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November 2, 2020

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

Re: Formal Case No. 1130

Dear Ms. Westbrook-Sedgwick:

During the course of the FC No. 1130 PowerPath DC working groups, Pepco participated in the Non-Wires Alternatives ("NWA") Working Group where the Company worked with PowerPath DC stakeholders and distributed energy resource ("DER") developers to negotiate the Distribution System Planning for Non-Wires Alternatives Process ("DSP/NWA Process"). Through these discussions Pepco sought to design a transparent process that created a platform for Pepco to incorporate new, innovate DER technologies into its distribution system planning in order to defer large-scale utility investments, such as new substations and other equipment upgrades. On January 24, 2020, the Public Service Commission of the District of Columbia ("Commission") issued Order No. 20286[1] directing Pepco "to submit a revised DSP/NWA implementation timeframe, and noting the Commission "Commission supports an accelerated implementation of DSP/NWA process in three (3) years."

Pepco submits the following report on the current status of the pilot year of implementing DSP/NWA Process.

A. DSP/NWA Process

In February 2020, Pepco filed its revised timeline for implementation of the DSP/NWA Process. As part of the revised timeline, Pepco committed to update the Commission on its progress implementing DSP/NWA Process milestones for the pilot year of the program. In this first year, the Company is focused on developing a transparent

[1] *In the Matter of the Investigation into Modernizing the Energy Delivery System for Increased* Sustainability, Formal Case No. 1130, Order No. 20286 (Jan. 24, 2020) ("Order No. 20286") at P 38.

process that provides a level playing field to evaluate solutions capable of deferring planned utility investments. Any solution selected through the process will be required to maintain the safe, reliable, and cost-effective service provided by Pepco.

On June 1, 2020, Pepco held its second workshop regarding the DSP/NWA Process: Utility & Stakeholder Locational Constraints Report Preparation. The workshop was well attended, with approximately 12 organizations represented. After reiterating background on the load forecasting methodology and the importance of load impacting factors, Pepco discussed the Locational Constraints Report. The Locational Constraints Report reflects the capacity constraints that are the subject of the DSP/NWA Process for that year. Each of the constraints in the Locational Constraints Report will be the subject of an RFP in the current DSP/NWA Process cycle. The constraints may require either a single RFP in the current cycle or may be the subject of multiple RFPs over multiple DSP/NWA Process cycles. On June 18, 2020, Pepco held a follow-up workshop with interested stakeholders to explain the content and format of the Locational Constraints Report. On August 10, Pepco issued the Locational Constraints Report and Request for Information ("RFI") for distributed energy developers and other stakeholders to propose solutions for Pepco's consideration for inclusion in the final RFP.

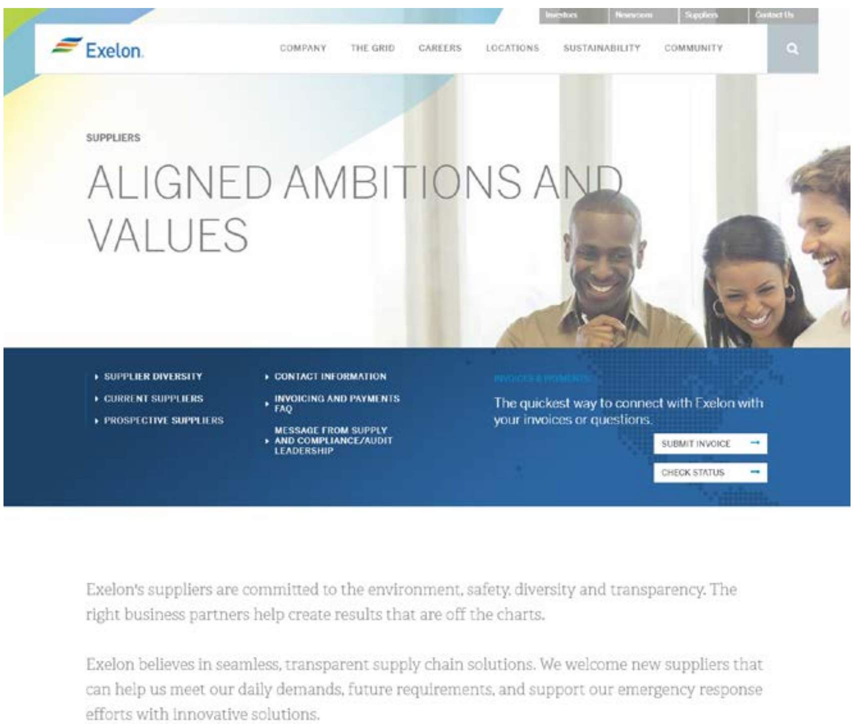
The locational constraint identified in the report is a substation forecasted to exceed 5 percent of its existing transformers' firm capacity by 2026, a timeframe that allows enough time to conduct a robust RFP process.[2] The original solution to address this constraint is to install the fifth transformer that was planned for the substation. During this pilot year of implementing the DSP/NWA Process, approximately ten constraints were identified by Pepco, validating the robustness of the locational constraint process and criteria. As expected with the initial implementation of the DSP/NWA Process, most of the identified constraints were already being addressed by Pepco because they were near-term constraints. These projects were deemed ineligible because either (1) the timing for the need was insufficient for consideration and construction had already begun, or (2) the integrated Capital Grid Project upgrades addressed the constraint. The Company will rely on the short-term system recommendations (completed in February of each year) and long-term system recommendations (completed in May of each year) to align its load forecasting and project planning with the new process, and, therefore, Pepco expects to offer more opportunities in future iterations of the DSP/NWA Process. This approach is consistent with Pepco's responsibility to implement the DSP/NWA Process while maintaining system integrity, minimizing costs passed on to customers, and providing DER developers with opportunities to propose solutions to meet system needs.

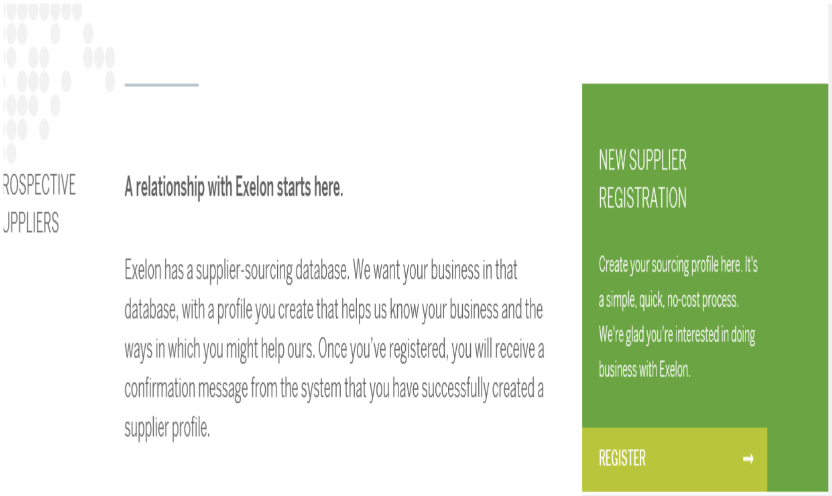
In response to the RFI, the Company received a robust response, including sixteen different developer solutions. The solutions ranged from utility-scale battery projects to customer-owned solar and battery and demand response aggregation schemes. These solutions informed Pepco's RFP regarding the range of solutions currently available and were invaluable

[2] See *Pepco's Update on the Distribution System Planning for Non-Wires Alternatives Process, Formal Case No. 1130* (Aug. 7, 2020).

in constructing an RFP that created a level playing field for different technologies to participate.

On October 1, 2020, Pepco held the third and final webinar, the DSP/NWA Workshop: Utility & Stakeholder RFP Prep, with over 50 DER developers and District attendees participating. The third webinar was designed to prepare developers to respond to the upcoming Nov. 2 RFP for the locational constraint described above. During the course of the webinar Pepco reviewed the locational constraint, discussed the RFP response format, described the Benefit-Cost Analysis ("BCA") Handbook and RFP response evaluation, and emphasized the importance of developer engagement with the District's workforce. Pepco provided a copy of the BCA Handbook to participants following the workshop. Further, Pepco directed interested DER developers to the Exelon procurement website for suppliers seeking to respond to the RFP, www.ExelonCorp.com/Suppliers.





Today, November 2, 2020, Pepco issued the RFP and the BCA Handbook through the Exelon procurement website, initiating the RFP process which will close on February 2, 2020. Pepco has included a copy of the BCA handbook as Attachment 1 to this report.

Going forward Pepco will assess the results of the pilot year of the DSP/NWA Process for improvements that can be made in subsequent iterations of the process. Further, Pepco will continue to engage with DER developers and District stakeholders regarding the development of the process. In doing so, Pepco will continue to strive for the transparency that has defined this process since it was first proposed and negotiated in the PowerPath DC NWA Working Group and defined by the first year of the process.

Sincerely,

/s/ *Andrea H. Harper*

Andrea H. Harper

Enclosures

cc: All Parties of Record

Benefit-to-Cost Analysis Handbook

for Locational Constraint Solutions

October 1, 2020

pepco®

An Exelon Company

Table of Contents

Version Summary

Version	Date	Updates Since Previous Version
1.0	10/01/2020	First Version

1 Introduction

As part of the PowerPath proceeding, the District of Columbia Public Service Commission ("the Commission") established the Distribution System Planning for Non-Wires Alternatives Process ("DSP/NWA Process") with the express goal of advancing the use of non-wires alternatives ("NWAs") to integrate new technologies as the distribution system evolves. To advance that goal, the DSP/NWA Process will solicit, evaluate, and select among third-party solutions designed to address upcoming capacity constraints identified as a result of the load forecasting process of Potomac Electric Power Company ("Pepco" or the "Company"). Pepco views the DSP/NWA Process as an opportunity to engage with the marketplace to identify innovative and cost-effective solutions to defer utility-proposed capacity solutions.

As the only electric utility in the District of Columbia, the Company is committed to providing safe and reliable service. Throughout each year, the Company undertakes robust distribution system planning analyses, including modeling and forecasting to identify upcoming load constraints. For load constraints that Pepco identifies, the Company develops a utility-proposed solution ("UPS") that will effectively address the specific constraint with a view to near- and long-term system needs. In the context of new and emerging grid technologies, Pepco continues to assess each technology's ability to meet forecasted grid constraints and provide value to both grid operations and customers.

Non-utility third parties have shown interest in proposing solutions using new technologies or new uses of existing technologies, sometimes referred to as non-wires alternatives, to meet locational constraint challenges. As Pepco continues to incorporate new non-wires alternatives as part of its own planning as they mature and costs decrease, these third-party solutions are best described as locational constraint solutions ("LCSs"). A locational constraint solution is a solution proposed to defer a utility-proposed solution.

The objective, transparent comparison of UPSs and LCSs forms the basis for the DSP/NWA Process and affords District stakeholders the opportunity to seek more and diverse solutions to meet grid needs. This Benefit-Cost Analysis Handbook ("BCA Handbook") provides the methodology for evaluating locational constraint solutions in Pepco's District of Columbia service territory. In this BCA Handbook, Pepco establishes a fair, consistent, and flexible framework for consideration of various solutions to advance the District's goals for a safe, clean, and reliable grid.

1.1 Background

In Order No. 20286[1], theCommission directed Pepco to move forward with the proposed DSP/NWA Process. An important part of the DSP/NWA Process is establishing a benefit-cost analysis that is performed to determine the cost-effectiveness of solutions used to address an identified capacity constraint.

In February 2020, the Company filed its revised timeline for implementation of the DSP/NWA Process. As part of the revised timeline, Pepco committed to update the Commission and provide certain documents to Staff for review, including a handbook to describe the methodology for evaluating capacity constraint solutions.

On October 1, 2020, Pepco held a workshop in which interested stakeholders were able to review and discuss the methodology included in the BCA Handbook as well as the Request for Proposal ("RFP") process in which it is used as part of the DSP/NWA Process.

1.2 Purpose

This BCA Handbook provides the methodology for evaluating LCSs in Pepco's District of Columbia service area, and this methodology will serve as the primary quantitative framework for the comparison of the benefits and costs associated with an LCS. The methodology outlined in this BCA Handbook addresses the cost-effectiveness test, valuation of benefit and cost streams, implementation of the BCA analysis, and specific calculations for benefit and cost streams.

There are a range of potential LCSs that may be able to meet localized and specific grid needs. To evaluate these LCSs on a level playing field, this BCA Handbook establishes an objective, transparent, and uniform approach to evaluating those solutions. The methodology in this BCA Handbook provides a robust framework for LCS evaluation that will identify projects and programs projected to provide the greatest net benefits for the District's residents from a societal perspective. This approach may evolve over time as conditions change and actual LCS applications provide for further learning.

Pepco's BCA Handbook is customized for the District of Columbia's unique service area and context, including the District's clean energy and climate goals. The methodology described in this BCA Handbook is designed only for the evaluation of proposed LCSs as a part of the DSP/NWA Process in the District of Columbia.

In developing this BCA Handbook, Pepco reviewed existing BCA literature and approaches, adopting aspects of these approaches as appropriate. Notably, many aspects of the BCA

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1 In the Matter of the Investigation into Modernizing the Energy Delivery System for Increased Sustainability, Formal Case No. 1130, Order No. 20286 (Jan. 24, 2020) ("Order No. 20286").

methodology Pepco advances are consistent with the non-wires BCA methodology that the State of New York Public Service Commission established.[2] The New York BCA methodology was developed through a public stakeholder process involving multiple rounds of filed comments from a broad spectrum of organizations, institutions, utilities, and DER service providers and is a widely referenced methodology.[3]

1.3 Analytical Approach

Pepco's evaluation of locational constraint solutions relies upon two key analytical frames: (1) a technical assessment of the LCS to demonstrate that it is capable of addressing the system constraint in whole or in part; and (2) a BCA model to assess the LCS benefits and costs to derive an estimate of net benefits.

Technical Assessment. In order to measure and compare LCS from a technical standpoint, Pepco requires information from a proposal, including but not limited to the technologies proposed, the sizes and specifications of the various technologies, the locations and interconnection on the Pepco system, operational characteristics including the planned timing of operation, and the plan to meet scheduled operational deadlines. The scope of the technical assessment is beyond the scope of this Handbook; however, if an LCS is unable to address the locational constraint in whole or in part, it would be removed from consideration.[4]

BCA Modeling. Pepco's BCA methodology identifies and quantifies the relevant net and incremental benefits and costs associated with the LCS. First, for each type of benefit and cost category, the BCA model accounts for cash or cash-equivalent values by year on a nominal basis, which comprise the value stream for that benefit or cost. The BCA model assesses incremental net benefits and costs, using the annual benefit and cost values of the UPS as a basis for determining a net result. Next, the BCA model determines the net present value ("NPV") of the benefit and cost value streams, applying a standard discount rate to those value streams and deriving the sum of those NPVs. Finally, the BCA model compares the NPV of costs and benefits and assigns a net value to the project. A resulting net positive value indicates that the implementation of the LCS is expected to provide a net benefit, and a resulting net negative value indicates that the LCS is expected to result in a net cost.

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2 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit Cost Analysis Framework, State of New York Public Service Commission Case 14-M-0101 (Jan. 21, 2016).

3 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit Cost Analysis Framework, State of New York Public Service Commission Case 14-M-0101 (Jan. 21, 2016).

4 The LCS may address the locational constraint either as a standalone solution or part of a broader portfolio.

Pepco's BCA methodology identifies benefits and costs from a societal perspective. The types of benefits included in the BCA model are identified in the "Benefits and Costs" section of this BCA Handbook and summarized in Figure 1. The BCA methodology employed in this context is designed to avoid overly speculative benefits, which ensures that the model results are justifiable and consistent.

Figure 1: Benefit and Cost Streams Included in BCA Handbook

Benefit/Cost Stream	Primary Data Sources
Benefits	
Avoided Generation Capacity Costs	PJM
Avoided Energy Costs	PJM; Intercontinental Exchange
Avoided Ancillary Service Costs	PJM
Avoided PJM Transmission Investment Costs	PJM
Deferred Pepco Distribution and Transmission Investment and O&M Costs	Pepco; project-specific inputs
Greenhouse Gas Emission Reductions	PJM; Environmental Protection Agency; Regional Greenhouse Gas Initiative
SO_2 and NOx Emission Reductions	Environmental Protection Agency
Incremental Reliability and Resiliency	Pepco
Costs	
LCS Costs	Project-specific input
Administrative Costs	Pepco
Incremental System Costs	Pepco
Implementation Risk Premium	Pepco

2 Cost-Effectiveness Test

A "cost test" is a basic framework for evaluating a project. The cost test represents benefits and costs from the perspective of a different set of affected stakeholders.

2.1 Societal Cost Test

The BCA methodology for evaluation of LCSs is based on the Societal Cost Test ("SCT"). The SCT is the most holistic way to capture the relevant benefits and costs of an LCS, as the test accounts for the aggregate interests of stakeholders and society.

Pepco selected the SCT framework for LCS evaluation as it captures externalities and avoids transfer payments. The SCT includes evaluation of externalities, such as GHG emission reduction benefits, which aligns with and supports the District's climate policy goals. Additionally, unlike approaches that adopt the perspective of a subset of stakeholders, application of the SCT perspective avoids treating "transfer payments" as benefits (or costs), which is discussed in greater detail in Section 2.2.

The use of an LCS is contingent upon demonstrating net positive benefits versus costs based on the SCT defined in this Handbook. In other words, to pass the SCT, the sum of benefits in today's dollars must exceed the sum of costs in today's dollars. Pepco may perform an evaluation of the LCS from other perspectives (e.g., customer rate impacts) for informational purposes under certain circumstances.

2.2 Avoidance of Transfer Payments in the SCT

A transfer payment represents a cash or value flow from certain members or groups within society to other members or groups within society without the creation of and accounting for additional value. For example, a transfer payment may arise in a case where a public transportation operator increases rider fares to fund a new expansion of bus routes. While the fare increases would result in increased revenue to the operator, the additional revenue cannot be counted as a benefit, as that revenue is the result of an equivalent payment from and cost to riders. This transfer payment is avoided in the methodology used in this BCA Handbook.

In some specific cases where a transfer payment serves a direct and beneficial policy goal, it may be appropriate to account for that payment in the BCA results, and some transfer payments are treated as benefits in the BCA as a way to facilitate progress toward District's clean energy and climate goals.[5] As a general rule, however, transfer payments that are treated as net societal benefits or costs in the BCA can create cross-subsidies resulting in unanticipated outcomes, including outcomes adverse to societal value.[6]

3 Valuation of Benefits and Costs

3.1 Marginal and Dynamic Nature of Costs and Benefits

Benefits and costs included within this BCA reflect marginal impacts, whenever practical, to reflect the LCSs impacts. The use of marginal evaluations is consistent with the SCT framework and is appropriate in this context, as the implementation of an LCS is not expected to affect the marginal resource in the PJM markets.[7] For example, at this time the implementation of an LCS is generally unlikely, based on size, to impact PJM-planned transmission investments to support the wholesale market, and as a result, this marginal

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5 The treatment of these transfer payments will likely evolve in response to District and federal policies related to promoting clean energy and climate change mitigation.

6 As noted earlier, on a case-by-case basis, if the unique circumstances regarding a given LCS warrant special attention to a specific subset of stakeholders, then the Commission may require additional evaluation focusing on that set of stakeholders.

7 There are contexts under which the use of average values is appropriate, such as if marginal values are unavailable or the impact would be sufficiently large to materially affect the marginal cost.

benefit is zero.[8] The use of an average transmission cost, in this context, would overstate the benefit of an LCS. This approach of using marginal benefits and costs is extended to other cost and benefit streams within this BCA methodology.

This BCA methodology also accounts for the dynamic nature of costs and benefits. The effects of investments on the grid are often non-linear in nature, with changes over time subject to a variety of factors that affect the benefits and costs associated with a given type of LCS. The value of a given benefit generally depends upon both the location of the respective LCS and the state of the grid over the effective life of the LCS. For example, a solar generation resource may be able to alleviate a particular feeder's peak hour constraint in the near term; but, as load patterns change over time, the peak hour of need may shift to a different time in the day, which may require a different solution.

3.2 Data Sources and Forecast Considerations

Evaluating benefit and cost streams requires developing forecasts of future values and cash-value estimates of externalities not currently priced in the market. The methodology laid out in this BCA Handbook relies on the following guidance regarding data sources and forecast considerations to inform valuation of benefit and cost streams:[9]

- **Market-based data** and appropriate extrapolation is used where practical. When market data is not available, widely vetted and widely accepted electric industry values are used. Values that are theoretical, overly speculative, poorly defined, or subject to bias are avoided.
- **More granular locational or temporal** assumptions are preferred and used when available and practical. Average values may be used in certain cases in which more granular data is not available.
- **PJM and Pepco are the sources** for wholesale market and distribution system data, to the extent possible.

Benefits, data sources, and forecasting approaches that that are overly speculative and unduly subject to bias are not included in this BCA. For example, significant problems have been identified with respect to proposals to treat "Macroeconomic Benefits" as a quantifiable benefit in certain contexts.[10] The inclusion of such benefits in this BCA could result in

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8 As discussed in subsequent sections, projects that may be able to affect PJM transmission investments based on size or location would be considered and valued in coordination with PJM.

9 Additional guidance pertaining to specific benefits and costs is provided in the "Benefits and Costs" section of this BCA Handbook.

10 See for example, Joint Comments of Baltimore Gas and Electric Company, Potomac Electric Power Company, and Delmarva Power & Light Company on the Final Report Prepared by Daymark Energy Advisors Entitled Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland, PC44 at 3-4 (Dec. 14, 2018). ML#223272

inefficient, costly decisions. Lengthy and disputed proceedings regarding underlying assumptions and assigned values for such benefit streams could slow the advancement of policy goals.

3.3 Avoidance of Double Counting

This BCA methodology is designed to avoid double counting of benefits, which may otherwise inaccurately reflect the true operational, financial, and societal value of a given project or initiative. To avoid double counting, the BCA carefully identifies the value streams derived from various operations and capabilities of an LCS and then clearly differentiates between the benefits and costs to ensure that BCA inputs are mutually exclusive. This evaluation ensures that a benefit has not been captured, in whole or in part, in another benefit category in the BCA.

For example, some LCSs may include energy efficiency or measures that may be assigned a benefit based on avoided energy costs. Multiple benefits are often included in the energy price electricity users pay, and, therefore, several societal benefits are already included, in whole or in part, in the avoided energy cost benefit stream, including:

- Distribution line and transmission line loss gross-up, which is applied to the energy price to reflect the line losses that result from delivering energy to the retail meter;[11]
- Partial carbon dioxide reduction benefits, which are reflected in the cost of Regional Greenhouse Gas Initiative ("RGGI") emission allowances embedded in energy prices; and,
- Avoided SO_2 and NOx benefits, which is the cost of emission allowances embedded in energy prices.

When considering the degree to which an LCS might provide value with respect to these types of benefits, it is important to recognize the extent to which the avoided energy cost benefit stream captures these benefits. For example, since the RGGI allowance price is less than the social cost of carbon, only a portion of the GHG reduction benefit is captured within the avoided energy benefit. As a result, a separate calculation is needed to capture the remaining value. For other benefit streams fully captured within the energy benefit, such as avoided SO_2 and NO_x emissions, a separate calculation to capture these values is not required and would constitute double counting.[12]

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11 These gross-ups accounts for the fact that a one megawatt hour reduction at the customer meter represents more than one more megawatt hour of avoided generation due to losses within the system.

12 This assumes that the societal costs of NO_x and SO_2 emissions are properly accounted for within their respective market prices, as discussed in following sections.

4 Implementation of the BCA Analysis

4.1 Net Present Value of Benefits Calculation

This BCA methodology evaluates LCSs using a net present value of net benefits. In other words, the annual benefit or cost streams are calculated and then discounted to the present day. The resulting costs are subtracted from the benefits to calculate net benefits. This net benefit approach, as opposed to the calculation of a ratio, avoids the potential for uncertainty of whether a value stream should be included in the numerator or denominator of the ratio.[13]

Generally, the time horizon of benefits and costs associated with the LCS reflects either the contracted life of the LCS, if third-party owned, or the life of the LCS, if utility owned. This approach reflects the benefits associated with the LCS costs and is not tied to the number of years that an LCS is able to defer the UPS. For example, if an LCS included a demand response component that was able to defer the UPS by three years with a ten-year contract, then the appropriate time horizon for analysis would be 10 years. A time horizon of three years would not capture the full benefits of the contracted LCS, and the extension of analysis beyond the ten-year time horizon would be arbitrary.

4.2 Discount Rate

The discount rate to be applied in the BCA is Pepco's weighted average cost of capital ("WACC") approved in Pepco's most recent rate case at the time of analysis. Pepco's WACC is a Commission-approved, transparent measure that is publicly known to all parties.[14] It is expressed in terms applicable for nominal cash flows, which is how the BCA model expresses benefit and cost cash and cash-equivalent values. LCSs subject to the BCA are, by definition, distribution investments designed to satisfy the same constraint with a high level of reliability. Therefore, the appropriate discount rate reflects the investment decision at the core of the DSP process.

The BCA uses a consistent Standard Inflation Rate using the most recently available 10-year long-term average for the Headline Consumer Price Index ("CPI") published in the quarterly Survey of Professional Forecasters by the Federal Reserve Bank of Philadelphia.[15]

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13 For example, if one LCS results in decrease in GHG emissions and a second LCS results in an increase in GHG emissions, it is unclear if both benefit/cost streams would appropriately be included in the numerator or denominator.

14 This approach is consistent with the approach approved by the New York Public Service Commission. See Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit Cost Analysis Framework, State of New York Public Service Commission Case 14-M-0101 (Jan. 21, 2016).

15 See https://www.philadelphiafed.org/research-and-data/real-time-center/survey-of-professional-forecasters.

5 Benefits and Costs

An investment, project, or program that is part of an LCS may involve multiple technology types, each associated with specific costs and different benefits. For example, a proposed LCS that uses demand response and storage to meet a distribution system need would have distinct benefits associated with its demand response and storage components. Each technology provides one or more functions that result in one or more quantified impacts that are valued as monetized benefits.[16] Described below are the various types of benefits and costs that are appropriate at this time and included in the BCA and the methods to be used to quantify these benefits and costs. Notably, for a given LCS, the quantification of a benefit value stream could be positive or negative, as benefits are measured incrementally to the utility-provided solution. In the context of a given type of benefit, an LCS may be more or less effective than the UPS.

5.1 Benefits

The following subsections outline the approach to estimate the value of the various benefits included in the BCA for an LCS. Each subsection of this Benefits section addresses an individual type of benefit. For a given LCS, the quantification of a benefit value stream may be positive or negative, as benefits are measured incrementally to the UPS, and an LCS may be more or less effective than the UPS. The subsequent Costs section at 5.2 discusses situations where the LCS contract costs may already reflect the monetization of certain benefits and, as a result, a separate valuation of the respective benefits as described in this section would constitute double counting.

5.1.1 Avoided Generation Capacity Costs

An LCS may avoid the need to procure incremental capacity resources in the PJM capacity market, the Reliability Pricing Model ("RPM"). The LCS can achieve an avoided capacity procurement in two ways: (1) direct participation in the RPM as an inframarginal capacity resource; or (2) reducing demand levels coincident with the PJM system peak. The reduction in demand levels could result from a load-reduction LCS or output from a resource that does not directly participate in the RPM.[17]

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16 If these technologies are integrated and work in concert, for example a system that integrates solar and storage together behind-the-meter, they would be evaluated as a "single" technology rather than attempting to individually assess the components.

17 For example, behind the meter photovoltaics do not participate directly in the RPM but may result in a lower peak demand.

To calculate this benefit, the BCA model estimates the amount of avoided RPM capacity and then values that avoided capacity at the projected RPM market price.[18] The calculation of avoided capacity costs varies based on whether the LCS participates directly in the RPM as a capacity supply resource ("direct participation resources") or indirectly as either a load reduction or other resource that does not participate in the RPM ("indirect participation resources"). The difference in calculation reflects the pricing structures of the RPM and the timing associated with the benefit.

The avoided capacity costs of directly participating LCSs are based on the RPM resource clearing price, and the indirectly participating LCSs are evaluated using the RPM net load price. Both prices are determined in the RPM auctions that PJM conducts. When PJM RPM Base Residual Auction ("BRA") prices are available (typically three years forward), these prices are used.[19] If the evaluation time horizon extends beyond the period in which RPM prices are cleared, the BCA model includes a projection of future capacity clearing prices. This projection results from calculating the average capacity price for the three most recent RPM Base Residual Auctions for the zone and escalating that average price at the Standard Inflation Rate. This approach recognizes that, in the absence of a long-term capacity forward market, recent forward prices represent the best available predictor of longer-term capacity prices for LCS BCA purposes, and the averaging of three years of recent prices mitigates potential bias associated with projecting using a single RPM clearing price.

18 Capacity market prices are differentiated by "Locational Deliverability Areas" within PJM. Pepco DC is located within the Pepco Locational Deliverability Area.

19 For example, the most recently available delivery year for which an RPM BRA has been run is 2021/22. For the Pepco zone the Capacity Resource Clearing Price is $140.00 per MW-day, while the Net Load Price is $140.53 per MW-day. Full results of the 2021/22 BRA are available at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-results.ashx?la=en.

Direct Participation Resources

Calculation

$$Avoided\ Capacity\ Costs_{Year} = \sum_{Zone} Expected\ Cleared\ MW_{Zone,Year} * PJM\ Capacity\ Price_{Zone,Year}$$

Where:

Expected Cleared $MW_{Zone,Year}$ (MW): projected unforced capacity ("UCAP")[20] from the LCS that are expected to clear in the RPM. There are several circumstances under which the Expected Cleared MW requires adjustments, including:

- The LCS owner contractually retains the economic rights to some or all of the capacity output. Only the portion of capacity Pepco retains is counted toward the avoided capacity costs.[21]
- Some or all of the resource may not clear the RPM due to PJM's market rules (e.g., if application of the PJM Minimum Offer Price Rule ("MOPR")[22] would result in the resource being offered into the RPM at a floor price that exceeds the projected RPM market clearing price for a given year.)[23]
- The LCS participates as only a summer or winter resource or aggregates with other resources to form a single capacity resource (and therefore must share a portion of the capacity benefit the aggregate resource provides), then the reduction in value associated with these limitations reflects the amount of cleared unforced capacity attributed to the LCS.[24]

PJM Capacity Price $_{Zone,Year}$ ($ per UCAP MW-Year): projected PJM resource capacity clearing price, expressed in unforced capacity terms, developed for the specific zone and year in question.

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20 This includes applicable derates as required by PJM. Per PJM Manual 21, PJM posts default class-average Nameplate-to-UCAP derate factors for wind and solar resources are available at: https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en. As of September 2020, values are 17.6% for wind resources in flat terrain, 14.7% for wind resources in mountainous terrain, 42% for ground-mounted fixed-panel solar, 60% for ground-mounted tracking solar, and 38% for non-ground-mounted solar.

21 As explained in Section 5.2.1, the contract cost accounts for the anticipated value retained by the LCS owner in the capacity market.

22 See FERC Docket EL16-49, ER18-1314, and EL18-178 (Consolidated) ordering PJM to institute an expanded MOPR. This proceeding is ongoing but is likely to be ruled on by FERC by the end of 2020.

Indirect Participation Resources

$$Avoided\ Capacity\ Costs_{Year} = \sum_{Zone} \frac{\Delta Peak\ Load_{Zone,Year}}{1 - Loss\%_{Bulk \rightarrow Retail}} * Forecast\ Pool\ Requirement_{Year} * Coincidence\ Factor_{Zone,Year} * PJM\ Net\ Load\ Capacity\ Price_{Zone,Year}$$

Where:

ΔPeak Load$_{Zone,Year}$ (MW): LCS-specific projected maximum reduction in load at the customer meter (i.e., not coincident with the PJM system peak).

Loss%$_{Bulk \rightarrow Retail}$ (dimensionless): percentage of cumulative line losses from the bulk retail pricing point (typically the PJM load zone) to the appropriate retail location of the LCS. This line loss percentage may vary depending on such factors as region and interconnection voltage.

Forecast Pool Requirement $_{Year}$ (dimensionless): capacity market parameter published by PJM for each RPM auction delivery year that reflects the additional reserve of unforced capacity that PJM must purchase per MW of peak load that PJM purchases through the RPM. For years for which PJM has not yet published a forecast pool requirement, the most recent forecast pool requirement is used.

Coincidence Factor$_{Zone,Year}$ (dimensionless): a resource-specific scaler reflecting the ratio of the load reduction associated with the LCS during the PJM system peak to the maximum reduction in load associated with the LCS. Unless the timing of the LCS peak output matches the timing of the PJM peak level, this parameter is less than one.

PJM Net Load Capacity Price $_{Zone,Year}$ ($ per UCAP MW-Year): the projected PJM net load capacity price, expressed in unforced capacity terms, developed for the applicable zone and year.

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23 For resources subject to the MOPR, the resource-specific capacity market price floor is compared to the forecasted marking clearing price. If the price floor is higher than the forecasted clearing price, then the resource has an Expected Cleared MW of zero.

24 For example, resources that have highly seasonal output may only offer summer or winter seasonal capacity that is compensated only for the output during the applicable season and must be matched with an equivalent amount of opposite-season capacity for the purposes of market clearing. See sections 4.9 and 4.10 of PJM Manual 18.

5.1.2 Avoided Energy Costs

An LCS avoids energy costs when it reduces the amount of energy that must be produced to serve PJM load, thereby avoiding production costs, such as fuel and variable maintenance. Avoided Energy Costs may result when an LCS either reduces the hour-to-hour net load that PJM must serve or when an LCS directly participates as an infra-marginal resource in the PJM energy market, displacing marginal energy resources. The amount of avoided energy associated with the LCS is valued at the appropriate PJM Locational Marginal Price ("LMP").

The LMP is the sum of three components expressed in dollars per megawatt-hour ($/MWh):

- System Energy Price – the production cost of serving an additional increment of energy demand on the PJM system, not including congestion and transmission losses. The price at which the marginal market seller has offered to supply an additional increment of energy from an energy resource drives the value of this component.
- Congestion Price – the marginal cost of transmission congestion costs at a given location on the system (whether positive or negative) based on the effect of increased generation or consumption on transmission line loadings.
- Line Loss Price – the marginal effect on transmission line loss costs (whether positive or negative) at a given location of the system based on the effect of increased generation or consumption on transmission line losses.

The LMP reflects other variable costs incurred by the marginal energy resource, including the market value of GHG emissions reductions, as RGGI allowance pricing represents, and the market value of SO_2 and NO_x emissions as cap-and-trade markets represent.

The energy price forecast is based on a combination of visible forward market price information and public PJM-developed data. The forecast is anchored around the single year of zonal projected energy prices developed by PJM in support of the current RPM base residual auction (the "PJM-projected year," which is 3 years forward under normal circumstances), which is then scaled upwards or downwards in earlier or later years based on market information. The following methodology is used to derive the energy price forecast, which assumes that the PJM forecast is three-years forward. To the extent that PJM provides a longer time-horizon or to the extent that the time horizon is shorter due to delays in the RPM auction timetable, Pepco will adapt its methodology.

- **Years 1-2:** the seasonal prices for the PJM-projected year (typically year 3) will be scaled proportionally upwards or downwards by the ratio of the annual all-hours average PJM Western Hub forward price, as reported on the Intercontinental Exchange for the applicable year relative to the same for the PJM-projected year (typically Year 3).

- **Year 3:** the energy price forecast will be based on the monthly on- and off-peak forward energy prices for the applicable zone as posted by PJM. The forward price data developed by PJM will be aggregated into summer (June – September) and non-summer (rest of year) on-peak and off-peak periods by calculating the simple average of the relevant monthly prices to create four seasonal prices (summer on-peak, summer off-peak, non-summer on-peak, non-summer off-peak).
- **Years 4-10:** the PJM-developed seasonal prices will be scaled upward or downward by the ratio of the annual average Henry Hub forward natural gas price as reported on the Intercontinental Exchange for the applicable year relative to the same for the farthest out year PJM forecasts.
- **Years 10+:** energy prices will be escalated at the Standard Inflation Rate.

<u>Calculation</u>

$$Avoided\ Energy\ Cost_{Year} = \sum_{Zone} \sum_{Season} \frac{\Delta Energy_{Zone,Year,Retail,Season}}{1 - Loss\%_{Zone,Bulk \to Retail}} * LMP_{Zone,Year,Bulk,Season}$$

Where:

Season: the four seasonal on-peak and off-peak time blocks: summer on-peak, summer off-peak, non-summer on-peak, and non-summer off-peak.

ΔEnergy$_{Zone,Year,Retail,Season}$ (MWh): for LCSs that participate directly in the PJM energy market, the project-specific forecast of energy production at the wholesale market level; or, for LCSs that participate as a retail load reduction rather than offer directly into the energy market, the change in energy consumption at the retail level. The forecast extends over the full time-horizon for evaluation of the LCS and incorporate any documented declines in performance the technology exhibits over time (e.g., declining solar resource output). Only the portion of energy Pepco retains is counted toward the avoided energy costs.

Loss%$_{Bulk \to Retail}$ (dimensionless): the percentage of cumulative line losses from the wholesale retail pricing point (typically the PJM load zone) to the appropriate retail location of the LCS. This line loss percentage may vary by such factors as region and interconnection voltage.

LMP$_{Zone,Year,Bulk,Season}$ ($ per MWh): the projected wholesale LMP for the zone applicable to the LCS, developed according to the principles discussed above.

5.1.3 Avoided Ancillary Services Costs

Ancillary services provide balance to the transmission system as power flows between generation resources and end-use customers and ensure reliable, stable service and power quality. Ancillary service benefits may accrue to selected LCSs that qualify and are willing and able to provide ancillary services to PJM. Such resources are subject to PJM requirements and must be selected and compensated by PJM to provide ancillary services.[25]

To the extent that an LCS is able to provide any of these services, it avoids the need to procure that service from an alternative resource and thereby avoids the production cost associated with providing the service, lowering total system production costs and increasing societal benefits.[26] The benefits associated with avoided ancillary services costs are explicitly quantified and included in the BCA only to the extent that economic rights to the ancillary service the LCS provides are transferred to Pepco. If the LCS retains the economic rights to the ancillary services product, then the value of the benefit is zero and is assumed to be incorporated into the contract cost of the LCS.

Avoided ancillary services benefits are based on the technology-class default ancillary services revenues calculated by PJM as a component of the forward-looking energy and ancillary services values it estimates for different types of resources in developing the parameters for the RPM Base Residual Auction.[27]

Regulation

Regulation maintains system frequency and manages differences between scheduled power flow and actual flow in the system. Resources that can quickly adjust consumption or generation in response to an automated signal can offer into the PJM regulation market to provide this service. PJM sets an hourly regulation procurement amount based on overall system needs.

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25 PJM compensates four types of ancillary services compensated by PJM: regulation, operating reserves reactive supply, and black start service. Due to technical requirements, it is unlikely that an LCS would be able to provide reactive power or black start service. If an LCS is able to provide these services, the Company will develop an appropriate benefit stream.

26 Unless a behind-the-meter LCS has an interface with a system that allows it to directly participate in PJM ancillary services procurement processes, a behind-the-meter LCS will not generate benefits associated with Avoided Ancillary Services Costs.

27 For the 2022/23 auction currently pending, which is the first auction for which PJM is required to calculate forward-looking energy and ancillary services revenues, PJM has provided forward-looking regulation and operating reserve revenue values for combustion turbines, combined-cycles, coal-fired steam resources, and batteries, and reactive service revenue values for all types of capacity resources. See https://www.pjm.com/-/media/committees-groups/committees/mic/2020/20200814-special/20200814-net-cone-values-and-indicative-eas-offset-workbook-supplemental.ashx for the most current values as of August 2020. Resources falling into other technology classes (e.g. wind and solar) are not generally able to provide regulation or operating reserve services and thus are not attributed any revenue for their provision.

Calculation

$$Avoided\ Regulation\ Benefit_{Year} = Regulation\ Revenue_{Class,Year} * Installed\ Capacity_{Class,Year}$$

Where:

Regulation Revenue$_{\textbf{Class,Year}}$ ($ per MW-Year): the most recently released forward-looking regulation service revenue estimate provided by PJM in support of the determination of RPM Base Residual Auction parameters for the technology class of the LCS in question (e.g., batteries, solar). For delivery years either before or after this point, the value provided by PJM is adjusted for inflation using the applicable Standard Inflation Rate. If PJM does not calculate a value for regulation revenue for the technology class of the LCS, then the LCS does not receive this benefit stream.

Installed Capacity$_{\textbf{Class,Year}}$ (MW): the LCS's project-specific projected Installed Capacity rating, determined in accordance with the market rules of the PJM RPM.

Operating Reserves

Operating reserves are additional capacity held in reserve above expected load during real-time operations to help prepare for unexpected contingencies that may occur in real time, such as the unexpected loss of a large generator, large swings in output of intermittent resources, or an unexpected increase in load. Resources selected to provide operating reserves in this process are required to keep the capacity selected for operating reserves unloaded unless PJM instructs to deploy those resources and compensates at the appropriate market clearing price.

Calculation

$$Avoided\ Operating\ Reserve\ Benefit_{Class,Year} = SR\ Revenue_{Class,Year} * Installed\ Capacity_{Class,Year} + NRSR\ Revenue_{Class,Year} * Installed\ Capacity_{Class,Year} + 30\ Minute\ Reserve\ Revenue_{Class,Year} * Installed\ Capacity_{Class,Year}$$

Where:

SR Revenue$_{\textbf{Class,Year}}$ ($ per MW): the most recently released, forward-looking synchronized reserve service revenue estimate PJM provides in support of the determination of RPM Base Residual Auction parameters for the technology class of the LCS in question (e.g., batteries, solar). This value is normalized to revenues per MW of Installed Capacity for each resource class. For the delivery year of the RPM for which this value is calculated, the value provided by PJM is used without adjustment. For delivery years either before or after this point, the value PJM provides is adjusted for inflation using the applicable Standard Inflation Rate.

NSR Revenue$_{Class,Year}$ ($ per MW): the most recently released, forward-looking non-synchronized reserve service revenue estimate PJM provides in support of the determination of RPM Base Residual Auction parameters for the technology class of the LCS in question (e.g., batteries, solar). This value is normalized to revenues per MW of Installed Capacity for each resource class. For the delivery year of the RPM for which this value is calculated, the value PJM provides is used without adjustment. For delivery years either before or after this point, the value provided by PJM is adjusted for inflation using the applicable Standard Inflation Rate.

30 Minute Reserve Revenue$_{Class,Year}$ ($ per MW): the most recently released, forward-looking 30-minute reserve service revenue estimate PJM provides in support of the determination of RPM Base Residual Auction parameters for the technology class of the LCS in question (e.g., batteries, solar). This value is normalized to revenues per MW of Installed Capacity for each resource class. For the delivery year of the RPM for which this value is calculated, the value PJM provides is used without adjustment. For delivery years either before or after this point, the value provided by PJM is adjusted for inflation using the applicable Standard Inflation Rate.

Installed Capacity$_{Class,Year}$ (MW): the LCS' project-specific projected Installed Capacity rating, determined in accordance with the market rules of the PJM RPM.

5.1.4 Avoided PJM Transmission Investment and O&M Costs

LCSs are unlikely to have operational characteristics that materially impact PJM's Regional Transmission Expansion Planning process or operations that allow for the avoidance or deferral of FERC-jurisdictional potential transmission projects or O&M costs. Thus, unless coordinated with PJM to defer the need for a specific transmission asset, LCSs are unlikely to produce a societal benefit related to FERC-jurisdictional transmission.[28]

5.1.5 Deferred Distribution and Subtransmission Investment and O&M Costs

The value of deferred distribution and subtransmission costs is specific to the time period that the LCS can defer the UPS. To defer the UPS, the LCS (or portfolio of LCSs developed) needs to both satisfy the constraint and meet the same safety and reliability requirements as the UPS. Based on the information provided by each potential LCS developer, Pepco

28 If an LCS is coordinated with PJM to defer a specific PJM-planned investment, the Company will develop an appropriate value for that project deferral.

calculates the deferral time period for the LCS and the resulting deferral value. As the benefits comparison is fundamentally between two investment options, the deferral value is based on the annual difference between the utility revenue requirements with and without the LCS.[29] All else held equal, an LCS that can defer the UPS for a longer time period necessarily produces higher benefits.

In addition to the UPS, the LCS may defer other capacity-related investments on the system. For example, a load reduction may be able to defer both a substation-related UPS as well as a distribution line project planned further in the future. However, the ability of an LCS to defer other capacity-related investments is contingent upon the location of the LCS, the operational characteristics of the LCS, and the specific timing and nature of other capacity-related investment needs on the system.

Calculation

$$Deferred\ T\&D\ Investment\ Cost_{Year} = Revenue\ Requirement\ without\ LCS_{Year} - Revenue\ Requirement\ with\ LCS_{Year}$$

Where:

Revenue Requirement without LCS ($): the levelized revenue requirement for the UPS and other capacity-related investments as calculated by Pepco (including inflation as applicable)

Revenue Requirement with LCS ($): the levelized revenue requirement if the LCS is implemented, including other capacity-related investments as calculated by Pepco (including inflation as applicable).

29 This approach is consistent with the approach approved by the New York Public Service Commission. See: Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit Cost Analysis Framework, State of New York Public Service Commission Case 14-M-0101 (Jan. 21, 2016).

5.1.6 GHG Emission Reductions

Emissions of GHGs, such as carbon dioxide (CO_2), impose externality costs on society in the form of climate change and related environmental damages. An LCS may create a reduction in GHG emissions (e.g., energy efficiency) or an increase in GHG emissions (e.g., natural gas turbine) relative to a UPS. The valuation of the benefit associated with avoided GHG emissions is based on United States Environmental Protection Agency ("EPA") Interagency Working Group's ("IWG") Social Cost of Carbon ("SCC") estimates.[30] The IWG has published the most heavily vetted, publicly scrutinized, and widely accepted evaluation of GHG emission damages a government agency in the United States has offered. The IWG's published value for a given year represents an estimate of the monetized damages associated with an incremental increase in CO_2 emissions in that given year.[31]

The valuation of GHG emission reductions is based on four different time periods during each year of the evaluation time horizon: summer on-peak, summer off-peak, non-summer on-peak, and non-summer off-peak. Each of the periods is defined in the Avoided Energy Costs section.

Because a portion of the value of GHG emissions reductions is captured through the RGGI market in the avoided energy costs benefit, this calculation represents only a portion of the value of GHG emissions.

<u>Calculation</u>

$$GHG\ Reduction_{Year} =$$

$$[\,SCC_{Year} - RGGI\ Price_{Year} * conv] * \sum_{Time\ Period} \left[\,Displaced\ Energy_{TimePeriod,Year} * Marginal\ CO_2 EmissionRate_{TimePeriod,Year}\right]$$

$$- SCC_{Year} * LCS\ Net\ Energy\ Output_{Year} * LCS\ EmissionRate_{Year}$$

Where:

SCC_{Year} (\$/ton CO_2): the SCC for the given year, measured in dollars per metric ton of CO_2 emissions, as the EPA IWG reports as the "central value" (i.e., the EPA IWG's calculation of the average of various estimates based on a three percent discount rate),[32] adjusted to be expressed in nominal dollars as of the given year. The SCC values provided by the EPA are expressed in 2007 dollars. These values are first inflated to current year nominal dollars

30 https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html

31 See: https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf

32 See https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html

using the simple averages of the monthly values for the BLS CPI-U index data (BLS CUUR0000SA0).[33] To express the dollars into future years, the Standard Inflation Rate is used.

RGGI Price$_{\mathbf{Year}}$ (\$/ton CO_2): the RGGI CO_2 emission allowance price. The average price from the four most recently reported quarterly RGGI auctions is used,[34] and this value is escalated at the same annual rate as the avoided energy price.

conv: The conversion rate between short tons RGGI uses and metric tons EPA uses for the SCC.[35] This value is equal to 1.10231, which is the ratio of short tons to metric tons.

Displaced Energy$_{\mathbf{TimePeriod,Year}}$ (MWh): the net energy at the wholesale level the LCS displaces in the given time period.

Marginal CO_2 Emission Rate$_{\mathbf{TimePeriod,Year}}$ (ton CO_2/MWh): the PJM marginal CO_2 emission rate for the given time period, measured in metric tons of CO_2 per megawatt-hour, calculated as the simple average of the applicable monthly values PJM reports, converted to metric tons.[36]

LCS Net Energy Output$_{\mathbf{Year}}$ (MWh): the net energy output from the LCS over the course of the given year.

LCS CO2 EmissionRate$_{\mathbf{Year}}$ (ton/MWh): the CO_2 emission rate for the LCS over the course of the given year expressed in metric tons/MWh.

5.1.7 SO_2 and NO_x Emission Reductions

The EPA's Acid Rain Program ("ARP"), Cross-State Air Pollution Rule ("CSAPR"), and CSAPR Update are emission regulations implemented through cap-and-trade emission allowance programs, designed specifically to reduce power plant emissions of SO_2 and NO_x. The market prices from these cap-and-trade markets provide reasonable estimates of the marginal cost of SO_2 and NO_X emissions for LCS BCA purposes.[37]

PJM wholesale energy market prices already incorporate the costs of the emission allowances associated with the marginal energy purchased or avoided for participating generators. Therefore, SO_2 and NO_X emissions costs that are avoided by displacing other

33 See https://data.bls.gov/timeseries/CUUR0000SA0
34 See https://www.rggi.org/auctions/auction-results/prices-volumes
35 See https://www.rggi.org/program-overview-and-design/elements
36 For example, see https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/2019-emissions-report.ashx?la=en.
37 The Clean Air Act, the umbrella law under which NO_x and SO_2 programs are implemented, also includes regulation of particulate matter (PM), and it may be appropriate to include the public health benefits attributable to the reduction in particulates from power plants in the future.

power generating resources are already captured in the Avoided Energy Costs benefit category. However, the EPA's programs only apply to electricity generators with a nameplate capacity greater than 25 MW.[38] To the extent that an LCS incorporates generation resources that have capacities less than or equal to 25 MW, the cost of the SO_2 and NO_X emissions from those generation resources are included as a societal cost (effectively netting from the gross SO_2 and NO_X emissions that are avoided by displacing other power generating resources) in the BCA.

Calculation

For generators not subject to the EPA programs described above (capacities less than or equal to 25 MW),

$$LCSEmissionsCost_{Year} = \sum_{SO2,NOx} NetEnergyOutput_{Year} * EmissionRate_{Year} * EmissionCost_{Year}$$

Where:

$\mathbf{NetEnergyOutput_{Year}}$ (MWh): the net energy output from the generator over the course of the given year.

$\mathbf{EmissionRate_{Year}}$ (ton/MWh): the applicable emission rate (for SO_2 or NO_X) for the generator over the course of the given year.

$\mathbf{EmissionCost_{Year}}$ ($/ton): the estimated market-based cost of SO_2 or NO_x emissions for the applicable location. Costs may be estimated from historical emission allowance spot prices the EPA reports.[39] Emission allowance spot prices for the most recent three years the EPA reports are used, with escalation over time calculated based on the Standard Inflation Rate. Costs pertaining to all applicable SO_2 and NO_x emissions programs (annual and seasonal) must be summed together.

38 See https://www.epa.gov/acidrain/acid-rain-program

39 See https://www3.epa.gov/airmarkets/progress/reports/market_activity_figures.html#figure2. See also Power Sector Programs Progress Report 2019, U.S. Environmental Protection Agency at 63. (https://www3.epa.gov/airmarkets/progress/reports/pdfs/2019_report.pdf)

5.1.8 Incremental Reliability and Resiliency

The U.S. Department of Energy defines reliability as "the ability of the system or its components to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components."[40] It defines resilience as "the ability of a system or its components to adapt to changing conditions and withstand and rapidly recover from disruptions."[41] Both concepts relate to the societal benefits or costs of reducing or increasing, respectively, the frequency and extent of power outages. Correspondingly, the value of Incremental Reliability and Resiliency pertains to the value to customers of reduced or increased frequency and extent of power outages.

Benefits for Incremental Reliability and Resiliency value are not included in the BCA to evaluate prospective LCSs at this time because (1) there is no approved resilience measurement approach or valuation approach, and (2) LCSs are solicited as a substitute for the UPS that is designed to satisfy the District's high expectations for reliability levels. LCSs are not solicited to further increase reliability levels beyond those expectations and, consequently, unlikely to provide incremental reliability benefits beyond the UPS.

5.2 Costs

The following subsections identify the types of costs to include in a BCA used to assess LCSs in the DSP/NWA Process and the quantification approach that is used to avoid double counting.

5.2.1 LCS Costs

Pepco will solicit LCS proposals to satisfy a direct need associated with the distribution system. The solutions may be either utility or third-party owned. The cost of an LCS is reflected through the offered contract and includes upfront investment costs as well as ongoing O&M costs. The LCS contract costs are reflected in the BCA as the annual revenue requirements needed to cover these costs. This approach places both utility and third-party owned LCSs on an even playing field.[42]

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40 Transforming the Nation's Electricity Sector: The Second Installment of the QER, U.S. Department of Energy (Jan. 2017). Available: https://www.energy.gov/sites/prod/files/2017/01/f34/Chapter%20IV%20Ensuring%20Electricity%20System%20Reliability%2C%20Security%2C%20and%20Resilience.pdf

41 Transforming the Nation's Electricity Sector: The Second Installment of the QER, U.S. Department of Energy (Jan. 2017) Available: https://www.energy.gov/sites/prod/files/2017/01/f34/Chapter%20IV%20Ensuring%20Electricity%20System%20Reliability%2C%20Security%2C%20and%20Resilience.pdf

42 For example, a utility-owned LCS is likely to have a large upfront payment while a third-party LCS is likely to be compensated through annual payments. If the two cost structures were not annualized,

If the LCS is third-party owned, only the benefits contractually assigned to Pepco are included in the BCA analysis in order to avoid double counting. As shown in the Benefits section, the societal benefits that an LCS may provide are often not limited to delivery system benefits. The monetization of these additional benefits may be retained by the owner of the LCS, contractually granted to the utility, or be externality benefits such as emission reductions. To the extent that the LCS owner retains the monetization of a given benefit, basic economic principles dictate that the monetary value that the LCS owner realizes from that benefit is already netted from the offered contract payments that the LCS owner requires from the utility. In such cases, a separate value is not attributed to that benefit in the BCA because that would constitute double counting.

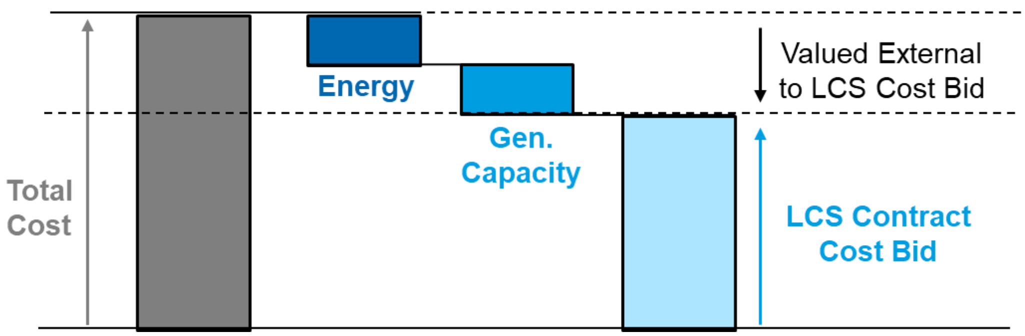
The effect of an LCS owner retaining benefit streams and the subsequent effect on contract costs is illustrated in Figure 2, which shows a hypothetical LCS that relieves the locational constraint and provides avoided energy and avoided generation capacity offered under two different contract structures. In the first contract structure (top chart in Figure 2), the third party contractually retains both the avoided energy and avoided generation capacity benefits. In the second contract structure (lower chart in Figure 2), the third party only contractually retains the avoided energy benefit, and the avoided generation capacity investment is contractually assigned to the Company. Under the first contract structure, the contract cost bid into the RFP is lower as the third party retains more benefit streams. During the evaluation of this bid, no benefit for avoided energy or avoided generation capacity would be assigned, as this would result in double counting. Under the second contract structure, the third party retains fewer benefit streams and the resulting contract cost is higher. However, in the valuation of the second contract structure, a benefit would be assigned for avoided generation capacity.[43]

the calculation would be biased toward third-party owned solutions due to the net present value calculation of costs, which are spread out over time.

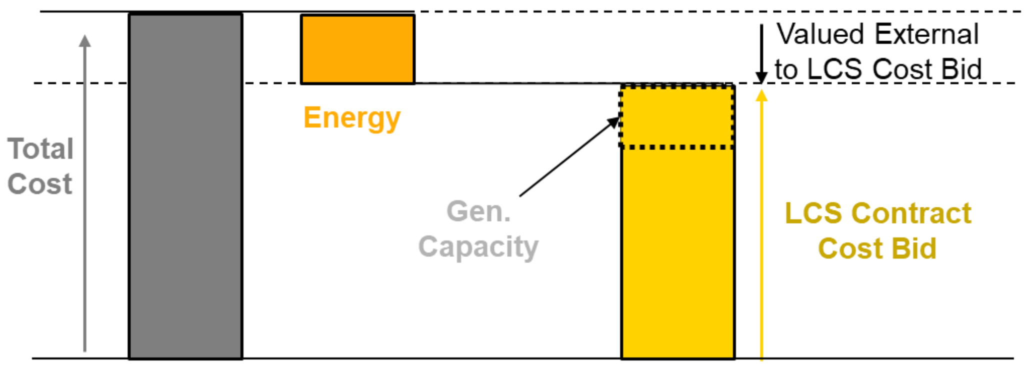
43 The two net costs may not be identical due to differences in forecasting of revenue streams.

Figure 2: Allocation of Benefit Monetization Rights and Effects on Contract Costs (Illustrative)

Structure 1: Avoided Energy and Generation Capacity Benefits Retained by Third Party



Structure 2: Avoided Energy Benefit Retained by Third Party



The bid prices for third-party owned LCSs that retain all monetizable rights reflect the benefit streams related to District and federal energy policy, such as metering policies, tax credits, and renewable energy credits. To the extent that the utility is able to monetize the same benefit streams for an utility-owned LCS, appropriate adjustments are made to these LCS costs.[44] This approach supports the District's leading climate change goals, including those established in the Clean Energy DC Omnibus Amendment Act of 2018, which moves the District toward a decarbonized electricity mix and sourcing 100% of the District's electricity needs from renewable generation resources by 2032.[45] This approach places LCSs on a level playing field with the Deferred Pepco Distribution and Transmission Investment Costs, which is based on the revenue requirement of the UPS that is already net of these benefit streams.

[44] For example, a third-party owned LCS may have access to different rate structures than a utility-owned LCS.

[45] This approach will be revisited to the extent that new or amended policies are advanced that create or materially affect monetizable benefits related to meeting District, regional, or federal energy policies.

5.2.2 Implementation Risk Premium

The implementation of an LCS through the RFP process presents financial risks, ultimately to District customers, for costs that are not incorporated into the LCS bid cost. These potential costs include increases in project cost between the bid price and final negotiated price and additional utility investment and O&M expenditures to enable the LCS that are not captured in the initial technical analysis. Based on the Company's experience with estimating project costs, these costs could represent a 10% to 30% increase relative to the bid price. The Implementation Risk Premium will not be applied until the Company has developed sufficient data to support a calculation based on the implementation of multiple LCSs, and the BCA Handbook will be updated at that point to support the inclusion of the risk premium.

5.2.3 Administrative Costs

Administrative costs include the incremental costs the utility incurs (and any other party outside of the LCS owner incurs) associated with administration of the LCS. These costs are separate from the LCS contract costs and any additional payments or credits to the LCS owner. Administrative costs include the costs of contracting and coordinating with the LCS owner, as well as measuring and verifying the effectiveness of the LCS over the duration of the contract. Estimates of these costs are expressed on an annual basis and included in the BCA as appropriate.

5.2.4 Incremental Distribution System Costs

Implementation of an LCS may require Pepco to make additional investments in the distribution system, such as expanding system capacity, implementing more sophisticated control functionalities, or enhancing protection to ensure seamless grid integration of new assets that comprise the LCS. These are incremental distribution costs, but they are not a part of administrative costs. To the extent that the LCS owner bears these costs, it is reasonable to assume that they are reflected in the LCS contract costs. To the extent that these costs are not included in the LCS contract cost, the costs are incorporated in the revenue requirement calculation of the "Avoided/Deferred Distribution and Subtransmission Investment Costs" benefit revenue requirement quantification.

6 Conclusion

This BCA Handbook and the BCA methodology advanced within it represent a common, consistent, and flexible approach to evaluating locational constraint solutions to meet distribution system planning needs in the District of Columbia. This approach is based on widely accepted foundations and generally exercised practices that derive justifiable and supportable results. From time to time, and subject to the learnings in DSP/NWA Process cycles, Pepco will update its methodology to ensure fairness, remain consistent with industry practices and Commission guidance, and address policy goals surrounding deployment of advanced energy technologies. In advancing this BCA Handbook, it is Pepco's intent to fairly assess and integrate innovative grid solutions that provide the greatest benefits at the least cost to the District of Columbia's residents, businesses, and communities. As part of Pepco's obligation to serve customers with safe and reliable service, the Company looks forward to realizing the benefits of these technologies as the District plans for future opportunities to enhance the distribution grid.

CERTIFICATE OF SERVICE

I hereby certify that a copy of Potomac Electric Power Company's Report on implementing DSP/NWA Process was served this November 2, 2020 on all parties in Formal Case No. 1130 by electronic mail.

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