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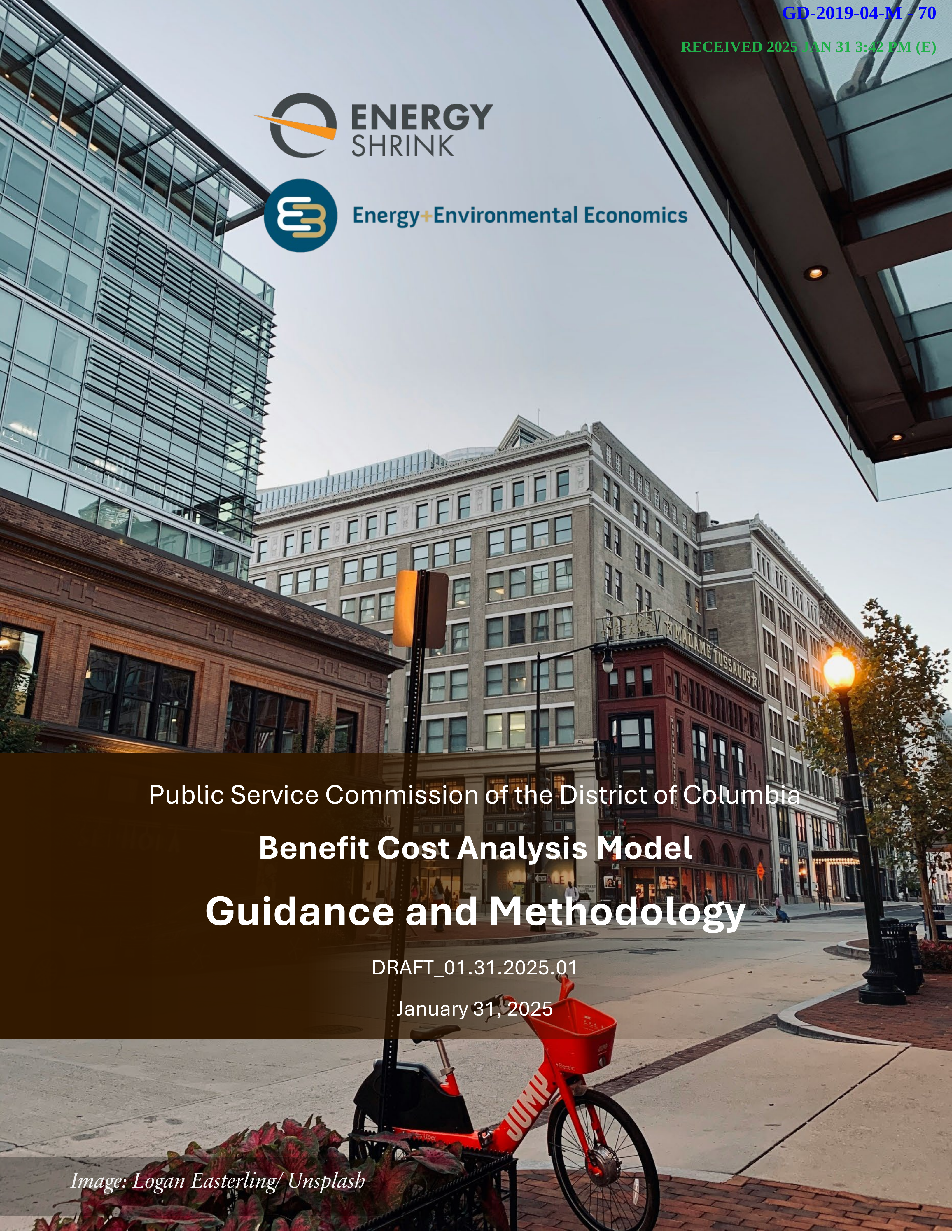

Energy Shrink

Energy+Environmental Economics

Public Service Commission of the District of Columbia

Benefit Cost Analysis Model

Guidance and Methodology

DRAFT_01.31.2025.01

January 31, 2025

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PUBLIC SERVICE COMMISSION
District of Columbia

Your Energy. Your Voice.

Benefit Cost Analysis Model

Guidance and Methodology

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Purpose

About this Document

This document is a guidebook for the use of the Benefit-Cost Analysis Model ("BCA Model") issued by the Public Service Commission of the District of Columbia ("DCPSC" or "the Commission"). The Commission regulates energy utilities (electricity and gas) in the District, in addition to telecommunications.

This document includes user guidance for the BCA Model and the methodology and calculations used in the Model for Part A[1]. (This guidance document will be updated after Part B of the BCA Model is complete.)

Purpose of the BCA Model

The purpose of the BCA Model is to serve as a screening tool to evaluate and compare utility initiatives designed to achieve the District's climate and public policy goals. With a uniform BCA Model that applies to all utility proposals, the Commission aims to provide a higher level of regulatory transparency into the decision-making process.

The Commission has selected the Societal Cost Test ("SCT") as the primary BCA test, and the Total Resource Cost ("TRC") as the secondary test to provide guidance to the Commission on initiatives related to natural gas and electricity. Note that the Commission shall rely on the BCA for guidance; however, the Commission is not required to approve all initiatives that are determined to be cost-effective or to reject all initiatives that are determined not to be cost-effective.

Process

The approach to the BCA Model and the methodology for calculations has been developed by the Energy Shrink Team of Consultants comprised of Energy Shrink, LLC and Energy and Environmental Economics, Inc. (E3) working in close coordination with the Commission Staff. To develop a meaningful approach to the BCA Model, the Consultant team reviewed Order No. 21938 (the "Order") and District policy goals.

[1] The BCA Model is being developed in two parts. Part B includes additional benefits and costs that are not as easily quantified, and will follow as an update to the BCA Model for Part A.

User Guidance

The BCA Model has been developed as a Microsoft Excel-based tool to make it accessible to users. Context-based user guidance is provided within the Model at the points of use.

Navigating the Model

The Excel tool is a workbook with several tabs; users should start from the leftmost tab named 'Start' in the workbook.

The three tabs after the Start page are where all the inputs and results can be viewed and saved.

Tab 1. Interactive Dashboard

The Interactive Dashboard is also the "Home" location of the tool. The instructions provide brief guidance for users to get started on the tool; they also link to a detailed 'User Guidance' tab provided for new users.

The Interactive Dashboard tab displays the Results of the BCA tests and **contains all the user inputs**. The two main parts of the tab are:

a. Results panel: The results of the SCT and TRC tests are displayed here once the user inputs have been made.
b. User Inputs: Users enter the inputs on benefits and costs plus a few other key assumptions for the initiative being evaluated into the designated fields including the following fields:

Element	Unit	Definition
Program Administrative Costs	$	Administrative costs to run the program
Operation & Maintenance	$	Operation & Maintenance costs specific to the program
Host Portion of DER Costs	$	Costs to construct or implement a DER borne by the DER host
Host Transaction Costs	$	Transaction cost between the utility and the DER or program host
Interconnection Fees	$	Fees to connect DERs to the transmission or distribution system
Host Customer Non-Energy Impacts	$	Additional benefits or costs to the DER or program host that are not incorporated in the utility revenue requirement
Utility Performance Incentives	$	Performance incentives offered by the electric or gas utility for the DER or program
Financial Incentives	$	Non-utility financial incentives for the DER or program (Utility incentives are treated as transfer payments)
Tax Credits	$	State or federal tax credits for the DER or program

Tab 2. Benefits & Costs Viewer

This tab displays a summary of the Benefits and Costs calculated by the BCA Model.

a. **Bundled results** show summarized values for the benefits and costs and grouped by "value streams" self-evident by their names and described in further sections in this methodology document.
b. **Detailed results** show the benefits and costs for each element evaluated in the BCA tests. Both net present values (NPV) and annual values are displayed.

Tab 3. Portfolio Viewer

This tab displays the results of all the programs that have been modeled and "saved" via the Interactive Dashboard for a portfolio view. Program data saved on this tab can be deleted for a single program or for all programs by using the buttons located between the two charts. The "Delete specified program data" button will delete the data associated with the program name selected in the drop-down located directly beneath the button. After deleting the selected data, other remaining data is shifted over to avoid gaps in the saved data arrays.

GHG Abatement Cost Curve

This tab contains two portfolio-level visualizations: a bar chart showing total SCT costs and benefits side-by-side for each saved program, and a carbon abatement curve. The abatement curve ranks each program by its dollars per ton of avoided CO_2e and then shows the amount of avoided CO_2e for each of these ranked programs. Using the dropdown to the left of the chart, the user can choose what dollar metric to use for this ranking: gross costs, gross benefits, or net benefits for either the TRC or SCT. Using TRC net benefits provides the most traditional view of carbon abatement, but other selections may help inform decision-making.

It is important to note that the carbon abatement curve does not represent overlap or interdependence in programs. Each program in the curve is regarded as independent from the others, so a user would need to input programs without overlapping carbon or benefit/cost impacts in order to use this feature accurately. For a portfolio of programs that are independent from one another, the total cost of abating a given amount of carbon is represented by the area under the curve up to the target abatement amount.

Tab 4. Test Element Calculations

The tabs to the right of the Portfolio Viewer tab in the BCA Model contain the Test Element Calculations. The tabs display the back-end calculations used in the modeling of the BCA. From left to right, the tabs contain:

- Month-Hour Electricity values calculated for the model by combining month-hour user inputs with back-end data
    - "Month-Hour" refers to the average value for each hour per month
- Electricity Test Elements with Hourly and Annual values
- Gas Test Elements with Annual values; note that the model does not have hourly analysis for gas
- GHG and Air Pollutant Test Elements with Month-Hour and Annual values
- Emission Rates and Cost Inputs for GHG and Air Pollutants
- Other Fuel Costs. The model includes:
    - Propane
    - Fuel Oil (* assumed 'Distillate fuel oil, 15 ppm Sulfur and under), and
    - Gasoline

Reference

The rightmost tabs contain the reference section of the BCA Model, which includes:

- User guidance
- Lookup values for dropdown menus, units and conversion factors used in the model

Benefit-Cost Tests & Key Assumptions

Benefit-Cost Tests

Standard cost-effectiveness tests have been used by Utility Commissions across the US to determine economic benefits versus costs of utility proposals from different stakeholder perspectives such as a utility, or a customer, or society. Most often, these tests have been used to determine the feasibility of energy efficiency (EE) or Demand Response (DR) programs offered by utilities in response to policy mandates, but they can also be used for projects proposed by other parties and other initiatives related to electric or gas energy use. The traditional tests looked at a single perspective such as the perspective of the Utility or of the Participant in a utility energy-efficiency program. A later entrant, the Total Resource Cost (TRC) test was devised to look more broadly at benefits and costs experienced by both the utility and the customers. The Societal Cost Test (SCT) broadens the TRC further to look at the economic impact on not just the utility and customer but also societal impacts such as environmental and public health impacts. The advantage of adopting an SCT as the primary test is that "externalities" such as impacts to the environment and public health can be selectively included to align with the policy goals of the jurisdiction.

The DC Commission has selected the SCT as the primary test to be able to help evaluate whether proposed initiatives help to address District policy goals.

Key Assumptions

In addition to the basic top-level information such as Program Name, Year of Analysis, Period of Analysis, and Sector Impacted, the Key Assumptions section includes the following key assumptions.

Societal Cost Test

Discount Rate

This is a key element that determines the present value of projected benefits and costs, and therefore the outcome of the BCA.

The Commission Order sets the societal discount rate as 2%.

Total Resource Cost

Discount Rate

The Commission Order sets the TRC discount rate as the utility Weighted Average Cost of Capital (WACC). This is a user input.

Test Element Methodology

To develop methodology for each of the test elements, each element was grouped into a "Value Stream Group": electricity elements, gas elements, environmental elements, other elements, and user inputs. Within a value stream, each of the combined element groups jointly use data sources and methodology. Table 1 shows each individual and grouped test element by value stream group. A full list of test elements as originally listed in the order is provided in Appendix Table 1.

Table 1. BCA Test Elements by Value Stream Group

SCT	TRC	Value Stream Group	Element No.	DATA	BCA TEST ELEMENTS
X	X	Electricity Elements	A01 + A06 + A07	VDER Stu	Energy and Ancillary Services (includes DRIPE) (E)
X	X	Electricity Elements	A02	VDER Stu	Generation Capacity (Electric)
X	X	Electricity Elements	A08 + A09	VDER Stu	Transmission Capacity and System Losses (E)
X	X	Electricity Elements	A10 + A12 + 13	VDER Stu	Distribution Capacity, O&M, and Voltage (E)
X	X	Electricity Elements	A11	VDER Stu	Distribution System Losses (E)
X	X	Electricity Elements	A20	VDER Stu	Credit and Collection Costs (E)
X	X	Electricity Elements	A05 + A04	VDER Stu	RPS Compliance (Includes Env. Compliance) (E)
X	X	Other Elements	A30	EIA Therr	Avoided Water Costs (E)
X		Environmental Elements (Electricity)	A14	NREL Car	CO2 (E)
X		Environmental Elements (Electricity)	A15	NREL Car	CH4 (E)
X		Environmental Elements (Electricity)	A16	NREL Car	N2O (E)
X		Environmental Elements (Electricity)	A17	EPA Emis	NOx (E)
X		Environmental Elements (Electricity)	A18	EPA Emis	SO2 (E)
X		Environmental Elements (Electricity)	A19	EPA Avo	PM (including subset of PM2.5) (E)
X	X	Gas Elements	A01 + A02 + A04	EIA Annu	Energy and Capacity Iincludes Environmental Compliance) (G)
X	X	Gas Elements	A08	Based or	Transmission Capacity (G)
X	X	Gas Elements	A10	WGL data	Distribution Capacity (G)
X	X	Gas Elements	A12	National E	Distribution O&M (G)
X	X	Gas Elements	A06	Avoided	Market Price Effects (G) (DRIPE)
X	X	Gas Elements	A20	WGL arre	Credit and Collection Costs (G)
X		Environmental Elements (Gas)	A14	EPA Emis	CO2 (G)
X		Environmental Elements (Gas)	A15 + A09 + A11	EPA Emis	CH4 (G) (includes Tx and Dx system losses)
X		Environmental Elements (Gas)	A16	EPA Emis	N2O (G)
X		Environmental Elements (Gas)	A17	EPA Emis	NOx (G)
X		Environmental Elements (Gas)	A18	EPA Emis	SO2 (G)
X		Environmental Elements (Gas)	A19	EPA Emis	PM (including subset of PM2.5) (G)
X	X	Other Elements	A03	EIA Histo	Propane - Other Fuels
X	X	Other Elements	A03	EIA Histo	Fuel Oil - Other Fuels
X	X	Other Elements	A03	EIA Histo	Gasoline - Other Fuels
X	X	User Inputs	A21	User Inpu	O&M
X	X	User Inputs	A25	User Inpu	Program Administration Costs
X	X	User Inputs	A22	User Inpu	Host Portion of DER Costs
X	X	User Inputs	A23	User Inpu	Host Transaction Costs
X	X	User Inputs	A24	User Inpu	Interconnection Fees
X	X	User Inputs	A28	User Inpu	Utility Performance Incentives
X	X	User Inputs	A26	User Inpu	Financial Incentives (non-ratepayer funded)
X	X	User Inputs	A27	User Inpu	Tax Incentives (non-State)
X		User Inputs	A29	User Inpu	Host Customer Non-Energy Impacts
X		Part B	B01	Pending	HFCs
X		Part B	B02	Pending	SF6
X		Part B	B03	Pending	Upstream Emissions
X		Part B	B04	Pending	Racial Equity
X		Part B	B05	Pending	Energy Burden (Equity)
X	X	Part B	B06	Pending	Locational and Temporal Value of DER
X		Part B	B07	Pending	Low-Income Impacts (Equity)
X		Part B	B08	Pending	Moderate-Income Impacts (Equity)
X		Part B	B09	Pending	Public Health
X	X	Part B	B10	Pending	Reliability
X	X	Part B	B11	Pending	Resilience

Electricity Elements

Many of the avoided costs developed for the electricity elements are based on the 2023 study "Value of Distributed Energy Resources Study for the District of Columbia" ("VDER study") conducted by Synapse under DCPSC Case FC-1130.[2] The Commission established the contract based on the direction of the MEDSIS Working Group to analyze the potential value of DERs and develop a framework for valuing DER services in DC. The VDER study used DC-specific data, including upgrade costs and peak load by feeder. One output of this study was electricity avoided costs. To maintain consistency within the jurisdiction, the BCA Model uses these avoided costs for the electricity elements within the BCA Model. Some of the costs are adjusted to align with current values and more recent projections, described below, while others are used directly from the VDER study.

The VDER study calculates avoided costs from 2020-2045. In the absence of VDER study data for 2046-2050, the electricity system avoided costs were assumed to remain steady from 2045 to 2050. The BCA study applies the 2045 avoided costs to the years 2046-2050. Note that the avoided costs derived from the VDER study may need to be revisited in the case of updates to the VDER study values.

The BCA Model accounts for value streams that apply to a wide variety of program types and DER technologies. The Model accommodates DERs such as solar panels that support the grid by producing renewable energy, which lowers costs associated with electricity generation, transmission, distribution, and potentially GHG compliance. Other technologies, like battery storage and load shifting demand response (e.g., managed EV charging) reduce grid costs by consuming energy during low-cost and/or low-GHG hours and discharging/avoiding consumption during high-cost and/or high-GHG hours. Meanwhile, technologies like energy efficiency and load shedding demand response lower load on the grid to provide benefits. The Model also accommodates programs that increase electric load such as EV adoption or building electrification. In these cases, the same values apply but should be input as costs to the system given that load is increasing.

Many of the benefits achieved by DERs match benefits that can also be achieved by their utility-scale counterparts (e.g., rooftop solar compared to utility scale), but distributed resources uniquely contribute value to the transmission and distribution systems, including the possibility of voltage control and avoiding losses. The VDER study identifies high values for DC associated with distribution capacity, energy, generation capacity, and GHG emissions.

[2] Synapse, 2023 "Value of Distributed Energy Resources Study for the District of Columbia" and filed as FC-1130-2023-M-759 on October 25, 2023. https://edocket.dcpsc.org/apis/api/Filing/download?attachId=194999&guidFileName=a1a60613-580e-46fe-8ca0-b6578d6f2c1d.pdf

The VDER study uses a counterfactual method[3] to determine avoided electricity costs. They run one forecast based on their expected deployment of DERs and a counterfactual case in which DER penetration is frozen at today's values. They then base the value of DER on the difference between these cases. While this mechanic appropriately determines the value of the entire portfolio of DERs that differentiate their two cases, it is less appropriate for determining the value of a single program, whose impact on the grid will be more marginal than transformational. This likely results in avoided costs that, for evaluation of programs with more modest impacts, tend to overstate the value of DERs to the grid.

Energy, Ancillary Services, Market Price Effect, Environmental Compliance, and Transmission System Losses

The BCA Model uses the VDER study for the electricity avoided cost components in this section. DERs can provide value by generating electricity and avoiding grid-scale electricity generation, potentially resulting in energy cost savings. By reducing electricity needed to be sent across transmission lines, DERs can lower power losses on the system, known as transmission losses. If a DER has lower emissions output than the marginal grid resource in a given hour, the cost of complying with SO_2 and NO_X emissions regulations, or environmental compliance, is reduced. Additionally, some DERs can provide savings for procurement of ancillary services (AS), should the DER be able to provide regulation, spin, and other grid support. DERs can also reduce the price of electricity due to demand effects and fuel volatility. Energy DRIPE (or Demand Reduction Induced Price Effect) refers to the decrease in market price for electricity that results from a DER reducing demand for electricity. Market price risk reductions represent the decreased risk of fuel price volatility by having DERs providing electricity that is disconnected to fuel prices.

Element	Unit	Definition	Data Source(s)
Avoided Energy Generation	$/MWh	Avoided cost of electricity supplied to customers	Synapse, 2023 "Value of Distributed Energy Resources Study for the District of Columbia" • VDER energy costs include each of these components. • Energy prices capped at $500/MWh
Energy DRIPE	$/MWh	Price effect in the wholesale markets caused by a reduction or increase in demand	
Ancillary Services Costs	$/MWh	Avoided costs of services required to maintain electric grid stability and power quality	
Avoided Transmission Losses	$/MWh	Avoided costs associated with electricity lost through the transmission system	

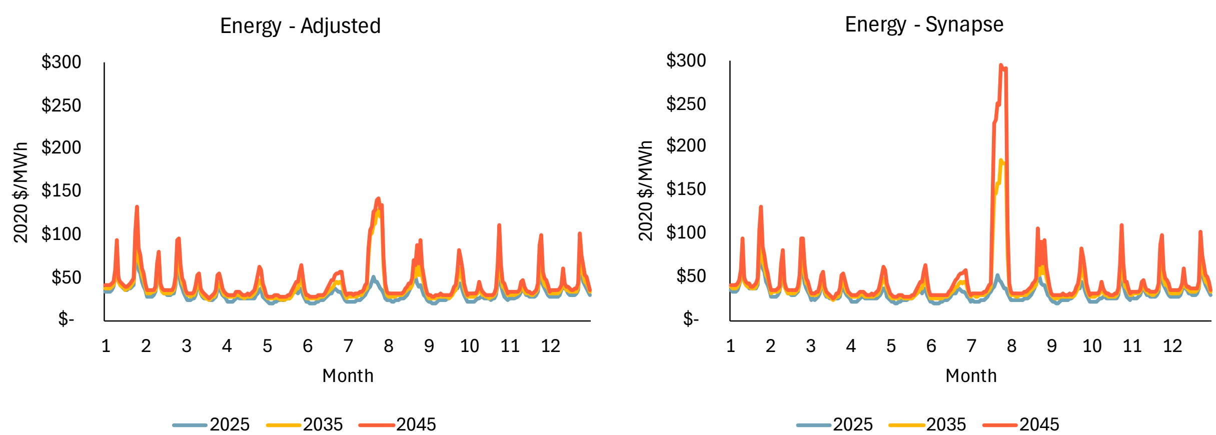
[3] An economic modeling method that assumes a condition differently to determine a hypothetical outcome

Market Price Risk Reductions	$/MWh	Risk of fuel price volatility	
Environmental Compliance	$/MWh	Cost to comply with environmental regulations	

Methodology

The VDER study used the EnCompass model to develop a forecast of energy prices for the 2021–2045 planning horizon. These prices include each of the components in the table listed above: avoided energy generation, energy DRIPE, ancillary services, avoided transmission losses, market price risk reductions, and environmental compliance. A $500/MWh price cap is applied to the energy costs from the VDER study, illustrated in Figure 1. The price cap reduces the summer scarcity prices to be on the same order as, but still larger than, winter price peaks in the 2045 forecast prices.

Figure 1. Avoided Energy Costs Adjustments (2020 $/MWh) on a month-hour average basis



All detailed methodology described below is derived from the VDER study.

Avoided Energy Generation

DC participates in the PJM wholesale market, which determines the energy resources that meet demand. The marginal generator in PJM that is displaced by the DER determines the avoided fuel and operational costs, which reflect the avoided energy costs. Synapse calculates these costs in the Encompass model.

Energy DRIPE

To calculate Energy DRIPE, the VDER study modeled the change in wholesale market prices due to a hypothetical reduction in DC energy consumption and peak demand from DERs. Because the market clearing price is reduced for all load in DC, the value is then multiplied by the energy or generation capacity needs of DC to determine the total impact.

Ancillary Services Costs

In DC, electricity providers obtain regulation and reserves via PJM's AS market. AS costs calculated in the EnCompass model include up and down regulation, spinning and non-spinning reserves, and up and down supplemental reserves.

Avoided Transmission Losses

DERs on the grid can result in less demand, reducing the supply of electricity transmitted along transmission lines. When electricity is transmitted, some of it is lost because of resistance on the lines. The cost of this lost electricity is included in the energy price from the EnCompass model.

Market Price Risk Reductions

DERs may reduce exposure to energy market price swings by shifting loads to off-peak times and improving energy efficiency. This lowers the impact of supply-demand imbalances and fuel price changes. The VDER study estimates an 8% risk premium for unhedged energy purchases based on the 2021 AESC study as a proxy for evaluating risk in the District of Columbia.[4] The study assumes 63% of energy in DC is hedged and 37% is exposed to market fluctuations. The resulting Market Price Risk Reductions is included in the energy avoided cost.

Environmental Compliance

Environmental compliance is the cost of complying with SO_2 and NO_X emissions regulations. Specifically, these regulations include the Cross-State Air Pollution Rule (CSAPR), the Acid Rain Program (ARP), and the Regional Greenhouse Gas Initiative (RGGI).

[4] https://www.synapse-energy.com/aesc-2021-materials

Generation Capacity

The generation capacity forecast values were based on the VDER study. The costs are post-processed to align with the results of the 2024 PJM capacity auction, which resulted in substantially higher costs than previous years.

Generation capacity costs are the costs of supplying sufficient generation to meet annual peak demands, including a reserve margin to account for outages and any forecast errors. The avoided Generation Capacity costs reflect the annual market clearing price in the PJM capacity market, distributed in the hours each year where the system demand is at its highest.

Element	Unit	Definition	Data Source(s)
Generation Capacity	$/MWh	Avoided costs of generation capacity required to meet the forecasted system peak load	Synapse, 2023 "Value of Distributed Energy Resources Study for the District of Columbia" and PJM capacity auctions

Methodology

The VDER study used the EnCompass model to calculate their generation capacity forecast. It represents the market clearing price in the PJM capacity market with a 16% reserve margin, based on PJM's target reserve margins over the last ten years.

The study conducted a capacity-expansion simulation for the 2021–2045 planning horizon including planned unit additions and retirements. From this, the resource buildout was determined. Next, an hourly dispatch simulation was run for the same period, calibrated to historical PJM prices. The model estimated annual costs for new capacity, based on capital costs amortized over time, along with fixed and operating costs for existing fossil-fuel resources. EnCompass dispatched resources hourly to meet load, tracking production costs.

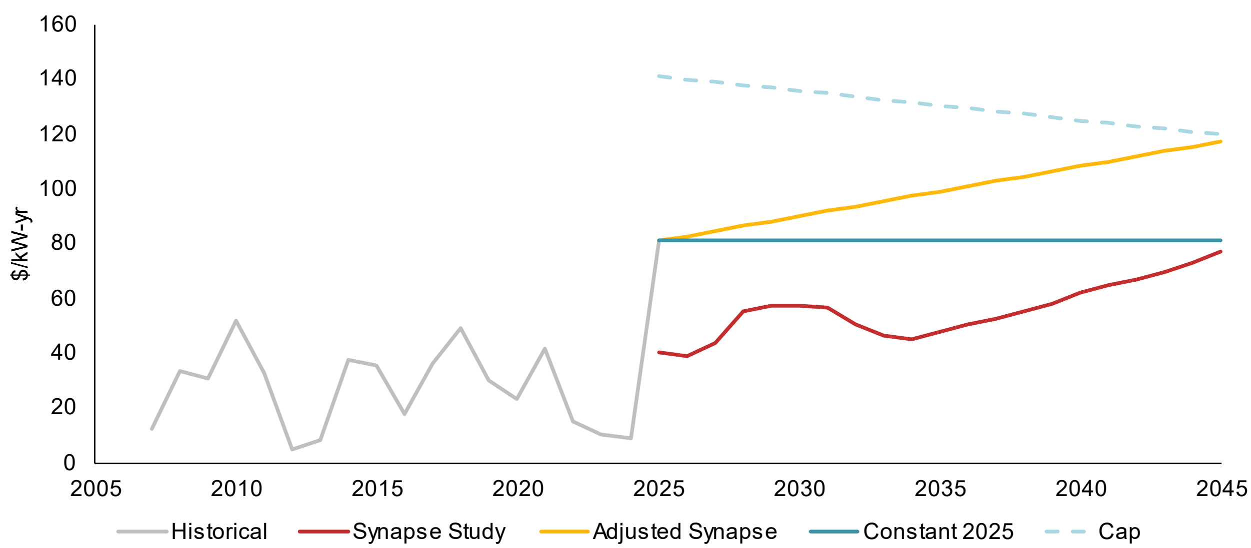
To estimate avoided costs from incremental DERs, the study used a hypothetical "No DER" scenario, which assumes no future DER additions while accounting for existing DER impacts. Total capacity costs were calculated for both scenarios, and the difference between them represents avoided costs.

Since the exact timing of peak demand is unpredictable, Synapse analyzed the top 100 load hours each year during the study period. About 84% of these hours occurred between 1 pm and 7 pm in July and August. Therefore, generation capacity costs were allocated across 266 weekday hours (1 pm to 7 pm) in these months each year.

For the BCA Model, the VDER study generation capacity costs were updated. The VDER study forecast for generation capacity is significantly lower than the most recent PJM capacity auction results for the year 2025. Given updates to PJM's capacity accrediting and need determination, the higher capacity prices will likely persist. Therefore, the VDER study prices are post-processed to align with the PJM auction results.

The generation capacity costs were escalated to scale with the results of the PJM capacity auction and remove year-to-year fluctuation in the costs to recognize the uncertainty in projecting capacity costs. This process is illustrated in Figure 2. First, the 2025 value is set to the PJM capacity price for 2025 from the most recent auction in July 2024. Then, the VDER study's projected 2045 capacity price is scaled by the difference in the 2025 PJM and 2025 VDER study capacity prices. Specifically, the adjusted 2045 price is the PJM 2025 price + (VDER study 2045 price – VDER study 2025 price). The price is limited to PJM's capacity price ceiling, which is the maximum cost of new entry (CONE) or 1.7x Net-CONE. Lastly, a linear regression is calculated between the adjusted 2025 and 2045 values to remove volatility. While a simplistic approach, it is necessitated by the lack of modeling data that aligns with real-world conditions.

Figure 2. Generation Capacity Adjustments ($/kW-yr)



Spreading the cost evenly over 266 hours does not acknowledge the fact that some hours are far more likely to be the hour of peak capacity need than others. To adjust for this dynamic, the VDER study results are further adjusted to align with the hours over which the avoided capacity cost applies. Ideally, the hours of capacity need would be linked to a loss-of-load probability study; stochastic system simulations using a variety of annual load and generation profiles would determine the risk of demand exceeding available generation for each hour of the year. And, the relative risk among hours would determine the allocation of capacity avoided cost across the year.

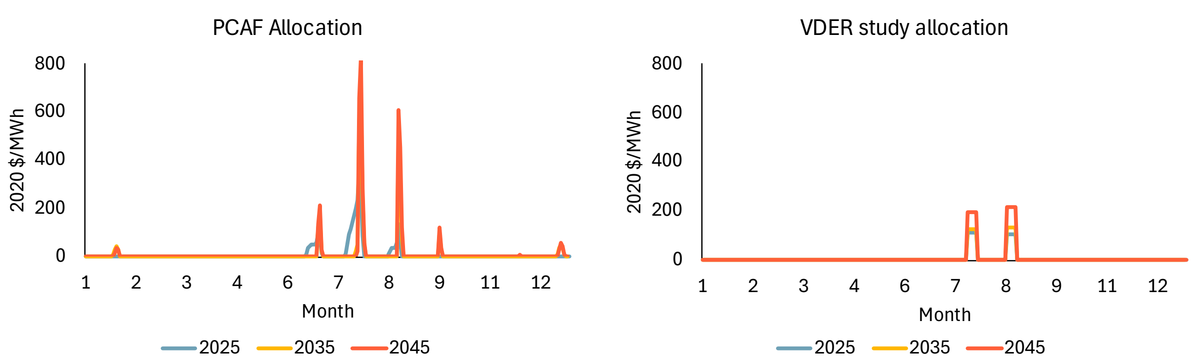
Lacking such a study, a simpler Peak Capacity Allocation Factor (PCAF) methodology is employed. The PCAF methodology generates a proxy list of risk hours based on load over a single year. A threshold level is set, in this case at the 150th ranked load hour, and all hours below this load level are assigned zero capacity cost. This means contributing energy to the system during these hours is not expected to impact generation capacity cost. Hours above the threshold are allocated a fraction of the capacity cost based on the difference between that hour's load and the threshold value.

Compared to evenly distributing capacity value over 266 hours, the PCAF method consolidates capacity value into a smaller number of hours; 150 in this case. Critically, PCAFs do not value those hours equally: nonzero PCAFs range from less than 0.000% to 3.1%, whereas flat allocation over 266 hours allocates 0.4% of the value into each hour. Another key advantage of the PCAF method is that it allows for year-to-year variation in the allocation factors: the values are reallocated based on different load profiles for each year of the model, thus enabling the timing of capacity value to evolve as load and generation profiles change over time.

Access to hourly load profiles from the VDER study were not available when developing this study. As a result, we base the PCAFs on hourly load profiles from NREL's Cambium simulations. For generation capacity, we use the "net_load_busbar_hourly" field, representing end use load minus variable generation.

The month-hour results of this improved allocation appear in Figure 3. The PCAF allocation factors allow for some hours to be more important for generation capacity than others and allow the hourly allocation to shift over time.

Figure 3. Generation Capacity Hourly Allocation Adjustments (2020 $/MWh)



RPS Compliance

The VDER study is used to develop the Renewable Portfolio Standard (RPS) Compliance forecast. RPS compliance represents the savings from avoiding purchases of a Tier I Renewable Energy Credit (REC) and a solar renewable energy credit (SREC) due to a DER.

Element	Unit	Definition	Data Source(s)
RPS Compliance	$/MWh	Increase or decrease in cost of compliance with renewable portfolio standards (RPS)	• Synapse, 2023 "Value of Distributed Energy Resources Study for the District of Columbia" • NREL, 2023 "Cambium Datasets"[5]

Methodology

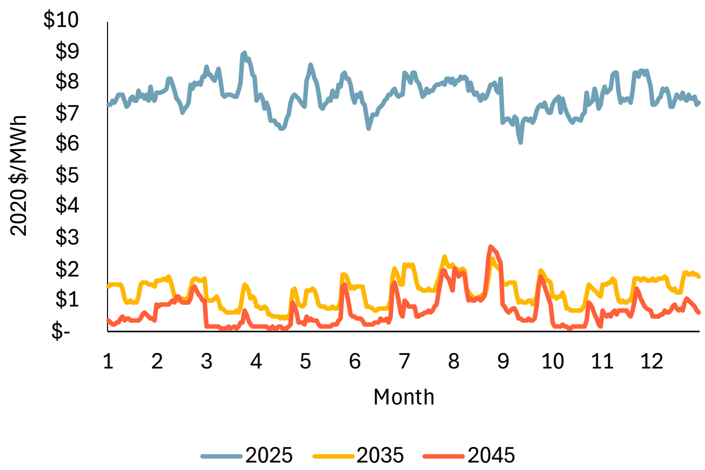
To calculate the REC compliance forecast, the VDER study uses the annual RPS requirement (% of electric sales) for Tier 1 RECs multiplied by the REC price forecast, using the moderate forecast scenario. The REC price forecast is from the 2020 ICF REC price forecast developed for Dominion in Virginia. For example, in a year where the REC price is $10 per MWh and the RPS target is 10 percent, the avoided RPS cost is $10 per MWh x 10 percent = $1.00 per MWh.

To calculate the SREC compliance forecast, the VDER study implemented the methodology from the DC Sustainable Energy Utility (DCSEU). The avoided cost is the difference between the SREC price and the RPS Alternative Compliance Payment (ACP), reflecting savings from meeting the solar carve-out with SRECs instead of the ACP. Only the difference is considered an avoided cost, as the SREC payment likely benefits DC residents. The SREC price is based on the previous year's average in the DC market and decreases over time in relation to the ACP. The avoided costs are calculated by multiplying the DCSEU Avoided Solar RPS Compliance Costs by the local solar carve-out.

The VDER study annual REC and SREC compliance forecasts is processed into hourly RPS compliance forecasts for the BCA Model. To do so, the REC and SREC compliance forecasts are added together. Then, to convert into hourly prices, the annual RPS compliance forecast is normalized by the hourly emissions forecast. The hourly emissions forecast is the CO_2e emissions forecast from NREL Cambium 2023, in the 95% Decarbonization by 2050 Scenario for DC's balancing area. The RPS Compliance Forecast is shown in Figure 4.

[5] NREL, 2023 "Cambium Datasets." Accessible at: https://scenarioviewer.nrel.gov/

Figure 4. RPS Compliance Forecast (2020 $/MWh)



Transmission Capacity

The VDER study is the basis for the Transmission Capacity forecast. Since DERs may reduce system peak demand, DERs may avoid transmission costs necessary to supply electricity during peak hours.

Element	Unit	Definition	Data Source(s)
Transmission Capacity	$/MWh	Avoided costs to construct and maintain the high-voltage transmission system to transport electricity safely and reliably	Synapse, 2023 “Value of Distributed Energy Resources Study for the District of Columbia”

Methodology

The avoided transmission capacity costs are based on the VDER study and adjusted for peak hours. To calculate avoided transmission capacity costs, the VDER study uses Pepco’s Formula Rate Annual Update to the Federal Energy Regulatory Commission, with inflation applied. At the time, Pepco’s transmission charge was $30.30/kW-year. Transmission costs have since grown with the increasing disconnect between costs of the current transmission system and the smaller pool of avoidable future transmission system costs. Like generation capacity, Synapse distributed this value over the annual peak hours for the PEPCO zone, which was estimated as weekdays in July and August from 1 pm to 7 pm.

The transmission capacity value was updated similarly to generation capacity, which is only realized during hours of the year when the transmission system is most stressed, threatening the need for new infrastructure investment. The hourly allocation from the VDER study, which does not change year-to-year, is updated to allocate value equally over a large number of hours for each year.

The same PCAF methodology described for generation capacity is used to allocate transmission costs to hours of the year. However, a different load profile from Cambium is used to approximate the probable transmission system need hours. In this case, the difference between the “enduse_load_hourly” and “distpv_MWh_hourly” fields is taken, representing end use load at the customer meter.

The month-hour results of this improved allocation appear in Figure 5. The PCAF panel of the figure makes apparent the relative likelihood of hours contributing to transmission capacity risk and the shifting importance of hours over time. As 2045 approaches, transmission peaks shift later in the day, and some risk starts to appear in non-summer months.

Figure 5. Transmission Capacity Adjustments (2020 $/MWh)

Distribution Capacity, Distribution Operation & Maintenance, and Distribution Voltage (Quality of Service)

The Distribution Capacity, Distribution O&M, and Distribution Voltage avoided cost components are derived from the VDER study. DERs can reduce the distribution system's peak load. When the peak load on the distribution system is reduced, upgrades to the system can be avoided. O&M and voltage regulations costs can also be reduced.

Distribution system loading is highly nonuniform, so distribution avoided costs are as well. Avoidable costs for most parts of the system will be negligible, given the headroom that exists in most areas. However, substations, feeders, or circuits that are approaching their maximum load may have large avoidable costs. This non-uniformity makes assignment of distribution avoided costs to programs applied at a system level highly uncertain. To truly capture the value of a proposed program to the distribution system would require distribution planning and identification of avoidable investments at a highly granular scale. Lacking this bespoke-to-a-program data, this study offers two paths of distribution valuation: a base value meant to represent a systemwide average and a high value meant to represent the possible impact on a highly-constrained feeder, investment in which is avoidable.

Element	Unit	Definition	Data Source(s)
Distribution Capacity	$/MWh	Avoided costs of substation and distribution line infrastructure to meet customer electricity demand	Synapse, 2023 "Value of Distributed Energy Resources Study for the District of Columbia"
Distribution O&M	$/MWh	Avoided costs to maintain safe and reliable operation of distribution facilities	
Distribution Voltage	$/MWh	Avoided costs of voltage regulation needed to ensure reliable and continuous electricity flow across the power grid	

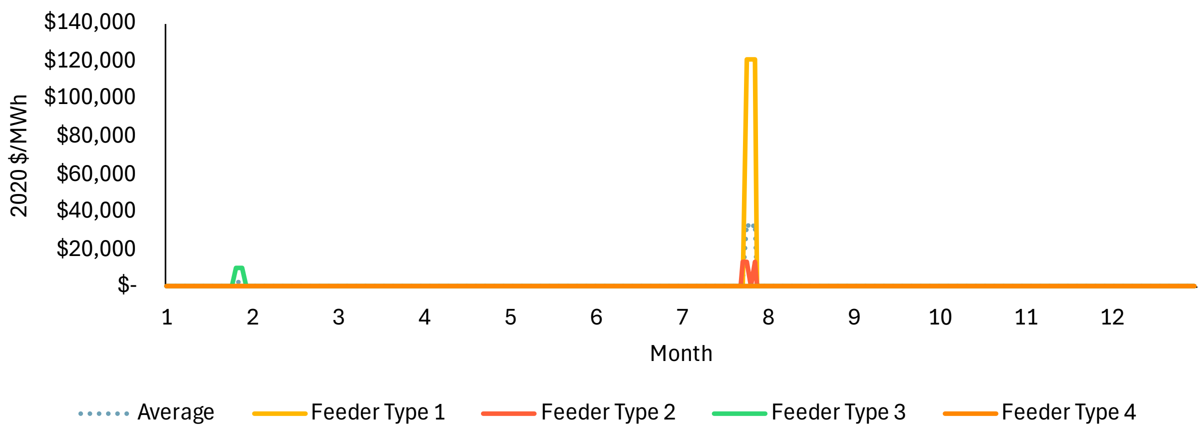
Methodology

The VDER study assesses 32 out of 765 Pepco feeders in DC that are approaching their capacity ratings. The impact of building and vehicle electrification on distribution capacity is modeled as a percent increase to the current hourly loads plus some shaping based on assumed load flexibility.

The avoided distribution capacity costs are zero until the peak exceeds the normal rating on the feeder. When peak exceeds a lines normal rating, the avoided cost is calculated as the incremental annual peak above the baseline multiplied by $385,500 per MW-year ($2020); a value is sourced from the Pepco Marginal Distribution Cost Study to represent possible upgrade cost.

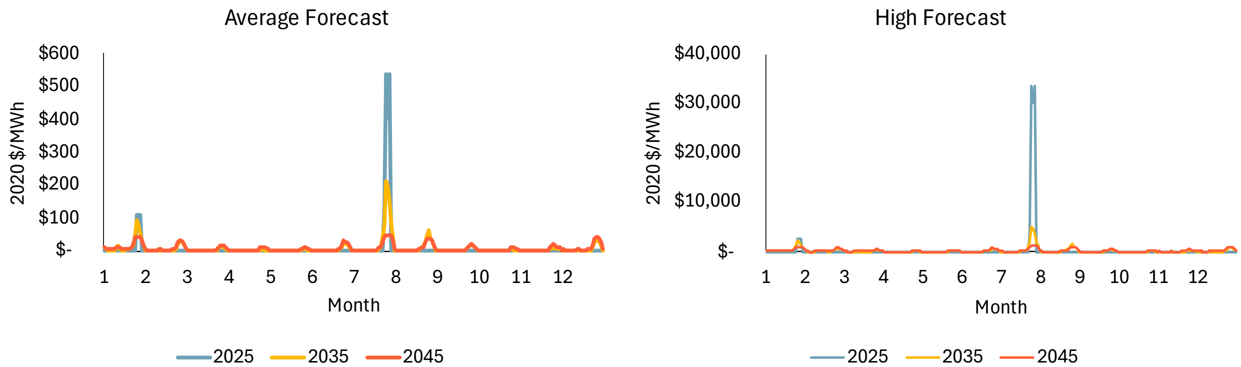
The VDER study reported the distribution avoided costs for four feeder types, shown in Figure 6. Little detail is visible in this view, as the large July peak for Feeder Type 1 dwarfs most other features.

Figure 6. VDER Study Distribution Capacity, O&M, Voltage Forecast for 2025 (2020 $/MWh) on a month-hour average basis



The VDER Study distribution costs reflect highly constrained feeders with much higher-than-average costs. The VDER study forecasts have been updated to calculate a high and an average cost forecast to appropriately value the costs to the distribution system depending on if programs are targeted to specific, constrained locations or not location specific. To calculate the high distribution avoided cost forecast, the forecasts for the four feeders studied by Synapse in the VDER study were averaged. To calculate the average distribution avoided cost forecast, the high distribution avoided cost forecast was multiplied by 32/765. This ratio makes two implicit assumptions: 1) that the avoided costs for the four feeders quantified in the study are representative of the avoided costs for the set of 32 feeders included in the study's initial assessment, and 2) that the remaining 733 feeders have negligible avoided cost. This creates an average avoided cost forecast that is more representative of a typical feeder. These hourly costs are then capped at $50,000/MWh to achieve $/kW-yr value consistent with average distribution capacity values reported in other jurisdictions. The results are shown in Figure 7. Unlike for transmission and generation capacity, the VDER study results are not reallocated for distribution capacity since they are based on actual load profiles for the feeders studied.

Figure 7. Distribution Capacity, O&M, and Voltage Adjustments (2020 $/MWh) shown for average and high forecasts on a month-hour average basis



The figure showcases a possibility unique to the distribution avoided cost. Near-term value is higher than long-term value. This dynamic reflects the idea that near-term distribution needs, if unmet otherwise, will be addressed by near-term distribution investment. Once new infrastructure has been built, the cost is sunk and no longer avoidable, so the value of intervention decreases. While this is true of a given near-term need, a more complete distribution planning exercise may reveal new needs arising on other feeders as the value on the most urgently identified feeders fades. These results are an appropriate estimate of costs given available data, but it will be valuable to revisit this avoided cost to take advantage of improving data coverage and granularity as distribution planning and forecasting evolve.

Distribution System Losses

The Distribution System Losses forecast was based on the VDER study. Similar to avoided transmission losses, DERs can reduce the electricity lost on the distribution system.

Element	Unit	Definition	Data Source(s)
Distribution System Losses	$/MWh	Avoided costs associated with electricity lost through the distribution system	Synapse, 2023 "Value of Distributed Energy Resources Study for the District of Columbia"

Methodology

To calculate avoided costs of distribution system losses, the VDER study uses an average of Pepco's 2015 reported default distribution loss factors from their rates (5.7% and 6.2% for energy) and scaled by 1.5 to account for marginal losses.

Credit & Collection Costs

The Credit & Collection Costs forecast are based on the VDER study. The credit and collections category includes costs related to bad debt, including arrearages, terminations, reconnections, customer calls, and collections. This study notes that reducing arrearages does little, if anything, to impact the total revenue requirement – collection shortfall is socialized across all customers, so reductions in arrearages most serve to reduce cost transfers among ratepayers. However, some nonzero impacts to the total revenue requirement may result from administrative costs and the cost of carrying bad debt from when it is incurred until when the collection true-up occurs.

Element	Unit	Definition	Data Source(s)
Credit & Collection Costs	$/MWh	Avoided utility costs associated with bad debt and arrearages	Synapse, 2023 "Value of Distributed Energy Resources Study for the District of Columbia"

Methodology

Pepco reports bad debt monthly, with a total of $3.8 million in 2019, representing 1.4% of residential revenue. Since it's difficult to precisely measure how DERs affect bad debt, it is assumed that reductions occur proportionally to revenue. Then, an additional 50% value is applied to account for avoided administrative costs.

Gas Elements

Unlike the electricity elements, there is not an equivalent avoided cost study for the gas system. The gas element avoided costs were developed with the best available data from Washington Gas and Light (WGL) and other publicly available sources.

Energy, Environmental Compliance, Transmission System Losses, Distribution System Losses

Energy costs reflect the commodity cost or the cost to purchase natural gas. Environmental compliance costs are captured by the commodity cost of gas. Similarly, natural gas lost in the transmission and distribution system before it arrives at the customer meter is still paid for by the utility and its customers and, therefore, is captured by the energy cost.

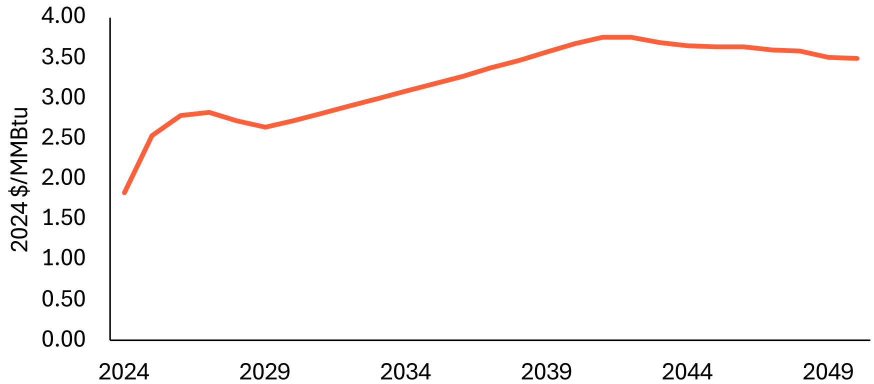
Element	Unit	Definition	Data Source(s)
Energy	$/MMBtu	Commodity cost of gas supplied to customers	Gas price forecast based on EIA natural gas forecast from the Annual Energy Outlook[6] and S&P Cap IQ forwards
Environmental Compliance	N/A	Cost to comply with environmental regulations	
Transmission System Losses	N/A	Commodity cost of gas lost in transmission system	
Distribution System Losses	N/A	Commodity cost of gas lost in distribution system	

Methodology

Natural gas commodity costs are based on the weighted average gas price of the major hubs from which WGL sources its gas: Columbia Gas Transmission (TCO), Eastern Gas Transmission and Storage (EGTS), and Transcontinental Gas Pipeline Company (Transco). In the near-term (2024-2028), the projections are derived from wholesale gas forward contracts obtained through SNL data from S&P Global. Over the long-term (2029-2050), the projections are based on the Henry Hub natural gas price forecast published in EIA's Annual Energy Outlook 2023. This forecast extends through 2040, after which the prices are linearly projected to 2050. To tailor each hub's long-term forecast to WGL's major hubs, the respective hub's forecast is adjusted using the historical average basis spread between each hub and Henry Hub.

[6] EIA Annual Energy Outlook 2023. https://www.eia.gov/outlooks/aeo/data/browser/

Figure 8. Weighted Average Gas Price Forecast (2024 $/MMBtu)



Transmission Capacity

Gas transmission capacity costs include the costs for pipeline transportation and storage of natural gas prior to entering DC's city gate.

Element	Unit	Definition	Data Source(s)
Transmission Capacity	$/(MMBtu/day)	Cost to contract pipelines to transport the gas from the gas well to the city gate	Derived from firm transportation recourse rates for the three major transmission lines WGL contracts from (Columbia Gas Transmission (TCO)[7], Eastern Gas Transmission and Storage[8], Transcontinental Gas Pipeline Company[9])

Methodology

Gas utilities contract for three components of transmission capacity: firm transportation, storage, and peaking services. Firm transportation contracts cover baseload demand, including the peak demand of all firm customers, and is the highest quality pipeline service because it is not interruptible. Storage capacity covers underground natural gas storage to provide gas for periods of higher gas demand. Peaking capacity contracts cover periods of peak gas demand from interruptible customers, like gas peaker plants generating electricity. To reduce transmission capacity contracts, gas utilities must achieve a continual threshold of volumetric demand reduction and have sufficient lead time to renegotiate contracts. Because of these dynamics, transmission capacity avoided costs

[7] Columbia Gas Transmission, LLC, FERC Tariff: Columbia Gas Transmission (TCO)
[8] Eastern Gas Transmission and Storage, FERC Gas Tariff, Firm Transportation Rate Schedule: infopost.bhegts.com/egts/tariff-link/tariff-rate-schedules
[9] Transcontinental Gas Pipeline Company, Part III - Rate Schedules, FERC Gas Tariff: Transco 1Line Portal

should only be counted if a program achieves sufficient peak demand reduction to reduce transportation capacity contracts.

If a program is projected to have demand reductions that meet these criteria, users would input the peak demand reductions expected from the proposed program in units of reduced MMBtu during the peak day. The transmission capacity avoided cost for peak demand reduction is derived from firm transportation (FT) recourse rates for the three major transmission lines from which WGL contracts its pipeline capacity (TCO, EGTS, and Transco). The FT recourse rate has two components used to derive the avoided cost: 1) the reservation charge, which is the payment for the right to reserve pipeline capacity regardless of the volume of gas transported, and 2) the usage charge, which is based on the volume of gas transported and is typically much lower than the reservation charge. The reservation charge and usage charge were summed for each pipeline, and the avoided cost is calculated as the weighted average of these charges based on the gas volumes from WGL's primary contracts. The resulting transmission cost that could be avoided with peak demand reductions is $7.353/(MMBtu/day).

Distribution Capacity

Distribution capacity reflects the costs to build distribution pipeline infrastructure.

Element	Unit	Definition	Data Source(s)
Distribution Capacity	$/customer $/mile	Cost to construct the distribution pipeline. Infrastructure, including mains and service lines	WGL-provided data for average cost per mile of main and average cost per service

Methodology

Three potential program structures were identified that impact how distribution capacity costs may be avoided: demand reduction programs, customer reduction programs, and programs that avoid main pipeline. The user identifies whether the proposed program includes demand reductions, customer reductions, and/or main pipeline avoided. The avoided cost value depends on the program structure as explained below and as described in Table 2.

Table 2. Distribution Capacity Avoided Cost Values by Program Structure

Program Structure	Unit	Avoided Cost Value	Data Source(s)
Demand Reductions	N/A	None	N/A
Customer Reductions	$/customer	Average Cost of Service: $32,656	WGL
Main Pipeline Avoided	$/mile	Average cost per mile of main: $8,300,000 Rate of return: 7.11%[10] Avoided cost per avoided mile: $6,893,857	WGL DCPSC

Demand reduction programs do not avoid distribution capacity costs. Distribution infrastructure is necessary to transport gas to end-use customers regardless of the volume of gas consumed. Customer reduction programs may avoid distribution capacity costs relating to service lines and meters if those investments are avoided for customers leaving the gas system. Avoiding main pipeline replacements or expansions does directly correspond to avoided distribution infrastructure costs.

The cost for the avoided main pipeline is processed to reflect its impact to WGL's revenue requirement (depreciation + return). Assuming a pipeline lifetime of 60 years, the pipeline depreciation is calculated as the average cost per mile of main divided by the lifetime. The utility return is the rate of return (7.11%) multiplied by the annual net book value of the pipeline, which is calculated as the initial cost of the main pipeline avoided minus the accumulated depreciation each year. The annual avoided cost is the net present value of the sum of the annual return and annual depreciation.

Distribution O&M

Distribution O&M reflects the cost to operate and maintain the gas distribution network, including supervision and engineering of the distribution network, installation and removal of customer meters, and customer service.

Element	Unit	Definition	Data Source(s)
Distribution O&M	$/customer	Cost to operate and maintain the gas distribution network	WGL historical O&M costs and customer counts National Bureau of Economic Research[11]

[10] WLG Rate of Return (RoR) for 2024 - Formal Case NO. 1169, Order No. 21939. Accessed at: https://edocket.dcpsc.org/apis/api/Filing/download?attachId=197526&guidFileName=c901ca24-b864-4b05-b6d1-c1dfc528fc03.pdf
[11] National Bureau of Economic Research. "Who Will Pay for Legacy Utility Costs?". June 2021, Revised March 2022. https://www.nber.org/system/files/working_papers/w28955/w28955.pdf

Methodology

As with distribution capacity, marginal demand reductions do not directly correspond to avoided O&M costs because distribution infrastructure and utility services must be maintained regardless of throughput. On the other hand, reducing gas customers may have some impact on O&M costs.

A study from the National Bureau of Economic Research that finds that the operational costs leaving with a customer depends on the type of expenditure.[12] Based on this study, WGL's historical O&M costs are grouped into two expense categories: Gas System O&M and Customer & Admin. Gas System O&M expenses include costs associated with the maintenance of gas distribution pipeline and engineering of the distribution network. Customer & Admin expenses include costs associated with employee salaries, customer assistance, and meter readings. The average $ per customer O&M cost for each category is calculated using WGL's historical customer counts. Based on the study, 10% of costs associated with Gas System O&M are assumed to be reduced for each customer departure and 50% of Customer & Admin costs are assumed to be reduced for each customer departure. Avoided costs for each O&M category are shown in Table 3.

Table 3. Distribution O&M Avoided Cost Values

O&M Category	Avoided Cost Value
Gas System	$14.89/customer
Customer & Admin	$61.96/customer

Market Price Effect (Demand Reduction Induced Price Effect (DRIPE))

DRIPE refers to the decrease in the market price of natural gas supply that results from reduced natural gas usage decreasing demand for supply. Natural gas DRIPE applies to the commodity cost of gas (i.e., energy cost) but not the transportation capacity costs as this cost is dependent on pipeline contracts and not the cost of gas itself.

Element	Unit	Definition	Data Source(s)
Market Price Effect	$/MMBtu	Near-term market price effect of reducing gas demand	Avoided Energy Supply Components in New England: 2024 Report[13] WGL gas throughput

[12] Ibid.

[13] Synapse Energy Economics, Inc. Avoided Energy Supply Components in New England: 2024 Report. Feb. 2024. https://www.synapse-energy.com/sites/default/files/AESC%202024.pdf

Methodology

The DRIPE calculation is based on the Synapse Avoided Energy Supply Components in New England (AESC) report. In the AESC, Synapse calculates the effect of changing gas demand on gas prices through a linear regression of the EIA's Annual Energy Outlook 2023. The shift in gas price is determined to be $0.067/MMBtu for one quadrillion Btu in demand reduction (in 2024 dollars).

Based on WGL data, DC's gas consumption was approximately 250,000,000 MMBtu. Multiplying the gas price shift by DC's annual gas consumption results in a natural gas DRIPE of $0.017 per MMBtu. The AESC report assumes that only a portion of gas consumption is responsive to DRIPE due to utilities securing short-term contracts for gas. The report also assumes that 50% of gas demand is locked into short-term contracts in Year 1 and that 20% of gas demand is locked into short-term contracts in Year 2. These assumptions are adopted, resulting in programs having a decreased DRIPE effect in the first two years after the program is implemented.

Unlike in the AESC report, the natural gas DRIPE is assumed to decay over time. The natural gas DRIPE impacts are limited to 10 years after the program start. While reducing gas demand theoretically maintains the gas supply to lower long-term costs, gas supply markets respond to many other factors, including demand for gas exports and inflation, which may limit the long-term impact of natural gas DRIPE.

Given the assumptions on the effects of short-term contracts and long-term durability of DRIPE, Table 4 shows natural gas DRIPE for each program start year.

Table 4. Natural Gas DRIPE Values

Year	Program Start Year																										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
2024																											
2025	0.01																										
2026	0.02	0.01																									
2027	0.02	0.02	0.01																								
2028	0.02	0.02	0.02	0.01																							
2029	0.02	0.02	0.02	0.02	0.01																						
2030	0.02	0.02	0.02	0.02	0.02	0.01																					
2031	0.02	0.02	0.02	0.02	0.02	0.02	0.01																				
2032	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01																			
2033	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01																		
2034	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01																	
2035		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01																
2036			0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01															
2037				0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01														
2038					0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01													
2039						0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01												
2040							0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01											
2041								0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01										
2042									0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01									
2043										0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01								
2044											0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01							
2045												0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01						
2046													0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01					
2047														0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01				
2048															0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01			
2049																0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01		
2050																	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	

Credit & Collection Costs

Credit & collection costs are the costs associated with customer arrearages, including the revenue shortfall itself, and operations costs associated with responding to overdue payments. The model focuses on arrearages themselves, as they are assumed to be the dominant component of credit and collection costs. As with electricity credits and collections, this study notes that changes to arrearages mostly impact transfers among ratepayers, as the among of socialized under-recovery changes. Though understanding changes to credit and collections is valuable for understanding program impacts outside of what can be captured by the TRC test.

Element	Unit	Definition	Data Source(s)
Credit & Collection Costs	$/MMBtu	Costs associated with crediting and collecting from customer accounts	WGL arrearage filing[14]

Methodology

The basis for the test element is the idea that arrearages will scale with the total volume of purchases. Thus, the credit & collections costs are calculated from WGL's historical arrearage data. The total dollar amount of residential customers in arrears is divided by the WGL gas volumes for each year to arrive at a $/MMBtu avoided credit & collection cost. The historic values are averaged and applied to future years. The avoided credit & collection costs is $0.054/MMBtu.

It is important to note that this avoided cost may not be appropriate to include in a TRC or SCT test because credit and collection costs are a transfer among utility customers. Under-collection from some customers is socialized as a cost to all ratepayers; reductions to under-collection change cost transfers between customers but do not save money for the gas system.

[14] ARDIR2024-02-G-11. https://edocket.dcpsc.org/apis/api/Filing/download?attachId=215776&guidFileName=2f51e10d-42f4-4998-aa82-bd72472cfe3f.pdf

Environmental Elements

Electricity GHG & Air Pollutant Emissions

Electricity GHG and air pollutant emissions result from emitting GHG and criteria air pollutants when generating electricity from fossil fuel resources.

Element	Unit	Definition	Data Source(s)
GHG (CO2, CH4, N2O)	$/MWh	Social costs from emitting GHG emissions	NREL Cambium[15] EPA Report on the SC of GHG[16]
Air Pollutants (NO_X, SO_2, $PM_{2.5}$)	$/MWh	Social costs from emitting criteria air pollutants	EPA eGRID[17], EPA AVERT[18] EPA Report on Estimating the Benefit per Ton of Reducing Directly-Emitted PM2.5[19]

Methodology

As directed in the Order, the electricity GHG emissions rates are sourced from the long-run marginal emission rate (LRMER) from the NREL Cambium model for the mid-case with 95% decarbonization by 2050, which most closely matches DC's decarbonization goals. NREL Cambium calculates hourly energy data in 5-year increments from 2025-2045. The interim year values are linearly interpolated and averaged on a month-hour basis.

The air pollutant emission factors for NO_X and SO_2 are drawn from the EPA eGRID database and the emission factor for $PM_{2.5}$ is sourced from AVERT for the Mid-Atlantic region, as shown in Table 5.

Table 5. Emission Factors for Electricity Generation

NOx	SO2	PM2.5
lb/MWh	lb/MWh	lb/MWh
2.88	0.03	0.9

[15] NREL Cambium. 2024. https://www.nrel.gov/analysis/cambium.html
[16] EPA Report on the Social Cost of Greenhouse Gases. 2023. Table A.5. https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf
[17] EPA Emissions & Generation Resource Integrated Database (eGRID). 2022. https://www.epa.gov/egrid
[18] EPA Avoided Emission Rates Generated from AVERT. 2022. https://www.epa.gov/avert/avoided-emission-rates-generated-avert
[19] EPA Technical Support Document: Estimating the Benefit per Ton of Reducing Directly-Emitted PM2.5 Precursors and Ozone Precursors from 21 Sectors. 2024. Table 8. https://www.epa.gov/system/files/documents/2024-06/source-apportionment-tsd-2024.pdf

Gas GHG & Air Pollutant Emissions

GHG and air pollutant emissions result from emitting GHG and criteria air pollutants from natural gas transportation and end-use combustion, including the emissions from leaks within the transmission and distribution infrastructure.

Element	Unit	Definition	Data Source(s)
GHG (CO2, CH4, N2O)	kg/MMBtu	Social costs from emitting GHG emissions	EPA Emission Factors for GHG Inventories[20]
Air Pollutants (NOx, SO2, PM2.5)	kg/MMBtu	Social costs from emitting criteria air pollutants	EPA Emission Factors from Natural Gas Combustion[21]
Transmission System Losses (CH4)	%	Social cost from emitting fugitive CH4 emissions in the transmission system	Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain[22]
Distribution System Losses (CH4)	Kg/mile or service	Social cost from emitting fugitive CH4 emissions in the distribution system	EPA 40 CFR Part 98 Subpart W Emissions Factors[23]

Methodology

For GHG and air pollutant emissions resulting from combustion that occurs at the customer end-use, emission factors are sourced from the EPA reported in kg for each pollutant per gas MMBtu, shown in Table 6. The emissions factor (kg/MMBtu) is multiplied by the gas demand reduction (MMBtu) to arrive at a total kg of emissions reduction.

Table 6. Emission Factors for Stationary Natural Gas Source

CO2	CH4	N2O	NOx	SO2	PM2.5
kg/MMBtu	kg/MMBtu	kg/MMBtu	kg/MMBtu	kg/MMBtu	kg/MMBtu
53.060	0.001	0.000	0.042	0.000	0.003

To account for upstream methane leakage, 2.3% of gas throughput is assumed to be lost in the production and transportation of the gas based on the 2018 study an "Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain." To calculate methane

[20] EPA Emission Factors for Greenhouse Gas Inventories. Jun 2024. https://www.epa.gov/system/files/documents/2024-02/ghg-emission-factors-hub-2024.pdf
[21] EPA Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion. Sep 2020. https://www.epa.gov/sites/default/files/2020-09/documents/1.4_natural_gas_combustion.pdf
[22] Alvarez et. al. "Assessment of methane emissions from the U.S. oil and gas supply chain". Jun 2018. https://www.science.org/doi/10.1126/science.aar7204
[23] Environmental Protection Agency. 40 CFR Part 98 Subpart W. Table W-5 to Subpart W of Part 98—Default Methane Population Emission Factors. https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-W#p-98.233(q)(3)(vi)

emissions from transmissions system losses, the gas demand reduction (MMBtu) is multiplied by the methane emissions factor (kg/MMBtu) by the loss factor (%) to arrive at a total kg of emissions reduction.

Methane leakage in the distribution system has been found not to be dependent on gas throughput but on the type of pipeline material. WGL reports emissions from distribution losses based on the EPA's 40 CFR Part 98 Subpart W emissions factors for distribution pipeline and services, as shown in Table 7. Note that Subpart W presents these factors in units of cubic feet per hour, while the Table 7 values have been converted to metric tons per year. The same emissions factors are applied to calculate emissions distribution losses in the BCA Model. The user must specify the number of main and service pipeline miles by material that are avoided by the proposed program. The main pipeline miles avoided and the customer count reduction is multiplied by the distribution emissions factors for main pipeline and service pipeline respectively to arrive at a total kg of emissions reductions.

Table 7. Emission Factors for Distribution System Losses

Parameter	mt CH4
Per mile cast iron distribution pipeline	4.61
Per mile unprotected steel distribution pipeline	2.13
Per mile protected steel distribution pipeline	0.059
Per mile plastic distribution pipeline	0.191
Per copper service	0.005
Per unprotected steel service	0.032
Per protected steel service	0.003
Per plastic service	0.0002

Electricity and Gas GHG and Air Pollutant Cost

The electricity and gas GHG and air pollutant costs reflect the social cost of emitting CO_2, CH_4, N_2O, NO_X, SO_2, and $PM_{2.5}$.

Methodology

The default values in the BCA Model utilize IPCC AR6 GWP as multipliers for $/ton costs of CH_4 and N_2O as per the Order. The Commission has adopted the recommendation to use the 100-year time horizon for GHG evaluation. The Commission has further adopted the following GWPs for each of the GHG pollutants that will be evaluated in Part A, based on IPCC AR6:

- GWP-100 of CO_2 is 1;
- GWP-100 of fossil CH_4 is 29.8;
- GWP-100 of N_2O is 273.

Per discussions with the Commission, the finalized cost values shown in Table 8 are used for the GHG and air pollutant $/ton inputs.

To calculate the social cost for each GHG and air pollutant, the $/ton cost is converted to a $/kg value to align with the emissions rate for each pollutant. The social cost is multiplied by the emissions rate to determine an annual or month-hour GHG or air pollutant cost based on the costs provided in Table 8.

Table 8. Social Costs of GHGs and Air Pollutants

Element	Social Cost for Electricity ($/ton)	Social Cost for Gas ($/ton)	Data Source(s)
CO_2	$212	$212	EPA Report on the SC of GHG[24]
CH_4	$2,025	$2,025	
N_2O	$60,267	$60,267	
NO_X	$7,710	$13,800	EPA Report on Estimating the Benefit per Ton of Reducing Directly-Emitted PM2.5[25]
SO_2	$57,000	$29,900	
$PM_{2.5}$	$113,000	$140,000	

[24] EPA Report on the Social Cost of Greenhouse Gases. 2023. Table A.5.
https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf

[25] EPA Technical Support Document: Estimating the Benefit per Ton of Reducing Directly-Emitted PM2.5 Precursors and Ozone Precursors from 21 Sectors. 2024. Table 8.
https://www.epa.gov/system/files/documents/2024-06/source-apportionment-tsd-2024.pdf

Other Elements

Other Fuels

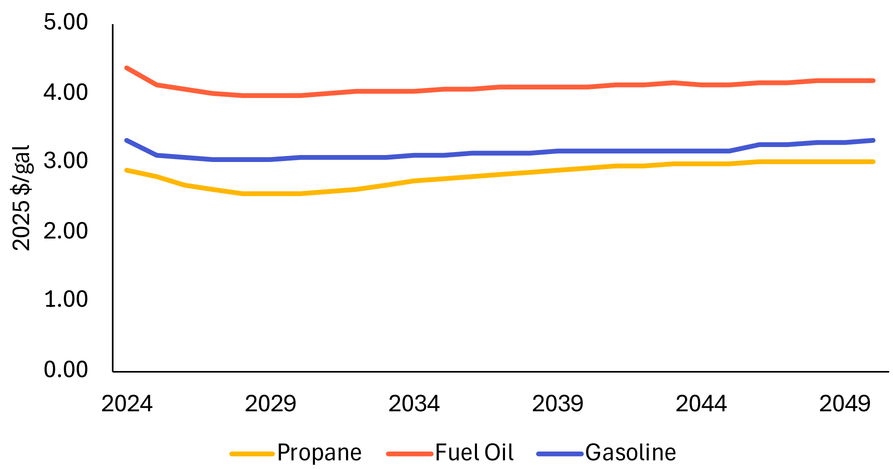
Programs may target reductions in propane, fuel oil, and gasoline, which will result in cost changes for customers switching fuels or avoiding backup generation fuels.

Element	Unit	Definition	Data Source(s)
Propane	$/gal	Cost of propane fuel	EIA Annual Energy Outlook[26]
Fuel Oil	$/gal	Cost of Fuel Oil #2	
Gasoline	$/gal	Cost of gasoline	

Methodology

Future fuel prices are sourced from the EIA's Annual Energy Outlook reference case. Propane and distillate fuel oil are based on the residential prices and gasoline is based on the transportation motor gasoline, which is the sales weighted average price for all gasoline grades.

Figure 9. Other Fuels Price Forecast (2025 $/gal)



[26] EIA Annual Energy Outlook 2023. Table 12. Petroleum and Other Liquids Prices https://www.eia.gov/outlooks/aeo/data/browser/#/?id=12-AEO2023

Avoided Water

Avoided water cost reflects the water cost avoided due to a reduction in water demand within DC. This element applies to end use water demand and not water demand associated with bulk-scale energy production.

Element	Unit	Definition	Data Source(s)
Avoided Water	$/gal	Avoided water cost from reducing water demand	DC Water Cost of Service Study 2024[27], 2022[28], 2020[29]

Methodology

The DC Water Cost of Service Study prepares a Revenue Sufficiency Model and Cost of Service analysis. The study includes an allocation of DC Water's revenue requirement into functional categories consistent with the operating characteristics of the utility, including:

- **Source of Supply and Treatment:** costs to purchase potable water from the Washington Aqueduct
- **Distribution:** costs of infrastructure to transport water through the distribution system
- **Storage:** costs of storage facilities to provide adequate supply of water to serve peak and average demand
- **Pumping:** costs associated with electricity required to operate the pumping facilities
- **Customer Service/Meter:** costs to install/operate customer meters and provide customer service
- **Administration/General:** administrative and general costs to provide water service

Reduction in water volumes directly impacts the costs for Source of Supply and Treatment and Pumping, whereas it does not have a direct impact on infrastructure, customer service, or administration costs. To calculate the avoided water cost resulting from demand reduction, the Source of Supply and Treatment costs are added to the Pumping costs for the years 2021-2026 reported in the DC Water Cost of Service studies and divided by the respective year's water consumption to determine an annual cost of water ($/ccf). The nominal values are converted into real values in $2025 dollars and averaged to $1.66/ccf or $0.002/gal, which is applied to all future years.

[27] Raftelis. DC Water Cost of Service Study Final Report. 2024. https://www.dcwater.com/sites/default/files/finance/rates/FY%202025%20-%20FY%202026%20Cost%20of%20Service%20Study%20Report.pdf
[28] Raftelis. DC Water Cost of Service Study Final Report. 2022. https://www.dcwater.com/sites/default/files/finance/rates/2023%20Cost%20of%20Service%20Study.pdf
[29] Raftelis. DC Water Cost of Service Study Final Report. 2020. https://www.dcwater.com/sites/default/files/finance/cost-of-service/2021_COS_Study_Final_Report.pdf

Appendix

Appendix Table 1. Complete List of BCA Elements

SCT	TRC	COMPLETE LIST OF BCA ELEMENTS AS PER ORDER 21938			
X	X	Electricity Elements	A01		Energy (Electric)
X	X	Gas Elements	A01		Energy (Gas)
X	X	Electricity Elements	A02		Capacity (Electric)
X	X	Gas Elements	A02		Capacity (Gas)
X	X	Other Elements	A03		Other Fuels (propane, oil, gasoline)
X	X	Electricity Elements	A04		Environmental Compliance (E)
X	X	Gas Elements	A04		Environmental Compliance (G)
X	X	Electricity Elements	A05		RPS Compliance (E)
X	X	Electricity Elements	A06		Market Price Effects (E)
X	X	Gas Elements	A06		Market Price Effects (G)
X	X	Electricity Elements	A07		PJM Ancillary Services (E only)
X	X	Electricity Elements	A08		Transmission Capacity (E)
X	X	Gas Elements	A08		Transmission Capacity (G)
X	X	Electricity Elements	A09		Transmission System Losses (E)
X	X	Gas Elements	A09		Transmission System Losses (G)
X	X	Electricity Elements	A10		Distribution Capacity (E)
X	X	Gas Elements	A10		Distribution Capacity (G)
X	X	Electricity Elements	A11		Distribution System Losses (E)
X	X	Gas Elements	A11		Distribution System Losses (G)
X	X	Electricity Elements	A12		Distribution O&M (E)
X	X	Gas Elements	A12		Distribution O&M (G)
X	X	Electricity Elements	A13		Distribution Voltage (Quality of Service)
X		Environmental Elements	A14		CO2
X		Environmental Elements	A15		CH4
X		Environmental Elements	A16		N2O
X		Environmental Elements	A17		NOx
X		Environmental Elements	A18		SO2
X		Environmental Elements	A19		PM (including subset of PM2.5)
X	X	Electricity Elements	A20		Credit and Collection Costs (E)
X	X	Gas Elements	A20		Credit and Collection Costs (G)
X	X	User Inputs	A21		O&M
X	X	User Inputs	A22		Host Portion of DER Costs
X	X	User Inputs	A23		Host Transaction Costs
X	X	User Inputs	A24		Interconnection Fees
X	X	User Inputs	A25		Program Administration Costs (E)
X	X	User Inputs	A25		Program Administration Costs (G)
X	X	User Inputs	A26		Financial Incentives (E)
X	X	User Inputs	A26		Financial Incentives (G)
X	X	User Inputs	A27		Tax Incentives (H)
X	X	User Inputs	A28		Utility Performance Incentives (E)
X	X	User Inputs	A28		Utility Performance Incentives (G)
X		User Inputs	A29		Host Customer Non-Energy Impacts
X	X	Other Elements	A30		Avoided Water Costs (E)
X			B01		HFCs
X			B02		SF6
X			B03		Upstream Emissions
X			B04		Racial Equity
X			B05		Energy Burden (Equity)
X	X		B06		Locational and Temporal Value of DER
X			B07		Low-Income Impacts (Equity)
X			B08		Moderate-Income Impacts (Equity)
X			B09		Public Health
X	X		B10		Reliability
X	X		B11		Resilience