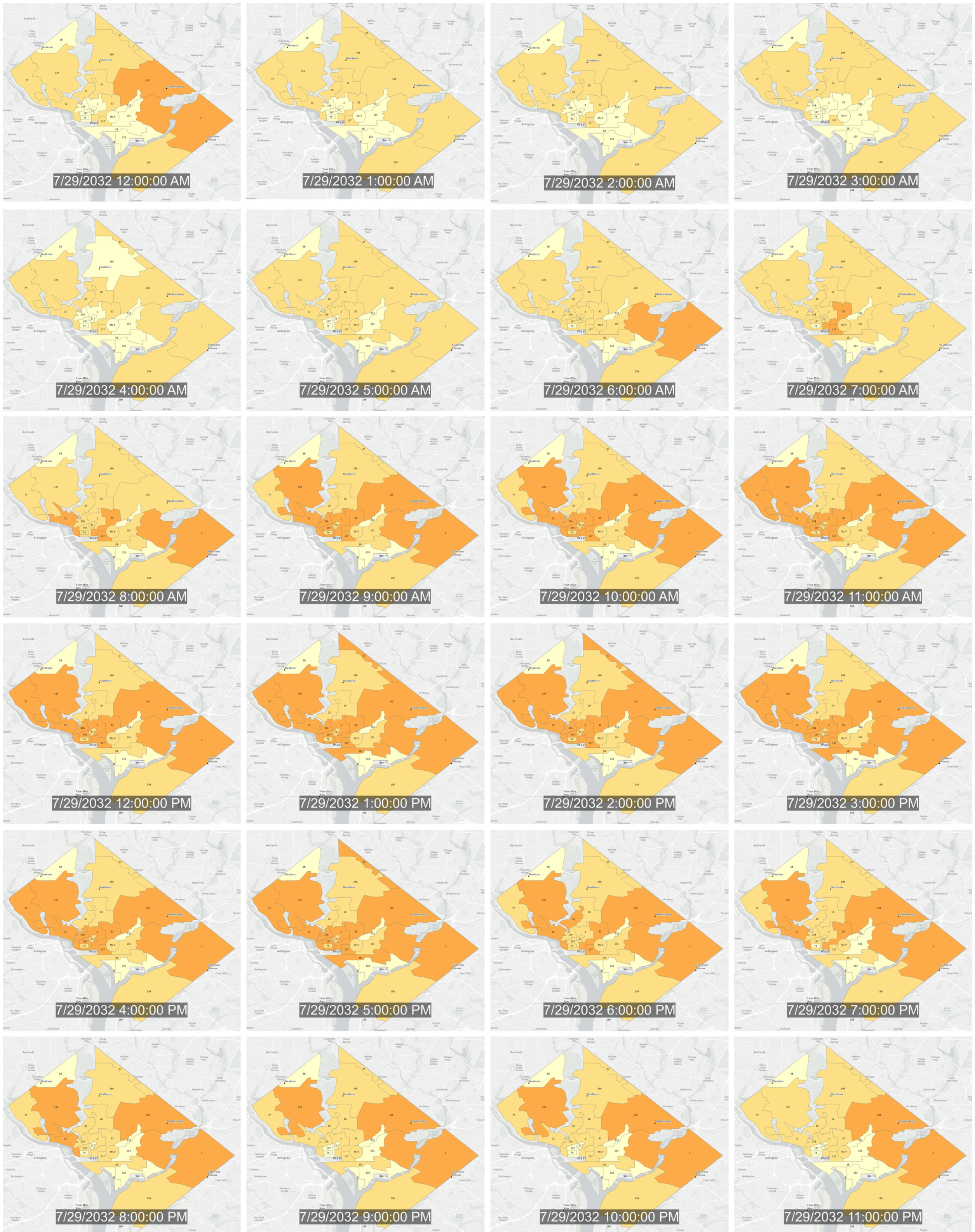


Figure 28. Modeled hourly load as a fraction of the capacity of each substation in the District of Columbia on a summer peak day in 2032



ROADMAP TASK 3: GRID EMISSIONS ASSESSMENT

Introduction

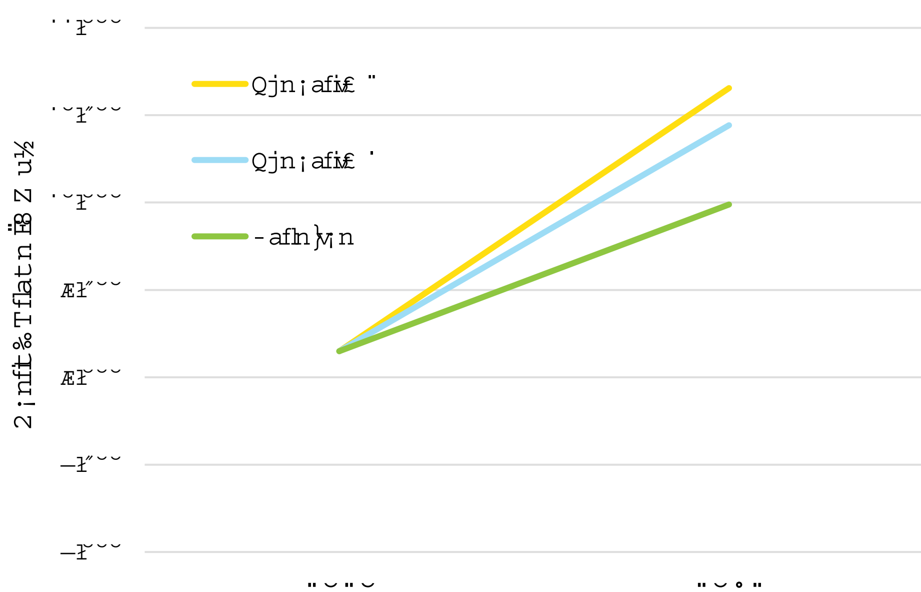
WattTime analyzed the GHG impact of the anticipated changes to the building sector in D.C. from 2020 to 2032 (from Task 1). The analysis examined how emissions are impacted by scenarios with varying degrees of efficiency and electrification measures.

WattTime also analyzed the GHG emissions impact of increased EV adoption in D.C. from 2019 through 2050 (from Task 2), specifically the change in emissions from the electricity sector as a result of EV charging. The analysis examined how emissions are impacted by various EV adoption rates, charging patterns, and equipment types. We also evaluated the potential for further emissions savings through GHG-optimized smart charging.

Methodology and Assumptions

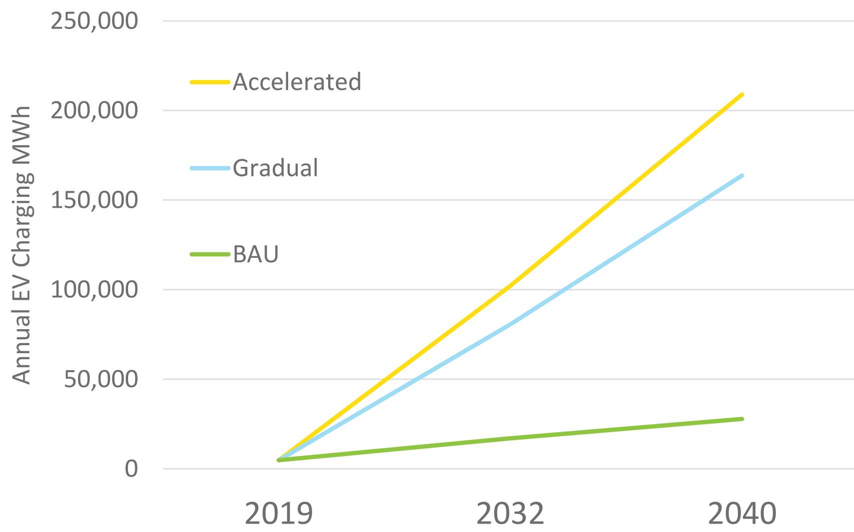
Building Fleet Electricity Consumption. WattTime's analysis utilized outputs from Task 1 as a basis for defining the timing and quantity of electrical consumption of D.C.'s building fleet. Task 1 projected the aggregated grid loads for multiple scenarios of electrification and efficiency.

Figure 29: Three scenarios for the trajectory of aggregated building electrical loads



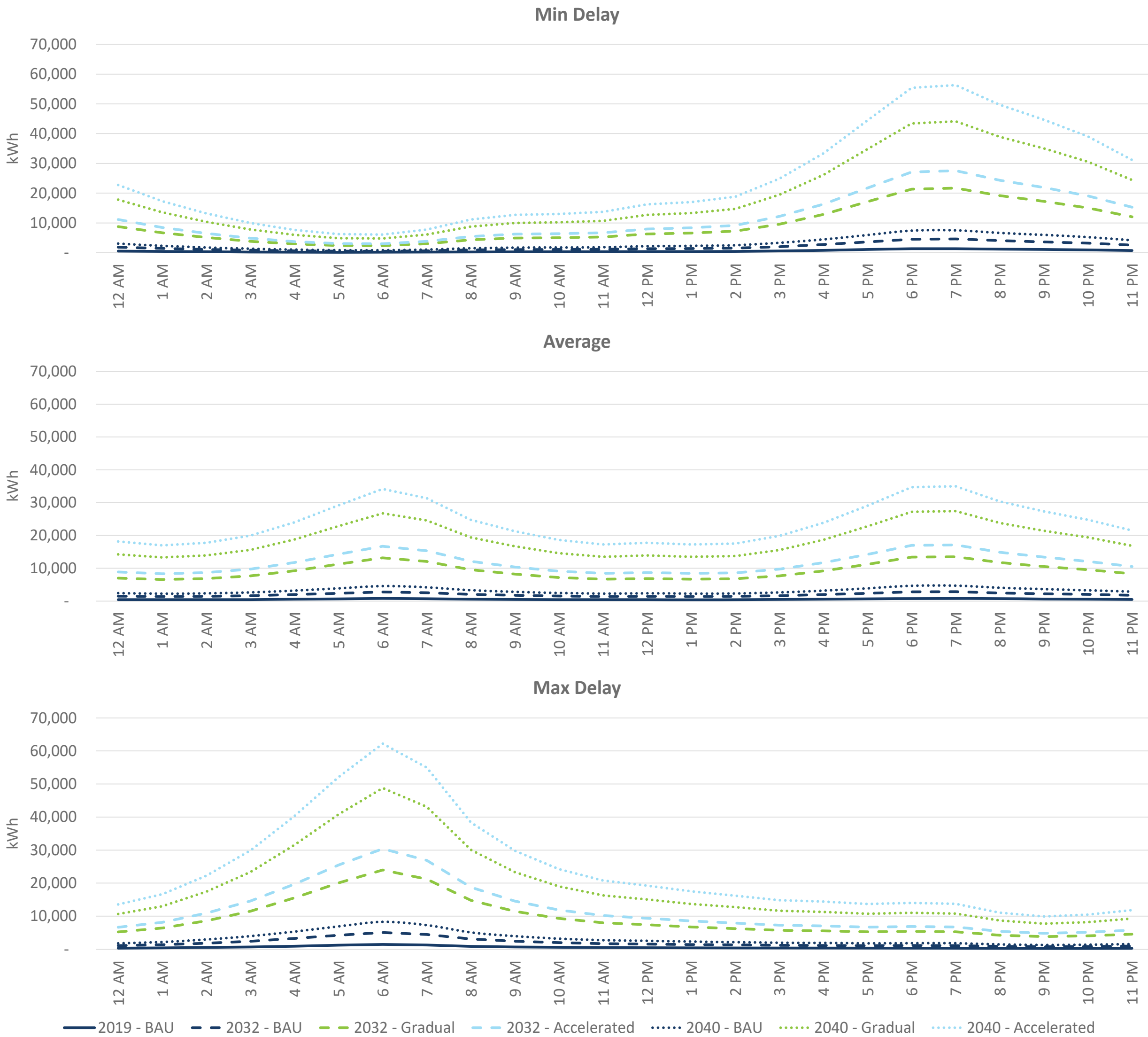
EV Fleet Electricity Consumption. WattTime's analysis utilized outputs from Task 2 as a basis for defining the timing and quantity of electrical consumption of DC's EV fleet. Task 2 projected the adoption rates which defines our assumption for the year-over-year growth of the EV fleet, for three scenarios, "Business As Usual," "Gradual," and "Accelerated."

Figure 30: Three scenarios for the trajectory of future EV adoption



Task 2 also analyzed how daily charging behavior within the fleet would affect grid-level electricity demand. Three scenarios for charging behavior from Task 2 were used for the Task 3 analysis, "Min Delay," "Average," and "Max Delay."

Figure 31: Three scenarios for fleet charging behavior, which show how fleet's charging load grows as EV adoption grows. A longer "delay" refers to the delay of charging commencement after the vehicle is plugged in.



Electric Grid Regions and Generator Mix. Washington DC is served by a local electric grid that is balanced by PJM at the Atlantic subregion level (PJM Atlantic, for short). The emissions intensity of a grid is highly dependent on the fractional contributions, or mix, of generator types which have varying emissions intensities (CO2 lbs/MWh). PJM's grid mix in future years is uncertain and more so in the latter years of this analysis period which extends to 2050. The predicted grid mix for the years 2032 and 2040 was estimated using RPS targets from states within the PJM ISO and published Utility Integrated Resource Plans. A proxy grid was chosen to represent the future PJM Atlantic region for this analysis. The existing grid region which most closely resembled the future grid mix and for which WattTime has existing emissions data is the 2019 CAISO region, which we used as a proxy.

PJM Grid Mix	2019	2032 (est.)	2040 (est.)	CAISO 2019
Variable Renewable	4%	31%	42%	32%
Carbon-free (Hydro/Nuclear)	36%	36%	31%	25%
Fossil-powered	61%	33%	27%	43%

Marginal Emissions Rates and Emissions Savings. For assessing the change in carbon emissions associated with an end-use operational change (in this case deciding when to charge an EV during the day) or a technology implementation (buying an EV instead of an ICE vehicle), the *marginal* emissions impact is used to quantify the savings of that action. Marginal emissions intensity is the rate of emissions (in this case carbon dioxide emissions in lbs/MWh) of the specific responding generator(s) that will turn on/off or ramp up/down to satisfy the increase/decrease in electric load. WattTime maintains marginal emissions models known as Marginal Operating Emissions Rates (MOERs) for all regions in the US (and many others globally) and used historical marginal emissions rates from our database for this analysis. More detail about WattTime's marginal emissions rates models and methodology can be found in Appendix D.

We calculate the emissions impact of a scenario by multiplying the energy consumed by the emissions intensity of the energy generated on the grid at that time. When comparing scenarios to determine the emissions savings (avoided emissions) from an action, we use the difference between marginal emissions impact.

$$Emissions\ (lbs\ CO2) = Energy\ Consumed\ (kWh) \times Emissions\ Intensity\ (\frac{lbs\ CO2}{kWh})$$

$$\begin{aligned} &Avoided\ Emissions\ (lbs\ CO2) \\ &\quad = \sum_{i=0}^{n} Energy\ Consumed\ (MWh)_i \times Marginal\ Emissions\ (\frac{lbs\ CO2}{MWh})_i \\ &\quad - \sum_{j=0}^{n} Energy\ Consumed\ (MWh)_j \times Marginal\ Emissions\ (\frac{lbs\ CO2}{MWh})_j \end{aligned}$$

Marginal Emissions Profiles

WattTime used historical marginal emissions from our MOER database for this analysis. The character of the datasets is demonstrated in the following graphs.

Figure 32: Example PJM Atlantic MOER data for one day at five-minute intervals.

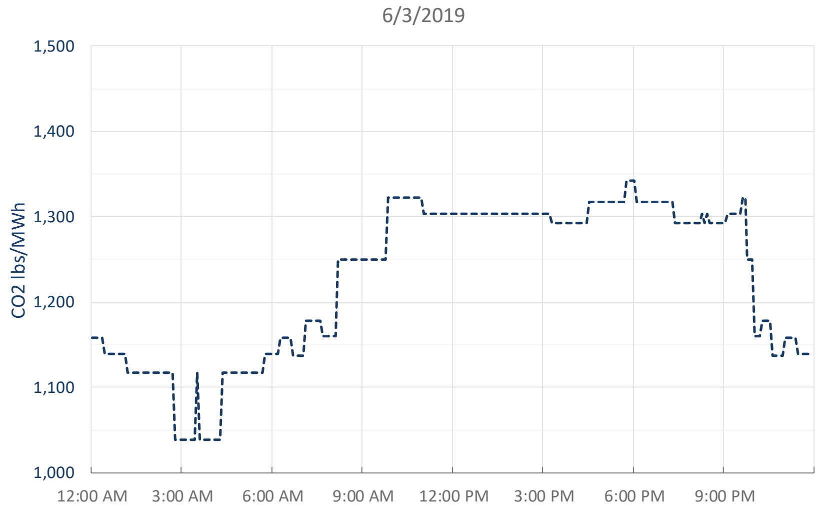


Figure 33: 2019 PJM Atlantic MOER data heat map.

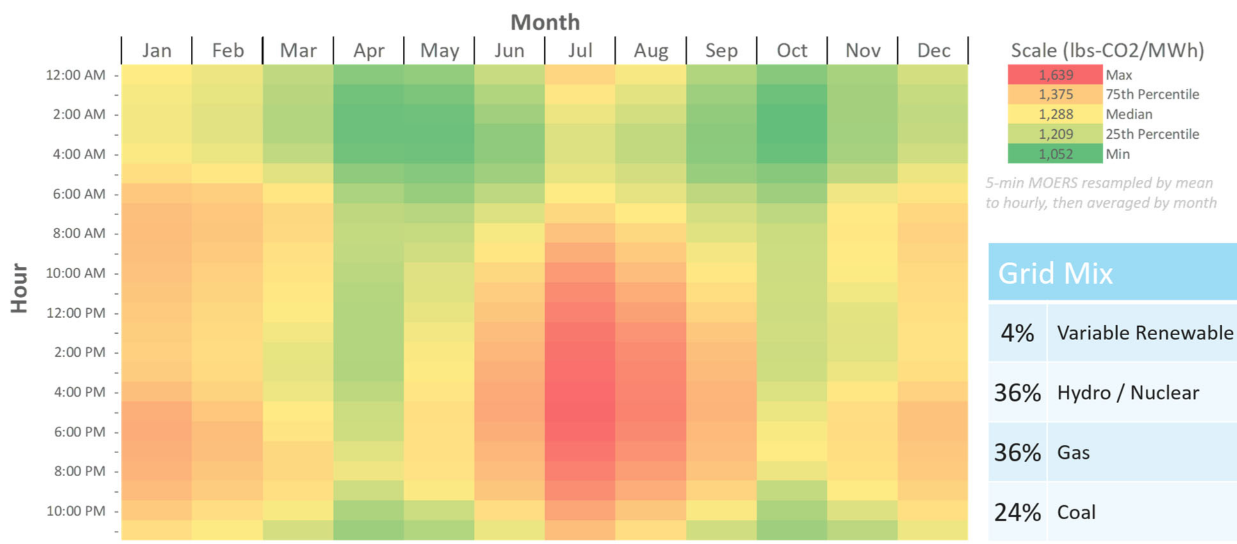
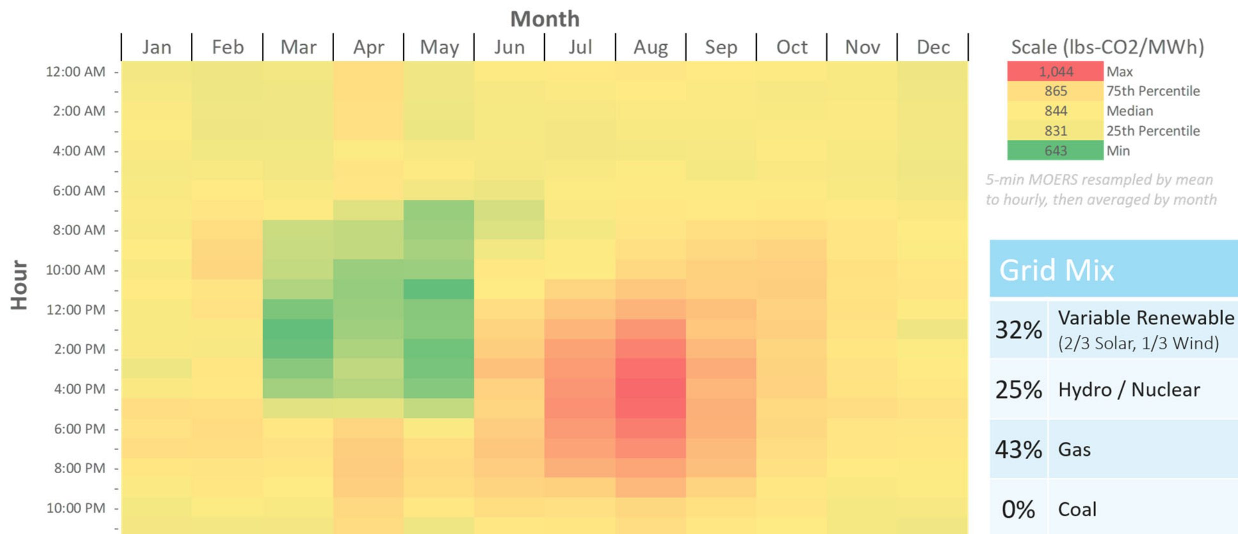


Figure 34: 2019 CAISO NP15 MOER data heat map. This dataset was used as a proxy grid for PJM Atlantic in 2032 and 2040.



Carbon Emissions Analysis & Findings

Electric Vehicle Carbon Analysis. First, we've quantified the carbon emission impact of the existing EV fleet in Washington DC, using 2019 as a baseline. The electric load on the grid of the current fleet of EV chargers is roughly equivalent to 1,500 passenger vehicles driving 30 miles per day on average (though the true mix includes a variety of vehicle types and mileage). The locational marginal price (LMP) history was used to quantify the wholesale cost of charging the fleet.

Table 8: 2019 Baseline Emissions and Costs from the existing EV fleet. (% differences are relative to the Min Delay scenario)

Scenario	Emissions (lbs CO2)	Costs (Wholesale)
Min Delay	6,516,000	$131,000
Average	6,381,000 (-2%)	$125,000 (-5%)
Max Delay	6,246,000 (-4%)	$119,000 (-9%)

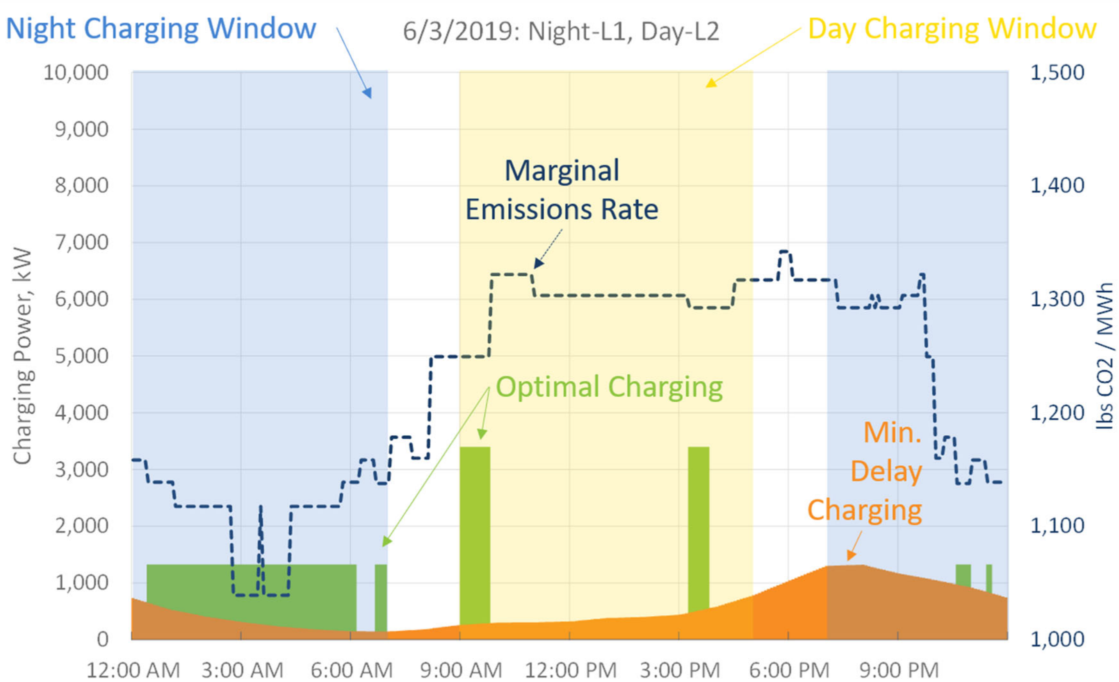
Marginal emissions analysis is used to quantify the emissions impact of choices being made (including 1) the choice to buy an EV, and 2) the choice of when to charge the EV). The fleetwide emissions impact of the collective choices to buy an EV is quantified for the three adoption rate scenarios. By 2040, the electricity emissions from charging the EV fleet is expected to have grown by at least 4x and as much as 28x.

Table 9: CO2 emissions impact of a growing EV fleet's electrical usage (Min Delay scenario). (Multiples of the 2019 Baseline are shown)

Emissions, lbs CO2	2019	2032	2040
B.A.U.	6,516,000	14,590,000 (2x)	23,894,000 (4x)
Gradual	-	69,128,000 (11x)	140,429,000 (22x)
Accelerated	-	87,676,000 (13x)	179,224,000 (28x)

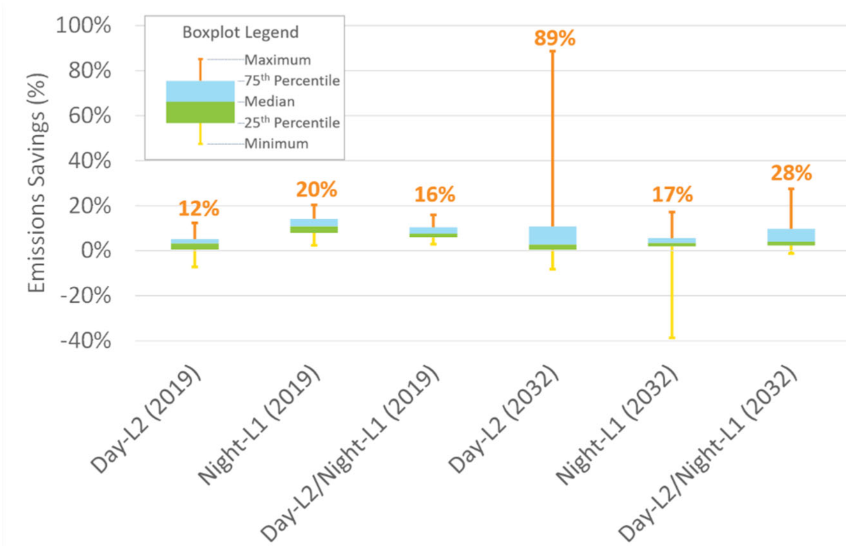
Emissions can be reduced on a day-to-day basis by giving EV owners access to the real-time and predicted marginal emissions data for their local electrical grids, and a means to automatically charge their vehicles at the times of lowest emissions. This is called emissions-optimal charging. The opportunity for emissions reduction from employing emissions-optimal charging fleetwide was simulated by shifting charging times to the lowest emissions intervals, while still respecting that a full charge is needed at the end of the charging session (window). Emissions-optimal charging performance was compared to the non-smart charging scenario, Min Delay, which represents immediate charging by each vehicle in the fleet.

Figure 35: An example day demonstrating the difference in the electricity profile for charging the entire fleet between the baseline (Min Delay) and the optimal (emissions-optimized with level 2 charging during the day and level 1 charging at night). Optimal charging shifts charging energy use to the periods of lowest marginal emissions while ensuring a full charge by the end of the session.



Emissions-optimal charging results were calculated for day-only, night-only, and day+night charging windows. Both level 1 and level 2 charging rates were simulated, to measure sensitivity to this factor. **Daily carbon emissions reductions reached as high as 89%.**

Figure 36: Statistical analysis of the daily carbon savings for emissions-optimal charging compared with "Min Delay" charging for various charging window scenarios in 2019 and 2032. The highest daily carbon savings of 89% is seen in 2032 when all charging is limited to the daytime at level 2. Savings go negative on a few days because the emissions-optimal simulations are limited to a specific charging window (i.e. day or night only) and the baseline "min delay" scenario is based on fleetwide charging spread over an entire 24-hr period.



Impact of Optimizing Electric Vehicle Charging. The carbon emissions reductions that could be achieved by full implementation of emissions-optimal charging, instead of non-smart immediate charging (Min Delay) are presented here. All findings shown here represent the "gradual" EV adoption scenario.

Figure 37: Emissions-optimal smart-charging can result in 3-12% annual savings, depending on the charging windows and types of chargers assumed.

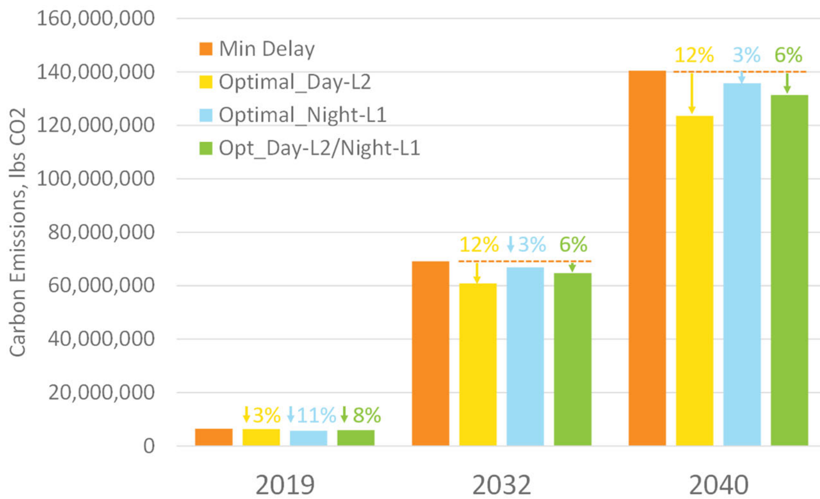
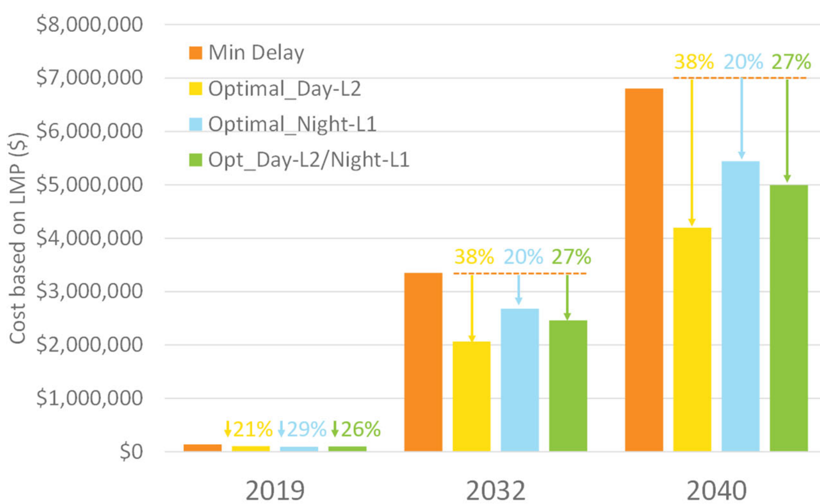


Figure 38: Emissions-optimal smart-charging reduces not only carbon emissions but also the wholesale cost of charging.



Buildings Carbon Analysis. First, we quantified the marginal carbon emissions impact of the electricity use of buildings in Washington DC (using the total building demand from all substations which was reported in Task 1). Then, we analyzed the marginal carbon emissions for the building load projections for 2032. The increase in emissions from the baseline to scenarios 1 and 2 in the 2032 projection come not only from the increase in energy usage, but also from the timing of that energy usage. These scenarios tend to use energy at slightly dirtier times, as you can see by the slightly higher annual average emissions rates in Table 10.

Table 10: 2020 electricity emissions of the existing buildings fleet and the projected emissions of the 2032 buildings fleet in 3 scenarios (% differences are relative to the 2020 baseline)

Emissions, Tons CO2	2020	2032
Baseline	6,197,000	3,679,000 (-41%)
Scenario 1	-	3,865,000 (-38%)
Scenario 2	-	3,964,000 (-36%)

Table 11: Annual average marginal emission rates for the analyzed scenarios

Emissions Rate, CO2 lbs/MWh	2020	2032
Baseline	1,355	737
Scenario 1	-	740
Scenario 2	-	744

Impact of Optimizing Flexible Building Loads. Next, we analyzed the potential marginal emissions impact that continuously optimized load flexibility could have in buildings (what we call Automated Emissions Reduction, or AER). This load flexibility analysis was performed on the aggregated load of the entire region to determine the rough magnitude of the opportunity. Building-specific results will vary depending on load profiles and flexibility of energy consuming devices. Here are the assumptions driving this analysis:

- Control window: 24 hours (energy shifted from the 12 dirtiest hours to the 12 cleanest)
- Load shift limit: A maximum of 25% of the energy in any interval can be shifted
- Peak load limit: 100% (The load shifting simulation will not increase the annual peak demand)

Figure 39: Automated Emissions Reduction shifts load from high-emissions times to low emissions times of the day. This example is from Scenario 2 in 2032.

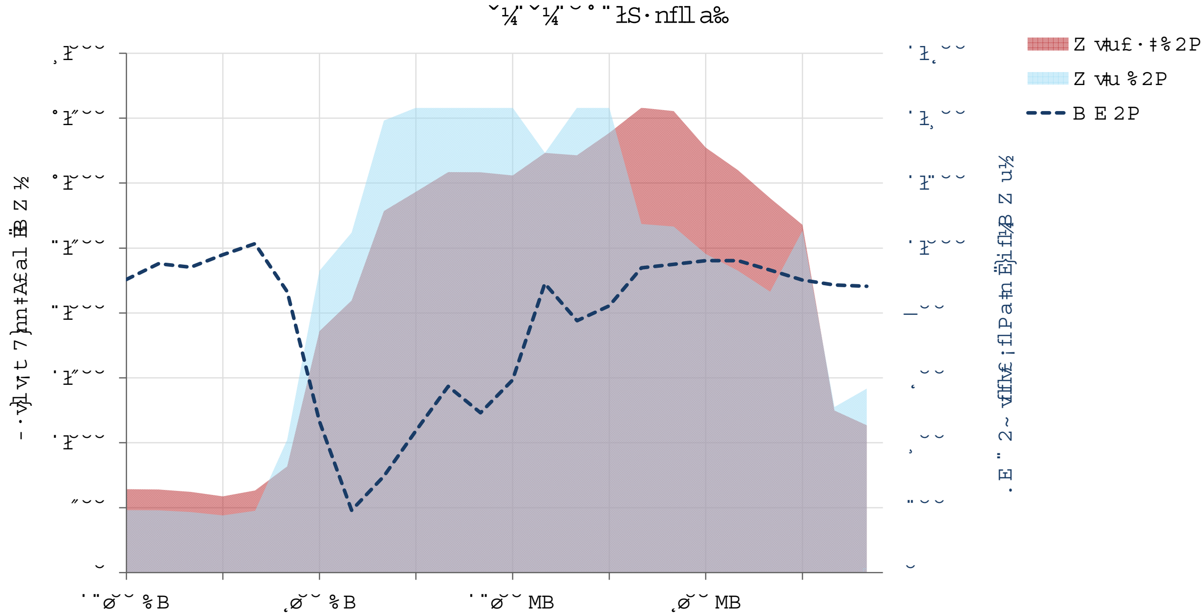


Table 12: The annual CO_2 savings that can be achieved for each scenario with Automated Emissions Reduction, with an average of 25% of the building's fleet having flexibility to shift.

CO2 Savings from AER (Tons)	2020	2032
Baseline	63,078	239,018
Scenario 1	-	248,207
Scenario 2	-	252,773

Table 13: The annual CO_2 savings from AER, when compared to the total annual emissions of the building fleet without using AER.

CO2 Savings (% of total emissions)	2020	2032
Baseline	1.0%	6.5%
Scenario 1	-	6.4%
Scenario 2	-	6.4%

Table 14: The annual CO_2 savings from AER, when compared to the annual emissions of the building fleet's flexible load only without using AER. This is a more appropriate comparison since it shows how effective AER is on the load that could be controlled.

CO2 Savings (% of flexible load emissions)	2020	2032
Baseline	10.4%	48.4%
Scenario 1	-	47.9%
Scenario 2	-	47.4%

Conclusions

EV Charging Conclusions. By 2050, the electrical energy consumption for EV charging in the District will increase by up to 62 times the usage from 2019, which is up to 300 MWh per year. This would result in 40 times more carbon emissions caused by the electricity used to charge EVs, from an additional 250 Million lbs of CO2.

For a given load on the grid, the GHG impact can be reduced, by shifting the usage to the times of lower marginal carbon intensity. **For the future EV fleet, we found that carbon emissions reductions of 3-12% can be expected on an annual basis through smart-charging with an emissions-optimal control scheme.**

If PJM's grid in the future has more renewables than the proxy grid for this analysis – CAISO in 2019 – then emissions savings will be even greater (As more variable renewables penetrate the grid, low marginal emissions instances become more frequent, which would drive further carbon savings achieved by emissions-optimal charging).

Building Load Flexibility Conclusions. We estimate that **evolution of the building fleet between today and 2032 will result in a 36-41% decrease in CO_2 emissions**, depending on the scenario. This decrease is expected despite a growing overall load for this sector by 9-16%. Most of this decrease is driven by the estimated 45% reduction in carbon intensity of the PJM grid as more renewables replace fossil resources.

The GHG emissions impact of buildings can be further reduced by employing Automated Emissions Reduction to leverage load flexibility such that more energy is used during low emissions periods. Our simulation which assumes 25% of building loads are flexible by 2032 shows that the carbon impact of buildings can be reduced by about 6.5% of their total emissions, or 48% of their emissions that come from flexible loads.

Note: Additional Information about calculations can be found in Appendix D.

ROADMAP TASK 4: GRID ANALYSIS

Introduction

The objective of Task 4 is to assess the expected infrastructure upgrades that Pepco may need to implement to support the projected increases in load due to building electrification and new EV charging using traditional strategies, i.e., feeder reinforcements, new feeders, and reactive support, as required. Task 5 assesses non-wires alternatives (NWA) to those upgrades.

Methodology and Assumptions

The analytical methodology involved analyzing the technical reinforcements required for three feeders that were selected due to large projected loads as a result of building electrification and EV charging. The analysis consisted of the following:

- Analyze expected load increases and timing resulting from building electrification and EV charging with a 2032 horizon year.
- Quantify substation impacts for summer and winter peaks resulting from adding the electrification load and EV load to the PEPCO forecasted summer and winter peaks, considering the timing of the loads.
- Translate substation loading impact to the feeder level considering the type of load served.
- Select three different representative feeders for analysis
- Assess the performance of these feeders with the forecasted increased loads under normal and emergency conditions, and note performance violations.
- Identify infrastructure necessary to address the performance violations and test their effectiveness.
- Determine the capital cost of the reinforcements identified.

The analysis was founded upon the following inputs and assumptions

- Pepco's summer peak load forecast extrapolated to 2032
- Pepco's winter peak for 2017 to 2020 and timing that was used to determine ratios of substation summer peak to winter peak to create the base winter peak forecast and expected time of the day.
- Building Electrification and Energy Efficiency (Task 1) for two separate scenarios consisting of: a) Scenario 1: 13% of the buildings in DC with electrification and higher energy efficiency and b) Scenario 2: 32% of the buildings in DC with electrification and higher energy efficiency, the load increases were identified by comparing with a Base Case (Business As Usual – BAU). **Under Scenario 2, the impact of energy efficiency was**

<u>such that the resulting summer peak was lower than the Base Case before electrification for some substations.</u>
Electric Vehicle Charging (Task 2): Two scenarios were provided (Gradual and Accelerated) and two charging strategies as discussed below.

2032 Electrification and EV Load Increases and Timing.

Building electrification impact was provided as hourly loads for 2032 by Pepco substation for the Base Case (or Baseline) and the two Scenarios indicated above (13% of buildings in DC with electrification and 32% of the buildings electrification). To assess the impact, the load difference between the Scenarios and the Baseline was assessed across representative windows when Pepco's summer and winter system peaks. **<u>Note that the absolute largest difference between the Scenarios and Baseline typically occurs in early hours of the morning when other loads are much smaller, and the net impact is mitigated.</u>**

In the Baseline case, the summer peak occurred at all substations on July 27 and at hours that varied by substation between 16:00 and 19:00. Thus, the electrification impact (the maximum difference between a Scenario and the Baseline) was identified for this window. For the winter peak, some substations peaked early in the day, from 9:00 to 13:00. (Group 1), while other peaked later in the day, from 14:00. to 21:00. (Group 2). Thus, depending on the substation, the impact (difference between the Scenario and the Baseline) is determined as the maximum difference in either the first or second window.

The EV impact and timing was derived considering the two scenarios provided (Gradual and Accelerated) and the charging strategies; Min Delay where the vehicles are connected and start charging when connected at home and Max Delay where the vehicles are charged so that they are fully charged by the morning (see Figure 40 and Figure 41 below). **<u>As the impact of EV charging was found to be relatively modest when compared with electrification, the analysis was carried out for the Accelerated scenario and min delay in charging to consider a worst case peak impact scenario.</u>**

Figure 40: Min Delay Representative Charging Load Profiles.

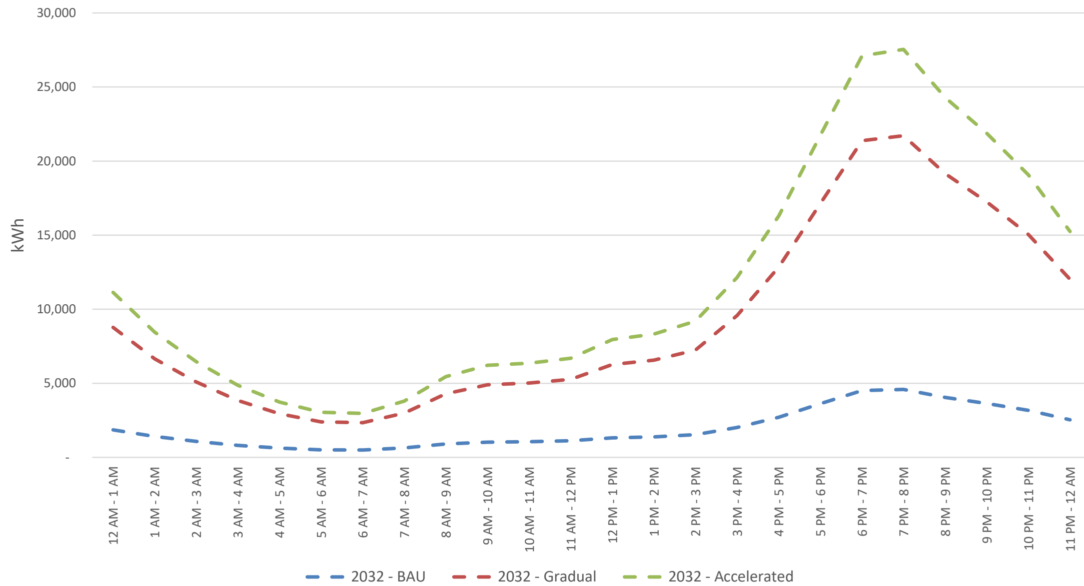
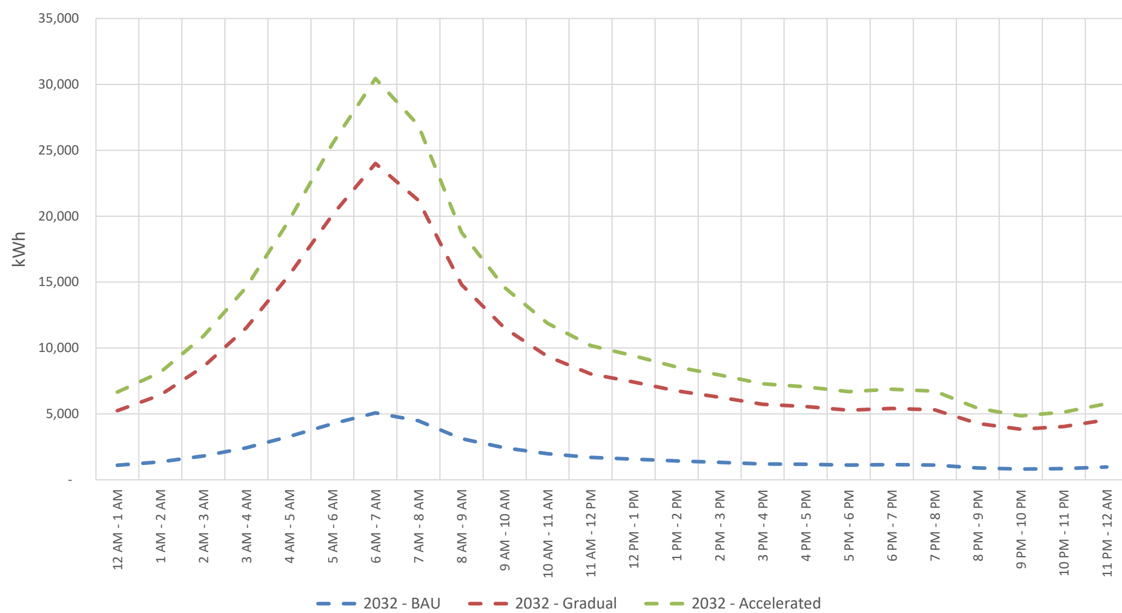


Figure 41: Max Delay Representative Charging Load Profiles.



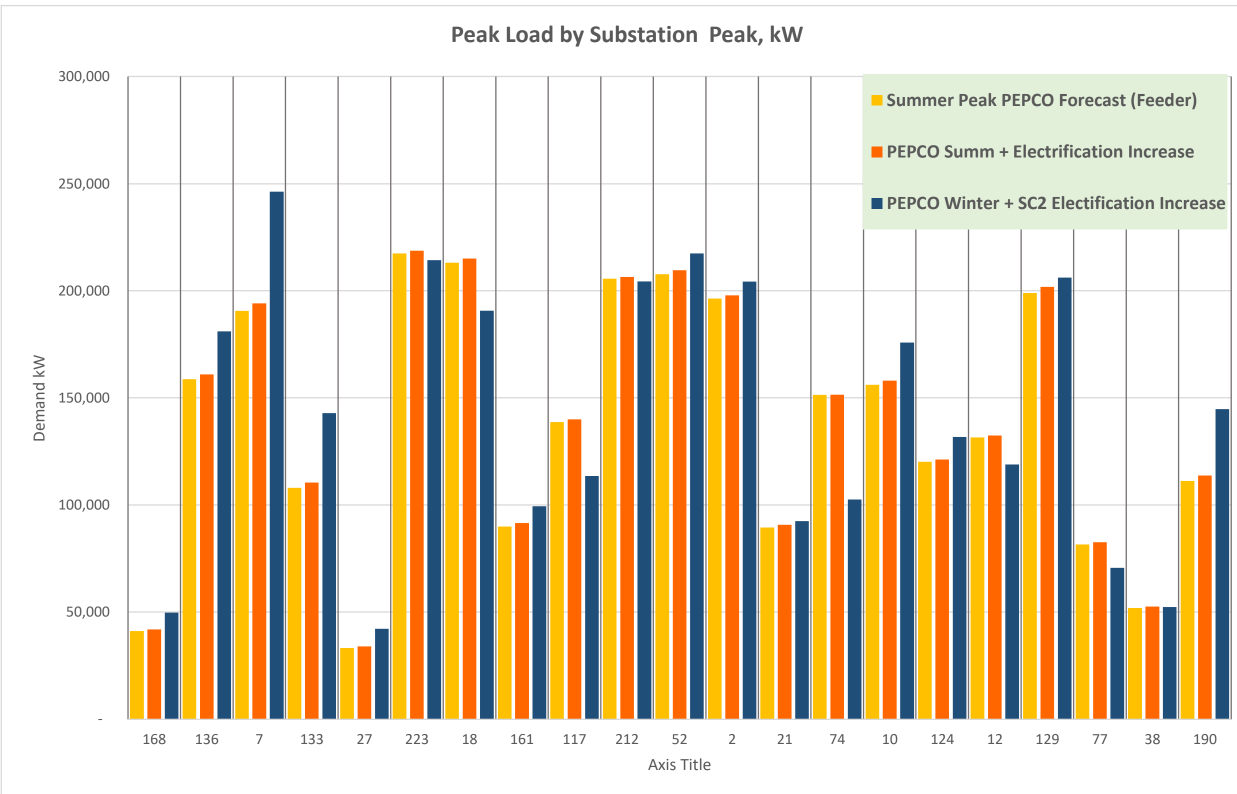
Identification of impact at the substation of adding the electrification load and EV.

The electrification loads were added to each Pepco substation forecast considering the timing and values discussed above. At fourteen of the substations, the impact of the electrification was sufficient to change the substation from summer to winter peaking (14% increase over the

Pepco's forecasted peak). Twelve substations remained summer peaking and the impact was much smaller (about 1% increase).

Figure 42 below depicts the 2032 non-coincident[35] summer peak (Pepco forecast), summer peak with electrification and winter peak with electrification, by substation. As can be observed, some substations are significantly impacted, including Benning (Sub 7), Alabama Ave. (Sub. 136), 12th & Irving (Sub. 133), Takoma (Sub. 27) and Fort Slocum (Sub. 190), all during the winter peak. Figure 42 also indicates that the summer peaks after electrification are very close to those of PEPCO's forecast. **<u>It is apparent that the increased load from electrification is lower during summer peak, and largely offset by energy efficiency efforts.</u>**

Figure 42: Electrification Impact by Substation.



The EV impact was added to the load above as derived from the Accelerated adoption scenario with minimum delay forecast, as indicated earlier.

[35] This is the sum of the individual feeder peak load starting from PEPCO's provided forecast

Once the non-coincident peak by substation was identified, the individual peaks of the associated feeders were determined as discussed below.

Substation loading impact at the feeder level.

Pepco provided their summer feeder peak load forecast through 2029, and the growth from 2020 was applied to extrapolate the load to 2032. By using the historic winter to summer peak ratios, the corresponding winter peak was estimated. Additionally, the analysis distinguished between distribution feeders which supply customer loads that were likely to include electrified building and EV charging loads versus those that were unlikely to include those loads and should be excluded from the analysis. The feeders that are likely to host the electrification and EV loads include the feeders identified by Pepco as "MV Radial" and MV/LV Network/spot-network Feeders. There are two groups of feeders unlikely to host the projected electrification and EV loads. The first group is those that serve sub-transmission functions (e.g., connect to 13/4 kV substations). The second group is those that provide high voltage supply to a particular customer or group (e.g., Metro, DHS, H.T. East Group, etc.), that could include electrification and EV charging, but this would result in a large, differentiated addition resulting in a specific project.

A total of 371 feeders across 19 substations (see Table 15) were identified as likely to include incremental loads due to building electrification and EV charging. The load was allocated to these individual feeders with a two-step process. First the total incremental load per substation was determined and then this load was allocated to the substation's feeders, in proportion to their initial feeder load, i.e., a feeder that supplies a larger initial load would have a larger share of the total incremental load assigned to the substation.

Table 15: Substations with Feeders used for the allocation of Electrification and EV loads

Substation	Feeders
Alabama Ave. Sub. 136	12
Northeast Sub. 212	30
Benning Sub. 7	19
Fort Slocum Sub. 190	17
12th & Irving Sub. 133	21
Takoma Sub. 27	4
Florida Ave. Sub. 10	27
Champlain Sub. 25	12
Harrison Sub. 38	8
Tenth St Sub. 52	32

Substation	Feeders
O St. Sub 2	30
F Street Sub. 74	18
22nd St. Sub. 124	24
Little Falls Sub. 77	12
Van Ness Sub.129	30
Ninth St. Sub. 117	12
I St. Sub. 197	30
New Jersey Ave Sub. 161	9
L St. Sub. 21	24
Total	**371**

Feeder Selection

Feeders were selected for analysis by first considering those feeders that were expected to experience overloads based on the summer feeder loading capability as reported by Pepco once the electrification and EV loads were added. The three feeders that were selected were: Benning Sub. 7 – 15708, 12th & Irving Sub. 133 – 14009, and Takoma Sub. 27 – 15199. For more detailed information about feeder selection, see Appendix E.

In the next sections, we review the simulated performance of these feeders with the forecasted increased loads under normal and emergency conditions, performance violations, and determine the capital expenditure by feeder. The modeling approach and the planning criteria utilized are included with Appendix E.

Feeder Analysis Overview

The study presented in this report begins with the 2020 condition of selected Pepco feeders as representative of the current condition and the distribution network is planned considering forecasted load for 2032 including electrification and EV impact.

The general procedure followed to analyze the selected feeders is as follows:

1. Assessment of selected feeder performance for each planning term (2020 and 2032 with and without the electrification and EV impact) under normal and emergency conditions and identification of violations
2. Reconfiguration (load transfers) and switching strategy considered as the first approach to address violations, and if not possible to fully mitigate the violations, determination of reinforcements.
3. Determination of proposed capacitors additions to manage voltage and power factor.

4. Verification of solutions
5. Summary of investments and determination of capital expenditures.

With a few exceptions, load transferring was not found to be a feasible solution as the adjacent feeders considered were also highly loaded.

Results

Feeder 14009, 12th & Irving Substation: Feeder 14009 can be operated without any overloading or voltage violation under normal conditions in 2032 with the building and vehicle electrification loads. As no overloading or voltage violations were identified under normal or emergency conditions, no investments are necessary for this feeder. Although the initial screen for this feeder indicated overload, we identified that the winter rating used by Pepco was much higher than the summer rating and that this was enough to address the expected overload once we received the detailed models.

Upon the occurrence of the worst fault on Feeder 14009, [redacted] the entire feeder load needs to be transferred to the [redacted] feeders. None of [redacted] feeders alone have enough capacity to receive all loads of Feeder 14009.

The remaining reliability concern is based on the existing system configuration. Siemens proposes a wires solution with total capital expenditures of $421,652.

Feeder 15708, Benning Substation: Feeder 15708 can be operated without any overloading or voltage violation under normal conditions through 2032. However, when electrification loads are included in 2032, the mainline of the Feeder 15708 would be overloaded, even considering winter ratings. Under emergency condition, none of the [redacted] feeders have enough capacity to provide backup to Feeder 15708 as it is already overloaded under normal conditions.

The basic design of the area for the emergency condition is to use a feeder that is unloaded and available for backup. The solution must avoid the overload of that feeder when it takes the load of feeder 15708. The first step is to transfer load from feeder 15708 to another feeder so that neither is overloaded under normal conditions, allowing a different feeder to provide backup without overloading.

The total estimated capital expenditure for the wires solution is $1,791,501.

Feeder 15199, Takoma Substation: Feeder 15199 can be operated without any overloading or voltage violation under normal conditions through 2032. However, when electrification loads are included in 2032, some sections along the mainline of the Feeder 15199 would be overloaded, and some sections could become overloaded during emergency conditions. Under emergency conditions, none of the [redacted] feeders have enough capacity to provide backup to Feeder 15199 as it is already overloaded under normal conditions.

Assessing the geographical layout of Feeder 15199, we see that Feeder [redacted] is the only candidate to provide backup, [redacted]. However, Feeder [redacted] is already loaded. [redacted] a new feeder from the Grant Avenue substation is proposed in 2032 to take the load towards the end of Feeder 15199. Other alternatives for this feeder were considered starting from Fort Slocum or Linden Substations, but this would result in longer routes [redacted]. A few short sections would be overloaded when reconnecting parts of 15199 to the new feeder and they would need to be upgraded.

The total capital expenditure for the proposed wires solutions is estimated to be $4,213,606.

Detailed analyses, diagrams, and results for each feeder are included in Appendix E.

Summary of Findings and Conclusions

Pepco's system is expected to be able to accommodate the impacts of building electrification and EV connection, and the majority of the feeders analyzed were not expected to experience overloads, even when considering the summer ratings. However, 31 of the 371 feeders that were expected to receive increased loads were identified as candidates for potential overload, and a further review found that in a sample of 3 feeders selected within this group, two could have significant overloads that could be addressed with traditional "wires" solutions ranging from approximately $2 million for feeder 15708 out of Benning substation to little over $4 million for feeder 15199 out of Takoma Substation. The feeder analyses and diagrams are included in Appendix E.

ROADMAP TASK 5: GRID IMPACT MITIGATION

1. Introduction

The objective of Task 5 is to evaluate non-wires alternatives (NWA) to meet increased demand resulting from electrification. In Task 4, Siemens led the development of traditional wires-based approaches to maintaining reliability while serving increased winter peak demand on a set of three illustrative feeders (Feeders 14009, 15708, and 15199). This task takes as a starting point the same demand and resulting reliability challenges, but develops approaches that use distributed energy resources (DERs) such as demand response (DR) and battery energy storage systems (batteries or BESS) to provide NWA to the traditional wires approach. We compare the performance and value provided by the wires and non-wires approaches in the specific examples of the three feeders, and then draw insights that apply more generally to grid planning in anticipation of a greater degree of electrification.

This chapter is structured as follows. In subsection 2, we introduce DR and BESS resources and describe how we characterized the resources available on each of the feeders. In subsection 3, we describe our methods and results regarding the value that DERs can provide other than their value providing reliability service on these feeders. For example, a battery can provide winter and summer capacity value in regional markets, as well as arbitrage energy value from charging during low-cost periods and discharging during high-cost periods.

In subsection 4, we walk through each of the three feeders. We describe the reliability challenge for each one and show an illustrative NWA portfolio that meets each challenge. Then we quantify the cost of the NWA approach and compare that cost to the wholesale market value the DERs can provide and the cost of the traditional wires solution. Together, these three examples inform subsection 5, which draws the insights from the three feeder analyses together, alongside some important caveats for our work, to provide broader take-aways for grid planning.

2. Distributed energy resource characterization

Demand response

A variety of DR measures and programs are available to reduce winter peak load across different customer segments. They can be categorized into load-response programs and price-response programs. Our NWA analysis focuses on load response programs for space heating and water heating for residential customers and space heating, water heating and lighting for commercial customers. Load response programs typically include direct load control (DLC) programs, curtailable load programs and interruptible tariffs. Price-response programs, which are not part of our analysis, include time-of-use rates, critical peak pricing, and peak time rebates.

DLC can be used to control various end-uses for residential and small commercial customers in exchange for financial incentives. Many utilities traditionally implemented DLC programs to cycle central air-conditioners (AC) via load control switches, but some utilities also use DLC programs to control other end-uses such as hot water, pool pumps and lighting.[36] A newer type of DLC is a "bring your own thermostat" (BYOT) program where a utility remotely controls customers' smart thermostats via the Internet.[37] An emerging DLC is an EV charging control program where a utility ensures that customers do not use EV chargers during peak hours. However, Our NWA analysis does not include this DR strategy as we expect the amount of available EV in the targeted feeders may be limited.

Demand curtailment programs and interruptible programs are typically used to control loads for commercial and industrial customers. Curtailable load programs target specific end-use loads and are offered to medium to large customers. Participants in this type of program receive advanced notices about peak events from their utility and receive financial payments for their load reductions. Load reduction can be voluntary or mandatory depending on the agreement with the utility. Interruptible programs (also sometimes called interruptible tariffs) typically target large customers and turn off major portions or even all of a facility's load during specified peak periods. Participants in this type of program receive lower energy bills during normal operation and also additional incentives for interruptible events. But they may need to pay severe penalties for non-performance during peak events.[38]

Demand response performance

Our methodology to estimate winter peak impacts from demand response consists of two separate steps. We first estimated winter peak load reductions in terms of percentage of peak loads based on (a) end-use specific load reduction factors (in percentage of end-use peak loads) and (b) cumulative DR participation rates through 2032. We then apply the cumulative peak load reduction factors to hourly end-use loads for each feeder during winter peak days to estimate peak reductions in kW.

We developed key assumptions for potential winter peak demand reductions based on a literature review of DR potential studies. Table 16 provides a summary of winter peak savings factors by end-use and sector. To develop these estimates, we established specific program designs. For residential customers, we assumed DLC programs for space and water heating end-uses for residential customers. For commercial customers, we assumed DLC, load curtailment load, and interruptible load programs for space heating, water heating, and lighting end-uses.

[36] Rocky Mountain Institute. 2006. Demand Response: A Introduction – Overview of programs, technologies, and lessons learned. Available at: http://large.stanford.edu/courses/2014/ph240/lin2/docs/2440_doc_1.pdf

[37] *a good source for BYOT

[38] Rocky Mountain Institute. 2006.

Table 16. Demand Response Winter Peak Savings Factors

End-use	% Savings	Sources and notes
Residential End-Use		
Space heating	20%	The impact ranges from 1 to 2.9 kW based on the following studies: Cadmus (2018) Demand Response Potential in Bonneville Power Administration's Public Utility Service Area; Navigant (2011) 2011 EM&V Report for PSE Residential Demand Response Pilot Program; Brattle (2016) PGE DR Market Research 2016-2035; Center for Energy and Environment (CEE) (2019) Minnesota Energy Efficiency Potential Study: 2020-2029. Appendix E; and Tierra (2020) Duke Energy Winter Peak Targeted DSM Plan study
Domestic hot water	100%	Assumes water heater is turned off during the DR event. Based on various studies including Cadmus (2018) DR Potential in BPA and CEE (2019) MN EE Potential Study: 2020-2029. Appendix E.
Commercial End-Use		
Space heating	25%	Ranges from 20 to 30% based on Cadmus (2018) Demand Response Potential in Bonneville Power Administration's Public Utility Service Area; Brattle (2016) PGE DR Market Research 2016-2035; Siemens (2017) C&I Technical Test Final Report
Domestic hot water	100%	Synapse assumption
Lighting	20%	Cadmus (2018) Demand Response Potential in Bonneville Power Administration's Public Utility Service Area

Source: Cadmus. 2018. Demand Response Potential in Bonneville Power Administration's Public Utility Service Area Final Report; and Navigant (2011) 2011 EM&V Report for PSE Residential Demand Response Pilot Program

For estimating cumulative participation rates, we assumed that Pepco starts implementing DR programs starting in 2023 and continues offering the programs through 2032 to address the grid constraints Siemens identified for 2032. We developed annual average participation rates by end-use type based on a 2021 report authored by the Department of Energy (DOE) titled "A National Roadmap for Grid-Interactive Efficient Buildings" and estimated cumulative participation rates through 2032 as shown in Table 17.

Table 17. Demand Response Cumulative Participation Rates through 2032

End-use	%	Sources and notes
Residential End-Use		
Space heating	30%	assumed a 3 percent annual average participation rate based on U.S. DOE. (2021) A National Roadmap for Grid-Interactive Efficient Buildings.
Domestic hot water	30%	assumed a 3 percent annual average participation rate based on U.S. DOE. (2021)
Commercial End-Use		

Space heating	25%	assumed a 2.5 percent annual average participation rate based on U.S. DOE. (2021)
Domestic hot water	15%	assumed a 1.5 percent annual average participation rate based on U.S. DOE. (2021)
Lighting	15%	assumed a 1.5 percent annual average participation rate based on U.S. DOE. (2021)

Finally, we applied these DR performance factors to hourly loads for winter peak days and estimated total peak load reductions by end-use and sector. The results of this analysis are presented in the following section. In this analysis we used the same hourly loads as used by Siemens' analysis as discussed in Task 4, and disaggregated the load into several key end-uses based on Integral's building energy modeling at the substation level as discussed in Task 1. We then projected winter peak load reduction impacts by end-use assuming cumulative participants in demand response programs from 2023 through 2032.

Demand response costs

Table 18 presents a summary of DR program costs by end-use. We developed DR program costs primarily based on a 2018 study by Cadmus conducted for Bonneville Power Administration and a 2020 study by Tierra conducted for Duke Energy. We developed measure-specific costs and program administration costs separately. We assumed the administration costs are equal to 9 percent of the total program cost based on the 2018 Cadmus study.

Table 18. Levelized Demand Response Program Cost

End-use	$/kW-year ($2020)	Sources and notes
Residential End-Use		
Space heating	$41	Average of Cadmus (2018) BPA DR potential study and Tierra (2020) Duke Energy Winter Peak Targeted DSM Plan study. We derived the levelized costs/kW-year for Tierra (2020), assuming certain annual DR maintenance costs (i.e., 50% of the 1st year implementation cost and 25% of the 1st year admin cost for the following years)
Domestic hot water	$151	Same sources and methodology as used for residential space heating
Commercial End-Use		
Space heating	$140	Same sources and methodology as used for residential space heating
Domestic hot water	$140	Same sources and methodology as used for residential space heating
Lighting	$53	Same sources and methodology as used for residential space heating

Batteries

Our NWA analysis also includes residential and commercial batteries. We developed the total capacity of batteries based on the capacity need for each feeder adjusted for the reduced load we modeled for demand response. We then split the total battery capacity needs into residential and commercial scale batteries, using the share of residential and commercial building loads during winter peak hours for each feeder.

The focus of the NWA analysis is to assess whether NWA resources are cost-effective relative to traditional distribution investment options. However, unlike DR, batteries can be easily dispatched and sell energy and ancillary services to the wholesale market. Batteries can provide additional values for the system and for the battery owners as they can absorb energy when prices are very low during off-peak hours and discharge and sell energy during peak hours. Thus, our analysis also includes the value of this market price arbitrage by batteries in addition to generation capacity and distribution values.

Battery performance

Our battery analysis set the total battery size in terms of energy in MWh and capacity in MW for each feeder that are large enough to fill the feeder capacity gaps we identified. We then modeled the batteries so that they discharge energy during peak hours at the rate of the total battery size each hour. When the batteries are not used for grid support, we assumed that the batteries charge each hour at the rate of the battery power rating until they reach 100 percent state of charge. We also assumed a 15 percent energy loss for the charge and discharge cycle.

Battery cost

Our battery cost estimates are derived from the latest cost estimates developed by the National Renewable Energy Laboratory's (NREL) "2021 Annual Technology Baseline (ATB) Cost and Performance Data for Electricity Generation Technologies" as shown in Table 19. These costs represent levelized costs of projected battery costs by NREL from 2023 to 2032 over which our analysis assumes that batteries are deployed for the selected feeders. NREL provides four different battery cost components: battery energy capital cost ($/kWh), battery power capital cost ($/kW), battery capital cost constant ($), and fixed operation and maintenance costs ($/kW-yr.). This cost breakdown including battery energy capital costs allows for the development of battery capital costs for different battery durations (e.g., 2-hour battery, 4-hour battery).

Table 19. Battery Cost Assumptions for 2033 to 2032 ($2020)

Battery Cost Type	Unit	Value
Battery Energy Capital Cost ($/kWh)		
Commercial Battery Storage	$/kWh	$133
Residential Battery Storage	$/kWh	$181
Battery Power Capital Cost ($/kW)		
Commercial Battery Storage	$/kW	$353
Residential Battery Storage	$/kW	$1,387
Battery Capital Cost Constant ($)		
Commercial Battery Storage	$	$229,865
Residential Battery Storage	$	$4,848
Fixed Operation and Maintenance Expenses ($/kW-yr)		
Commercial Battery Storage	% of total installed cost	2.5%
Residential Battery Storage	% of total installed cost	2.5%

Source: NREL. 2021. 2021 Annual Technology Baseline (ATB) Cost and Performance Data for Electricity Generation Technologies. Available at: https://data.openei.org/submissions/4129.

We estimated the total system costs of a battery using the following equation developed by NREL that contains all the battery cost components.

> Total System Cost ($/kW) = (Battery Pack Cost ($/kWh) × Storage Duration (hr) + Battery Power Capacity (kW) × BOS Cost ($/kW) + Battery Power Constant ($)) / Battery Power Capacity (kW)[39]

Total annual costs per kW-year is a useful metric to compare the cost of one resource to another (e.g., DR). Such costs can be estimated by annualizing the total system costs and combined with annual fixed costs. Assuming an annual carrying cost rate of 10.3 percent, the total annual costs range from about $170 per kW-year for commercial batteries to $420 per kW-year for the highest-capacity residential batteries. The blended portfolios used in the NWA

[39] NREL. "Commercial Battery Storage." Available at: https://atb.nrel.gov/electricity/2021/commercial_battery_storage.

designs discussed later have average costs between $250 and $270 per kW-year. Residential battery costs are about 200 to 250 percent higher than commercial scale batteries.

It is important to note that program costs which include customer incentives do not have to cover the entire battery costs especially when programs are a bring-your-own-device (BYOD) type program. In such a program, a utility provides incentives to customers for securing the right to control customer-owned batteries so that the utility can bid battery energy and capacity in the wholesale markets or support transmission and distribution grids. For our analysis, we have taken a societal perspective for costs and included the full system cost, rather than the utility cost. Where our analysis shows that the NWA solution only makes economic sense if residents value on-site resilience at a level greater than some threshold, this is indicative that a program design that requires residents to contribute to the cost may be appropriate to align costs and benefits.

3. Components of the DER value stack

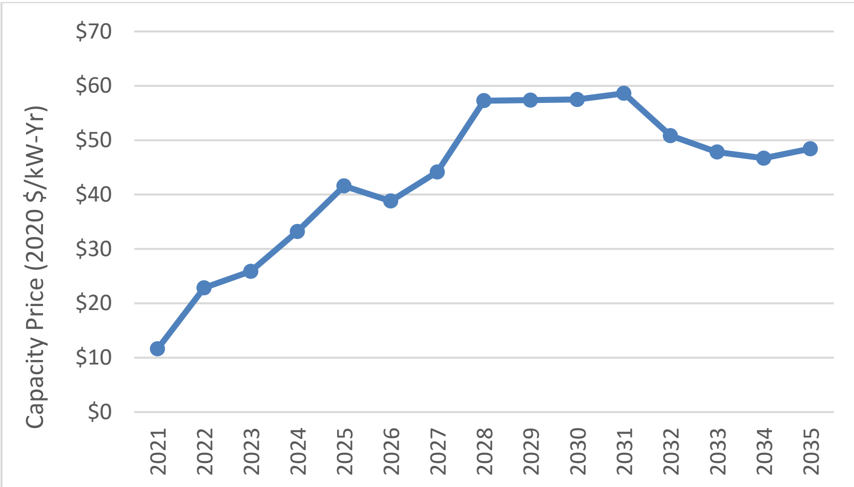
Generation Capacity

Synapse has other ongoing work in which we are modeling the PJM wholesale markets that serve the District using an electric system dispatch modeling EnCompass.[40] This analysis includes values for generation capacity and energy from today through 2035. For the purpose of analyzing the benefits of NWA analysis on behalf of D.C. DOEE, we used the preliminary avoided cost estimates from this study.

Figure 43 presents a forecast of capacity prices (in 2020$/kW-year) in the PJM market through 2035 developed for our other project. Capacity prices are currently about $20 per kW-year and are expected to increase to about $60 per kW-year in 3 years and stay at the $50 to $60 per kW-year range in the following several years. For analysis of the DER-based reliability solutions, we levelized the capacity value from 2030 to 2035, resulting in an average value of $52 per kW-year.

[40] EnCompass is a capacity expansion and generation dispatch model developed by Anchor Power Solutions.

Figure 43. Projected capacity prices in PJM



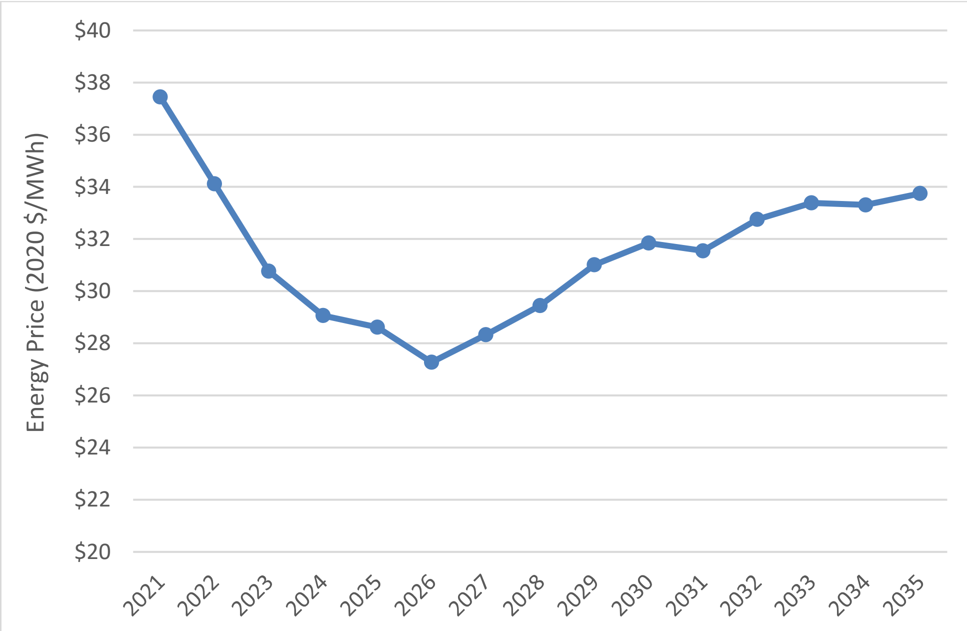
Source: Synapse analysis

Energy

Figure 44 presents a projection of annual average energy prices for the PEPCO zone in the PJM market.[41] The forecasted prices range from $27-$38 per MWh in 2020 dollars. Annual average prices smooth out the variation in energy prices throughout the year. In contrast, hourly energy prices vary substantially. Figure 45 presents average hourly energy prices by month for 2032. The difference between the average lowest prices over 4 hours and the average highest prices over 4 hours range from 28 percent (April) to 183 percent (July). These price differences are much larger than the typical energy loss factor of 15 percent for batteries. Thus, this presents an important opportunity for batteries to pursue energy arbitrage while reducing system costs.

[41] PEPCO Zone refers to the zonal definition as defined by PJM and includes both Pepco DC and Maryland utility territories. Pepco DC solely refers to the Pepco utility's territory in DC.

Figure 44. Projected PEPCO zone average annual energy price



Source: Synapse analysis

Figure 45. Projected 2032 average hourly energy prices by month

	Hour Ending																							
Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
January	35	35	35	35	36	39	46	54	41	39	37	36	33	34	35	37	42	57	63	52	49	46	42	37
February	29	29	30	30	31	33	43	44	35	32	30	30	29	29	29	30	32	39	48	47	40	37	35	31
March	26	26	26	26	27	30	35	34	29	26	25	24	23	22	23	25	26	28	32	33	31	29	28	26
April	25	25	25	25	26	27	28	27	26	25	25	25	25	25	26	27	28	29	31	33	32	30	28	25
May	24	23	23	23	24	24	24	23	23	23	22	23	23	24	24	27	28	30	30	33	33	30	27	24
June	24	23	23	23	23	24	24	25	25	25	26	27	28	29	30	31	34	34	34	35	34	30	27	24
July	25	25	25	25	25	25	25	26	27	29	32	33	45	59	60	65	64	74	71	70	58	43	31	27
August	26	25	25	25	25	25	26	27	27	28	29	30	31	30	33	39	38	42	40	43	38	34	31	26
September	23	23	23	23	23	24	25	25	24	24	25	24	23	24	25	27	28	34	38	38	34	30	28	24
October	25	25	25	25	26	29	31	30	28	27	26	26	25	25	25	26	30	35	43	37	33	31	30	26
November	27	27	27	27	27	29	32	33	30	28	28	27	27	27	28	29	32	42	43	37	34	33	31	28
December	29	29	29	29	29	31	35	40	35	33	32	31	31	31	31	32	36	47	43	40	38	37	35	30

Source: Synapse analysis

To value the energy arbitrage performed by batteries installed as part of a NWA, we assumed the battery would be available to charge for four hours during the lowest-cost hours, then discharge for the highest-cost four hour period. Executing this pattern each day, the pure energy arbitrage would produce revenue of $22,902 per year per MW of capacity. After adjusting for 15 percent round-trip energy loss, a real-world battery with access to wholesale pricing would see revenue of $19,467 per year per MW. Note that this value assumes no net impact from distribution rates. This implies that the distribution utility and its rate designs or programs have accounted for the BESS losses in return for providing services as part of the

NWA, or some other equivalent accommodation. (If there were time of use distribution rates with a sufficient ratio of peak to off-peak rates, an end use customer could see further benefit.)

Batteries that are part of NWAs would need to maintain some level of charge to provide their reliability function. However, this has minimal to no effect on the energy arbitrage value, because the times when the local loads are high, and thus the batteries need to be available to dispatch for reliability, directly overlap with the times when the wholesale market prices are high.

Table 20. Value of 4-hour energy arbitrage using batteries, 2032

Month	Average costs in the lowest 4 hours ($/MWh)	Ave. costs in the highest 4 hours ($/MWh)	% delta	$ per month per MW capacity
1	34.2	56.4	65%	2,751
2	29.3	45.8	56%	1,843
3	23.2	33.3	44%	1,254
4	24.8	31.8	28%	844
5	22.6	31.6	40%	1,123
6	23.2	34.3	48%	1,336
7	24.8	70.0	183%	5,614
8	25.3	41.1	63%	1,970
9	22.9	36.2	58%	1,589
10	25.1	37.0	48%	1,482
11	27.0	39.0	44%	1,434
12	29.1	42.5	46%	1,662
	Annual total ($/MW/year)			$22,902
	After 15% losses ($/MW/year)			$19,467

Source: Synapse analysis

<u>Ancillary services</u>

Batteries and demand response are capable of providing ancillary services such as regulation (quickly ramping net load up and down to maintain grid frequency), voltage support (providing power injection or load reduction when voltage levels are low), or reserves (being available to dispatch in the event that other resources trip offline or fail to perform as expected). We have not included values for these services in our estimation of the value provided by DERs in the early 2030s because they are highly uncertain that far in the future. Specifically, the incremental value of additional DERs in providing these services depends on the overall makeup of the portfolio. If there are many MW of batteries on the grid, for example, the value of incremental regulation service or reserves may be lower than if there are relatively few. We also cannot be sure whether the NWA DERs would be dispatched to provide these services or if other DERs would instead be dispatched. DERs that are being counted on to provide distribution-level reliability services may have to maintain different states of charge or different availability during winter peak periods than other grid resources, and thus may be less available to provide ancillary services. Nonetheless, in actual implementation DERs used in NWAs may find that they can provide some ancillary services and earn additional value.

4. Feeder analysis

<u>14009 (Irving)</u>
As demonstrated by Siemens and documented in Task 4, at the modeled 2032 load, Feeder 14009 (served by the 12th and Irving substation) does not exceed the ratings of its components under normal operating conditions. In addition, in the event of an emergency need to shift all of the feeder's load on to [redacted] feeders, there is available capacity on those feeders.

[redacted] The [redacted] loads at risk in this case are larger in 2032 than they are today, due to electrification load growth.

DERs could be used to mitigate the [redacted] load issue. In this case, an NWA portfolio would be required to serve the [redacted] loads in an islanded condition for up to 5 hours. As Siemens has documented, the expense [redacted] for backup is relatively small. However, DERs that provide sufficient value outside of the emergency context could still be a cost-effective alternative. This other value could come from sources such as avoided wholesale market costs (e.g., for capacity or energy) or resident value from resilience.

Resident value from resilience is difficult to quantify, but it could result from DERs that provide resilience to either larger-scale grid issues (e.g., a cascaded transmission or generation failure) or to multiple local line outages that exceed the conditions for which the distribution grid's reliability is planned. We do not attempt to quantify this resilience value in this report.

To illustrate the wholesale market value of DERs that could island each lateral, we examined a combination of batteries and DR that could meet the worst 5-hour load condition on each lateral. We assumed the same load shape on each lateral but scaled the peak load to the 2032 projected peak load condition.

Area A is a lateral with a load of 1.11 MW in 2020, rising to 1.55 MW in 2032. To cover this load during the worst 5-hour period would require 7.29 MWh. DR can contribute to this need, providing 0.08 MW on peak and a total of 0.46 MWh, at an annual cost of about $17,000. This leaves 1.47 MW and 6.83 MWh to be met by battery resources. Approximately 60 percent of the load on the feeder is from commercial buildings, and 40 percent from residential, so we assume that split for the battery resources, resulting in 0.88 MW of commercial-scale batteries and 0.59 MW of residential-scale.

These batteries have a combined capital cost of about $3.08 million, and annual operating costs of about $77,000. If the batteries were treated as a utility-owned asset with a 20-year life and a 20 percent salvage value, the ongoing annual cost of this approach to reliability in Area A would be $411,000, of which $394,000 is for the batteries and $17,000 is for demand response. In contrast, the "wires" solution to Area A has an estimated capital cost of $269,141, which translates to an annual carrying cost of about $26,000.[42]

The estimated annual value of the Area A battery and DR resources in the wholesale markets is about $109,000, so the wires solution is the more cost-effective option, unless the local building owners and residents value the added resilience of the battery solution at more than $276,000 (that is, $411,000-$26,000-$109,000) per year.

Area B of Feeder 14009 is another lateral with a similar situation to Area A, but a peak load of 0.79 MW. Under our assumptions that load shapes are the same for laterals as for the whole feeder, the results of Area A scale directly to Area B, multiplied by 51 percent (that is, 0.79/1.55). The wires solution has an estimated capital cost of $133,502, which translates to an annual carrying cost of about $12,700, which is also almost exactly half the cost of the wires solution in Area A. Therefore, a similar result holds overall: the wires solution is more cost-effective unless the local building owners and residents value the added resilience of the battery solution at more than about $141,000 per year.

<u>15708 (Benning)</u>

We estimate that the load on Feeder 15708 would rise to exceed the ratings of feeder components at winter peak by 7.9 percent (0.86 MW) during normal operation in 2032. [redacted] If the load on 15708 were reduced by 0.86 MW at winter peak, it would not experience overloads during normal operation, and it would allow Pepco to transfer load to another feeder.

Feeder's 15708 load is split between two distinct regions that are [redacted], respectively, of the point where switching would take place between [redacted]

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[42] We developed an annualized carrying cost ratio of 9.5 percent based on Pepco's cost of capital and standard utility depreciation and recovery of distribution assets. This annual carrying cost calculation assumes the wires would be depreciated over 60 years with a 60 percent net salvage cost.

related feeders. [redacted] At today's loads, this backup can be accomplished by using a combination of Feeders [redacted]. At the higher 2032 loads [redacted] can still be backed up by [redacted], while Siemens showed [redacted] requires some additional support because [redacted] can no longer carry the whole of the [redacted] load in addition to its own load.

A DER-based NWA to this situation must therefore meet two separate criteria: it must be able to lower the load on 15708 by 0.86 MW or more on a recurring basis during normal operations, and it must lower the load on the [redacted] on 15708 by enough that the existing capabilities of [redacted] can carry that [redacted] load during an emergency.

This implies that a DER-based solution that can lower the net load on the [redacted] of 15708 for five hours and meet a peak load of 4.75 MW would be sufficient to address the emergency backup need. This DER solution would also be able to lower the 15708 load by 0.86 MW for an extended period during normal operations, so no additional DERs are require to meet the first criterion. Examining feeder load shapes and selecting the worst five-hour stretch, this solution would need to be able to provide 22.2 MWh and a peak load of 4.75 MW (average duration 4.7 hours). DR can provide about 0.31 MW and 1.5 MWh, leaving a deficit of 4.44 MW and 20.7 MWh to be met with batteries. Assuming a 60/40 split between commercial and residential batteries, such a suite of batteries would cost $9.3 million, with annual operating costs of about $232,000. Overall, the annual carrying and operational cost of the DR and battery approach would be about $1.19 million. The DER solution on Feeder 15708 would provide a levelized annual wholesale benefit of $333,000. Therefore, the annual net cost of the DER solution is about $962,000.

In contrast, Siemens estimated the annual carrying cost of the wires approach would be about $170,000. This leaves a gap of almost $800,000 between the net cost of the DER approach and the net cost of the wires approach. If the additional resilience provided by the DERs is worth at least this much to the residents and building owners in this area, then the DER approach would be cost-effective. Otherwise, the wires approach has lower net cost.

<u>15199 (Takoma)</u>

Under the assumptions developed in this report, by 2032 the load on Feeder 15199, served by the Takoma substation, rises beyond the ratings of its components during normal operation. Specifically, Siemens has identified that sections of the feeder experience loads that are 103.5 percent of their rated capacity during winter peak. Resolving this issue would require about 370 kW of load reduction during peak times. However, the driving need for new infrastructure is the emergency condition. Because the load on [redacted] feeders is also high by 2032, there is not sufficient capacity on these [redacted] feeders to carry all of Feeder 15199's load in the event that Feeder 15199 were to lose power from the substation. Any net load reduction that solves the emergency condition would also suffice to solve the smaller overload during normal operation.

Siemens developed a traditional wires-based solution to this condition that involves constructing a new feeder from the Grant Avenue substation to take some load from 15199. This new feeder can take some of Feeder 15199's load during normal operation, and each of the feeders provides back up to the other in emergency conditions. Several components of Feeder 15199 are also upgraded to carry slightly more power. Overall, Siemens estimates this approach has a capital cost of $4,213,606. This corresponds to an annualized carrying cost of $400,000.

Similar to the case of Feeder 14009, the DER-based solution in this case must handle a 5-hour emergency while carrying a large portion of the feeder's load. [redacted] This would leave a peak load 7.68 MW to be carried by DERs for the duration of the emergency condition. Because load is not always at the peak, the cumulative energy to be supplied by DERs during the emergency event would be 34.1 MWh, for an average duration of 4.4 hours.

DR can contribute to reduce the load during this condition. We estimate that the building stock on this feeder could supply 0.15 MW of peak demand reduction and 0.74 MWh of energy avoided during a five-hour emergency event, at an annual cost of $26,000. This leaves 7.53 MW peak and 33.4 MWh of energy to be supplied by battery resources.

As with Feeder 14009, we assumed that the batteries deployed on the feeder would reflect the range of different kinds of buildings – 70 percent large commercial batteries and 30 percent smaller residential batteries. To supply 7.53 MW peak and 33.4 MWh of energy would require a capital cost of $14.1 million with an annual operations and maintenance cost of $353,000. The annual carrying cost of the battery portion would therefore be $1.45 million and the DER solution as a whole therefore has an annual cost of $1.83 million.

The DER solution on Feeder 15199 would provide a levelized annual wholesale benefit of $546,000. Therefore, the annual net cost of the DER solution is about $1.26 million. When compared to the cost of the wires solution ($400,000/year), we see that the DER-based approach is more expensive, on net, by about $885,000, or just over a factor of three, before accounting for local resilience value.

<u>Summary of results</u>

Table 1 presents the cost and benefit results of the four NWA options developed for these three feeders, alongside the costs of the wires solutions developed in Task 4.

Table 21. Summary design and economic results for non-wires and wires alternatives on three feeders

	14009 A	14009 B	15708	15199
DR capacity (MW)	0.08	0.04	0.31	0.15
DR energy (MWh)	0.46	0.23	1.5	0.74
DR annual cost	$17,000	$9,000	$107,000	$26,000
BESS capacity (MW)	1.47	0.75	4.44	7.53
BESS energy (MWh)	6.90	3.52	20.67	33.38
BESS annual cost	$394,000	$201,000	$1,188,000	$1,805,000
DR & BESS market value	$109,000	$56,000	$322,000	$546,000
Net annual NWA cost	$302,000	$154,000	$962,000	$1,285,000
Annual wires soln. cost	$26,000	$13,000	$170,000	$400,000

5. Conclusions

Our analysis of NWA to the wires investments identified in Task 4, viewed within the context of this project as a whole, illustrates a number of conclusions that can inform grid planning in the District and elsewhere as the building and transportation sectors electrify and decarbonize.

Many feeders do not require investment for at least another decade
When Siemens screened feeders to identify feeders for further analysis, many feeders did not show likely overloads in 2032, a decade from now. In addition, the substation-level load analysis shows that loads remain below the peak capacity of Pepco's substations over the next decade. This means that there is time to plan for the future grid and make strategic investments in DERs. DERs generally require customer participation, which may take time to develop. Building programs and customer engagement over the next decade could be an essential component to using DERs effectively once loads do rise enough to drive investments.

Anticipation of future grid state is important for solution planning
The "wires" solution to Feeder 15708 works in part because in 2032 the overall load on Feeders 15708 and another feeder remains below the combined capacity of the two lines. By transferring a small portion of the load from 15708 to the other feeder and thus making the loads more equal to each other, the wires solution is able to use a third feeder as a backup for these two feeders, while keeping normal operation loads below the limits of all components. Building and transportation electrification is incomplete in 2032 in our modeled scenario. As described in Task 1, all new buildings would incorporate electric systems, and roughly 32 percent of existing buildings would be electrified by 2032. This leaves extensive potential further electrification, and further increases in winter peak loads. Once the loads on Feeder 15708 and the backup feeder rise any further beyond the 2032 levels examined here, Pepco would need to build a new feeder in this area to carry loads during normal operation or provide

backup (or both). Similarly, a DER-based approach to this area that can meet the needs in 2032 could be insufficient in 2033.

This example illustrates that our analysis of the 2032 load is a snapshot of a transforming grid. Winter peak load on a rapidly electrifying feeder may rise by half a MW per year or more. DER-based solutions can be more incremental to deploy than wires solutions, but nonetheless require investment in assets or programs with lifetimes of a decade or more. **Distribution planning will need to identify the load in the likely end state condition, as well as the path to that end, and make both wires and DER investments in an integrated way to meet both today's and future reliability needs.** Mobile batteries that can be re-used in a different application after serving as an NWA could also provide additional value.

DERs could play a substantial role in wholesale markets as the grid shifts toward zero carbon supplies

Recent studies of deep decarbonization, such as Massachusetts's 2050 Roadmap[43] and New York's Draft Scoping Plan,[44] as well as national studies like Net Zero America,[45] have shown that batteries and flexible loads are essential components for managing grids with high proportions of variable renewables. While the model results vary based on resource portfolios and transmission assumptions, the total capacity of battery storage often substantially exceeds 10 percent of total system peaks. (For the District, Pepco's electrification study[46] shows peak load rising to about 3,500 MW by 2050. This indicates a potential value for at least 350 MW if not 700 MW or more of batteries to support delivering reliable supply to the District.) **If this storage were installed as DERs, rather than associated with power plants remote from load, it could provide a substantial resource for distribution planning.** In a situation where batteries can allow a feeder upgrade or construction to be deferred, for example, the value of the batteries to the bulk system does not disappear when the feeder investment is finally made.

Cost estimates of traditional components and DERs have a large impact on relative economics

The cost of the traditional wires components that Siemens used in its analysis is based on Siemens's experience in multiple jurisdictions, but it is not specifically tailored to construction costs in the District and it does not reflect detailed engineering design on Pepco's system. According to Siemens, Pepco may use planning-level costs for underground feeders that are

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[43] Executive Office of Energy and Environmental Affairs and the Cadmus Group. *Massachusetts 2050 Decarbonization Roadmap*. December 2020. https://www.mass.gov/info-details/ma-decarbonization-roadmap.

[44] New York Climate Action Council. *Climate Action Council Draft Scoping Plan*. December 20, 2021. https://climate.ny.gov/Draft-Scoping-Plan.

[45] Larson, E. et al. *Net-Zero America: Potential Pathways, Infrastructure, and Impacts, Final Report Summary*, Princeton University, Princeton, NJ, 29 October 2021. https://netzeroamerica.princeton.edu/the-report

[46] Hledik et al., An Assessment of Electrification Impacts on the Pepco DC System. Prepared for Pepco, August 2021. https://www.pepco.com/Documents/1167%20%20Pepco%27s%20Electrification%20Study%20%20082721.pdf.

more than four times as high as the Siemens estimates. If the wires solutions in Feeders 15708 and 15199 cost four times as much, the NWA solutions would be cost-effective or very close to it. Similar uncertainty could impact the cost of DER approaches. Our experience indicates that, rather than making assumptions about the relative costs of traditional and NWA approaches, it is important to carefully price the components of multiple options using the best available market data.

Local resilience needs could shape investment patterns

Our analysis shows that local resilience needs could make the difference between whether DER-based or traditional wires solutions as the best economic decision. While the traditional wires approaches are designed to deliver a very high degree of reliability, distributed solutions can be more resilient by protecting loads from rare but highly consequential supply-side events. If a neighborhood or other collection of residents, businesses, and government facilities determines that a resilience hub or other similar approach is valuable in their area, integrating that resource with distribution planning could defer or change the needs for other grid investments. Transparency and integrated planning are essential for such an approach to succeed.

CONCLUSIONS

This Roadmap demonstrates that Pepco's system is well-equipped to handle projected electrification loads from buildings and transportation to 2032. By 2032, combined electrification loads are not expected to exceed substation capacity in any zone within the District. Therefore, the District should continue to embrace fuel-switching policies to stay on track to meeting its climate mandates.

By modeling the "worst-case" scenario for peak demand at the feeder level, the grid analysis found that certain feeders could experience constraints resulting from building and transportation electrification loads in 2032, which can be mitigated by either traditional grid investments or NWA. Beyond 2032, electrification loads will continue to increase, highlighting the important role for energy efficiency and DER to play in mitigating these new loads. Efficiency, demand response, and other DER should be integrated into the grid planning process to serve as solutions to grid constraints. DOEE reiterates its call to the Commission to require Pepco to undertake integrated distribution system planning for prudent system utilization beyond 2032.

As is clear from the NWA assessment of this Roadmap, there are DER solutions available to address load constraints. Without an appropriate Benefit Cost Test adopted by the Commission, the capital cost of certain DER projects may be higher than the traditional wires procurement cost. An adopted Benefit Cost Test that accounts for all societal costs and benefits, including GHG emissions, air quality impacts, and resilience, will appropriately value the role of DER in addressing future electrification constraints. The development of such a cost test, along with integrated distribution planning and grid modernization, is critical to meeting the District's statutory Climate Neutrality mandate for 2045.

Appendix A: Policy Documents Supporting Electrification

a. Intergovernmental Panel on Climate Change

To begin with the world's leading authority on climate change mitigation, the Intergovernmental Panel on Climate Change, in its Report on Global Warming of 1.5ºC, stated with "high confidence" that global pathways to limit global warming to 1.5ºC require lower energy use and faster electrification of energy end use.[47] In fact, the Report specifically calls out the need to deeply cut methane as well as electrifying "energy end use", e.g., space and water heating:

> **Limiting warming to 1.5ºC implies reaching net zero CO_2 emissions globally around 2050 and concurrent deep reductions in emissions of non-CO_2 forcers, particularly methane (high confidence).** Such mitigation pathways are characterized by energy-demand reductions, decarbonization of electricity and other fuels, electrification of energy end use, deep reductions in agricultural emissions, and some form of CDR with carbon storage on land or sequestration in geological reservoirs. Low energy demand and low demand for land- and GHG-intensive consumption goods facilitate limiting warming to as close as possible to 1.5ºC. (emphasis added)[48]

b. Deep Decarbonization Pathway Project

The Deep Decarbonization Pathway Project (DDPP), developed as a global initiative for the United Nations and comprising energy research teams from 15 countries with the largest GHG footprints, produced a report for the United States in November 2015. The report was primarily authored by researchers from the Pacific Northwest National Laboratory, the Lawrence Berkeley National Laboratory, and Energy + Environmental Economics. The report, articulating the "three pillars" of deep decarbonization—energy demand reduction, decarbonized electricity, electrification—provides the key finding:

> The principal finding of this study … is that it is technically feasible to achieve an 80% greenhouse gas reduction below 1990 levels by 2050 in the United States, and that multiple alternative pathways exist to achieve these reductions using existing commercial or near-commercial technologies. Reductions are achieved through high levels of energy efficiency, decarbonization of electric generation, electrification of most end uses, and switching the remaining end uses to lower carbon fuels. (emphasis added)[49]

[47] IPCC Report on Global Warming of 1.5ºC (2018), p.15, C.2.2., Summary for Policymakers.
[48] Id. at p.33.
[49] See "Abstract," http://deepdecarbonization.org/wp-content/uploads/2015/09/US_DDPP_Report_Final.pdf

In particular, the DDPP analysis shows that achieving 80% GHG reductions, let alone carbon neutrality, means electrifying practically all of the energy demand in the residential sector, and electrifying nearly all of the energy demand in the commercial sector, as shown in the graphs below:[50]

Figure 13. Residential Energy Demand, All Decarbonization Cases

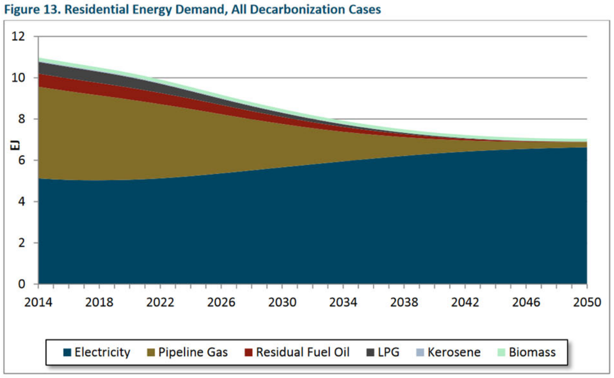
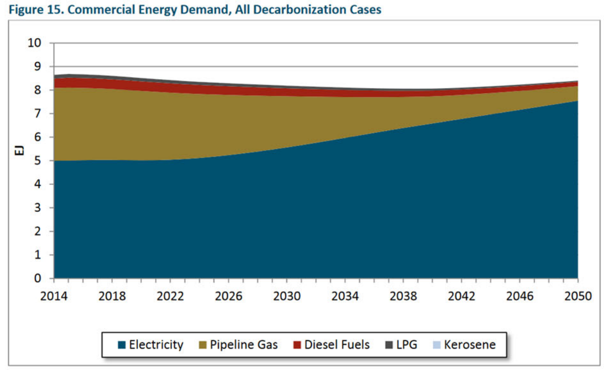


Figure 15. Commercial Energy Demand, All Decarbonization Cases



Regarding the role of renewable natural gas, hydrogen, or synthetic methane (referred to as "power-to-gas" in the Plan), the DDPP report in discussing policy implications states: "Biomass refining (for biogas and biodiesel, not ethanol) and **the production of hydrogen and synthetic natural gas from electricity provide alternative low-carbon fuels for applications in which electrification is difficult**" (emphasis added).[51] In the DDPP analysis, such "applications in which electrification is difficult" refers to heavy-duty transportation and industrial activities. Residential and commercial space heating and water heating represent some of the easiest applications, which is why the graphs above show nearly complete electrification of energy demand in the residential and commercial sectors.

c. United States Mid-Century Strategy for Deep Decarbonization

Lastly, the Obama Administration in 2016 submitted "the United States Mid-Century Strategy for Deep Decarbonization" to the United Nations in accordance with the 2015 Paris Climate Agreement. In the document, it recognizes the following: "Nearly all deep decarbonization scenarios show large increases in the deployment of certain technologies and strategies, including energy efficiency, electrification, wind, solar, and biomass" (emphasis added).[52] Further, the Mid-Century Strategy identifies only two strategies for decarbonizing the building sector— energy efficiency and electrification of space and water heating:[53]

[50] See http://usddpp.org/downloads/2014-technical-report.pdf.
[51] P.20, http://usddpp.org/downloads/2015-report-on-policy-implications.pdf.
[52] P.30, https://obamawhitehouse.archives.gov/sites/default/files/docs/mid_century_strategy_report-final.pdf.
[53] Id., p.60.

THE MCS VISION FOR THE BUILDINGS SECTOR

The MCS analysis points to two primary strategies for transitioning to a low-carbon buildings sector:

1. **Energy efficiency.** The continuation of recent trends toward increased energy efficiency in the building sector can reduce costs for consumers, increase system flexibility, and reduce the required buildout of clean power systems (or other low-carbon fuels), making the energy sector transition less costly and easier to achieve. For example, continued efficiency improvements in lighting, building shells, and building energy systems will yield significant benefits. More compact and efficient building designs will lower the energy demands of new buildings.
2. **Electrification of end-uses.** Further electrifying building end-uses—combined with the near-complete decarbonization of the grid—is an important strategy to reduce building emissions. A key opportunity for electrification in buildings lies in space heating and hot water heating appliances. About half of U.S. floor space is currently heated with systems that directly burn fuels. Increased electrification represents an acceleration in current trends for residential and commercial space heating in certain regions of the country (see Box 4.5).

d. New Jersey's 2050 Energy Master Plan 2020

New Jersey provides an excellent case study for how states are approaching building decarbonization. In 2019, New Jersey Governor Phil Murphy issued an Energy Master Plan that provides a pathway to meeting the state's 2050 100% clean energy targets, and the 80% GHG reduction by 2050 requirement under the Global Warming Response Act. The Energy Master Plan is an integration of 7 underlying technical studies (energy efficiency, energy storage, solar energy, optimal voltage, offshore wind, microgrids, alternative fuel vehicles) and an Integrated Energy Plan that incorporates the findings from these studies via cost-based scenario modeling. The Energy Master Plan uses 7 main strategies, including the three pillars of deep decarbonization as shown in Strategies 3 through 5 below:[54]

3. Maximize energy efficiency and conservation and reduce peak demand	• **Continued prioritization of energy efficiency** measures and programs can significantly reduce energy consumption—including through the adoption of electric vehicles and heat pumps—and lower the costs of powering New Jersey's economy with clean energy.
4. Reduce energy consumption and emissions from the building sector	• **Building electrification reduces final energy demand** and allows buildings to efficiently utilize clean electricity for space heat and water heat. • **Electrification programs for new construction** can lay the groundwork for an in-state workforce to retrofit existing buildings.
5. Decarbonize and modernize New Jersey's energy system	• **New Jersey's electricity load doubles by 2050** due to building and vehicle electrification. • **Carefully planned grid modernization** investments can support electrification while containing costs for ratepayers. • **New Jersey's natural gas use declines to less than one fifth of today's levels by 2050**, likely reducing the need for gas distribution system expansion.

[54] P. 17, https://www.nj.gov/emp/docs/pdf/2020_NJBPU_EMP.pdf

These strategies illustrate that New Jersey's approach to decarbonizing the building sector is through electrification, and they are concurrently planning to modernize the grid and reduce investment in the gas distribution system. Similar to the District's, New Jersey's approach projects an 85% reduction of gas consumption by 2050 from today's levels. A few key findings from the Integrated Energy Plan regarding the least-cost pathway to decarbonizing buildings are as follows:

- **Building electrification reduces total energy use.** While building electrification increases electricity use, it reduces total energy needs because heat pumps are much more efficient than direct combustion of fossil fuels for heat. In 2050, Variation 3 requires 25% more total final energy than the Least Cost scenario.
- **Building electrification is the most cost-effective path to achieving further emissions reductions beyond those required by the GWRA.** If gas use in buildings is retained, further emissions reductions require either substituting natural gas with much more expensive carbon-neutral bio- or synthetic gases, or transitioning buildings to electrification by retrofitting gas appliances with heat pumps before their useful life is over. In comparison, in the Least Cost scenario, buildings are retrofitted during stock rollover events, in which gas appliances are replaced with heat pumps at the point of an appliance's natural retirement, thus limiting stranded assets.

Relevant Integrated Energy Plan Findings

- **Electrification reduces annual costs by 50% in 2050, compared to retaining gas use in buildings, in order to meet emissions targets.** Electrification is cheaper, despite low natural gas costs, because emissions targets require substituting a significant fraction of natural gas with carbon-neutral fuels. In the Least Cost scenario, carbon-neutral fuels are not required until the late 2040s and are primarily used in the electricity sector. In Variation 3, carbon-neutral fuel use starts earlier, and five times as much carbon-neutral fuel is required in 2050.
- **Building heating and cooling appliance costs are lower when buildings are electrified.** Total appliance costs are lower in the Least Cost scenario compared to Variation 3 because modern heat pumps provide both heating and cooling needs, negating the need to purchase separate furnaces and air conditioners.
- **Building electrification contributes to increased New Jersey electricity demand, and shifts the electricity demand peak to winter months.** As buildings electrify, peak demand shifts from the summer (in which air conditioning drives peak demand) to the winter, in which newly electrified heat sources drive increased demand.

In addition to New Jersey, other states such as New York and California are implementing building electrification to decarbonize the sector.[55] With respect to cities, major cities that have pledged deep cuts to GHG emissions by 2050 are actively pursuing building electrification, such as New York and Vancouver. The decarbonization pathway identified in the Clean Energy DC Plan and further elaborated upon in the 2050 Carbon Neutrality Strategy, is firmly supported by these authorities and the technical findings.

[55] "*The Challenge of Retail Gas in California's Low-Carbon Future,*" concluding "building electrification, which reduces or eliminates the use of gas in buildings, is likely to be a lower-cost, lower-risk long-term strategy compared to renewable natural gas." https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/index.html; see also joint NYSERDA and utilities' filing on "New Efficiency: New York Implementation Plan", 3/6/2020.

Appendix B: Task 1 Assumptions

Table A.1: Abbreviated set of envelope assumptions for existing buildings without efficiency upgrades, by typology.

Typology	Program	WWR	Win U (W/m2·K)	Win SHGC	Wall U (W/m2·K)	Roof U (W/m2·K)
1	Commercial	0.4	1.5	0.5	2.5	0.4
2	Mixed Use	0.4	1.5	0.5	2.5	0.4
3	Commercial	0.6	1.5	0.4	2.5	1.2
4	Commercial	0.2	5	0.5	0.6	0.4
5	Multifamily	0.6	5	0.3	2.5	0.4
6	Commercial	0.4	5	0.4	2.5	1.2
7	Multifamily	0.4	3	0.5	0.6	0.4
8	Industrial	0.6	5	0.3	2.5	1.2
9	Multifamily	0.4	5	0.5	2.5	0.2
10	Industrial	0.4	3	0.4	0.6	0.2
11	Multifamily	0.6	5	0.5	0.6	1.2
12	Commercial	0.6	3	0.4	2.5	0.4
13	Industrial	0.2	3	0.4	0.6	0.4
14	Multifamily	0.2	5	0.5	2.5	1.2
15	Commercial	0.6	5	0.5	2.5	1.2
16	Commercial	0.6	5	0.5	2.5	0.4
17	Healthcare	0.6	3	0.3	2.5	0.2
18	Mixed Use	0.6	5	0.5	2.5	1.2
19	Multifamily	0.4	3	0.5	0.6	0.4
20	Multifamily	0.4	1.5	0.4	0.6	0.2
21	Education	0.6	5	0.5	2.5	1.2
22	Healthcare	0.2	5	0.5	2.5	0.4
23	Mixed Use	0.4	5	0.4	2.5	0.4
24	Single-Family	0.2	3	0.4	0.6	0.4
25	Single Family	0.6	1.5	0.5	0.6	1.2
26	Single Family	0.2	5	0.5	0.6	0.4
27	Single Family	0.2	1.5	0.4	0.6	0.2
28	Single Family	0.4	3	0.4	0.6	0.4
29	Single Family	0.2	1.5	0.4	0.6	0.2
30	Single Family	0.2	3	0.5	0.3	0.4

Table A.2: Abbreviated set of system assumptions for existing buildings. When existing buildings are upgraded to electric systems without other improvements to efficiency, the average seasonal heating COP becomes 3.0 while all other assumptions remain the same.

Typology	Program	EPD (W/m2)	LPD (W/m2)	HR Effectiveness	Cooling COP	Heating COP
1	Commercial	5	25	0	4	3
2	Mixed Use	25	15	0	4	0.7
3	Commercial	25	25	0	2	0.7
4	Commercial	25	25	0	6	0.7
5	Multifamily	5	15	0.3	2	0.7
6	Commercial	5	25	0.6	2	0.7
7	Multifamily	5	10	0	6	0.7
8	Industrial	25	25	0	2	0.7
9	Multifamily	5	10	0	4	0.7
10	Industrial	5	15	0.6	6	0.7
11	Multifamily	5	15	0	4	1
12	Commercial	25	25	0.3	4	0.7
13	Industrial	5	10	0.6	6	0.7
14	Multifamily	5	10	0.3	4	0.7
15	Commercial	5	15	0.3	2	0.7
16	Commercial	25	10	0	2	0.7
17	Healthcare	25	10	0.6	4	0.7
18	Mixed Use	25	10	0.3	6	0.7
19	Multifamily	5	25	0.6	6	0.7
20	Multifamily	5	10	0.3	6	0.7
21	Education	5	25	0	4	0.7
22	Healthcare	25	25	0.3	4	0.7
23	Mixed Use	25	10	0.3	2	0.7
24	Single-Family	5	10	0.6	6	0.7
25	Single Family	5	10	0.6	4	0.7
26	Single Family	5	10	0.3	4	0.7
27	Single Family	5	10	0.3	6	0.7
28	Single Family	5	10	0.6	6	0.7
29	Single Family	5	10	0.6	6	0.7
30	Single Family	5	10	0.6	6	0.7

Table A.3: Abbreviated set of envelope assumptions for existing buildings with efficiency improvements alongside electrification.

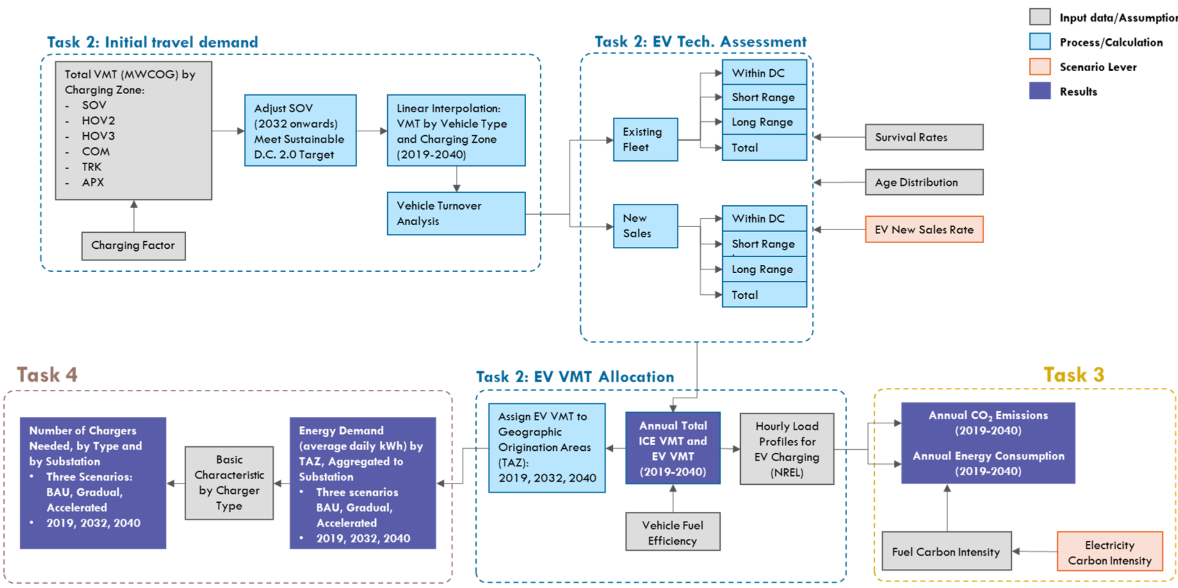
Typology	Program	WWR	Win U (W/m2·K)	Win SHGC	Wall U (W/m2·K)	Roof U (W/m2·K)
1	Commercial	0.4	1.5	0.3	0.3	0.2
2	Mixed Use	0.4	1.5	0.3	0.6	0.4
3	Commercial	0.6	1.5	0.3	0.6	0.4
4	Commercial	0.2	1.5	0.3	0.6	0.4
5	Multifamily	0.6	1.5	0.3	0.6	0.4
6	Commercial	0.4	1.5	0.3	0.3	0.2
7	Multifamily	0.4	1.5	0.3	0.3	0.2
8	Industrial	0.6	1.5	0.3	0.6	0.4
9	Multifamily	0.4	1.5	0.3	0.6	0.4
10	Industrial	0.4	1.5	0.3	0.6	0.4
11	Multifamily	0.6	1.5	0.3	0.3	0.2
12	Commercial	0.6	1.5	0.3	0.3	0.2
13	Industrial	0.2	1.5	0.3	0.3	0.2
14	Multifamily	0.2	1.5	0.3	0.3	0.2
15	Commercial	0.6	1.5	0.3	0.3	0.2
16	Commercial	0.6	1.5	0.3	0.3	0.2
17	Healthcare	0.6	1.5	0.3	0.3	0.2
18	Mixed Use	0.6	1.5	0.3	0.3	0.2
19	Multifamily	0.4	1.5	0.3	0.6	0.4
20	Multifamily	0.4	1.5	0.3	0.6	0.4
21	Education	0.6	1.5	0.3	0.6	0.4
22	Healthcare	0.2	1.5	0.3	0.6	0.4
23	Mixed Use	0.4	1.5	0.3	0.3	0.2
24	Single-Family	0.2	1.5	0.3	0.3	0.2
25	Single Family	0.6	1.5	0.3	0.6	0.4
26	Single Family	0.2	1.5	0.3	0.6	0.4
27	Single Family	0.2	1.5	0.3	0.6	0.4
28	Single Family	0.4	1.5	0.4	0.6	0.4
29	Single Family	0.2	1.5	0.4	0.6	0.2
30	Single Family	0.2	1.5	0.5	0.3	0.4

Table A.4: Abbreviated set of system assumptions for existing buildings with efficiency improvements alongside electrification.

Typology	Program	EPD (W/m2)	LPD (W/m2)	HR Effectiveness	Cooling COP	Heating COP
1	Commercial	5	20	0.3	4	3
2	Mixed Use	20	10	0.3	4	3
3	Commercial	25	20	0.3	4	3
4	Commercial	20	20	0.3	6	3
5	Multifamily	5	10	0.3	4	3
6	Commercial	5	15	0.6	4	3
7	Multifamily	5	10	0.3	6	3
8	Industrial	25	15	0.3	4	3
9	Multifamily	5	10	0.3	4	3
10	Industrial	5	15	0.6	6	3
11	Multifamily	5	10	0.3	4	3
12	Commercial	20	15	0.3	4	3
13	Industrial	5	10	0.6	6	3
14	Multifamily	5	10	0.3	4	3
15	Commercial	5	20	0.3	4	3
16	Commercial	20	10	0.3	4	3
17	Healthcare	25	10	0.6	4	3
18	Mixed Use	20	10	0.3	6	3
19	Multifamily	5	15	0.6	6	3
20	Multifamily	5	10	0.3	6	3
21	Education	5	15	0.3	4	3
22	Healthcare	25	15	0.3	4	3
23	Mixed Use	20	10	0.3	4	3
24	Single-Family	5	10	0.6	6	3
25	Single Family	5	10	0.6	4	3
26	Single Family	5	10	0.3	4	3
27	Single Family	5	10	0.3	6	3
28	Single Family	5	10	0.6	6	3
29	Single Family	5	10	0.6	6	3
30	Single Family	5	10	0.6	6	3

Appendix C: Task 2 Detailed Transportation Methodology and Assumptions

This appendix details the methodology used in Task 2 to estimate the energy demand in the transportation sector. The figure below is copied for reference purposes from the methodology overview briefly discussed under Task 2. The next sections describe each of the three core steps in the methodology and two additional steps generating the outputs for Task 3 and Task 4.



Initial travel demand

The first step uses regional travel demand data provided by the Metropolitan Washington Council of Governments (MWCOG). MWCOG generated these data through its TPB travel forecasting model.[56] The dataset used in this assessment contains the number of vehicle trips between all the 3,722 Traffic Analysis Zones (TAZs) within the Washington Metro Area in 2019, 2030, and 2040. MWCOG's transportation model defines six vehicle types:

- Single-Occupancy Vehicles (SOV). Light-duty vehicles with only the driver.
- High-Occupancy Vehicles 2 (HOV2). Light-duty vehicles with the driver and one passenger.
- High-Occupancy Vehicles +3 (HOV3). Light-duty vehicles with the driver and two or more passengers.
- Commercial Vehicles (COM). Vans and light-duty trucks used for cargo transportation.
- Trucks (TRK). Heavy-duty trucks used for cargo transportation

[56] This model provides regional travel demand forecasts and air quality assessments to support both long-range transportation planning and the development of the six-year Transportation Improvement Program (TIP).

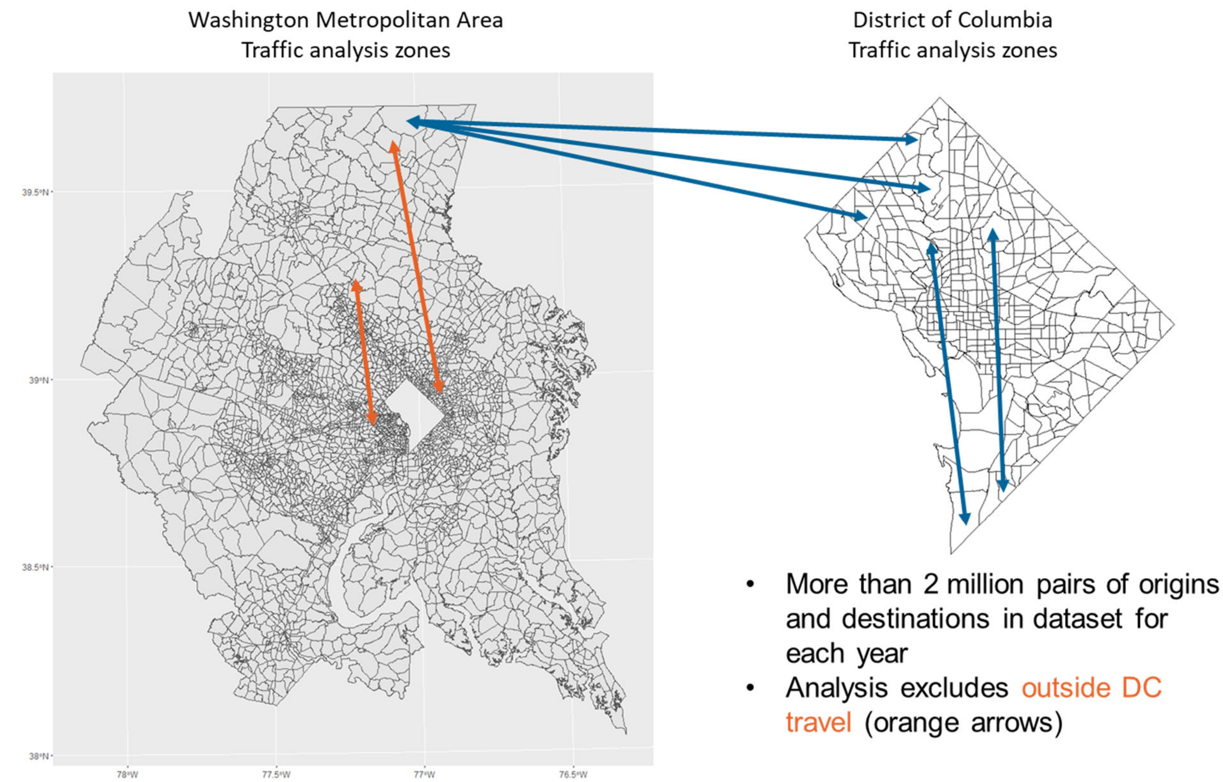
- Airport Vehicles (APX). Light-duty vehicles traveling to and from Washington Metropolitan Area major airports.

This dataset is passed through a set of processes to obtain Vehicle Miles Traveled (VMT) by vehicle type expected to require energy within the District of Columbia Boundaries. These processes are:

- Filter trips that start and end within D.C. boundary (internal trips) and those with at least one end within the District (external trips). In other words, the analysis removes trips involving traveling between non-D.C. TAZs. (Figure E1)
- Adjust the number of trips by SOV, HOV2, HOV3 and APX vehicles to obtain an aggregated commute share by auto of 25% in 2032.
- Geo-process distance for every pair of TAZ and then multiply it by the corresponding trips to obtain VMT by vehicle type.
- Estimate the VMT that will charge within D.C. limits only. This is due to the objective of determining the energy requirements for the District exclusively. Although studies on EV users' behavior are still a relatively new field, and there is a fair amount of research needed to draw significant conclusions; early evidence suggests that the longer the distance traveled by EVs the higher the willingness of drivers to replenish the battery. The methodology segments VMT into three categories:
    - Within DC. Consists of VMT generated by trips starting and ending within the District boundaries; therefore, the energy demand is assigned to the District grid.
    - Short Range. Consists of VMT generated by trips ending in the District with a roundtrip distance below 14.5 miles. Such trips will not require recharging within D.C.; instead, they will re-charge at their home location.
    - Long Range. Consists of the VMT generated by trips ending in the District with a roundtrip distance of 14.5 miles or more. These will need to re-charge at some capacity within the District.

Interpolating 2019, 2032, and 2040 years generates the base VMT travel needs by vehicle type and charging zones. The next core step is to define the electrification rates for each scenario.

Figure A.1 Trips by traffic analysis zone (TAZ) included in the energy demand estimation



EV technology assessment

The second core step is to split the total VMT generated by internal combustion vehicles and battery-electric vehicles. The methodology starts by categorizing the current vehicle fleet by vehicle age. (DOE) Then, using vehicle survival rates, (EPA) the model estimates the VMT generated by the existing fleet and the VMT that new vehicles will cover over 2019-2040. Lastly, this process splits the new VMT further into internal combustion VMT and battery-electric VMT. The adoption of different electrification rates in this step creates the three different EV scenarios: business as usual, gradual, and accelerated. The electrification rates are one of the most critical levers affecting the transportation sector's future electricity demand. This analysis adopts contrasting EV electric rates to capture the ample range in energy demand outcomes. Figure A.2 shows the rates and sources applied to each vehicle type.

Figure A.2 New Electric Vehicle Sales Rates

	Passenger Car (SOV, HOV2, HOV3, APX)			Passenger Truck (COM)			Bus			Single Unit Truck (TRK)		
Year	BAU	Gradual	Accelerated	BAU	Gradual	Accelerated	BAU	Gradual	Accelerated	BAU	Gradual	Accelerated
2019	3.4%	5.5%	6.2%	0.5%	2.7%	3.4%	0.0%	3.2%	4.1%	0.6%	0.7%	0.9%
2021	4.4%	10.7%	13.0%	1.1%	7.8%	10.0%	0.2%	9.6%	12.4%	0.7%	2.1%	2.7%
2030	9.0%	34.0%	43.2%	2.1%	30.6%	39.6%	9.1%	38.2%	49.4%	0.9%	8.5%	10.9%
2040	14.0%	60.0%	73.3%	3.0%	56.0%	70.7%	32.7%	70.0%	85.9%	1.2%	15.5%	19.0%

SOURCES

SOV, HV2, HV3, APX	
BAU	% of EV Share estimated from projected sales (Cars and Light Trucks) from the 2020 Annual Energy Outlook. Source: Reference table 38 in transportation section available at: https://www.eia.gov/outlooks/aeo/tables_ref.php
Gradual	% of EV share obtained from BNEF Electric Vehicle Outlook 2018. Linear trend for 2018-2040 to reach 56% and then assumes 100% is reached by 2050. Source: Bloomberg New Energy Finance (BNEF) – Electric Vehicle Outlook 2018 available at: https://about.bnef.com/electric-vehicle-outlook/#_toc-download
Accelerated	% of EV shares are based on the same forecast of BNEF of 56% but reached 5 years earlier (by 2035)
COM	
BAU	Same methodology and source as in SOV, HV2, HV3, APX, but using Light Turck sales category in the EIA tables.
Gradual	Same methodology and source as in SOV, HV2, HV3, APX, but using BNEF forecast of 56% EV Light Commercial Vehicles sales of by 2040
Accelerated	Same methodology and source as in SOV, HV2, HV3, APX (with 56% share by 2035)
TRK	
BAU	% of EV share are taken from the Energy Innovation Simulator v. 1.4.3. Source: Source: Values are obtained from policy selector -> BAU scenario -> Transport: New Vehicles Sales by Technology -> Med and Heavy Freight Trucks. Available at https://us.energypolicy.solutions/scenarios/home
Gradual	Same methodology and source as in SOV, HV2, HV3, APX, but using BNEF forecast of 20% EV Heavy Commercial Vehicles sales of by 2040
Accelerated	Same methodology and source as in SOV, HV2, HV3, APX (with 20% share by 2035)

EV VMT Allocation

The third core step has two components that will feed outputs for Task 2 and Task 4. The first component assigns back the EV VMT to each original traffic analysis zone (TAZ) for 2019, 2032, and 2040. This applies each TAZ's VMT share (calculated in the initial travel demand step) to the estimated EV VMT. For example, if TAZ 1 accounted for 1% of the total VMT traveled within the District (or with a D.C. destination), then 1% of the total EV VMT is assigned to TAZ 1. In other words, the model assumes that the distribution of travel forecasted by MWCOG's will remain the same regardless of whether the trips are on fossil-fuel powered vehicles or battery-electric. It also does not assume any explicit redistribution of travel based on population or employment future growth in the District, however, the MWCOGs forecast is consistent with the Visualize 2045 long-range transportation plan, which has some land use and demographic projects already embedded.

The second component transforms the 2019-2040 EV VMT into daily hourly energy demand for 2019, 2032, and 2040 under BAU, Gradual, and Accelerated scenarios. The disaggregation uses hourly load profiles developed and provided by the National Renewable Energy Laboratory (NREL). The hourly load profiles contain data for home charging (low power), public charging (level 2), and DC fast charging. Additionally, each charger type consists of two load profile curves: min delay and max delay. Min delay curves assume that BEVs arrive at their home location, and they are plugged-in immediately. Max delay assumes that BEVs are plugged-in but wait to begin charging until the last possible minute while still achieving a full charge before the next day's first trip. Min and max delay are theoretical maximums; the actual loads will be somewhere in-between, and aspects such as electricity rates and smart charging programs can influence the outcome. This analysis produces hourly energy demand using min, max, and average delay profiles.

Charging Location Assumptions

As with gas- and diesel-powered vehicles, it is not expected that all electric vehicles (EVs) driving in the District will necessarily re-charge within the District. This document details charging location assumptions for passenger vehicles and transit buses.

The first two sections identify analysis assumptions. The third section provides further detail supporting these assumptions.

Passenger Vehicle Charging Assumptions

For passenger vehicle charging behavior, the following charging zones and charging factors were designated based on patterns demonstrated by existing EV drivers:

Figure A.3 Charging Zones and Associated Charging Factors Defined

Charging Zone	Charging Zone ID	Charging Factor	Round-Trip Distance Break Values	Definition	How Charging Factor is Applied
Within DC	W	100%	All distances	All trip pairs that start and end within the District	100% of EV trips within DC are assumed to be charging within the District.
Short Range	S	0%	< 14.5 miles	All trip pairs that start or end in the District, and have their opposite terminus outside DC, within 14.5 miles of the District boundary.	0% of short range EV trips with a terminus outside DC are assumed to be charging within the District.
Long Range	L	30%	≥ 14.5 miles	All trip pairs that start or end in the District, and have their opposite terminus outside DC, 14.5 miles or farther from the District boundary.	30% of long range EV trips with a terminus outside DC are assumed to be charging within the District.

Peak EV charging time is assumed to be overnight.

Transit Vehicle Charging Assumptions

The following assumptions applies for transit vehicle charging behavior:

- Most electric transit buses will charge during off hours, at least in the short term.
  - Pending future electric bus models and their driving ranges per charge, this may change.
- Current electric transit bus charging takes place at the following locations:
  - Andrews Federal Center Bus Garage, Suitland, Maryland
  - DC Streetcar Testing and Commissioning Site, Washington, DC

Passenger Vehicles

The passenger vehicle charging zones and factors are based on the following research highlights regarding existing EV charging behavior:

- Most EV drivers do the majority of their vehicle charging at home.[57, 58, 59, 60]
    - Often this charging is on a 120-volt wall plug; this charging configuration is relatively inexpensive and requires no special equipment.[61, 62]
    - In a US Department of Energy (US DOE) study, study participants with access to EV charging both at home and work, did 98% of their vehicle charging at these two locations while their vehicles were not in use. [63]
- Charging away from home becomes more frequent for round-trip driving distances longer than 29 miles. This is based on the pair of US DOE tables in Figure A.4.[64]
- The US DOE's Idaho National Laboratory recommends focusing charging infrastructure at home, workplaces, and in public "hot spots." Public hot spots, are recommended for Level 2 or DC fast charging stations, where charging speed is in higher demand. [65]
- Peak EV charging time is overnight.
    - Peak travel times are commonly associated with morning and evening peak commute times. However, EV drivers primarily charge their vehicles at home, at night,[66] or at their workplace while they work.[67]

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[57] US Department of Energy, "Charging at Home," page 126. https://www.energy.gov/eere/electricvehicles/charging-home
[58] Fleming, Charles, "How will I charge my electric vehicle? And where? And how much will it cost?" Los Angeles Times, September 26, 2016. https://www.latimes.com/business/autos/la-fi-hy-agenda-ev-charging-20160920-snap-story.html
[59] Idaho National Laboratory, "Plugged In: How Americans Charge Their Electric Vehicles," US Department of Energy, 2015. https://avt.inl.gov/sites/default/files/pdf/arra/PluggedInSummaryReport.pdf
[60] Nicholas, Michael, Dale Hall, and Nic Lutsey, "Quantifying the Electric Vehicle Charging Infrastructure Gap Across U.S. Markets," The International Council on Clean Transportation, January 2019. https://theicct.org/sites/default/files/publications/US_charging_Gap_20190124.pdf
[61] Fleming, Charles, "How will I charge my electric vehicle? And where? And how much will it cost?" Los Angeles Times, September 26, 2016. https://www.latimes.com/business/autos/la-fi-hy-agenda-ev-charging-20160920-snap-story.html
[62] Nicholas, Michael, Dale Hall, and Nic Lutsey, "Quantifying the Electric Vehicle Charging Infrastructure Gap Across U.S. Markets," The International Council on Clean Transportation, January 2019. https://theicct.org/sites/default/files/publications/US_charging_Gap_20190124.pdf
[63] Idaho National Laboratory, "Plugged In: How Americans Charge Their Electric Vehicles," US Department of Energy, 2015. https://avt.inl.gov/sites/default/files/pdf/arra/PluggedInSummaryReport.pdf
[64] Ibid.
[65] Ibid.
[66] Fleming, Charles, "How will I charge my electric vehicle? And where? And how much will it cost?" Los Angeles Times, September 26, 2016. https://www.latimes.com/business/autos/la-fi-hy-agenda-ev-charging-20160920-snap-story.html
[67] Idaho National Laboratory, "Plugged In: How Americans Charge Their Electric Vehicles," US Department of Energy, 2015. https://avt.inl.gov/sites/default/files/pdf/arra/PluggedInSummaryReport.pdf

- According to the Metropolitan Washington Council of Governments (MWCOG) State of the Commute Survey Report, peak commute times are 7:00am- 9:59am in the DC metro region.[68]
- EV drivers participating in an Idaho National Laboratory study demonstrated a peak charge time of 12:00am to 3:00am.[69]
- Workplaces are often drivers' second-most frequent vehicle parking location, after their home.[70]

▪ Charging infrastructure levels are defined in Figure A.4.

Figure A.4 Tendency to Charge Electric Vehicle Away From Home

Table 2

Tendency to charge away from home:	**Never**	**Sometimes[2]**	**Frequently[3]**	**Most of the time[4]**
Leaf average daily driving distance (mi)	25	31	43	32
Volt average daily driving distance in EV mode (mi)	25	29	40	26

[2]>0 to 30% of all charging events [3]>30 to 60% of all charging events [4]>60% of all charging events

However, most drivers did not charge away from home frequently (see Table 3), so the overall contribution to EV miles traveled was small.

Table 3

Tendency to charge away from home:	**Never**	**Sometimes[2]**	**Frequently[3]**	**Most of the time[4]**
Percent of Leafs	13%	69%	14%	4%
Percent of Volts	5%	81%	13%	1%

[2]>0 to 30% of all charging events [3]>30 to 60% of all charging events [4]>60% of all charging events

Source: Idaho National Laboratory, 2015

[68] National Capital Region Transportation Planning Board, "2019 State of the Commute Survey: Technical Survey Report," Metropolitan Washington Council of Governments, September 17, 2019. https://www.mwcog.org/file.aspx?D=Ef86kBZskK%2fbZ3wYMdT2ssVON%2fYeH2q81sDcWcfLFoY%3d&A=q34yU5mmXjWLzLaLcIeFJ4INHQIuCUSRCCgLTjEGcXg%3d
[69] Idaho National Laboratory, "Plugged In: How Americans Charge Their Electric Vehicles," US Department of Energy, 2015. https://avt.inl.gov/sites/default/files/pdf/arra/PluggedInSummaryReport.pdf
[70] Nicholas, Michael, Dale Hall, and Nic Lutsey, "Quantifying the Electric Vehicle Charging Infrastructure Gap Across U.S. Markets," International Council on Clean Transportation, January 2019. https://theicct.org/sites/default/files/publications/US_charging_Gap_20190124.pdf

Figure A.5 EV Charging Infrastructure

Charging Level	Voltage	Protection Type	Typical Power	Electric Vehicle Miles of Range per Hour	Setting
Level 1	120 V AC	None or breaker in cable	1.2–1.4 kW AC	3–4 miles	Primarily home and some workplace
Level 2	208 V – 240 V AC	Pilot function and breaker in hardwired charging station	3.3–6.6 kW AC	10–20 miles	Home, workplace, and public with hardwired station
DC Fast	400 V – 1,000 V DC	Monitoring and communication between vehicle and EVSE	50 kW or more	150 –1,000 miles	Public, frequently intercity

Source: The International Council on Clean Transportation, 2019

Bus Transit Vehicles

We gathered the following data on charging infrastructure from Washington Metropolitan Area Transit Authority (WMATA) and District Department of Transportation (DDOT) staff.

- 15 electric buses are active in the two agencies' fleets:
  - WMATA: 1 New Flyer XE40 (2016 model year)
  - DDOT: 14 Proterra Catalyst E2 (2018 model year)
- Both agencies currently charge their electric buses during off hours at the following bus depots:
  - WMATA: Andrews Federal Center Bus Garage, Suitland, Maryland[71]
  - DDOT: DC Streetcar Testing and Commissioning Site, Washington, DC (Figure A.6)
- **Error! Reference source not found.**Figure A.6 lists prospective EV charging locations identified by WMATA and DDOT.
- WMATA is currently in the second phase of developing its Electric Bus Deployment Strategy. This phase is focused on testing EV bus models from different manufacturers.

Figure A.6 Prospective Electric Bus Charging Facilities

Location	Agency	En Route / Depot Charging	Anticipated Date to Start Operations	Capacity Notes
Northern Bus Garage	WMATA	Depot	2024	▪ 7 megawatts ▪ 750 buses

[71] Wenck, Andi, "Metro opens new bus garage at Andrew's Federal Center Sunday," WUSA9, June 21, 2019. https://www.wusa9.com/article/news/local/maryland/metro-opens-new-bus-garage-at-andrews-federal-center-sunday/65-7c293ce2-3bcb-4caf-b00b-f7679cb1eb2e

Location	Agency	En Route / Depot Charging	Anticipated Date to Start Operations	Capacity Notes
Bladensburg Bus Garage	WMATA	Depot	In planning	Would be more than Northern Bus Garage
Western Bus Garage	WMATA	Depot	Currently in visioning stage; not in planning yet	
Sheppard Parkway Bus Garage	WMATA	Depot	Currently in visioning stage; not in planning yet	
Congress Heights Metro Station	DDOT	En Route	Identified opportunity	
Union Station Garage Bus Terminal	DDOT	En Route	Identified opportunity	

Source: WMATA and DDOT staff

Figure A.7 DC Streetcar Testing and Commissioning Site

Source: Google Streetview, 2719 S Capitol St SE, Washington, DC, November 2018; accessed January 6, 2020.

Appendix D: Task 3 Marginal Emissions Rates Models and Methodology

Marginal Emissions Model

WattTime uses an empirical marginal emissions model built on top of EIA and US EPA power plant emissions data to estimate real-time and forecast marginal operating emissions rates for balancing authorities and independent system operators. The model is based on work presented in *Marginal Emissions Factors for the U.S. Electricity System* by Kyle Siler-Evans, Ines Lima Azevedo, and M.Granger Morgan[72], but with a few key enhancements, such as bringing the model into real time using data from ISOs, and using the model to forecast the next 24 hours of marginal emissions rates.

Considering Other Models for Future Marginal Emissions Rates

Cambium from NREL is an assumption-based simulation of the operation of future electricity grids that produces marginal emissions rates at hourly granularity, for U.S. electricity grid regions. Cambium data is currently available for 5 scenarios and for every 2nd year between 2020 and 2050. Cambium produces both Short-run and Long-run marginal emissions rates (SRMER and LRMER). Short-run emissions rates generally are applicable to evaluating the outcomes of operational decision making (as WattTime has done in the above analysis). WattTime has performed a preliminary evaluation of the Cambium SRMERs and concluded that while they are applicable to this analysis in theory, the actual profiles are not realistic or predictable enough for practical use. Cambium SRMER are “an ongoing area of research” and “SRMER values are not appropriate for real-time operational decision-making,” according to NREL’s Cambium documentation.

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[72] Siler-Evans, Kyle, et al. “Marginal Emissions Factors for the U.S. Electricity System.” *Environmental Science & Technology*, vol. 46, no. 9, 2012, pp. 4742–4748., doi:10.1021/es300145v.

Appendix E: Task 4 Feeder Selection Methodology, Modeling and Assumptions, Planning Criteria, and Detailed Feeder Analysis and Results

Feeder Selection

A total of 31 feeders of the 371 were found likely to experience overloads. From these feeders, an initial set of six were selected (see red bars in Figure A.8 and Table A.5 below) with the following criteria:

- No more of one feeder per substation unless they represented two construction technologies (radial feeder vs. LVAC network vs Spot Network). Note Benning in Table A.5.
- Higher overloads should be included, but also intermediate overloads so a view on the range of the investments can be estimated (see Figure A.8 **Error! Reference source not found.**) for range of overloads.
- A range of representative construction practices should be represented, if possible, i.e., not all selected feeders should be 100% underground or overhead. Note Benning and Takoma in Table A.5.

Figure A.8: Feeder Selection Results

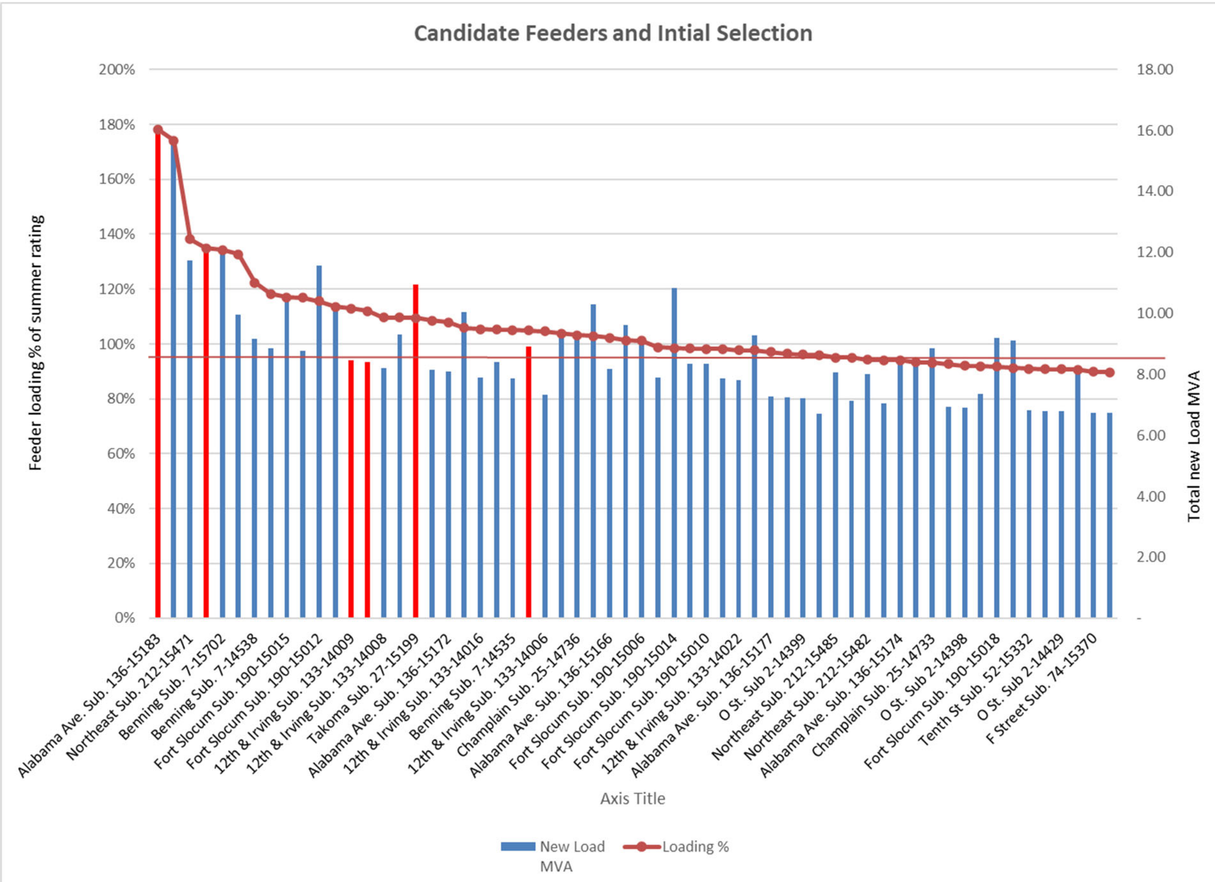


Table A.5: Initial Feeder Selection

Sub	Feeder	New Load MVA	Loading %	Overhead %	Feeder Type Note
Alabama Ave. Sub. 136	15183	16.0	178%		Distribution Feeders
Benning Sub. 7	15708	12.1	135%	0%	Underground Dis. Feed (West)
12th & Irving Sub. 133	14009	8.5	113%	89%	Distribution Feeders, 12
Benning Sub. 7	14536	8.4	112%	0%	NW Spot Network System
Takoma Sub. 27	15199	11.0	110%	69%	Distribution Feeders
Florida Ave. Sub. 10	15341	8.9	105%	0%	LVAC Network South

Engineering simulation model information was requested for the feeders above and based on the data provided and the completeness for the data, the selection was narrowed to the three feeders highlighted above; Benning Sub. 7 – 15708 high loadings underground, 12th & Irving Sub. 133 - 14009 intermediate loadings largely overhead and Takoma Sub. 27 – 15199 intermediate loadings and mixed. No modeling information was available for the LVAC or Spot networks.

Network Modeling, Load Assumptions and Scenarios

System planning assesses the network performance and defines the needs for network strengthening to provide safe, reliable, and economic service to customers considering future loads and demands. Therefore, the distribution network should be analyzed under the load scenarios that represent the maximum possible stresses for the feeder under consideration and the adjacent feeders that will operate together during emergency conditions.

Noting the impact of electrification and electric vehicles on the selected feeders' demand, winter peak load was selected as the base load condition. Additionally, the adjacent feeder summer peak loads were adjusted to winter loads, and are assumed to peak at the same time, to make a conservative forecast. These feeders were also modeled to include the expected impact of the electrification and electric vehicles as provided in the forecast.

The analyses were conducted for 2020 as is, 2032 without the incremental electrification and EV loads, and 2032 with these incremental loads.

PEPCO provided network models for the selected feeders of interest and the adjacent feeders in CYME, which was converted to PSS®SINCAL, which is Siemens' power system analysis software and widely used for distribution system planning. While creating the network model in PSS®SINCAL, model data was examined to ensure consistency and ratings confirmed with PEPCO.

The network models started at the distribution medium voltage (MV) bus of the transmission to distribution substations and included all distribution switching elements. Loads were modeled directly at the MV level. The new projected feeder load was allocated to the network model in proportion to the existing modeled load as provided in the CYME model, basically representing uniform growth.

Planning Criteria

Planning criteria area set of rules that are used to design and assess the performance of a network. There are elements of the planning criteria that are uniform across utilities in the US and some that are specific to each utility. The analysis was conducted considering the planning criteria that PEPCO is expected to follow as summarized below.

<u>Voltage Limits</u>

The system is expected to be planned to follow at least ANSI C84.1 limits, this standard allows normal and emergency conditions voltage limits. However, for PEPCO's system no emergency conditions deviation was allowed and the volage was planned to stay within the ranges below.

- Maximum voltage is 105% of nominal voltage
- Minimum voltage is 97.5% of nominal voltage

Loading Limits

Mainlines should have reserve capacity to provide a backup to adjacent feeders during faults resulting in loss of supply or maintenance. Therefore, planning loading limits for equipment are defined for PEPCO system as below.

- Normal Operating Condition: 80% of nominal ampacity
- Emergency Operation Condition : Maximum loading is 100% of nominal ampacity

Note that the 80% maximum loading under normal operation is a guideline and its application can depend on the maximum allowed number of switching maneuvers to transfer load to adjacent feeders and the time it takes to perform them. If the maneuvers can be done remotely or even automatically with FLISR[73] higher number of maneuvers are allowed as crews do not need to travel and the restoration time can be managed well. This is the case with PEPCO, we understand.

Contingency Criteria

Main feeders must have a way to supply the mainline load under emergency (n-1) condition by reconnection of open loops. This criterion is used for both underground and overhead feeders.

Laterals connected to main feeders with a load greater than 500 kVA must have a way to reconnect to the mainline (open loop service) in case of a faulted section, limiting the maximum amount of load without means of a backup to 500 kVA.

Power Factor

Power factor should be kept close to unity for increasing efficiency and reducing losses of system.

Standard Equipment

In PEPCO system, 500 CU kcmil underground cable is most used for mainlines. Therefore, 500 CU kcmil underground cable was selected for new feeders and reconductoring. It provides a good voltage profile along the mainline, and additional capacity for emergency operation conditions and future load growth. If higher capacity is required, 600 CU kcmil underground

[73] FLISR = Fault Location Isolation and Service Restoration is an automatic system that upon the occurrence of a fault isolates it and transfers the healthy parts of the feeder to adjacent feeders without overloading them.

cable or doubling could be considered. For short connections to provide a backup could be same conductor size to match as existing system design.

Capacitor Banks

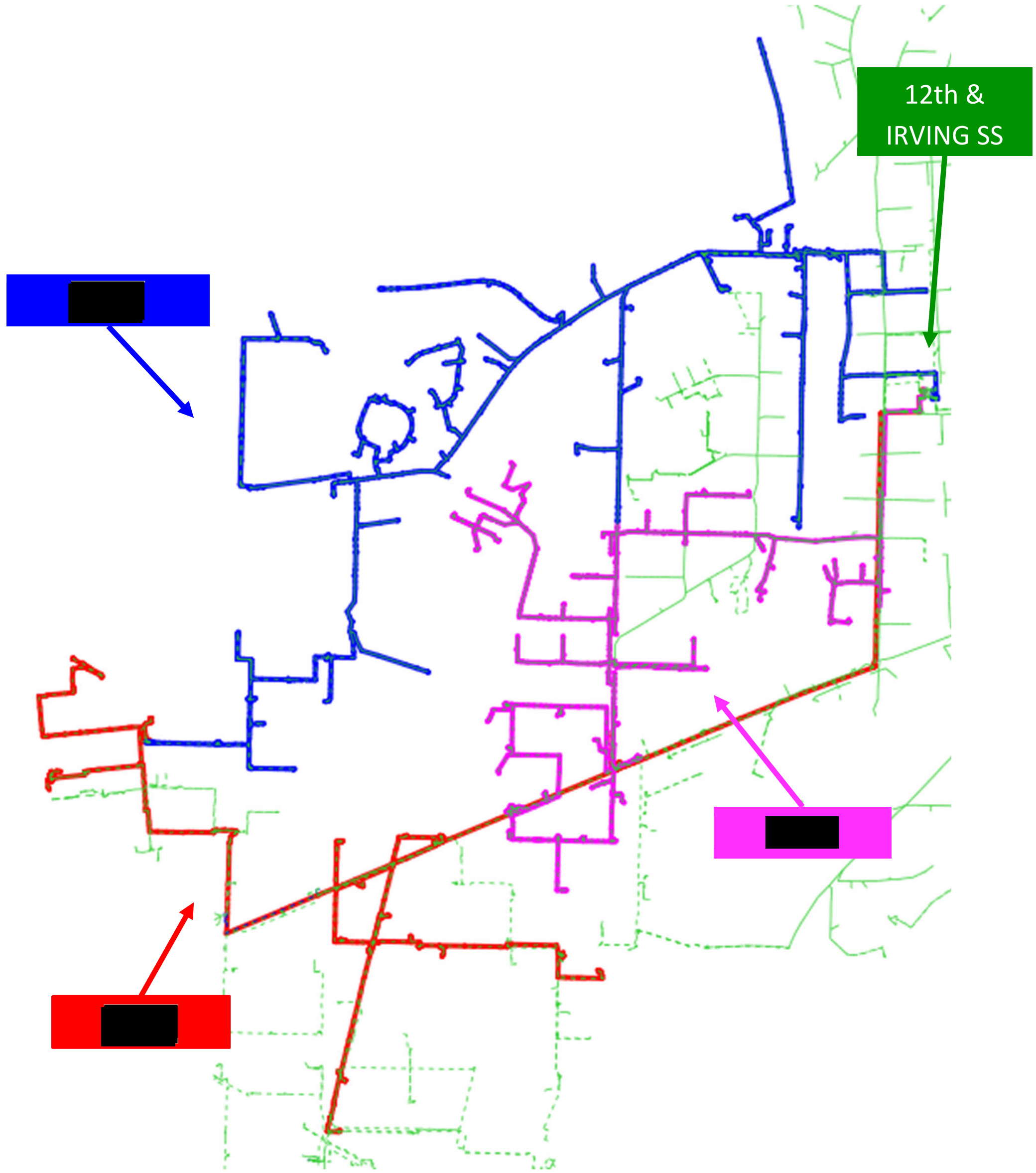
300 kVAr and multipliers are the most common used in US utilities. Therefore multiple capacitor banks were selected as standard type for this analysis.

Feeder Analysis, Results, Solutions, Capital Expenditure Estimates

12th & Irving Substation Feeder 14009

Feeder 14009 connects to the 12th & Irving Substation (SS), has existing feeders that can be considered for load transfer during emergency. The model included other feeders that could be considered for transferring, but this initial set was found appropriate for the study. Figure A.9 shows an overview of the area under study (Area 1).

Figure A.9: Supply Area for 12th & Irving Substation Feeder 14009 (Area 1)



The modeled load at these feeders is shown in Table A.6 under current configuration and before any load transfers.

Table A.6: Feeder loads of Area 1 before any transfer or investments

	2020	2032	2032 Elec. & EV
Feeder	P [MW]	P [MW]	P [MW]
[redacted]	5.85	5.17	8.17
[redacted]	5.17	4.78	7.64
[redacted]	2.99	2.66	4.37

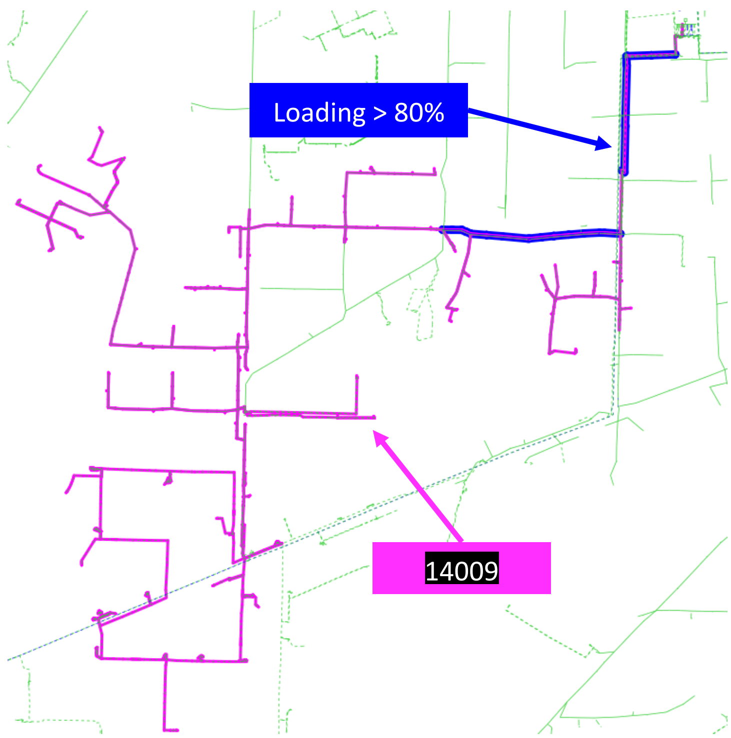
Normal Conditions – Winter Peak

Considering the current configuration, Feeder 14009 can be operated without any overloading or voltage violation under normal conditions in 2020, 2032 and also by 2032 with the electrification and electric vehicle impact. There would be sections loaded higher than 80% of their ampacities mainly substation exit, as shown in Table A.7 and shown in Figure A.10 for the 2032 case with the incremental loads.

Table A.7: Status of Feeder 14009 under normal condition in 2032 with electrification and EV impact

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Season	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
12TH & IRVING SUB 133	14009	Under Normal Condition		Winter	82.7%	100.0%	2032+Elec&EV

Figure A.10: Loaded sections higher than 80% under Feeder 14009 normal condition in 2032 with electrification and EV impact



Emergency Conditions – Winter Peak

Upon the occurrence of the worst fault on Feeder 14009, which would imply the loss of the section right out of the substation, the entire feeder load needs to be transferred to the adjacent feeders. None of the other feeders alone have enough capacity to receive all loads of Feeder 14009. However, feeders [redacted] (colored red) and [redacted] (colored blue) can take each part of the load of Feeder 14009 without any violation as shown in Table A.8.

Table A.8: Status of Feeder 14009 under emergency condition in 2032 with electrification and EV impact

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Season	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
12TH & IRVING SUB 133	14009	[redacted]	[redacted]	Winter	99.1%	99.7%	2032+Elec&EV

Solutions Assessment

As no overloading or voltage violations were identified under normal or emergency conditions, no investments are necessary for this feeder. It is to be noted that although the initial screening indicated that this feeder would overload, when the detailed models were made available, we identified that the winter rating used by PEPCO was much higher than in summer rating and enough to address the expected overload.

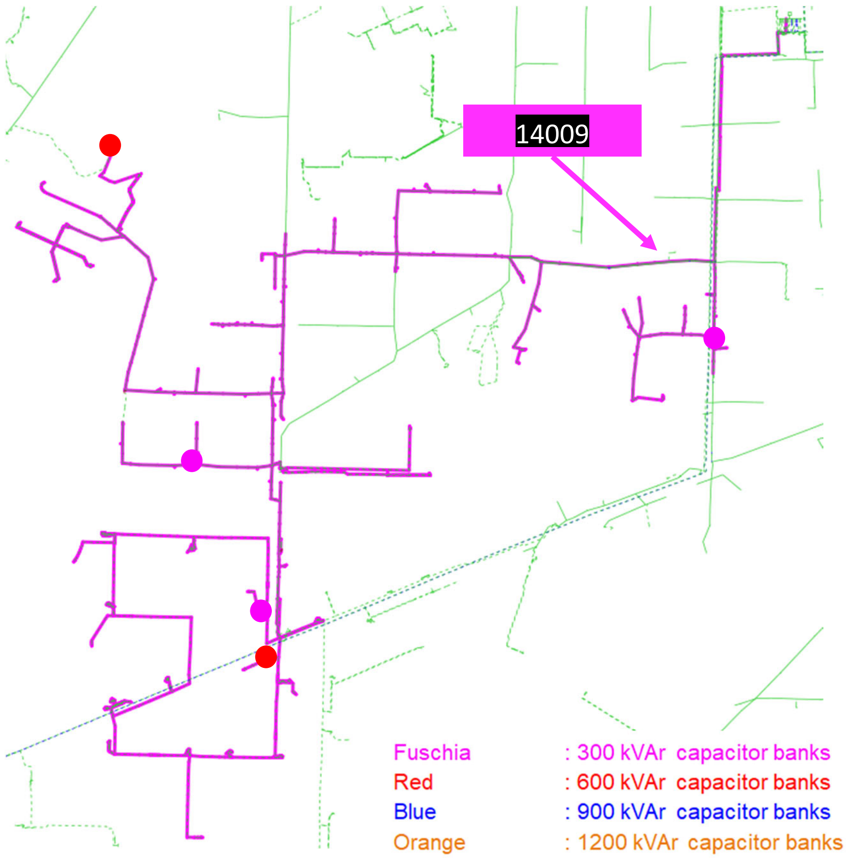
Power Factor Correction – Winter Peak

A 3 x 300 kVAr and a 2 x 600 kVAr capacitor bank are proposed to improve power factor along Feeder 14009. They are sized to keep the power factor as seen from the substation close to unity but prevent injection of reactive power to transmission and improve the volage profile. They are listed in Table A.9 according to sizes and the location is shown in Figure A.11.

Table A.9: New capacitor banks along the Feeder 14009

Feeder Name	300 kVAr	600 kVAr
FDR_14009	3	2

Figure A.11: New capacitor banks along the Feeder 14009



<u>Lateral assessment – Winter Peak</u>

In addition to these analyses, each lateral having a load greater than 500 kW was checked to confirm the possibility of a backup. Along the Feeder 14009, there are laterals with no possibility of backup as shown in Figure A.12, and the corresponding winter peak load for 2032 including electrification and electric vehicles impact are shown in Table A.10.

Figure A.12: Laterals without backup along the Feeder 14009

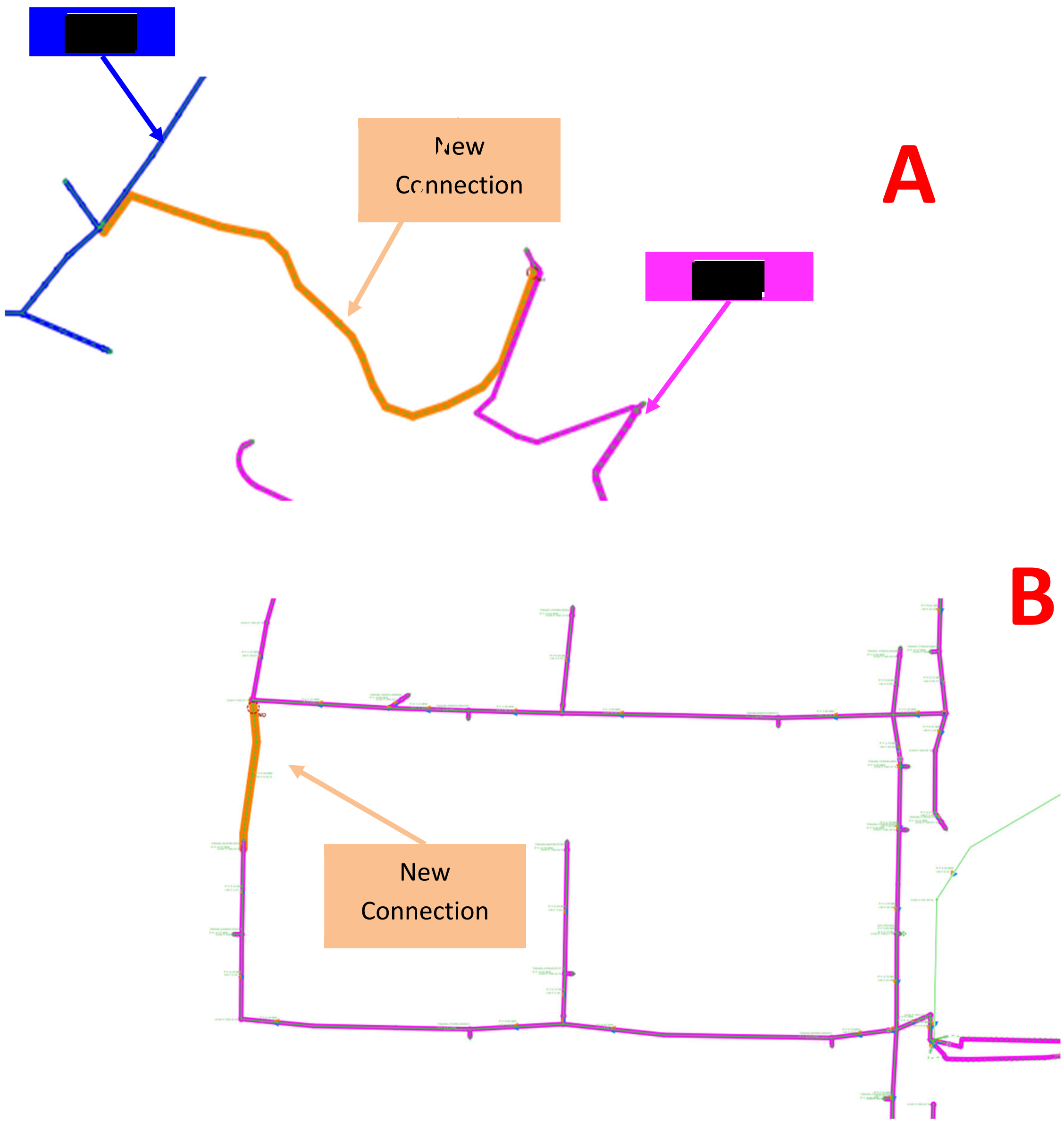
[redacted]

Table A.10: Load demand of the laterals without a back-up

[redacted]

To address the above, the new connections (Project A - #2 CU - 0.159 mi, Project B - 500 kcmil CU 0.035 mi and Project C - #2 CU - 0.016 mi) are proposed to avoid losing this load [redacted] The proposed projects are shown in Figure A.13 and listed in Table A.11.

Figure A.13: Project A, B and C for Area 1



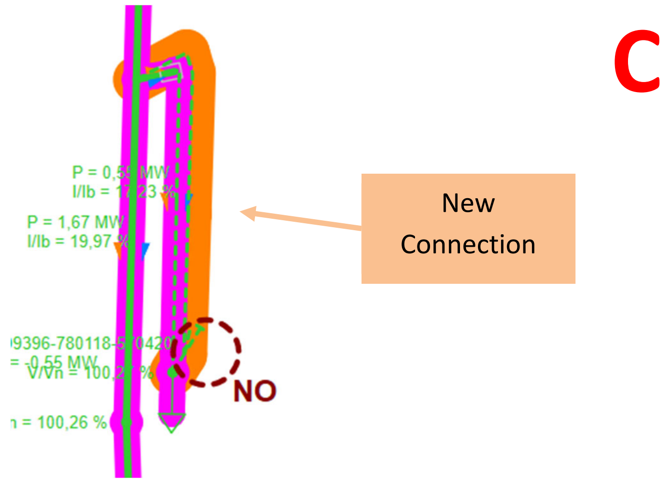


Table A.11: Proposed projects for Area 1

Element Name	Type Name	l [mi]	Year	Project
L8567_INV	3P#2CUP_13.8KV	0.159	2032+Elec&EV	A
L8568_INV	3P500CURN_13.8KV	0.035	2032+Elec&EV	B
L8569_INV	3P#2CUP_13.8KV	0.016	2032+Elec&EV	C

<u>Capital Expenditures</u>

Based on the proposed projects and capacitor banks investments, an indicative capital expenditure budget is calculated. These costs were estimated using typical unit costs for US utilities as listed in Table A.12[74].

[74] PEPCO provided unit costs towards the end of the project that were significantly higher than the representative costs above. While this could be due in part to particularities of the Washington DC construction environment, the analysis was conducted using our indicative costs.

Table A.12: The selected unit costs for CapEx calculation

Cables	Unit Cost [$/mile]
Underground feeder, 3# 500 CU	$1,521,492
Underground feeder, 3# 600 CU	$1,663,461
Underground feeder, 3# 1/0 CU	$1,209,865
Underground feeder, 3# 2 CU	$1,187,994
Capacitor Banks	**Unit Cost [$]**
300 kVAr	$4,073
600 kVAr	$8,146
900 kVAr	$12,220
1200 kVAr	$16,293
Switching Equipment	**Unit Cost [$]**
Breaker - MV	$149,085
Switch 600 Amp Class	$80,250

The estimated capital expenditure required for the selected feeder 14009 out of 12th & Irving Substation is listed in Table A.13. In addition to the proposed projects, estimated budget for the capacitor banks is listed in Table A.14.

Table A.13: Capital Expenditures estimated for Feeder 14009 - 12th & Irving Substation

Project Name	Total Line Length [mi]	Number of Breaker	Number of Switch	Comment	Line Cost [$]	Breaker Cost [$]	Switch Cost [$]	Total Cost [$]
A	0.159	0	1	For lateral backups	$188,891	$0	$80,250	$269,141
B	0.035	0	1	For lateral backups	$53,252	$0	$80,250	$133,502
C	0.016	0	0	For lateral backups	$19,008	$0	$0	$19,008
Total	**0.21**	**0**	**2**		**$261,151**	**$0**	**$160,500**	**$421,652**

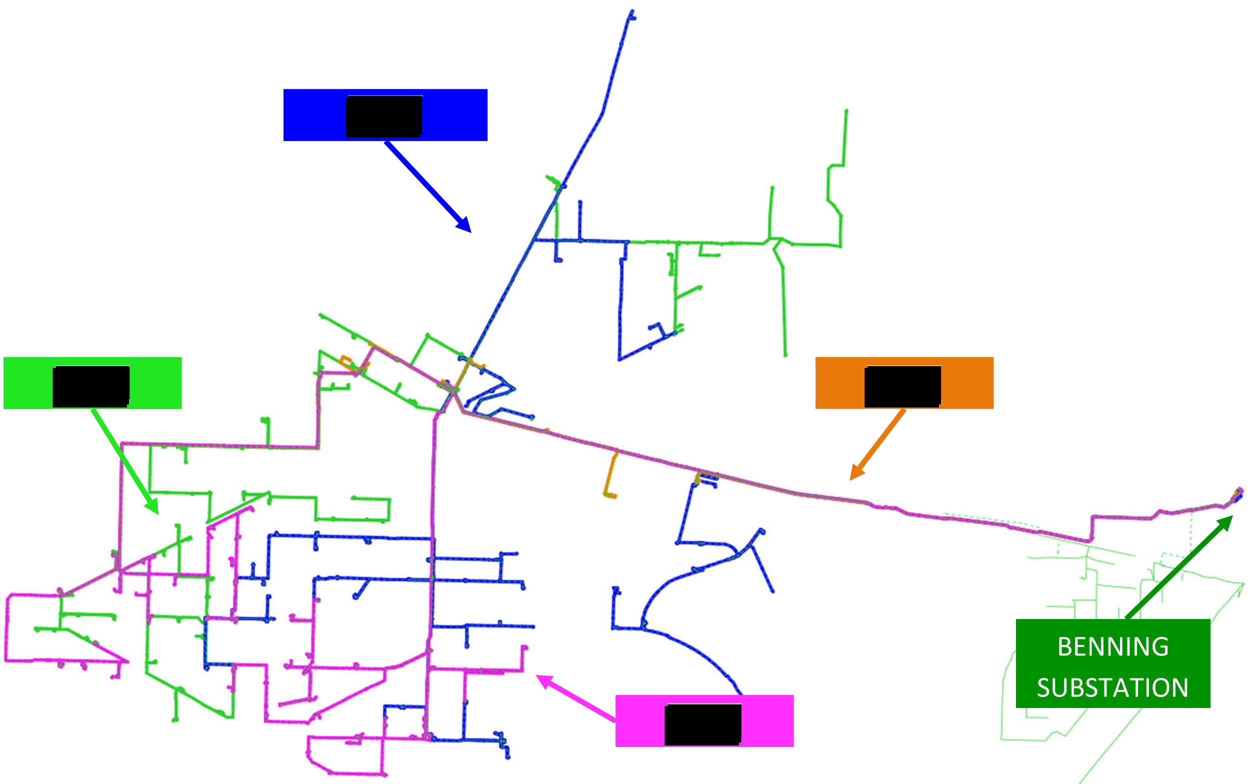
Table A.14: Capacitor investments for Feeder 14009 - 12th & Irving Substation

Capacitor Banks	
Number of Capacitor Banks	5
Total Reactive Power [kVAr]	2,100
Total Cost [$]	**$28,512**

Benning Substation Feeder 15708

Feeder 15708 connects to Benning (SS) and has feeders [redacted] and can be considered for load transfer during emergency. As before, the model included other feeders that could be considered for transferring but they are less well located. Figure A.14 shows an overview of the area under study (Area 2).

Figure A.14: Supply area for Benning Substation Feeder 15708 (Area 2)



The load at these feeders is shown in Table A.15 considering the current configuration and before any load transfers.

Table A.15: Feeder loads of Area 2 before any transfer or investment

	2020	2032	2032 Elec & EV
Feeder	**P [MW]**	**P [MW]**	**P [MW]**
[redacted]	7.20	6.85	11.84
[redacted]	6.94	6.82	11.76
[redacted]	5.92	5.80	9.97
[redacted]	0.00	0.00	0.00

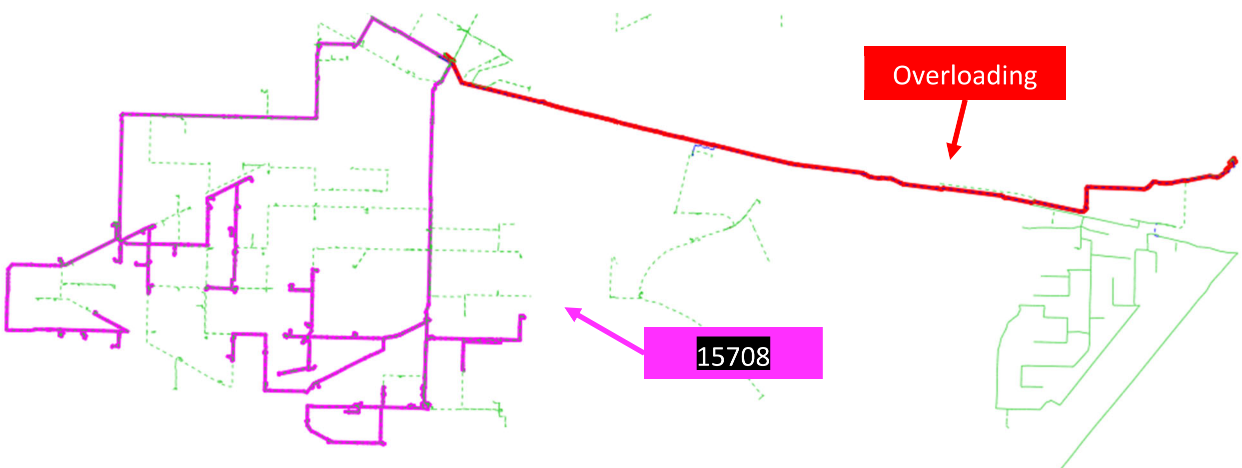
Normal Conditions – Winter Peak

Considering the current configuration, Feeder 15708 can be operated without any overloading or voltage violation under normal conditions in 2020 and 2032. However, when electrification and electric vehicle impact are included in 2032, the mainline of the Feeder 15708 would be overloaded to 107.9% as shown in Table A.16 and Figure A.15, even considering winter ratings.

Table A.16: Loading violation of Feeder 15708 under normal condition in 2032 with electrification and EV impact

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Season	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
BENNING SUB 7	15708	Under Normal Condition		Winter	107.9%	99.6%	2032+Elec&EV

Figure A.15: Loading violation of Feeder 15708 under normal condition in 2032 with electrification and EV impact



Emergency Conditions – Winter Peak

Under emergency condition, none [redacted] have enough capacity to provide backup to Feeder 15708 as it is already overloaded 107.9% under normal conditions.

The basic design of the area for emergency condition is the use of feeder [redacted] which is unloaded and available for backup. This is shown in Figure A.16 where feeder [redacted] is highlighted with a dotted line parallel to its route and we see that [redacted]

[redacted]

[redacted]

Thus, the solution must both avoid the overload of [redacted] when it takes the load of 15708 and address the situation with [redacted].

Figure A.16: Feeder 15704 Role in backing up Area 2 feeders.

[redacted]

<u>Solutions Assessment</u>

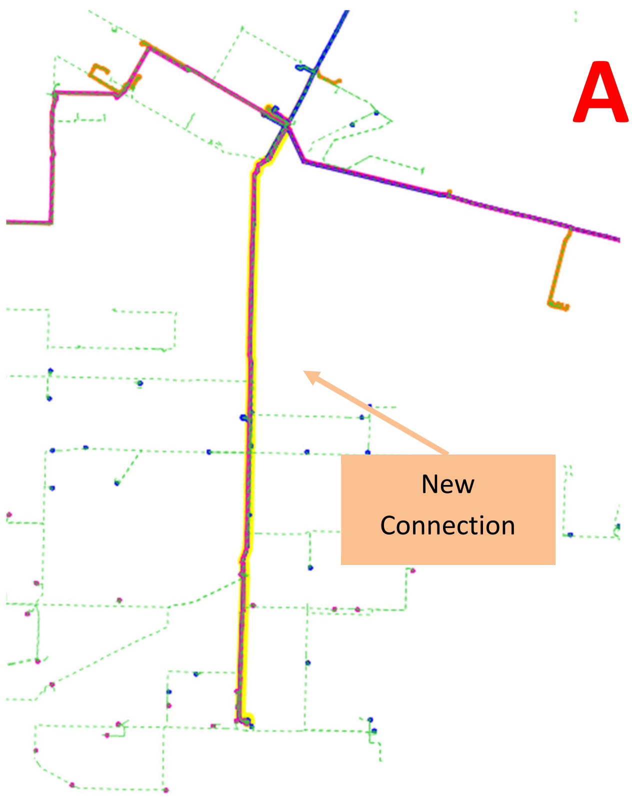
As [redacted] has some available capacity for additional loading the first step is to transfer load from [redacted] to [redacted] so neither is overloaded under normal conditions allowing [redacted] to provide backup without overloading with only a minor investment discussed below. The load transferring is shown in Figure A.16 and the effect in Table A.17.

Table A.17: Loads of Feeder [redacted] and Feeder [redacted] in proposed supply area

Feeder	2032 Elec& EV	
	Existing	Proposed
	P [MW]	P [MW]
FDR_[redacted]	11.83	10.79
FDR_[redacted]	9.97	11.02

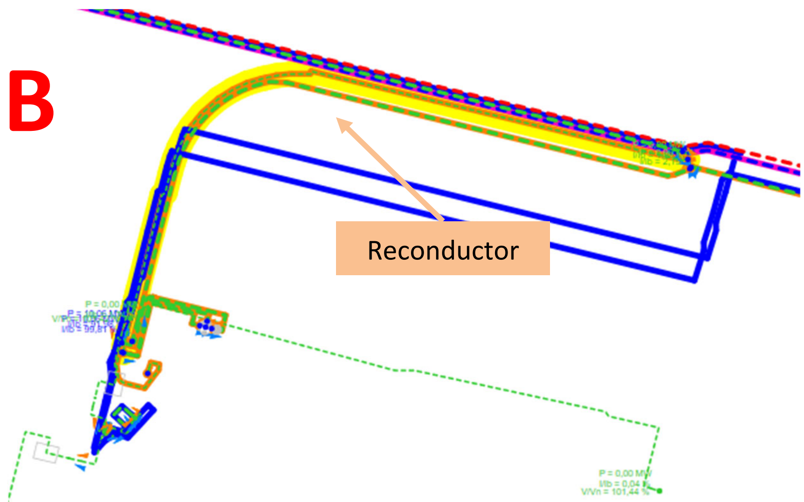
To address the backup issue of the [redacted] discussed above, a new section (Project A - 600 kcmil CU - 0.82 mi) is proposed to create a new connection between Feeders 15708, [redacted] (backup feeder) as shown in Figure A.17.

Figure A.17: Project A in Area 2 – new connection between Feeder 15708, [redacted]



Finally, when Feeder 15708 is transferred to Feeder [redacted] under emergency conditions, a short section of 15704 would be overloaded and it would need to be upgraded to 600 kcmil cable (Project B - 600 kcmil CU - 0.06 mi) and shown in Figure A.18.

Figure A.18: Project B in Area 2 – reconductoring a short section on Feeder [redacted] *mainline*

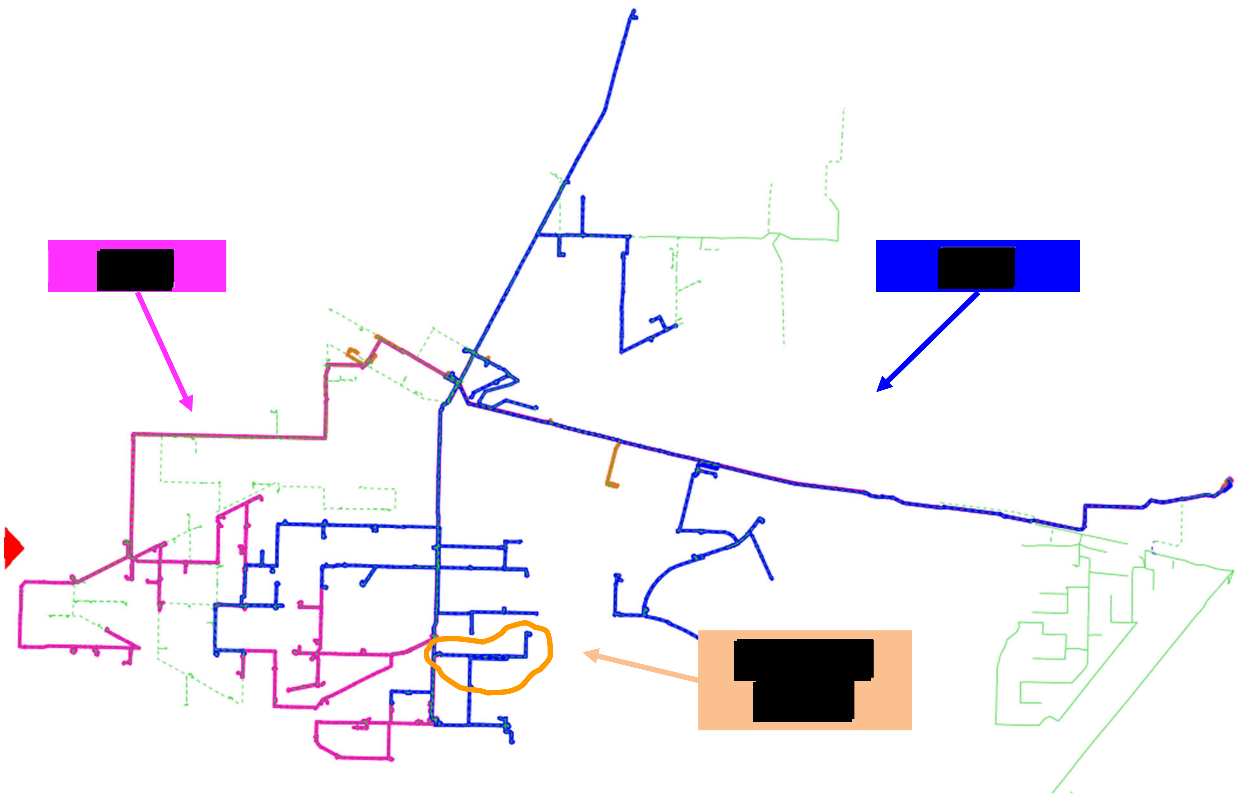


After these investments and reconfiguration of its supply area, Feeder 15708 could be transferred to Feeder [redacted] without any overloading or voltage violation. The result of contingency case is shown in Table A.18

Table A.18: Verification of Feeder 15708 status under emergency condition in 2032 with electrification and EV impact

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Season	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
BENNING SUB 7	15708	[redacted]	-	Winter	96.6%	99.2%	2032+Elec&EV

Figure A.19: Proposed supply area for Feeder 15708 and Feeder [redacted] in 2032 with electrification and EV impact



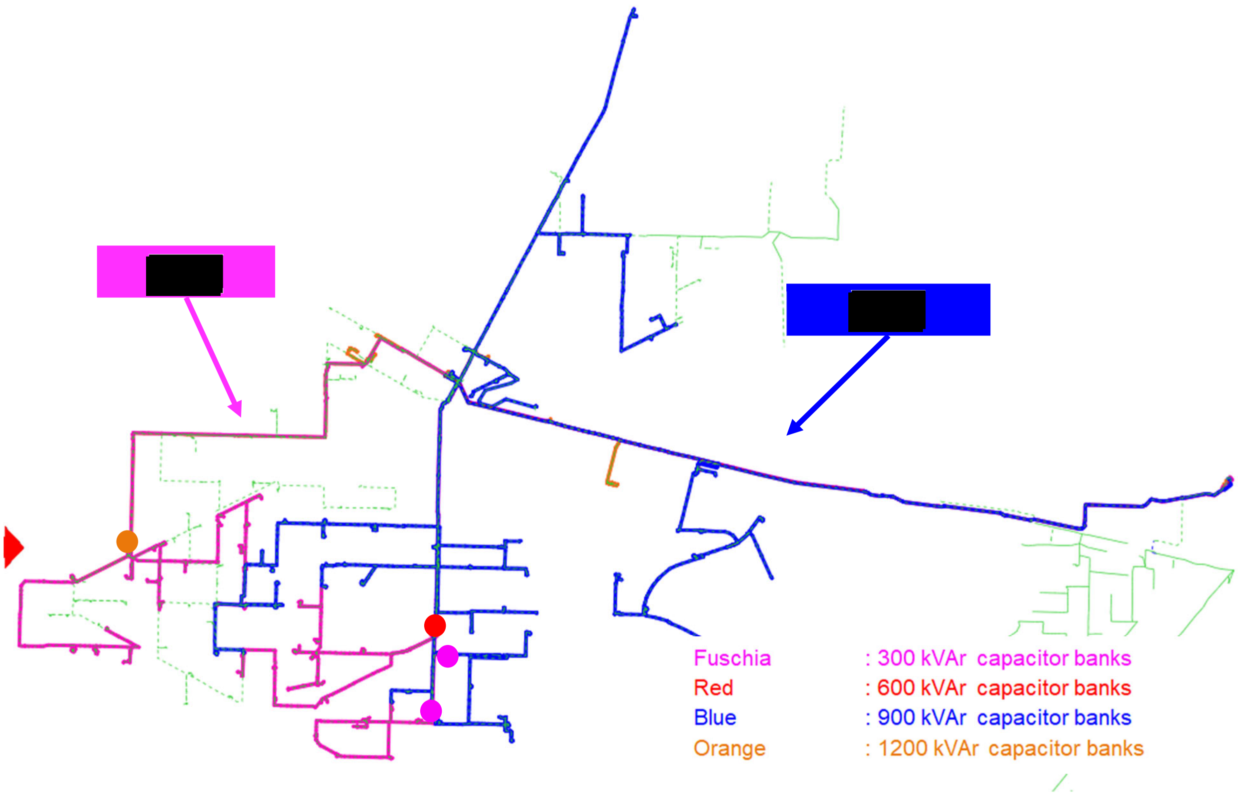
Power Factor Correction – Winter Peak

A 1 x 300 kVAr, 1 x 600 kVAr and 1 x 1200 kVAr capacitor bank are proposed to improve power factor along the Feeder 15708 and 1 x 300 kVAr capacitor bank is proposed along the Feeder 15703. They are sized to keep the power factor as seen from the substation close to unity but prevent injection of reactive power to transmission and improve the volage profile. They are listed in Table A.19 according to sizes and the location is shown in Figure A.20.

Table A.19: New capacitor banks along the Feeder [redacted] and Feeder [redacted]

Feeder Name	300 kVAr	600 kVAr	1200 kVAr
FDR[redacted]	1	1	1
FDR_[redacted]	1	-	-

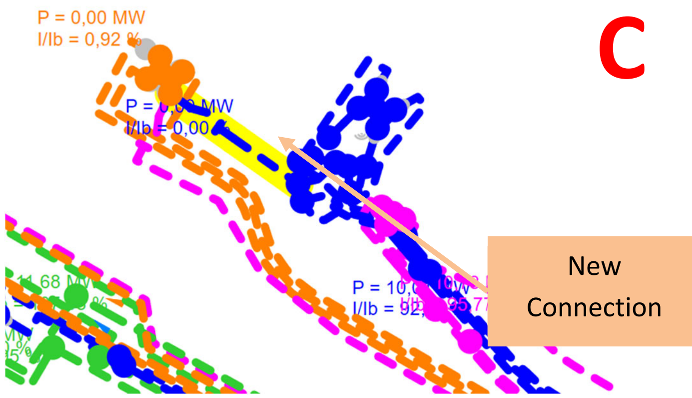
Figure A.20: New capacitor banks along the Feeder 15708 and Feeder [redacted]



<u>Lateral assessment – Winter Peak</u>

In addition to these analyses, each lateral having a load greater than 500 kW is checked considering backup perspective. [redacted] Each part of the feeder has a backup from adjacent feeders. [redacted] This new connection (Project C - 600 kcmil CU - 0.01 mi) is shown in Figure A.21.

Figure A.21: Project C in Area 2 – new connection between Feeder [redacted] *and Feeder* [redacted]



<u>Capital Expenditures</u>

The proposed projects for Area 2 are listed in Table A.22.

Table A.20: Proposed projects for Area 2

Element Name	Type Name	l [mi]	Year	Project
L3698_INV	3P600CUUNK_13.8KV	0.82	2032+Elec&EV	A
L3700_INV	3P600CUUNK_13.8KV	0.06	2032+Elec&EV	B
L3704_INV	3P600CUUNK_13.8KV	0.01	2032+Elec&EV	C

Based on the proposed projects and capacitor banks investments, an indicative capital expenditure budget is calculated by using the unit costs listed in Table A.12. The estimated capital expenditure budget for the projects proposed for Area 2 is listed in Table A.21. In addition to the proposed projects, estimated budget for the capacitor banks is listed in Table A.22.

Table A.21: CapEx budget of each project in Area 2

Project Name	Total Line Length [mi]	Number of Breaker	Number of Switch	Comment	Line Cost [$]	Breaker Cost [$]	Switch Cost [$]	Total Cost [$]
A	0.818	0	2	New Section	$1,360,711	$0	$160,500	$1,521,212
B	0.06	0	0	Overloaded Section	$99,808	$0	$0	$99,808
C	0.01	0	2	For lateral backup	$9,981	$0	$160,500	$170,481

Total	**0.884**	**0**	**4**		**$1,470,500**	**$0**	**$321,001**	**$1,791,501**

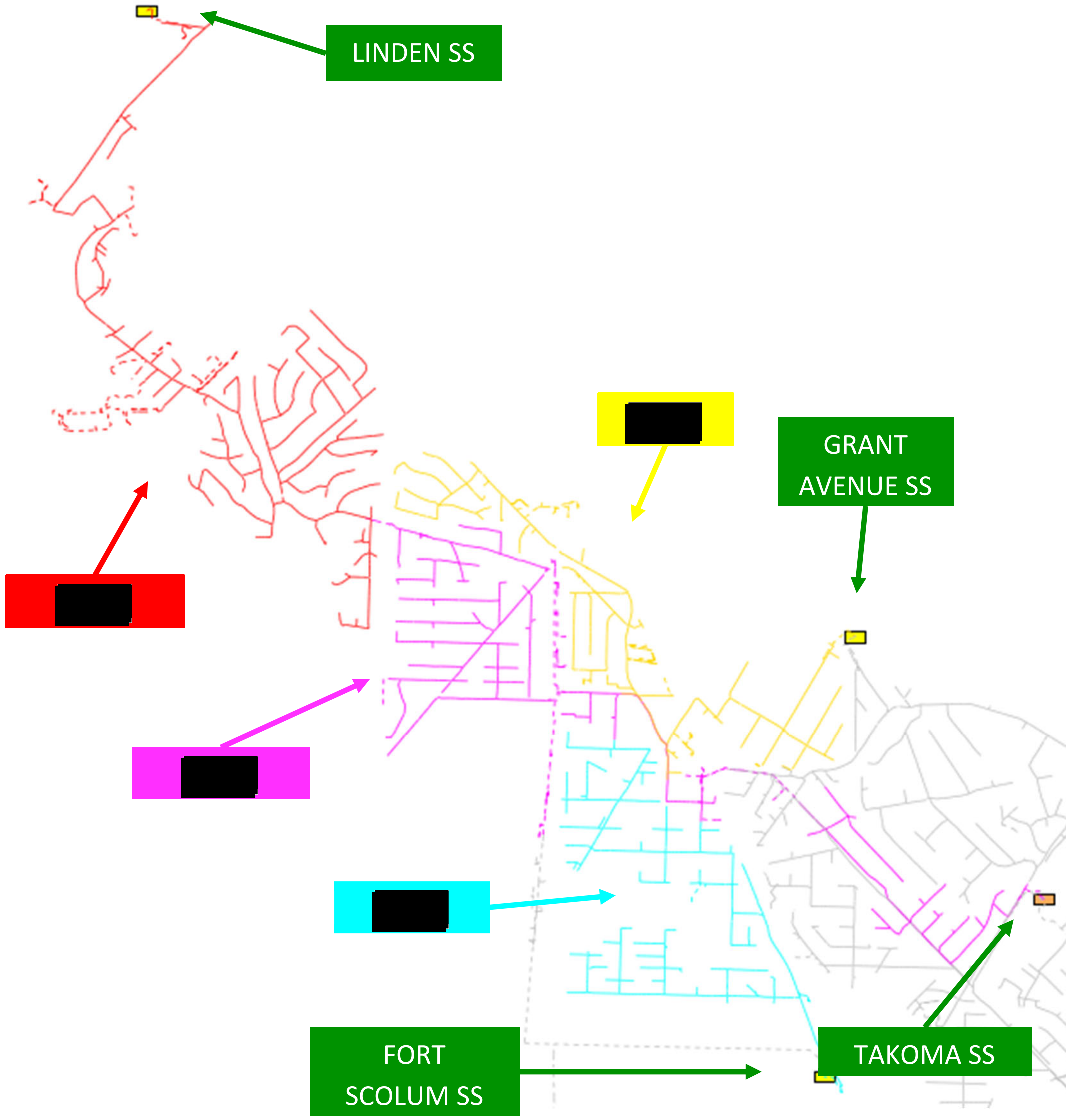
Table A.22: Required capacitor investments for Feeder [redacted]

Capacitor Banks	
Number of Capacitor Banks	4
Total Reactive Power [kVAr]	2,400
Total Cost [$]	**$32,585**

Takoma Substation Feeder 15199

Feeder 15199 connects to Takoma and has feeders [redacted] and can be considered for load transfer during emergency. As before, the model included other feeders that could be considered for transferring but they are less well located. Figure A.22 shows an overview of the area under study (Area 3).

Figure A.22: Supply area of associated feeders in Area 3



The load at these feeders is shown in Table A.23 considering the current configuration and before any load transfers.

Table A.23: Feeder loads of Area 3 before any transfer or investment

	2020	2032	2032 Elec & EV
Feeder	**P [MW]**	**P [MW]**	**P [MW]**
FDR_[redacted]	5,90	5,92	10,90
FDR_[redacted]	5,31	5,32	9,54
FDR_[redacted]	4,07	4,01	8,83
FDR_[redacted]	4,93	3,97	6,18

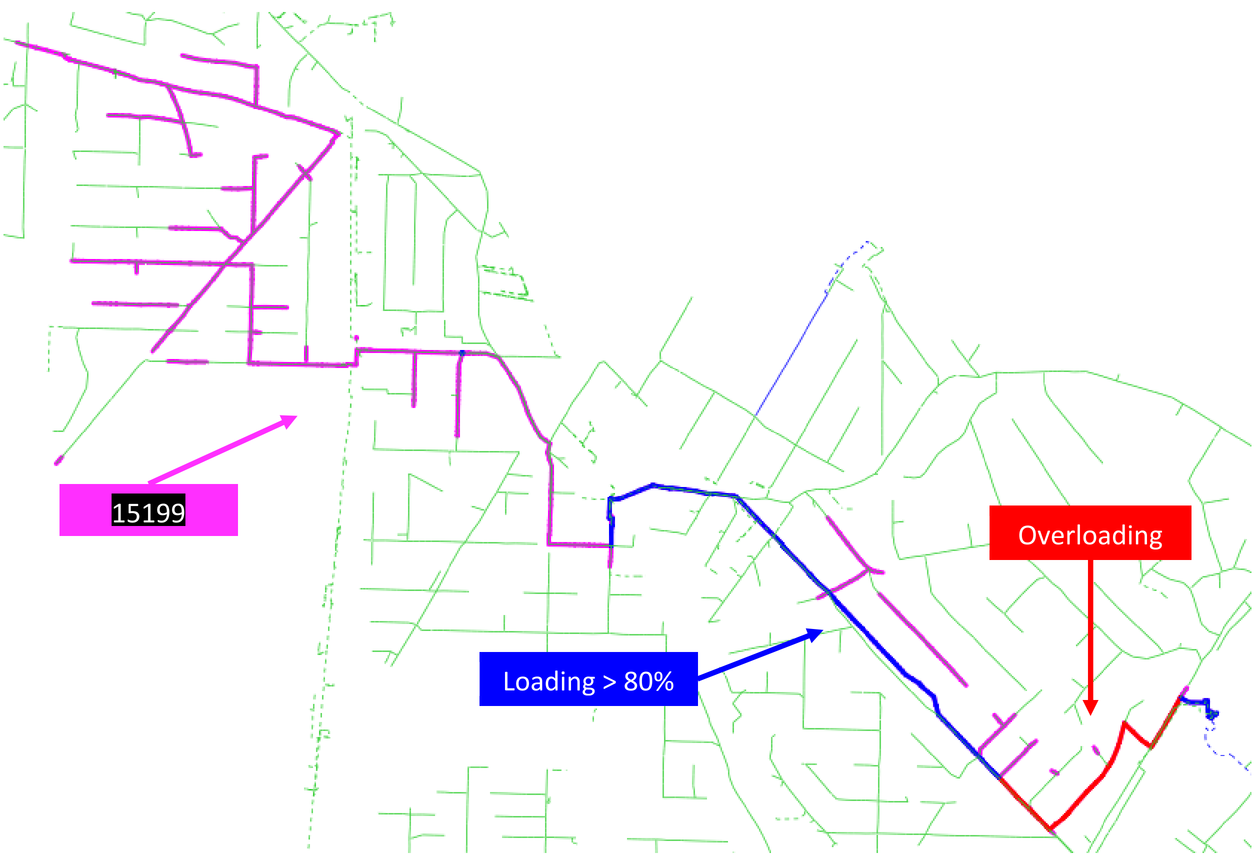
Normal Conditions – Winter Peak

Considering the current configuration, Feeder 15199 can be operated without any overloading or voltage violation under normal conditions in 2020 and 2032. However, when electrification and electric vehicle impact are included in 2032, some sections along the mainline of the Feeder 15199 would be overloaded (103.5% loading) and some sections would be loaded higher than 80% which could result in overloading during emergency. The described overloading violation is shown in Table A.24 and Figure A.23.

Table A.24: Loading violation of Feeder 15199 under normal condition in 2032 with electrification and EV impact

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Season	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
TAKOMA SUB 27	15199	Under Normal Condition		Winter	103.5%	99.0%	2032+Elec&EV

Figure A.23: Loading violation of Feeder 15199 under normal condition in 2032 with electrification and EV impact



Emergency Conditions – Winter Peak

Under emergency condition, none of [redacted] feeders have enough capacity to provide backup to Feeder 15199 as it is already overloaded 103.5% under normal conditions.

Assessing the geographical layout of Feeder 15199, we see that the [redacted] A solution was required.

Solutions Assessment

Considering the lack of reserve capacity of adjacent feeders and to address emergency operations and the heavy loadings, a new feeder GA_1 (Project A - 500 kcmil CU - 1.83 mi) from Grant Avenue is proposed in 2032 to take the load towards the end Feeder 15199, [redacted] as shown in Figure A.24. Other alternatives for this feeder were considered starting from Fort Slocum or Linden Substations, but this would result in longer routes of [redacted] respectively.

A few short sections would be overloaded when reconnecting parts of 15199 to the new feeder GA_1 and they would need to be upgraded (Project B & C, 500 kcmil CU - 0.045 mi) as shown in Figure A.25 and Figure A.26.

Figure A.24: Project A in Area 3 – new feeder from Grant Avenue Substation

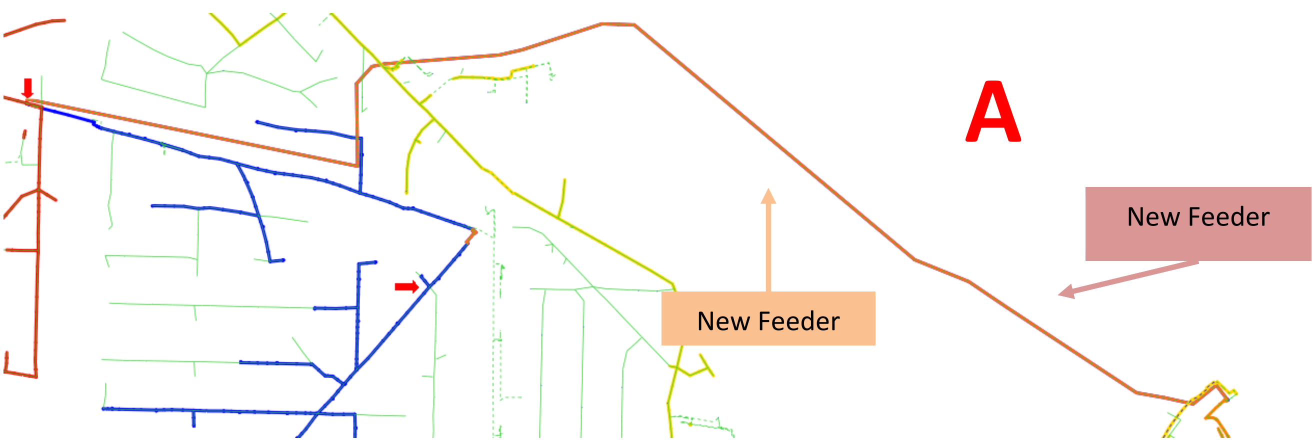


Figure A.25: Project B in Area 3 – reconductoring a short section on Feeder GA_1 mainline

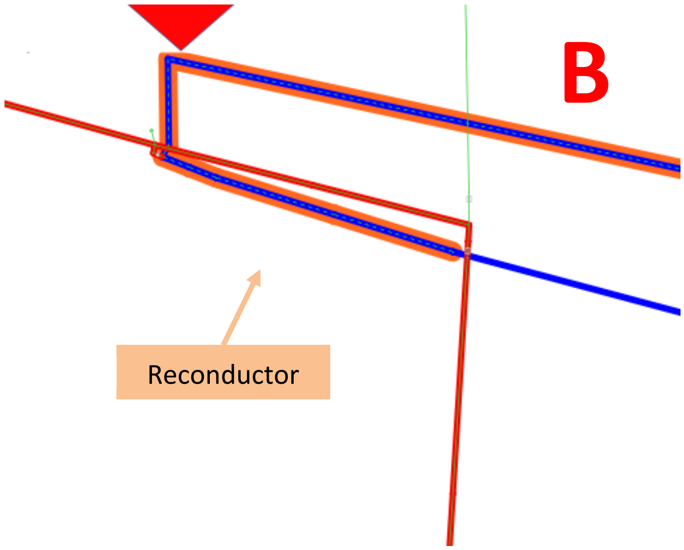
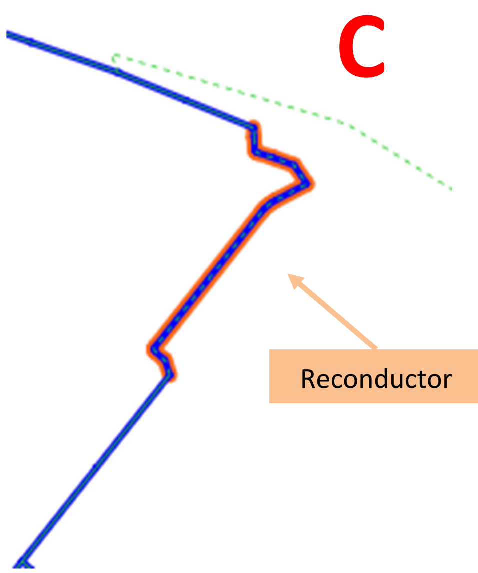
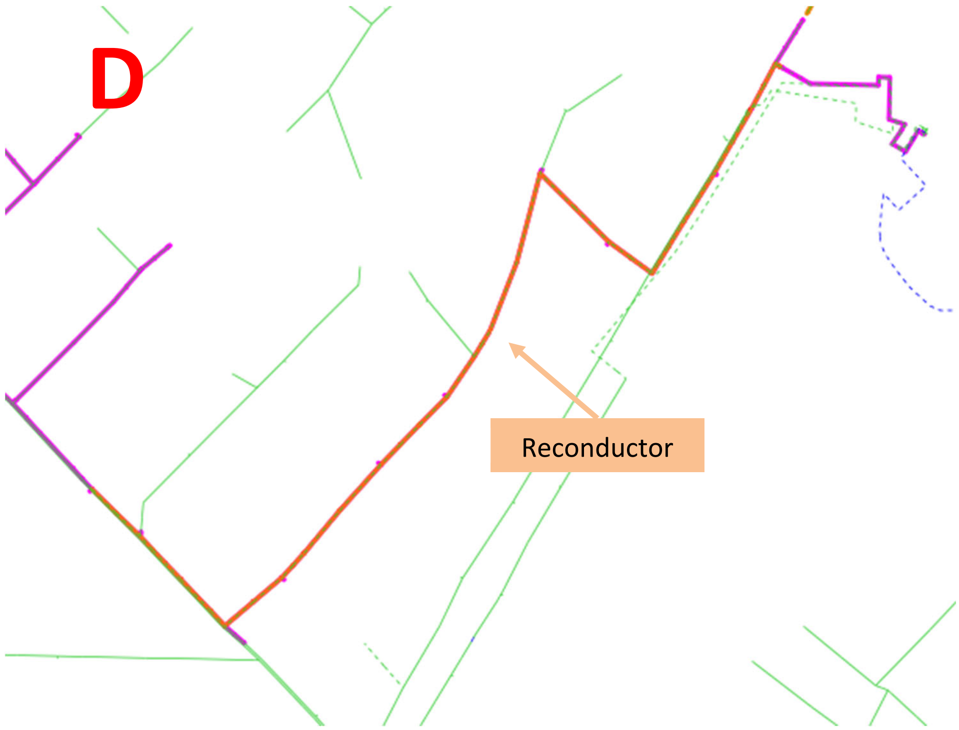


Figure A.26: Project C in Area 3 – reconductoring a short section on Feeder GA_1 mainline



With the transfer above, Feeder 15199 would not experience overloads during normal conditions, but when Feeder GA_1 is transferred to Feeder 15199 during emergencies (same as actual operating scenario), some sections would be overloaded. Therefore, these overloaded sections should be upgraded (Project D, 600 kcmil CU - 0.48 mi) as shown in Figure A.27.

Figure A.27: Project D in Area 3 – reconductoring the sections on Feeder 15199 mainline



After these investments, Feeder 15199 could be transferred during emergencies to [redacted] and the new Feeder GA_1 could be transferred to Feeder 15199 in 2032 without any overloading or voltage violation.

The results of each contingency case are shown in the Table A.25. The proposed supply area for 15199 and GA_1 is as shown in Figure A.28. According to proposed supply area, Feeder 15199 demand would be 2.85 MW and Feeder GA_1 demand would be 7.97 MW in 2032 including electrification and electric vehicles impact as listed in Table A.26.

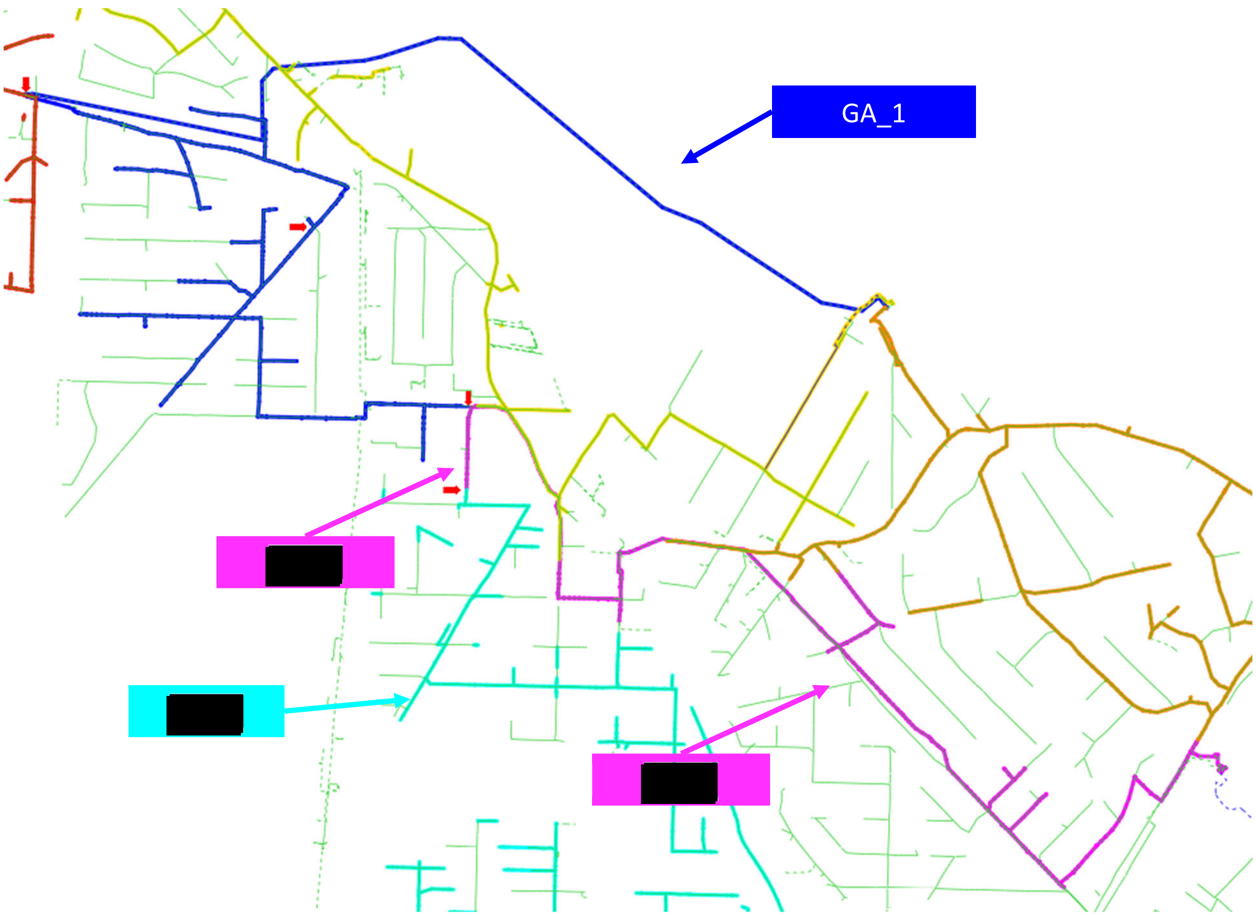
Table A.25: Verification of Feeder 15199 and Feeder GA_1 status under emergency condition in 2032 with electrification and EV impact

Substation	Main Feeder	Back-Up Feeder-1	Back-Up Feeder-2	Season	Max Line Loading [%]	Minimum Voltage [%]	Appearance Year
TAKOMA SUB 27	15199	[redacted]	-	Winter	88.3%	101.5%	2032+Elec&EV
GRANT AVENUE SUB 183	GA_1	15199	-	Winter	98.9%	100.2%	2032+Elec&EV

Table A.26: Loads of Feeder 15199 and Feeder GA_1 in proposed supply area

Feeder	2032 Elec & EV	
	Existing	Proposed
	P [MW]	P [MW]
FDR_15199	10.90	2.85
GA_1	-	7.97

Figure A.28: Proposed supply area for Feeder 15199 and Feeder GA_1 in 2032 with electrification and EV impact



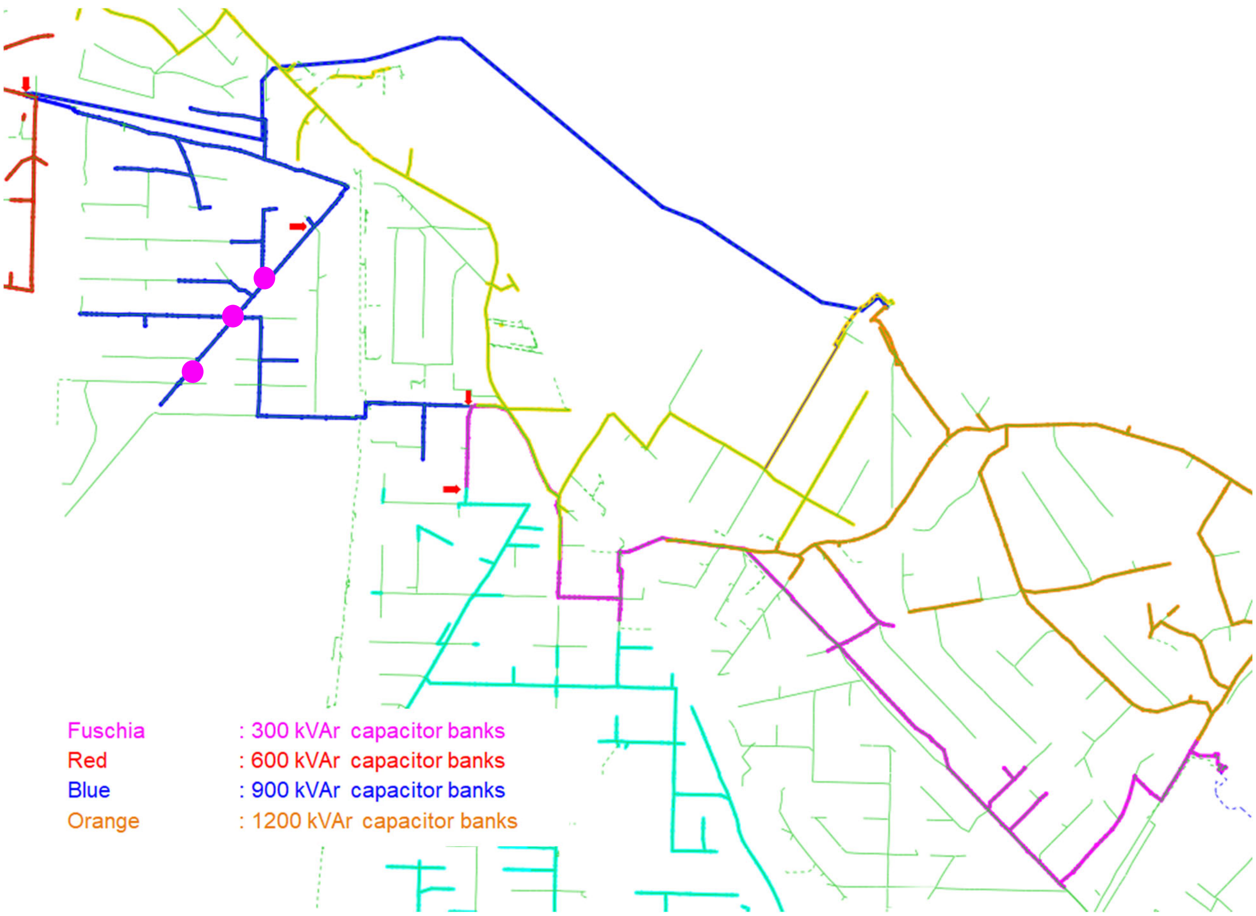
Power Factor Correction – Winter Peak

Addition of 3 x 300 kVAr capacitor banks are proposed to improve the power factor at various locations along the Feeder GA_1. They are sized to keep the power factor as seen from the substation close to unity but prevent injection of reactive power to transmission and improve the volage profile. There is no capacitor bank requirement for Feeder 15199. They are listed in Table A.27 according to sizes. Location of capacitor banks is shown in Figure A.29.

Table A.27: New capacitor banks along the Feeder GA_1

Feeder Name	300 kVAr
FDR_15199	-
GA_1	3

Figure A.29: New capacitor banks along the Feeder GA_1



<u>Lateral assessment – Winter Peak</u>

In addition to these analyses, each lateral having a load greater than 500 kW is checked considering backup perspective. Along the GA_1 feeder, two laterals have no backup, and they are radially supplied. Therefore, the new connections (Project E - 1/0 CU - 0.056 mi and Project F - 1/0 CU - 0.019 mi) are proposed to satisfy emergency criteria as shown in Figure A.30 and Figure A.31.

Figure A.30: Project E in Area 3 – new connection along the Feeder GA_1

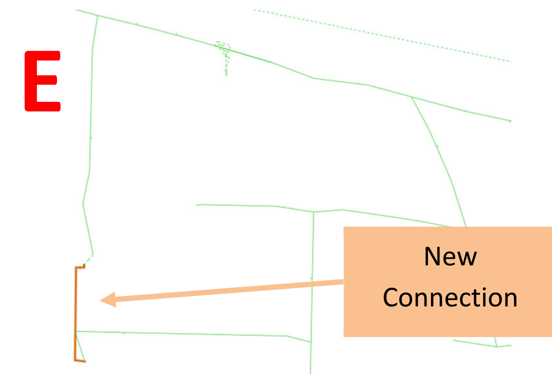
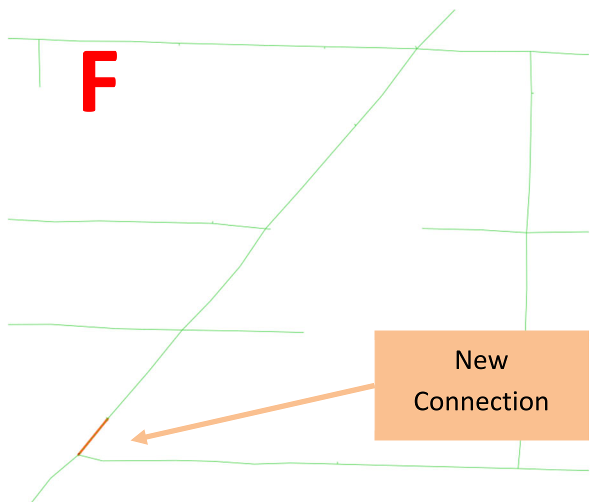


Figure A.31: Project E in Area 3 – new connection along the Feeder GA_1



<u>Capital Expenditures</u>

The proposed projects for Area 3 are listed in Table A.28.

Table A.28: Proposed projects for Area 3

Element Name	Type Name	l [mi]	Year	Project
L5211_INV	3P600CURN_13.8KV	0.019	2032+Elec&EV	D
L5212_INV	3P600CURN_13.8KV	0.017	2032+Elec&EV	D
L5213_INV	3P600CURN_13.8KV	0.015	2032+Elec&EV	D
L5214_INV	3P600CURN_13.8KV	0.082	2032+Elec&EV	D
L5215_INV	3P600CURN_13.8KV	0.041	2032+Elec&EV	D
L5216_INV	3P600CURN_13.8KV	0.023	2032+Elec&EV	D
L5217_INV	3P600CURN_13.8KV	0.031	2032+Elec&EV	D
L5218_INV	3P600CURN_13.8KV	0.014	2032+Elec&EV	D
L5219_INV	3P600CURN_13.8KV	0.026	2032+Elec&EV	D

Element Name	Type Name	l [mi]	Year	Project
L5220_INV	3P600CURN_13.8KV	0.016	2032+Elec&EV	D
L5221_INV	3P600CURN_13.8KV	0.023	2032+Elec&EV	D
L5222_INV	3P600CURN_13.8KV	0.02	2032+Elec&EV	D
L5223_INV	3P600CURN_13.8KV	0.031	2032+Elec&EV	D
L5224_INV	3P600CURN_13.8KV	0.049	2032+Elec&EV	D
L5225_INV	3P600CURN_13.8KV	0.028	2032+Elec&EV	D
L5226_INV	3P600CURN_13.8KV	0.002	2032+Elec&EV	D
L5227_INV	3P600CURN_13.8KV	0.001	2032+Elec&EV	D
L5228_INV	3P600CURN_13.8KV	0.021	2032+Elec&EV	D
L5229_INV	3P600CURN_13.8KV	0.022	2032+Elec&EV	D
L5203_INV	3P500CURN_13.8KV	1.831	2032+Elec&EV	A
L5208_INV	3P500CURN_13.8KV	0.004	2032+Elec&EV	B
L5209_INV	3P500CURN_13.8KV	0.015	2032+Elec&EV	B
L5210_INV	3P500CURN_13.8KV	0.026	2032+Elec&EV	C
L5234_INV	3P1/0CUUNK_13.8KV	0.056	2032+Elec&EV	E
L5235_INV	3P1/0CUUNK_13.8KV	0.019	2032+Elec&EV	F

Based on the proposed projects and capacitor banks investments, an indicative capital expenditure budget is calculated by using the unit costs as listed in Table A.12. The estimated capital expenditure budget for the projects proposed for Area 3 is listed in Table A.29. In addition to the proposed projects, estimated budget for the capacitor banks is listed in Table A.30.

Table A.29: CapEx budget of each project in Area 3

Project Name	Total Line Length [mi]	Number of Breaker	Number of Switch	Comment	Line Cost [$]	Breaker Cost [$]	Switch Cost [$]	Total Cost [$]
A	1.831	1	2	New Feeder	$2,785,852	$149,085	$160,500	$3,095,438
B	0.019	0	0	Overloaded Section	$28,908	$0	$0	$28,908
C	0.026	0	0	Overloaded Section	$39,559	$0	$0	$39,559
D	0.48	0	0	Overloaded Section	$798,461	$0	$0	$798,461
E	0.056	0	1	For lateral backups	$67,752	$0	$80,250	$148,003
F	0.02	0	1	For lateral backups	$22,987	$0	$80,250	$103,238
Total	**2.431**	**1**	**4**		**$3,743,521**	**$149,085**	**$321,001**	**$4,213,606**

Table A.30: Required capacitor investments for Feeder 15199 and Feeder GA_1

Capacitor Banks	
Number of Capacitor Banks	3
Total Reactive Power [kVAr]	900
Total Cost [$]	**$12,220**

CERTIFICATE OF SERVICE

I certify that on April 5, 2023, a copy of the Strategic Electrification Roadmap For Buildings and Transportation in the District of Columbia (Public Version) was electronically delivered to the following parties:

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