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COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

PETITION OF	)	
	)	
APPALACHIAN POWER COMPANY	)	
	)	**CASE NO. PUR-2025-00028**
For Approval of a Minimum Bill, Tariffs, and	)	
Agreements to Implement a Shared Solar	)	
Program, Pursuant to § 56-594.4 of the	)	
Code of Virginia	)	

DIRECT TESTIMONY OF ANIRUDH KSHEMENDRANATH

ON BEHALF OF THE

COALITION FOR COMMUNITY SOLAR ACCESS

May 12, 2025

Summary of Direct Testimony of Anirudh Kshemendranath

In my testimony, I provide CCSA's recommended minimum bill structure, based on an evaluation of the benefits and costs of the Shared Solar Program over 25 years (the operational lifespan of a shared solar facility).

Because the benefits of the program outweigh the costs, CCSA recommends that the Commission adopt a simple minimum bill structure of $0.

As an alternative, if the Commission is inclined to itemize the costs and benefits of the program based on current costs in the APCo tariff, consistent with the structure proposed by APCo, I recommend that the Commission incorporate additional benefits that APCo failed to include in its minimum bill proposal.

Under either approach, the result is either a negative minimum bill or a $0 minimum bill because the benefits of the program exceed the costs.

DIRECT TESTIMONY
OF
ANIRUDH KSHEMENDRANATH
ON BEHALF OF
THE COALITION FOR COMMUNITY SOLAR ACCESS
BEFORE THE VIRGINIA STATE CORPORATION COMMISSION
CASE NO. PUR-2025-00028

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. PLEASE PROVIDE YOUR NAME, EMPLOYER, AND BUSINESS ADDRESS.

A. My name is Anirudh Kshemendranath. I am a Senior Consultant at 6893449 CANADA INC (doing business as Dunsky Energy + Climate Advisors), and my business address is 555 Richmond St W #1110, Toronto, ON M5V 3B1.

Q. PLEASE SUMMARIZE YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I completed a Bachelor of Technology degree in Metallurgy and Material Science from the National Institute of Technology in Nagpur, India. I also obtained a Master of Science degree in Energy Science, Technology, and Policy from Carnegie Mellon University in Pittsburgh, Pennsylvania. I have obtained a Master of Business Administration degree from Quantic School of Business and Technology, licensed by the District of Columbia Higher Education Licensure Commission in Washington, DC, completed in 2021. I have worked in the energy and utility industry for over 10 years, specializing in energy storage, solar adoption, distributed energy resources ("DERs"), utility planning, and rate design. I have been a Senior Consultant at Dunsky Energy and Climate Advisors ("Dunsky") since April 2024, previously serving as a Consultant since April 2022, and a Senior Principal Analyst since August 2021. Prior to these roles, I worked as an Independent Senior Principal Analyst with Dunsky from August 2019 to July 2022. At Dunsky, I provide analytical and strategic consultation across multiple jurisdictions, focusing primarily on the United States. For a full description of Dunsky and my work there, please see **Exhibit A**.

Q. PLEASE DESCRIBE YOUR EXPERIENCE TESTIFYING BEFORE REGULATORY AGENCIES.

A. I have provided expert testimony before multiple regulatory commissions on rate design, DERs, and compensation frameworks. For a history of my expert testimony, please see **Exhibit B**.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING TODAY?

A. I am testifying on behalf of the Coalition for Community Solar Access ("CCSA").

II. PURPOSE AND SCOPE

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide analysis and recommendations regarding the minimum bill for the shared solar program in Appalachian Power Company's ("APCo") service territory (the "Shared Solar Program"). CCSA recommends that the Commission implement a minimum bill of $0 because the benefits of the program to APCo exceed the costs borne by the utility. In support of this recommendation, my testimony includes two analyses: (1) a high level "Benefit-Cost Assessment" for the Shared Solar Program as a whole, highlighting omissions in APCo's analysis and appropriate corrections; and (2) a "Value Stack" Analysis, which assesses the individual costs and benefits based on current tariff rates, with corresponding benefits presented on a subscription basis by customer class.[1]

[1] A high-level Benefit-Cost Assessment draws upon the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources 2020* for methodological guidance.

Q. WHAT ARE THE REQUIREMENTS FOR THE MINIMUM BILL?

A. The Commission directed APCo to file a minimum bill proposal addressing the following:[2]

- The costs of all utility infrastructure and services used to provide electric service;
- The administrative costs necessary for operation of the Shared Solar Program;
- Any other costs necessary to ensure subscribing customers pay a fair share of the costs of providing electric services;
- A quantification of the benefits of shared solar to the electric grid and to the Commonwealth; and
- An explanation of how the minimum bill proposed ensures that the costs shifted to customers not in a Shared Solar Program are minimized.

These directives from the Order are consistent with the statutory requirements in Va. Code § 56-594.4 D and the Commission's Rules Governing Shared Solar Program, 20VAC5-340-80 (Minimum bill composition).

Q. WHAT IS THE REQUIRED MINIMUM BILL CALCULATION?

A. The applicable costs to consider for the minimum bill are the costs of "utility infrastructure and services used to provide electric service and administrative costs of the shared solar program" and "further costs the Commission deems relevant to ensure subscribing customers pay a fair share of the costs of providing electric services."[3] Once the costs are determined, the next step is to "calculate the benefits of shared solar to the electric grid and

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[2] *See Ex Parte: In re: Future Minimum Bill Proceedings of Appalachian Power Co. Pursuant to Code § 56-594.4*, Case No. PUR-2025-00028, Order Initiating Proceedings (Apr. 1, 2025) ("APCo Minimum Bill Proceeding"). In the Order, the Commission directs Appalachian Power Company to file its minimum bill proposal by April 1, 2025, and directs the inclusion of cost categories, administrative charges, and quantified benefits of shared solar pursuant to Virginia Code § 56-594.4.

[3] Va. Code § 56-594.4 D.

to the Commonwealth and deduct such benefits from other costs."[4] The statutory formula for calculating the minimum bill is:

Costs – Benefits = Minimum Bill

Q. WHAT ARE YOUR FINDINGS?

A. The benefits of the Shared Solar Program—both to the electric grid and to the Commonwealth—exceed the costs.

Finding One: Based on my review of APCo's testimony and the requirements established in the Commission's Order, I find that APCo has not fulfilled its obligation to conduct a comprehensive Benefit-Cost Assessment ("BCA"). The analysis submitted by APCo is incomplete as it excludes multiple key benefit categories, undervalues the benefits it does identify, and fails to meet the analytical requirements as spelled out in the Commission's directive. Specifically, APCo incorrectly calculated the transmission charge credit and omits quantification of critical grid benefits such as avoided energy, avoided generation capacity, avoided distribution and transmission capacity, risk mitigation from long-term price stability, demand reduction induced price effect, interconnection upgrade costs, REC price suppression, and generation reliability. To address these omissions, I conducted a detailed review of APCo's methodology and applied corrections where required to account for the associated quantifiable costs and benefits. In doing so, I identified a number of benefits that were omitted from APCo's analysis, which have been routinely recognized and quantified in other jurisdictions' assessment of the value of distributed solar. Below, I present updated figures that apply corrections to APCo's analysis and incorporate evidence from other jurisdictions to highlight critical benefits that APCo

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[4] Va. Code § 56-594.4 D.

failed to include in its analysis. These findings illustrate how a comprehensive accounting of utility and non-utility benefits (*i.e.*, those to the Commonwealth) would likely result in a benefit-cost ratio well above 1.0. This analysis demonstrates that APCo's minimum bill proposal falls short of statutory requirements, and as a result, significantly understates the overall net value of the Shared Solar Program.

APCo correctly includes the following categories of benefits in its proposed minimum bill:

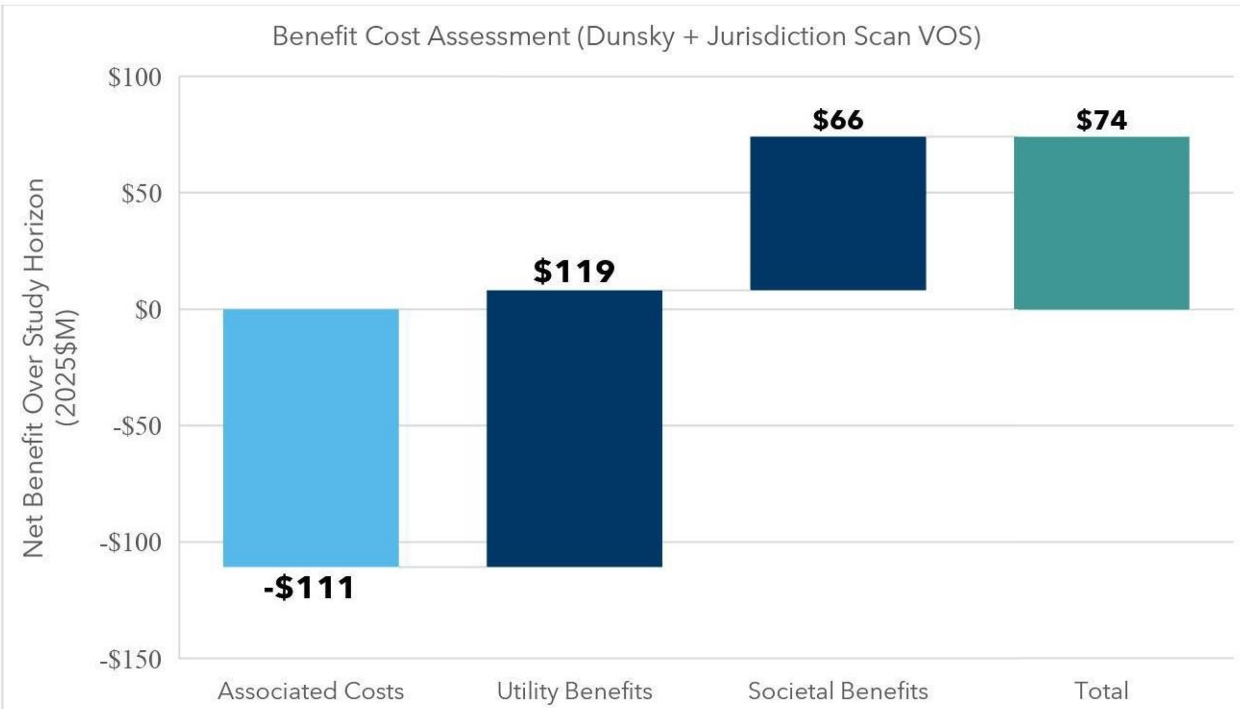
- Transmission Charge Credit
- Avoided Ancillary Service Cost
- REC Credit

However, APCo overlooks the following list of benefits to the electric grid that the Commission should include in its BCA of the Shared Solar Program:

- Avoided Energy Cost
- Avoided Generation Capacity Cost
- Avoided Line Losses Cost
- Avoided Hedging Risk Premium
- Avoided Transmission Capacity Cost
- Avoided Distribution Capacity Cost
- Renewable Energy Credit
- Demand Reduction Induced Price Effect (DRIPE) Benefit
- Interconnection Upgrade Benefit
- REC Price Suppression Benefit
- Generation Reliability Benefit
- Distribution System Opex Benefit

As shown in Figure 1, below, when accounting for all associated costs, the total cost of the Shared Solar Program is approximately $111 million cumulatively over the 2025 to 2052 study period. However, when grid benefits are fully recognized and quantified, including those identified in both the corrected analysis and analyses from other jurisdictions, the total grid benefits rise to $119 million, resulting in a net utility savings of $8 million. When other benefits to the Commonwealth are included, such as avoided air pollutants, avoided greenhouse gas (GHG) emissions, local job impacts, and economic development, the total aggregate benefit to the grid and the Commonwealth from the Shared Solar Program increases to approximately $74 million. These results confirm that the program delivers significant and enduring benefits well exceeding its costs.

Figure 1: Benefit-Cost Assessment of Shared Solar Program (Comprehensive Components) – all values in real $2025



Finding Two: Correcting APCo's analysis shows that the program is a net benefit to all ratepayers. Table 1 below presents a summary of my assessment of the utility costs and benefits, presented in the columns titled "CCSA" alongside APCo's assessment. As shown below, for a typical residential customer (1,000 kWh/month) APCo estimates a net utility cost of approximately $49, whereas the corrected analysis shows a net utility benefit of approximately $15. The discrepancy is even more significant for a non-residential General Service (GS) subscriber (10,000 kWh/month); accounting for a comprehensive set of utility benefits results in a net benefit of $310/month. For a non-residential Large Primary Service (LPS) subscriber (500,000 kWh/month), the result is a net benefit of $29,071/month.

Table 1: Summary of Minimum Bill Calculation for Typical Residential, General Service, and Large Primary Service Customers – all values in real $2025

	Residential		General Service		Large Primary Service	
	CCSA	APCo	CCSA	APCo	CCSA	APCo
Gross Utility Costs	$127.2	$89.3	$1,117	$773	$42,257	$20,307
Gross Utility Benefits	$142.7	$40.6	$1,427	$398	$71,328	$19,715
Net Utility Benefits	**$15.5**	**-$48.7**	**$310**	**-$375**	**$29,071**	**-$592**
Commonwealth Benefits	$177.0	--	$1,770	--	$88,491	$0
Total Net Benefits	**$192.4**	**-$48.7**	**$2,080**	**-$375**	**$117,562**	**-$592**

When Commonwealth benefits, such as job and economic impacts, reduced greenhouse gas (GHG) emissions, and air pollutant reduction benefits, are also included, the total monthly benefits to the grid and the Commonwealth for residential customers exceed their total costs by approximately $192. For GS customers, the total benefits exceed the costs by $2,080, while for LPS customers, the total benefits exceed the costs by $117,562. These findings show that shared solar is not only cost-effective from a utility perspective but also generates substantial benefit for the grid and the Commonwealth as a whole. This reinforces CCSA's recommendation that the Commission adopt a $0 minimum bill, which reflects that the program produces no net utility cost. Applying a larger minimum bill could hinder Shared Solar Program participation, thereby preventing ratepayers and the Commonwealth from accessing the full potential value of shared solar.

Finding Three: Because the grid benefits from shared solar exceed the associated costs, the program will impose no meaningful cost shift to non-participating customers. In fact, shared solar facilities contribute benefits to the grid that exceed the costs of the program, even before accounting for Commonwealth benefits.[5]

The Shared Solar Program is a net-positive program for both the grid and the Commonwealth. It supports Virginia's clean energy goals, including those set out in the Virginia Clean Economy Act ("VCEA"), and delivers significant utility, economic and environmental value. These findings strongly support the adoption of a $0 minimum bill.

Q. WHAT IS CCSA'S RECOMMENDATION FOR THE MINIMUM BILL IN THIS PROCEEDING?

A. Based on my independent analysis, the aggregate benefits of the Shared Solar Program when fully recognized and quantified—both to the grid and to the Commonwealth—exceed its total costs. When isolating for utility benefits, the benefits exceed the costs, so the Shared Solar Program does not result in a cost shift to non-participating customers.[6] Even under APCo's minimum bill framework, a corrected analysis demonstrates that shared solar provides net value to the grid, and in many cases, fully offsets the cost of serving subscribers.[7] Thus, CCSA recommends that the Commission adopt a cost-reflective and administratively simple minimum bill of $0. This approach aligns with the goals established in the Commission's Order—specifically: (i) ensuring subscribers pay their fair share of electric service costs; (ii) minimizing cost shifts to non-participants; and (iii) recognizing and deducting the benefits of shared solar to the electric grid and the Commonwealth from other program costs.

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[5] *See* Table 1: Summary of Minimum Bill Calculation for Residential, General Service, and Large Primary Service Customers.
[6] *See* infra Section III.
[7] *See* infra Section V.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY STRUCTURED?

A. The remainder of my testimony consists of four sections, each aligned with the core objectives of this proceeding:

III. **Benefit-Cost Assessment:** This section addresses the third goal of the docket—"to calculate the benefits of shared solar to the electric grid and the Commonwealth and deduct such benefits from other costs." In this section, I quantify the full costs of the program and compare them against the utility system and Commonwealth benefits to determine the net benefit of the Shared Solar Program. The benefit-cost assessment shows that a minimum bill of $0 is well justified.

IV. **Minimum Bill Component Assessment:** CCSA recommends that the Commission adopt a $0 minimum bill. Alternatively, if the Commission chooses to add benefits to the current minimum bill structure, modifications will be necessary. In this section, I use APCo's cost framework as a starting point and identify the necessary adjustments.

V. **Methodology for Valuing Shared Solar Benefits:** This section lays out the analytical approach and valuation methods used to quantify each component of utility and Commonwealth benefits. It includes modeling of avoided costs and non-utility impacts, aligned with best practices in DER valuation.

VI. **Summary of Findings and Recommendations:** This section presents my key conclusions and offers clear, actionable recommendations to the Commission regarding the appropriate minimum bill structure, based on the analysis provided.

III. BENEFIT-COST ASSESSMENT

Q. DOES APCO'S TESTIMONY AND PROPOSAL CONDUCT A FORMAL COST-EFFECTIVENESS EVALUATION OF THE SHARED SOLAR PROGRAM?

No. APCo did not conduct a fulsome comparison of the benefits and costs of the Shared Solar Program. Its testimony lacks a structured cost-effectiveness evaluation consistent with established regulatory standards. For example, the Commission's Rules Governing Cost/Benefit Measures Required for Demand-Side Management ("DSM") Programs in Virginia require robust analysis:

> Utility applicants shall analyze a proposed program from a multi-perspective approach using, at a minimum, the Participants Test, the Utility Cost Test, the Ratepayer Impact Measure Test, and the Total Resource Cost Test.[8]

While the DSM framework is not specifically applicable to the minimum bill calculation, both the DSM and Shared Solar programs require an assessment of program benefits. APCo's analysis regarding the minimum bill falls far short of providing a reasonable Benefit-Cost Assessment, much less meeting the Commission requirements for DSM programs. Notably, APCo has faced similar criticism in the context of its Net Energy Metering ("NEM") filings for failing to conduct a formal cost-effectiveness evaluation.[9] Because APCo has not conducted a full cost-effectiveness evaluation, I recommend that the Commission consider the benefit estimates presented in this testimony and compare them to APCo's stated program costs. While this gap in APCo's analysis underscores the

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[8] *See* 20 VAC 5-304-20.

[9] *See e.g., Petition of Appalachian Power Co. to Revise Net Metering Program Pursuant to § 56-594 of the Code of Virginia*, Case No. PUR-2024-00161, Prefiled Testimony of Staff Witness Steven E. Smith at 26 (Apr. 8, 2025) ("Staff agrees that there are generally costs and benefits associated with net metering. However, due to the deficiencies in [APCo's] petition, Staff cannot opine on the quantity of costs and benefits to net metering in [APCo's] service territory and the Commonwealth as a whole.").

need for a complete and compliant evaluation, I have nonetheless carefully reviewed the analysis APCo did conduct. Even within this narrow scope, I have identified several critical improvements and corrections that need to be addressed:

- **Corrections to the costs used in APCo's analysis:** To ensure accurate treatment of the incremental energy and capacity benefits associated with the Shared Solar Program, I have included the corresponding generation costs required to serve participating customers.
- **Corrections to the benefits used in APCo's analysis:** For the three categories of benefits identified in APCo's analysis, I have made key adjustments. Specifically, I corrected the calculation of transmission charges and renewable energy certificate ("REC") values, both of which were undervalued in APCo's analysis.
- **Inclusion of omitted benefit and cost categories:** I have added several categories of benefits that are commonly included in DER valuation studies, but were omitted in APCo's analysis for the minimum bill. These include avoided transmission and distribution capacity costs, the wholesale market risk premium, and other relevant factors such as avoided transmission and distribution upgrade costs borne by developers, improvements in generation reliability, and avoided distribution operations and maintenance expenses. These elements are necessary to produce a comprehensive estimate of the Shared Solar Program's aggregate benefits to the grid.[10]

[10] *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources 2020*, NATIONAL ENERGY SCREENING PROJECT, https://www.nationalenergyscreeningproject.org/) (last visited May 12, 2025) ("NSPM").

Q. DO YOU AGREE WITH APCO'S APPROACH USED TO DETERMINE THE COSTS OF THE SHARED SOLAR PROGRAM?

A. No. APCo's methodology generally represents a reasonable approach to identifying the full range of utility infrastructure and service costs required to deliver electricity. However, because APCo did not include generation *costs* in its cost assessment, it determined that it should not include generation *benefits*. I do not agree with APCo's exclusion of generation components. APCo should include both generation costs and benefits in its analysis. As demonstrated in my analysis, the Shared Solar Program delivers quantifiable energy and capacity benefits that are greater than the corresponding costs of providing these services. Therefore, the Commission should include both the incremental generation costs and benefits of shared solar in the minimum bill calculation. This approach is consistent with the National Standard Practice Manual ("NSPM"), which emphasizes that all relevant costs and benefits—utility system and societal—should be included in any comprehensive Benefit-Cost Assessment.[11]

Q. HOW SHOULD APCO'S GENERATION COSTS ANALYSIS BE CORRECTED?

A. The generation energy charge should be included in the gross minimum bill calculation. Including the generation energy charge in the gross minimum bill increases the estimated cost to $127.29 for a residential customer subscribing to 1,000 kWh per month, to approximately $1,117 for a GS customer with a monthly consumption of 10,000 kWh, and to $42,257 for a LPS customer with a monthly consumption of 500,000 kWh.[12] Including

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[11] *Id.*

[12] GS monthly average load is from CCSA 4-1 Attachment 1, which assumes a monthly demand of 40 kW. LPS monthly load is based on 74% load factor and 1,000 kW of demand. Residential monthly average load is from Workpaper NMC-1, specifically the "Sheet1" worksheet provided in response to Staff' first set of interrogatories to APCo, question 2. Both documents are attached hereto as **Exhibit C**. In CCSA 4-1 Attachment 1, APCo incorrectly

this cost would logically be coupled with the associated energy generation benefits that the utility accrues, ensuring a more accurate and balanced assessment of shared solar's net benefits.

Q. HOW DID YOU DETERMINE THE LIFETIME COSTS OF THE SHARED SOLAR PROGRAM?

A. In the absence of a comprehensive cost estimate provided by the utility, I used APCo's proposed cost elements as a proxy for Shared Solar Program costs.[13] These costs include the customer charge, administrative charge, base distribution rates, and other applicable charges such as Riders PIPP, BC RAC, A.5 RPS, EE RAC, and T.RAC. As noted above, I also added the generation charge to these charges to account for all categories of costs. I applied these charges to the residential, GS, and LPS customer classes, assuming 1,000 kWh/month, 10,000 kWh/month, and 500,000 kWh/month subscription levels, respectively.

To estimate lifetime costs, I assumed a stepwise capacity buildout of 50 MW of shared solar capacity—5 MW in 2025, followed by 15 MW in 2026, 10 MW in 2027, and 20 MW in 2028—and projected costs over a 25-year system life through 2052. All cost components were held constant in real 2025 dollars, except for the generation energy charge, which was escalated using forward energy price trends. The resulting cost streams

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applied the Rider BC RAC as a volumetric charge of $0.05/kWh when, based on the VA. S.C.C. TARIFF NO. 28, the NBP RIDER B.C. – R.A.C for a LPS Primary customer should be demand based $0.05 per kW. The corrected value was used in determining the gross minimum bill.

[13] *See* APCo Minimum Bill Proceeding, Petition at 4 (Apr. 1, 2025).

were discounted in present value using a 5% real discount rate.[14] Based on this assessment, the lifetime costs of the Shared Solar Program amount to approximately $110 million.

Table 2: Associated Lifetime Costs for the Shared Solar Program[15]

(2025-2052)

Cost Components	Charge ($M) Real $2025
Customer Charge	$4.88
Rider PIPP	$1.25
Rider BC RAC	$0.45
Rider A.5 RPS RAC	$0.96
Rider PCAP RAC	$0.11
Rider A.6 RPS RAC	$0.09
Energy Distribution	$32.92
Rider EE RAC	$2.22
Rider T.RAC	$29.43
Administrative Charge	$0.59
Energy Generation	$37.91
Total Lifetime Costs	**$110.80**

Q. DO YOU AGREE WITH APCO'S APPROACH TO EVALUATING THE BENEFITS OF THE SHARED SOLAR PROGRAM?

A. No. APCo's proposed Minimum Bill structure is inconsistent with standard practices in Benefit-Cost Assessment and fails to reflect a comprehensive set of benefits that shared solar provides to both the grid and the Commonwealth.

First, APCo's methodology only accounts for a narrow subset of utility system benefits, specifically avoided transmission charges, ancillary services, and REC value.

[14] Based on assumed utility nominal Weighted Average Cost of Capital of 7% and inflation of 2%. Zone of reasonable utility equity is 7.03% to 11.74%. Nat'l. Ass'n of Regl. Util. Comm'r. *Cost of Capital and Capital Markets: A Primer for Utility Regulators* (Dec. 2019), https://pubs.naruc.org/pub.cfm?id=CAD801A0-155D-0A36-316A-B9E8C935EE4D (detailed calculations can be found in **Exhibit D**, Shared Solar Workbook, Worksheet "Program Costs.").

[15] There are minor discrepancies between the total and component values due to rounding.

APCo's proposal does not account for broader grid benefits that directly accrue to the utility and to the grid, including avoided energy, generation capacity, and transmission capacity costs; avoided or deferred distribution system investments associated with shared solar interconnection; marginal line loss reductions; and long-term price stability benefits from fixed-price solar generation. Further, APCo's proposal fails to account for benefits to the Commonwealth, such as avoided GHG emissions, air pollutant reductions, job creation, economic development, or energy burden relief, even though these benefits are explicitly recognized in the Order initiating this proceeding – "calculate the benefits of shared solar to the electric grid and to the Commonwealth"[16] and are consistent with the Commonwealth's statutory energy goals under the VCEA.[17]

Second, APCo's calculation of avoided transmission charges is methodologically flawed. APCo incorrectly applies a net metering-based methodology that only considers net exports when estimating shared solar's impact on transmission demand. This is incorrect because the entire generation of a shared solar facility contributes to reduction in transmission charge obligation. Thus, the full generation profile of the shared solar facility should be credited against transmission coincident peaks, consistent with how transmission cost responsibilities are allocated within PJM.[18]

By failing to account for the full range of benefits provided by shared solar, including both grid and broader Commonwealth benefits, APCo's proposed $48 monthly minimum bill significantly undervalues the contribution of shared solar resources. APCo's proposal has the opposite effect of the law's intent by shifting costs to shared solar

[16] APCo Minimum Bill Proceeding, Order Initiating Proceedings at 3 (Feb. 10, 2025).
[17] Virginia Clean Economy Act, 2020 Va. Acts ch. 1193, codified at Va. Code § 56-585.5 A.
[18] APCo Minimum Bill Proceeding, Direct Testimony of Nicole M. Coon on behalf of Appalachian Power Company at 7 (Apr. 1, 2025).

subscribers, discouraging participation, and jeopardizing program viability. Indeed, as discussed by CCSA Witness Coggeshall, APCo's proposal, if adopted, could prevent the deployment of shared solar facilities in APCo's service territory.[19]

Q. BRIEFLY DESCRIBE THE METHODOLOGY YOU USED TO DETERMINE THE *BENEFITS* OF THE SHARED SOLAR PROGRAM.

A. I began by reviewing APCo's assessment of the Shared Solar Program's benefits and made corrections where possible. The next step was to ensure that a comprehensive set of benefits attributable to the program was captured in the analysis. Consistent with the recommendations before the Commission in Case No. PUR-2024-00120 regarding cost effectiveness evaluations for energy efficiency program, I used a Virginia Jurisdiction-Specific Test framework.[20] This framework incorporates all relevant utility system impacts, including avoided energy, capacity, transmission, distribution, and administrative costs. It also includes non-utility impacts that align with Virginia's public policy goals, such as GHG emission reductions, environmental externalities, economic development and equity considerations. This approach aligns with the Commission's ongoing rulemaking to establish standardized cost-effective tests for energy efficiency programs.[21] It also reflects best practices from the NSPM and leading Value of Solar ("VoS") studies.

Two core principles guided our benefit analysis: (1) a long-term, forward-looking perspective that reflects the 25-year life of shared solar assets; and (2) an evaluation of benefits on a marginal and incremental basis, capturing the avoided costs associated with

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[19] *See generally*, APCo Minimum Bill Proceeding, Direct Testimony of CCSA Witness Coggeshall (May 12, 2025).
[20] *See Ex Parte: In re: Promulgating Regulations Establishing a Single, Consistent Cost-Effectiveness Test for Use in Evaluating Proposed Energy Efficiency Programs*, Case No. PUR-2024-00120, Stakeholder Group Report (Mar. 26, 2025).
[21] *Id.*

new shared solar deployment. To ensure completeness, I also conducted a jurisdictional review of leading VoS studies to identify benefit categories that were not included in the analysis due to data limitations. Where possible, a high-level analysis of these additional categories was performed to estimate their contribution to the gross benefits of shared solar. These gross benefit estimates informed my understanding of the likely benefit-to-cost ratio that a full, comprehensive analysis would reveal for the program in Virginia. A detailed explanation of how the benefit components were calculated is included below in Section IV of this testimony.

Q. HOW DID YOU DETERMINE THE LIFETIME BENEFITS OF THE SHARED SOLAR PROGRAM?

A. To determine the lifetime benefits of the Shared Solar Program, I conducted a forward-looking, marginal value-based analysis consistent with the best practices outlined in the NSPM and leading VoS studies. The first step was to identify a comprehensive set of benefit categories incorporating both utility system impacts and Commonwealth-level benefits.[22]

To quantify these benefits, I used a single-axis tracking solar production profile developed using PVWatts modeling for an archetypal shared solar PV system located in Roanoke, Virginia. These production profiles were paired with forward-looking market forecasts for avoided energy, capacity, and transmission services. I modeled a phased deployment of 50 MW of shared solar capacity—5 MW in 2025, 15 MW in 2026, 10 MW

[22] The comprehensive benefit categories CCSA considered are consistent with the categories in the draft EEP Cost-Effectiveness Test Regulations filed along with Independent Monitor's final report on the Energy Efficiency Program Stakeholder Group Meetings in Case No. PUR-2024-00120 on March 26, 2025.

in 2027, and 20 MW in 2028—and evaluated benefits over a 25-year system life through 2052.

Each benefit stream was calculated on an annual basis and discounted to present value using a 5% real discount rate. This methodology ensures a robust, marginal-cost-based assessment of the long-term system and Commonwealth value delivered by the Shared Solar Program.

Based on this analysis, Table 3 presents the estimated lifetime benefits of the Shared Solar Program, disaggregated by benefit category and calculated using the methodology described above. These results reflect a comprehensive accounting of grid and Commonwealth benefits over the 2025–2052 study horizon.

Table 3: Utility and Commonwealth Benefits of the Shared Solar Program (2025-2052) – all values in real $2025

Benefit Components	Value ($M)
Avoided Energy	$35.46
Avoided Generation Capacity	$18.42
Avoided Ancillary Services	$1.36
Avoided Line Losses	$6.41
Avoided Hedging Risk Premium	$4.31
Transmission Charge Credit	$6.61
Avoided Transmission Capacity	$3.21
Avoided Distribution Capacity	$0.18
REC Credit	$26.62
GHG Reduction Benefits	$10.23
Air Pollutant Reduction Benefits	$2.22
Jobs & Economic Benefits	$53.54
Grid Lifetime Benefits	**$102.58**
Commonwealth Lifetime Benefits	**$66.00**
Total Lifetime Benefits	**$168.58**

Q. ARE THERE ADDITIONAL GRID BENEFITS THAT WERE NOT QUANTIFIED IN YOUR ANALYSIS?

A. Yes. While my analysis captures a comprehensive set of monetizable benefits, several utility system and grid components were not fully quantified due to data limitations. To assess their potential impact, I conducted a comparative review of distributed solar valuation studies from other jurisdictions, including New Hampshire and Maine. Through this comparative benchmarking, I identified key benefit categories commonly included in other jurisdictions but not reflected in my analysis.[23] These include the Demand Reduction Induced Price Effect ("DRIPE"), transmission and distribution interconnection upgrades paid by developers, REC Price Suppression Benefits, generation reliability benefits, and reductions in distribution system operating and maintenance expenses.

Q. WHAT IS THE POTENTIAL IMPACT OF THESE ADDITIONAL SYSTEM BENEFITS?

A. Using a proportional allocation approach based on these jurisdictions, I estimated the relative contribution of these omitted components to the gross utility benefits. Applying that ratio to the benefits already quantified in the analysis, the inclusion of these missing categories would increase the total utility system benefits of the Shared Solar Program by approximately 15%.

Table 4 below presents the total grid and Commonwealth-level benefits, as assessed in the analysis, alongside the adjusted total benefits that include components identified and

[23] New Hampshire – New Hampshire Department of Energy. *Value of Distributed Energy Resources (VDER) Study,* https://www.energy.nh.gov/value-distributed-energy-resources-study (last visited May 12, 2025); Maine: Sustainable Energy Advantage, LLC. *Analysis of 2024 Net Benefits of Net Energy Billing Program.* Prepared for the Maine Public Utilities Commission. March 31, 2025. Available at: https://www.maine.gov/mpuc/sites/maine.gov.mpuc/files/inline-files/Maine-NEB-Y2024_CBA_Final.pdf.

analyzed in studies from other jurisdictions. As presented in the table, the adjusted, more comprehensive total benefits are assessed at $118.94 million, demonstrating that the grid benefits from the Shared Solar Program alone should exceed the costs.

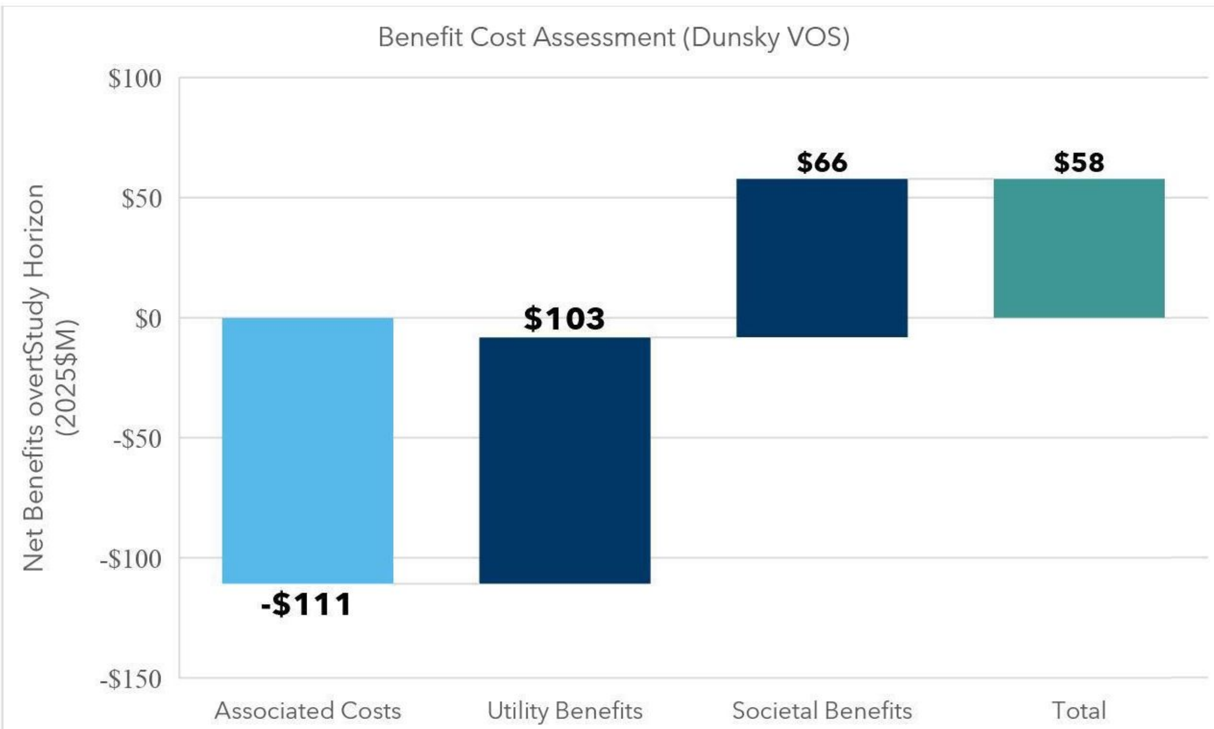
Table 4: Grid and Commonwealth Benefits of the Shared Solar Program (2025-2052) – all values in real $2025

Benefit Components	CCSA Study ($M)	CCSA Adjusted ($M)
Avoided Energy	$35.46	$35.46
Avoided Generation Capacity	$18.42	$18.42
Avoided Ancillary Services	$1.36	$1.36
Avoided Line Losses	$6.41	$6.41
Avoided Hedging Risk Premium	$4.31	$4.31
Transmission Charge Credit	$6.61	$6.61
Avoided Transmission Capacity	$3.21	$3.21
Avoided Distribution Capacity	$0.18	$0.18
REC Credit	$26.62	$26.62
DRIPE		$5.84
Interconnection Upgrade Benefit		$0.17
REC Price Suppression Benefit		$6.97
Generation Reliability Benefit		$0.27
Distribution System OpEx Benefit		$3.10
Grid Lifetime Benefits	**$102.58**	**$118.94**
GHG Reduction Benefits	$10.23	$10.23
Air Pollutant Reduction Benefits	$2.22	$2.22
Energy Burden	n/a	n/a
Jobs & Economic Benefits	$53.54	$53.54
Commonwealth Lifetime Benefits	**$66.00**	**$66.00**
Total Lifetime Benefits	**$168.58**	**$184.94**

Q. How do the benefits of shared solar compare to the costs of the program?

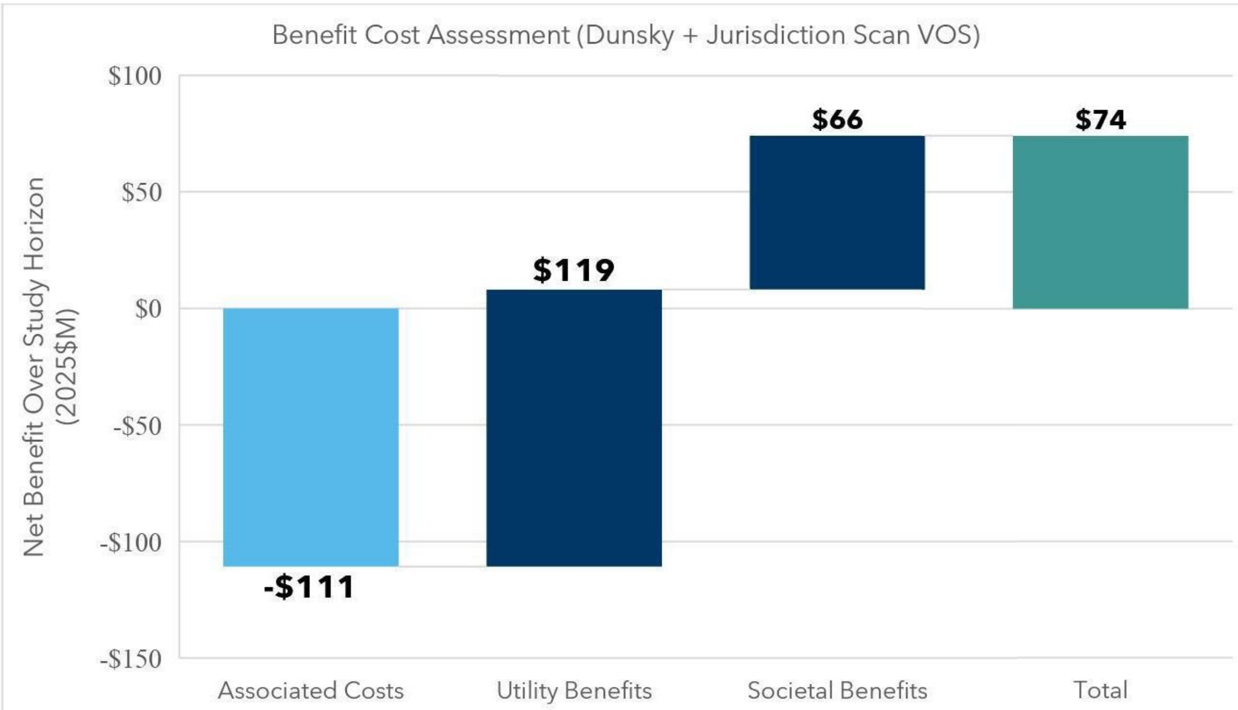
A. The total associated costs of the Shared Solar Program over the 2025–2052 study horizon amount to $111 million. As illustrated in Figure 2, below, when accounting for utility system benefits—including avoided energy, capacity, transmission, and other system-level cost savings—the net cost to the utility falls to approximately $8 million. However, when also factoring in broader Commonwealth-level benefits such as GHG emission reductions, improved public health outcomes from air pollutant reductions, job creation, and local economic value, the analysis shows that the Shared Solar Program delivers a total net benefit of approximately $58 million to the grid and the Commonwealth.

<u>Figure 2: Benefit Cost Assessment of Shared Solar Program (Selected Components) – all values in real $2025</u>



As shown in Figure 3, when including additional utility system benefit categories not captured in the primary analysis, but commonly included in other jurisdictions such as Maine and New Hampshire, total utility system benefits increase to $119 million, producing a net utility savings of $8 million. With Commonwealth benefits remaining the same, the total net benefit from the Shared Solar Program rises to approximately $74 million.

Figure 3: Benefit Cost Assessment of Shared Solar Program (Comprehensive Components) – all values in real $2025



These results demonstrate that even when evaluated solely on utility system impacts, shared solar either fully offsets or exceeds its associated program costs. When broader benefits are appropriately included, the program offers a substantial return on investment to both the grid and the Commonwealth, validating its role as a low-cost, high-impact clean energy solution.

IV. DETERMINATION OF THE BENEFITS OF SHARED SOLAR

A. Benefits of Shared Solar to the Electric Grid[24]

Q. WHAT ARE THE KEY GRID-RELATED BENEFITS OR UTILITY SYSTEM IMPACT COMPONENTS IDENTIFIED AND INCLUDED IN YOUR ANALYSIS OF THE SHARED SOLAR PROGRAM?

A. There are several grid-related benefits that represent avoided utility system costs attributable to shared solar generation. These components reflect established benefit-cost practices.

The key grid benefits included in the analysis were:

1. **Avoided Energy:** The reduced wholesale energy procurement required by APCo due to the shared solar generation offsetting system load during daylight hours.[25]
2. **Avoided Generation Capacity:** Shared solar's contribution to lowering the utility's peak demand, thereby reducing its capacity obligation in PJM.[26]
3. **Avoided Ancillary Services:** The reduction in total system load due to shared solar generation, which lowers the utility's share of ancillary service charges under PJM's load-based cost allocation.

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[24] Va. Code § 56-594.4 D.

[25] NAT'L ENERGY SCREENING PROJECT, NSPM Methods, Tools, and Resources Handbook at Chapter 3: Electric Utility System Impacts, Section 3.2.1, p.14 (2022) ("NPSM Handbook"). I used a solar production profile generated from the NREL PVWatts calculator. Specifically, I modeled the output of a 1-kilowatt (kW) DC, single-axis tracking photovoltaic system located in Roanoke, Virginia, which is representative of the APCo service territory. I used hourly AC output data generated by PVWatts, which reflects the system's delivered electricity after accounting for inverter and system losses. This production profile captures seasonal and diurnal variations in solar output. By using a standardized and publicly accessible modeling tool like PVWatts with default performance assumptions, the analysis ensures transparency, reproducibility, and alignment with common industry practices for valuing distributed solar generation.

[26] NPSM Handbook at Chapter 3: Electric Utility System Impacts, Section 3.2.2, p. 24. (2022).

4. **Avoided Line Losses:** The reduction in electricity line losses resulting from shared solar generation being closer to the point of consumption, particularly during high-load periods.[27]
5. **Avoided Hedging Risk Premium:** The value of long-term, fixed-cost shared solar generation in reducing exposure to wholesale market volatility and fossil fuel price uncertainty.[28]
6. **Transmission Charge Credit:** Shared solar's ability to reduce APCo's transmission peaks, thereby lowering its transmission charge obligation.
7. **Avoided Transmission Capacity:** The long-run marginal transmission capacity value to the electric system resulting from shared solar's ability to reduce the demand on the transmission system. By generating power closer to the point of use—particularly during peak hours—shared solar can defer or avoid investments in transmission infrastructure upgrades, reducing overall system costs over time.
8. **Avoided Distribution Capacity:** The potential for shared solar to defer or reduce the need for distribution system upgrades, particularly in areas experiencing load growth or congestion at the substation or feeder level.

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[27] Line losses grow exponentially with higher levels of load, and as such it is important that calculations account for marginal loss rates when determining this impact. *NSPM Handbook* at Chapter 3: Electric Utility System Impacts, Section 3.2.2, p. 68.

[28] In a 2002 study, Lawrence Berkeley National Laboratory found that energy efficiency and renewable energy can serve as a hedge against volatile natural gas costs. The research examined the cost of hedging gas price risk through financial hedging instruments by looking at the price of a 10-year natural gas swap (i.e., what it costs to lock in prices over the next 10 years). The study found that the incremental cost to hedge gas price risk exposure is potentially large enough— particularly if incorporated by policymakers and regulators into decision making practices such as BCA—to tip the scales away from new investments in variable-price, natural gas-fired generation and in favor of fixed-price investments in energy efficiency and renewable energy. *NSPM Handbook* at Chapter 6: Risk Assessment in Benefit-Cost Analysis, p. 196.

9. **REC Benefits:** the environmental compliance VoS generation, which displaces the need for APCo to procure RECs elsewhere to meet Virginia's Renewable Portfolio Standard (RPS) obligations.

Q. WHAT ARE THE APPLICABLE AVOIDED ENERGY COSTS?

A. The avoided energy costs for the minimum bill should be $35.94 for a customer subscribing to 1,000 kWh/month from shared solar. This avoided energy cost figure is based on the average hourly solar production for each month-hour combination paired with the corresponding average hourly real-time energy price for that period using PJM's Data Miner platform data.[29]

I multiplied each month-hour product by the number of days in the respective month to calculate the total monthly avoided energy value. These values were then summed across the year and normalized by total annual shared solar generation to arrive at a final avoided energy value expressed in dollars per kilowatt-hour.[30] A forecast based on the solar-weighted average forward energy price yields a lifetime benefit of $35.46M over the study horizon (2025-2052).[31] This approach ensures that the avoided energy value accurately reflects both the seasonal production profile of solar and the temporal variation in wholesale market pricing.

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[29] Data Miner 2, Settlements Verified Hourly LMPs, PJM, https://dataminer2.pjm.com/feed/rt_da_monthly_lmps (last visited May 12, 2025). Data parameters: Start Date – April 2024; End Date – March 2025; Pricing Node – AEP (ID: 8445784); Node Type – ZONE. Avoided cost values based on total_lmp_rt. The avoided energy cost is based on trailing 12-month energy price data from April 2024 to March 2025.

[30] Shared Solar Workbook. Worksheet: Energy – Last 12 Months. Internal analysis by Dunsky Energy and Climate Advisors, attached hereto as **Exhibit E**.

[31] The forward energy price forecast was derived using on-peak and off-peak futures data from NYMEX (ICE), weighted by projected hourly solar generation. For the first three months, actual 2025 PJM real-time prices were used. These were benchmarked against the most recent 12 months of avoided energy values using PJM Data Miner (*supra* note 27) and adjusted to reflect expected trends in solar-weighted market pricing. **Exhibit F** – Shared Solar Workbook. Worksheet: Energy Price Forecast. Internal analysis by Dunsky Energy and Climate Advisors, based on NYMEX futures data and PJM real-time prices.

Avoided energy costs are grid benefits that must be included in the minimum bill calculation. Indeed, APCo identified avoided energy costs as a benefit in the net metering proceeding.[32]

Q. WHAT ARE THE APPROPRIATE AVOIDED GENERATION CAPACITY COSTS?

A. The Commission should use an avoided generation capacity cost of $16.39 for a customer subscribing to 1,000 kWh/month from shared solar.[33] This number was calculated using PJM's published 5 CP hours for the years 2022 to 2024 and evaluating the average solar output during those hours using the same PVWatts-based generation profile developed for Roanoke, Virginia. I then calculated the three-year average of solar generation's effective contribution during the 5 CP events and expressed this as a percentage of nameplate capacity. I applied the Base Residual Auction ("BRA") clearing price for the "Rest of RTO" LDA, which is the appropriate pricing zone for APCo's territory, using the most recent auction results for the 2025/2026 delivery year, and then incorporated PJM's updated target reserve margin, which increased from 14.7% to 17.8% for the 2025–2026 planning year, into the valuation. The avoided capacity value was calculated using the following formula:

*Avoided Capacity Cost ($/kW) = Solar 5 CP Contribution (%) * Rest of RTO Auction Price ($/kW-yr) * (1 + Reserve Margin)*

[32] *Petition of Appalachian Power Company for approval to revise its net metering program pursuant to § 56-594 of the Code of Virginia*, Case No. PUR-2024-00161, Petition at 6 (Aug. 30, 2024).

[33] In this analysis, I estimate the effective capacity contribution of the 50 MW Shared solar program by modeling its incremental deployment over four years: 25 MW in Year 1, followed by 10 MW, 15 MW, and 20 MW in subsequent years, reaching the program cap. The capacity contribution is based on projected annual values declining from 39% in Year 1 to 32%, 31%, 22%, and 20% in Years 2–4, respectively. This results in a blended effective capacity value of 25% across the full deployment. Applying this 25% value to the estimated cost of new capacity yields an avoided generation capacity benefit of $16.39/MWh. If instead only the first-year capacity contribution (39%) were applied, the avoided generation capacity value would increase to $25.93/MWh.

This value was normalized over total annual solar production to express the avoided capacity cost on a per-kWh basis. A forecasted avoided capacity value by applying a 25% effective capacity factor to projected capacity prices for the AEP zone was also developed, using the Combustion Turbine Net Cost of New Entry ("Net CONE") estimates developed for the AEP Zone by Brattle.[34] The lifetime generation capacity benefit of shared solar comes to $18.42M over the study horizon (2025-2052).

Q. DO YOU EXPECT THE FUTURE AVOIDED GENERATION CAPACITY COST TO BE HIGHER THAN WHAT IS REFLECTED IN YOUR CURRENT ANALYSIS?

A. Yes. In my analysis, for 2025, I used the Net Cost of New Entry ("Net CONE") for a combustion turbine in the AEP Zone, developed by the Brattle Group in PJM, as a proxy for avoided generation capacity value. This approach provides a standardized and market-based estimate that reflects current conditions. However, there are strong indicators that capacity prices may rise substantially. According to PJM's latest Load Forecast Report, substantial summer and winter peak demand growth is projected in the AEP zone, where APCo operates.[35] This anticipated peak load growth will increase the system's capacity

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[34] The forecasted avoided generation capacity value was derived by applying a 25% effective capacity contribution—representing the effective capacity factor of the 50 MW Shared solar program—to future capacity price trajectories. *See In Re: Appalachian Power Co.'s Integrated Resource Plan Filing pursuant to Va. Code § 56-597 et seq.*, Case No. PUR-2022-00051, Application Exhibit E at 146 (Apr. 29, 2022); *In re Virginia Elec. & Power Co.'s 2024 Integrated Resource Plan Filing Pursuant to Va. Code § 56-597 et seq*., Case No. PUR-2024-00184, Application Appendix 5B-10 (Oct. 15, 2024); PJM Interconnection. *2025/2026 Base Residual Auction Report*, PJM INTERCONNECTION (July 30, 2024), https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx Capacity prices expressed in $/MW-day were converted to $/kW-year using a 365-day adjustment and then escalated for inflation beginning in 2041. All calculations and assumptions are documented in **Exhibit G** – Shared Solar Workbook, Worksheet: BRA Capacity. PJM Interconnection. *2025/2026 Base Residual Auction Report*. https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx

[35] 2025 Load Forecast Report at 26, PJM INTERCONNECTION (Jan. 24, 2025) https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf. This page details projected summer and winter peak demand growth for the American Electric Power ("AEP") zone.

needs, putting upward pressure on capacity market prices. If these trends materialize, the future avoided capacity value attributable to distributed resources like shared solar will be higher than the conservative values reflected in this analysis.

Given Virginia's clean energy and decarbonization goals, it is appropriate to compare shared solar against relatively clean capacity resources, such as battery energy storage systems ("BESS"). Net Cost of New Entry (CONE) for a BESS, as estimated by Brattle, is approximately 200% higher than the combustion turbine-based capacity value used in the analysis.[36] This suggests that the current valuation is likely understated and that the full long-term benefit of shared solar on capacity cost avoidance may be considerably greater.

Q. WHAT ARE THE APPROPRIATE AVOIDED ANCILLARY COSTS?

A. The Commission should use an avoided ancillary cost of $1.44 for a customer subscribing to 1,000 kWh/month from shared solar.[37] Avoided ancillary service costs reflect the reduction in certain wholesale market charges that the utility would otherwise incur to maintain grid reliability. These charges—such as those for frequency regulation, operating reserves, and other balancing services—are assessed by PJM on a load-serving entity's

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[36] The Brattle Group. *PJM CONE 2026/2027 Report*, prepared for PJM Interconnection, LLC. February 2024. *See* Table 28, p. 68 for indicative Net CONE estimates for CTs in the AEP zone. Available at: https://www.pjm.com/-/media/committees-groups/committees/mic/2024/20240206/20240206-item-03c-2026-2027-cone-study.ashx; The Net CONE represents the net annualized cost of constructing a new capacity resource, such as a combustion turbine, after accounting for expected energy and ancillary service market revenues. It reflects the long-run marginal cost of new capacity procurement and is a proxy for the incremental value of capacity in the market. Net CONE is commonly used to set capacity market demand curves because it captures the cost of the most economically feasible new entrant and the price signal required to support investment in new capacity under competitive conditions.

[37] The avoided ancillary service cost provided by APCo in Workpaper NMC-1 in response to Staff's first set of interrogatories, question 2 (attached hereto as **Exhibit C**) reflects an unscaled value of approximately $1.50 per 1,000 kWh/month for a typical residential customer. In contrast, my analysis treats line loss reductions as a separate benefit category and does not embed them within ancillary service values. As a result, my avoided ancillary service cost estimate appears lower. Moreover, APCo appears to have applied average line loss factors to derive its avoided ancillary service values. However, for cost-effectiveness analysis, the marginal line loss factor, which reflects the incremental losses associated with changes in load, should be applied. Using average losses understates the avoided cost benefit in APCo's estimate.

total served load. When a shared solar customer-generator exports electricity to the distribution system, it reduces the net load on the system. As a result, it lowers APCo's total load obligation used by PJM to allocate load-based ancillary service charges. This leads to a measurable, though modest, avoided cost.

My analysis estimated the avoided ancillary service cost at a rate of approximately \$1.414 per MWh.[38] This figure is based on dividing total PJM ancillary service costs by total Company load and provides a system-averaged value that captures the utility's cost exposure.[39] This approach accurately reflects the marginal cost reductions shared solar provides through reduced wholesale system demand. Assuming that ancillary service costs remain constant in real dollars throughout the study period, the avoided ancillary service costs from the Shared Solar Program will be \$1.36 million over the study horizon (2025-2052).

Q. WHAT ARE THE AVOIDED LINE LOSSES COSTS?

A. The Commission should use an avoided line loss of \$7.54 for a customer subscribing to 1,000 kWh/month from shared solar. To determine this, I adopted an average loss factor of 6.92% as reported in APCo's filings.[40] To estimate marginal losses, I applied a multiplier of 1.5 to the average loss factor, consistent with guidance from the Regulatory Assistance Project ("RAP"), which recommends this approach based on empirical studies in energy efficiency and DER valuation contexts. The resulting marginal line loss factor of 10.37% ($1.5 \times 6.91\%$) was applied to the value of:

[38] The inflation adjustment from 2024 to 2025 was made using a 2% Consumer Price Index (CPI) escalation factor to convert nominal 2024 values into real 2025 dollars. The avoided ancillary service cost value used by APCo was obtained from Workpaper NMC-2, provided in response to Staff's first set of interrogatories, question 2 (attached hereto as **Exhibit C**), specifically the "Combined-Ancillary" worksheet. This value does not include the line loss factor.

[39] See Workpaper NMC-2, Worksheet "Combined – Ancillary," attached hereto as **Exhibit C**.

[40] *Id*.

- Avoided energy,
- Avoided generation capacity,
- Avoided ancillary services, and
- Avoided transmission charges.

This adjustment ensures that the avoided cost values accurately reflect the full system benefit of reducing grid-delivered electricity. Assuming that line loss values vary proportionally with the forecasted avoided energy, generation capacity, ancillary costs, and transmission charges over the study horizon, avoided line losses yield total benefits of approximately $6.4 million.

Q. WHAT IS THE APPROPRIATE MARGINAL LINE LOSS FACTOR?

A. The marginal line loss factor used in this analysis was based on the concept that line losses increase nonlinearly with load. While utilities often use average loss factors in cost-of-service studies, marginal losses, which reflect the change in losses due to an incremental change in load or generation, are significantly higher, especially when the grid is under stress.

The theoretical basis for this lies in the formula for resistive losses: I^2R, where *I* represents current and *R* represents the resistance of the conductor. Because resistance (*R*) is effectively constant over time, losses increase with the square of the current. Therefore, during high-load conditions, the current on the system is much higher than average, often double or more. This leads to losses that are four times (2^2) greater than average.

To quantify this relationship, I adopted a marginal loss multiplier of 1.5, applied to APCo's reported average loss factor of 6.92%,[41] resulting in a marginal loss factor of approximately 10.37%.[42]

My use of a 1.5 multiplier is conservative within this context, yet reflective of industry precedent.[43] It ensures that the benefits of shared solar in reducing delivery losses are not understated and are grounded in a technically sound and regulator-accepted framework.

Q. WHAT IS THE APPROPRIATE AVOIDED HEDGING RISK PREMIUM?

A. The avoided risk premium is $4.19 for a customer subscribing to 1,000 kWh/month from shared solar. The avoided risk premium reflects the value of reducing exposure to fuel price volatility and wholesale market uncertainty. By generating fixed-cost electricity over a long-term horizon, shared solar helps insulate both utilities and ratepayers from fluctuations in fossil fuel prices and capacity market dynamics. This risk mitigation effect is especially relevant in an environment of increasing price uncertainty, supply disruptions, and load growth pressures.

To quantify this benefit, I applied an 8% risk premium to the value of avoided energy and generation capacity, representing the categories most sensitive to wholesale

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[41] Line loss values were obtained for secondary voltage levels across residential, commercial, and industrial customer classes using data from *Workpaper NMC-2* and *Workpaper NMC-3*, specifically from the "Combined Ancillary" worksheet. provided in response to Staff's first set of interrogatories, question 2 (attached hereto as **Exhibit C**).

[42] This approach aligns with best practices identified in the study: Jim Lazar and Xavier Baldwin, Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements, Regulatory Assistance Project, Aug. 2011. That study finds that during critical peak hours, marginal losses can be two to six times greater than average losses, depending on system configuration and load shape.

[43] A 1.5x multiplier for marginal line losses has been applied in the *New Hampshire Value of Distributed Energy Resources Study*, which was conducted under the direction of the New Hampshire Public Utilities Commission and facilitated by the New Hampshire Department of Energy. The study and its supporting methodology are available at: https://www.energy.nh.gov/value-distributed-energy-resources-study.

market volatility.[44] Over the study horizon, the avoided hedging risk premium yields total benefits of approximately $4.3 million.

Q. WHAT ADDITIONAL GRID-RELATED BENEFITS ATTRIBUTABLE TO THE SHARED SOLAR PROGRAM CAN BE MONETIZED BY THE UTILITY BUT WERE NOT INCLUDED IN YOUR ANALYSIS?

A. While this analysis captures a wide array of monetizable utility and non-utility benefits, there remain several grid-related value components that were not explicitly included in the initial analysis due to data limitations or the absence of standardized quantification methods. However, these benefits have been recognized in other VoS studies across jurisdictions such as Maine, New York, and Minnesota, and are relevant to the evaluation of the grid benefits of shared solar in Virginia. The inclusion of these missing categories would increase the total utility system benefits of the Shared Solar Program by approximately 15%. Therefore, they are included in the broader analysis of grid-related benefits. These include:

1. **DRIPE:** The market-wide price suppression that results from the addition of zero-marginal-cost solar generation into wholesale energy and capacity markets. By displacing higher-cost generation, shared solar reduces the clearing price, benefiting

[44] Synapse's AESC analyses, which are based in part on confidential supplier bid data—including bids submitted in Maryland within the PJM region—estimate the appropriate wholesale market risk premium to fall within a range of 5% to 10%. These studies are widely referenced in regulatory proceedings across the Northeast and represent one of the most comprehensive sources for DER benefit valuation. The most recent AESC 2024 study adopts an 8% risk premium, which is consistent with the value Dunsky has applied in prior analyses and which I adopt here for the purpose of this assessment. Synapse Energy Economics et al. *Avoided Energy Supply Components in New England: 2024 Report*, SYNAPSE ENERGY ECONOMICS, INC, released Feb. 7, 2024, amended May 24, 2024, https://www.synapse-energy.com/aesc-2024-materials.

all ratepayers. For this analysis, we include the Energy, Capacity, and Cross DRIPE impacts [45]

2. **Interconnection Upgrade Benefits:** A direct grid benefit. In most cases, shared solar developers fund distribution upgrades to facilitate interconnection. These upgrades often provide lasting grid value by improving hosting capacity or enhancing system reliability. For example, in Maine's Net Energy Billing docket, such upgrades were identified as providing shared benefits beyond the participating customer. Due to the lack of site-specific interconnection data for the APCo territory, this benefit was not quantified in the analysis.
3. **REC Price Suppression Benefits:** These benefits arise when shared solar displaces the need for utility procurement of RECs. By increasing REC supply, shared solar can exert downward pressure on REC market prices. While not explicitly modeled in the analysis, a relative impact assessment suggests that REC price compression provides modest utility savings, particularly in jurisdictions with binding RPS targets.[46]
4. **Generation Reliability Benefits:** Although not quantified, these benefits are material. Distributed solar can enhance grid resilience by reducing peak demand and generation reserve requirements, thereby lowering the likelihood of capacity shortfalls or outages.
5. **Distribution System Operating Expense Benefits:** Includes reductions in wear and tear on voltage regulation equipment, deferred transformer upgrades, and improved voltage profiles, which were not explicitly captured. These operational efficiencies are

[45] DRIPE benefits were calculated as in-state benefits and impacts to the other states in PJM were excluded from the analysis.
[46] REC Price Suppression Benefits were calculated as an in-state benefit.

increasingly recognized in distribution planning models but require detailed feeder-level data for accurate valuation.

Although not modeled, the inclusion of these components will further enhance the benefit-cost ratio of the Shared Solar Program, reinforcing the conclusion that it delivers net positive value to both APCo and the Commonwealth.

B. Modifications to APCo's Methodology for Calculating Benefits to the Electric Grid

Q. DO YOU HAVE ANY CONCERNS REGARDING APCO'S METHODOLOGY FOR CALCULATING CREDITS RELATED TO PJM ZONAL TRANSMISSION COSTS?

A. Yes, I have significant concerns with APCo's methodology, as described on page 7 of the Direct Testimony of Company witness Nicole M. Coon. APCo's approach estimates transmission credit benefits by analyzing only the excess generation exported to the grid by a typical net metering customer and assessing its coincidence with PJM's network service load ("NSL") peaks. This methodology is flawed for several reasons.

First, shared solar participants subscribe to the output of a shared solar facility, not to a behind-the-meter system. The entire production of a shared solar facility provides benefits to the grid and the Commonwealth; therefore, the total gross output of the shared solar facility, not just net excess generation, should be considered when calculating transmission benefits. By focusing solely on net exports, APCo understates the actual transmission cost savings that shared solar provides by reducing both individual customer load and the utility's overall contribution to zonal transmission peaks.

Second, APCo's analysis does not reflect the production profile of a single-axis tracking solar system, which is typical of shared solar facilities. These systems have extended generation profiles into late afternoon hours, better aligning with transmission system peak periods. Failing to use a profile consistent with the expected system design leads to a systematic undervaluation of shared solar's contribution to peak reduction and, therefore, understates the avoided transmission charges that should be credited to the program.

APCo's current approach to calculating transmission-related credits misrepresents the benefits provided by shared solar and results in a flawed and incomplete assessment of its value to the grid and to APCo.

Q. WHAT ARE THE APPROPRIATE TRANSMISSION CREDITS?

A. The Commission should adopt a transmission credit of $18.95 for a customer subscribing to 1,000 kWh/month from shared solar. Avoided transmission charges represent the reduction in a utility's transmission cost obligations when shared solar reduces demand during the system's peak transmission billing hours. In PJM, transmission charges are allocated based on a customer's contribution to the 12 Coincidental Peaks ("12 CPs"), which reflect the highest demand hours for each month in the PJM planning year (October through September). This avoided cost category is routinely included in benefit-cost assessments of DERs, particularly for those located in organized wholesale markets like PJM. APCo has confirmed that its transmission costs are based on the 12 CP methodology used by its parent company, AEP, within PJM.

My approach aligns with the coincident peak framework; however, unlike APCo's approach, which relies on a net-metering-based estimation of solar contributions, the methodology evaluates the total gross contribution of the shared solar facility to reducing transmission peak loads. This distinction is crucial, as shared solar facilities are expected to use single-axis tracking systems, which maintain production later into the afternoon and thereby contribute more meaningfully to peak-hour reductions than fixed-tilt systems typically used in behind-the-meter applications.

I calculated the above avoided transmission charges using the following steps:

1. Identify PJM's 12 CP hours for the 2022–2024 planning years (based on 2021–2023 demand data) and determine shared solar output during those hours using a monthly average solar profile for Roanoke, Virginia.

2. Estimate a three-year average solar 12 CP contribution of 19% for a 1 kW single-axis tracking system.

3. Developed a linear forecast of the Network Integration Transmission Service (NITS) rate for the AEP region for 2025 by applying a trendline to the historical NITS rates over the preceding seven years. This projected rate was then used to estimate avoided transmission charges. The avoided transmission value was calculated as:
   Avoided Transmission Cost = 3-Year Avg Solar 12 CP Contribution × NITS Rate

4. Levelize this value over the total annual generation from the shared solar facility to produce a per-kWh value.

The transmission credit benefit declines over time due to decreasing solar capacity values. Throughout the program's lifetime, the total benefit from transmission credits is estimated to be $6.61 million.

Q. WHAT ARE THE APPROPRIATE AVOIDED TRANSMISSION CAPACITY COSTS?

A. The avoided transmission capacity benefit is $3.40 for a customer subscribing to 1,000 kWh/month from shared solar. Avoided transmission capacity costs reflect the long-run marginal value of deferring or eliminating the need for new transmission infrastructure, due to shared solar's ability to reduce system peak demand. Unlike avoided transmission charges, these represent real, forward-looking system cost savings by mitigating upstream congestion and capacity needs.

To estimate these benefits, I first established an avoided transmission capacity value applicable to the APCo system, using a benchmark value of $40 per kilowatt-year.[47] To determine the contribution of the Shared Solar Program to reducing transmission capacity needs, I assessed the effective capacity contribution over the anticipated deployment timeline of the 50 MW program. This estimate accounts for a gradual decline in capacity value over time and reflects the performance of single-axis tracking systems during peak transmission hours. Based on this, I calculated a 12% effective capacity contribution, which I assume remains constant from 2025 through 2052 to represent the long-term contribution of shared solar to the transmission system. Levelized across the full 25-year study horizon, this results in a total avoided transmission capacity benefit of approximately $3.21 million. This value represents real, long-term deferral or avoidance of transmission infrastructure investment, and should be included in a full accounting of utility system benefits.

Q. DO YOU AGREE WITH APCO'S ASSERTION THAT TRANSMISSION COSTS ARE NOT AVOIDED BECAUSE THEY ARE FIXED WITHIN THE AEP ZONE, AND THAT REDUCING PEAKS DOES NOT AFFECT THE TOTAL REVENUE REQUIREMENT?

A. No. This assertion, as stated by APCo Witness Nicole M. Coon on page 8, lines 2 to 4 of her testimony, oversimplifies how transmission cost responsibility is allocated and how avoided costs are realized by the utility and its customers.

[47] *See Application of Virginia Elec. & Power Co. for Approval to Implement Demand-Side Management Programs and for Approval of Two Updated Rate Adjustment Clauses Pursuant to § 56-585.1 A 5 of the Code of Virginia*, Case No. PUR-2018-00168, Direct Testimony of Tim Woolf and Erin Malon on behalf of The Sierra Club at 333 (Feb. 6, 2019).

While the total revenue requirement for the AEP zone as a whole is fixed and determined by PJM, the cost allocated to each load-serving entity within the zone—such as APCo—is based on its contribution to the zonal CPs. Therefore, when shared solar reduces APCo's peak demand contribution, the utility's transmission cost allocation is immediately reduced, even if the zonal total remains constant.

In this context, shared solar reduces APCo's direct financial obligation, providing a tangible and monetizable benefit that is relevant for both program participants and non-participants.

To illustrate this point further: if utilities outside APCo's service territory were to install shared solar and reduce their CP-based contributions, a greater share of zonal costs would shift onto APCo's customers. Conversely, by adopting shared solar within APCo's territory, it protects its customers from such shifts and improves its relative cost position within the zone.

Therefore, APCo's statement overlooks this crucial dynamic and fails to consider the actual and immediate cost savings resulting from reducing peak demand in a CP-based transmission cost allocation framework.

Q. DO YOU AGREE WITH APCO'S POSITION THAT SHARED SOLAR FACILITIES PROVIDE NO AVOIDED DISTRIBUTION CAPACITY BENEFITS?[48] PLEASE EXPLAIN YOUR REASONING.

A. No, I disagree with APCo's assertion that shared solar facilities provide zero avoided distribution capacity benefits. Avoided distribution capacity is a well-established benefit category in regulatory and valuation frameworks across the U.S. In the absence of marginal

[48] *See* Direct Testimony of APCo Witness William K. Castle at 5-9.

cost estimates specific to APCo's system, I rely on avoided distribution values filed in a Virginia proceeding[49] and New York VDER. Based on this review, which shows a range from $14.54 to $200 per kW-year, I adopt a conservative estimate of $31.07/kW-year in my analysis.[50] This assumption is reasonable, well-supported, and consistent with Commission practice in comparable contexts.

Q. WHAT IS THE AVOIDED DISTRIBUTION CAPACITY BENEFIT?

A. The avoided distribution capacity is $0.19 for a customer subscribing to 1,000 kWh/month from shared solar.[51] Avoided distribution capacity costs represent the value of deferring or avoiding upgrades to distribution infrastructure that would otherwise be needed to serve growing or peak loads. Shared solar can reduce these peak loads at the feeder or substation level, particularly in constrained distribution capacity. Distribution system deferral benefits are recognized in benefit-cost frameworks and regulatory proceedings.[52] I assume that the avoided distribution capacity values remain flat in real dollars across the study period.[53]

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[49] Tim Woolf and Erin Malon, *Direct Testimony on behalf of The Sierra Club*, Application of Virginia Electric and Power Company for approval to implement demand-side management programs and updated RACs, Case No. PUR-2018-00168 at 333.

[50] The avoided distribution capacity cost used in this analysis is based on the average of two sources: (1) the average Demand Reduction Value (DRV) rates for Central Hudson, National Grid, NYSEG, Orange & Rockland, and RGE as published in New York's VDER workbooks; and (2) the average distribution capacity cost of $23/kW-year referenced in the direct testimony of Tim Woolf and Erin Malon before the Virginia State Corporation Commission in Docket No. PUR-2018-00168.

[51] The avoided distribution capacity value was determined by calculating a weighted average of the expected contribution from shared solar across participating customer classes. The analysis assumes a 60% residential and 40% commercial participation split. Avoided distribution capacity values were estimated separately for each class and then combined using this weighting to arrive at a program-wide avoided distribution capacity estimate. The underlying calculations can be found in **Exhibit H** – Shared Solar Workbook, specifically in the worksheets "Distribution Capacity Residential" and "Distribution Capacity Commercial."

[52] The NSPM and several state commissions, including in California and New York, acknowledge avoided distribution capacity as a relevant and often material value stream for DERs.

[53] The avoided distribution capacity value used in this analysis is based on 2019 Virginia-specific testimony. However, more recent data from New York suggests that marginal distribution values can be significantly higher. The New York Public Service Commission has approved a Marginal Cost of Service Study used to inform system-wide Distribution Relief Value ("DRV") rates for DERs. This study includes detailed estimates of marginal costs for transmission, primary, and secondary distribution infrastructure. According to the Value Stack DRV Calculator Phase 2, Revision 32 (DRV worksheet tab), the median DRV rate—representing the marginal distribution value—is

This approach to estimating avoided distribution capacity was based on a comparative demand-reduction framework, as follows:

1. Develop an average residential monthly demand profile (month-hour granularity) to represent typical residential load shapes across the year.

2. Pair this with the average solar production profile for a 1-kW single-axis tracking system located in Roanoke, Virginia (from PVWatts), also resolved to month-hour granularity.

3. Subtract solar production from residential demand at each month-hour to estimate net demand with solar generation.

4. By comparing the maximum demand pre- and post-solar, calculate the net peak demand reduction attributable to solar. This reflects the degree to which solar reduces the non-coincident peak demand on the distribution system.

5. Express this net demand reduction as a percentage of system capacity, and applied that percentage to the utility's average avoided distribution capacity cost (on a $/kW-year basis).[54]

6. Levelize this value over total annual solar production to express the avoided cost in $/kWh terms.

Assuming that the distribution capacity benefit remains flat over the study horizon, the lifetime benefits of the program are $0.18 million.

Q. WHAT IS THE APPROPRIATE REC VALUE?

A. The Commission should adopt an REC value of $35.00 for a customer subscribing to 1,000 kWh/month from shared solar. The REC value was calculated based on the marginal value of RECs that utilities must procure to meet Virginia's RPS targets. Shared solar facilities generate RECs that are eligible under Virginia's RPS framework. These RECs, when transferred to the utility as required by VA. Code § 56-594.4, directly reduce the utility's

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$61.44/kW-year, which is approximately 2.6 times higher than the avoided distribution capacity value used in this analysis. This comparison underscores the potential conservativeness of the Virginia estimate.

[54] The avoided distribution capacity cost methodology draws on values established in the Direct Testimony of Tim Woolf and Erin Malon on behalf of the Sierra Club, *supra* note 42.

obligation to procure additional certificates in the market, thereby lowering its compliance costs. To estimate the avoided RPS cost per kilowatt-hour, I used the RPS avoided costs as a proxy for the marginal cost of RPS compliance.[55] This serves as a reasonable conservative proxy for the avoided cost per MWh of REC production attributable to shared solar.

C. <u>Benefits of Shared Solar to the Commonwealth</u>[56]

Q. WHAT ARE THE NON-GRID BENEFITS OF SHARED SOLAR TO THE COMMONWEALTH?

A. APCo did not propose any non-grid benefits for the minimum bill, ignoring the statutory requirement and the Commission directive to "calculate the benefits of shared solar to the electric grid and the Commonwealth."[57] Despite this, the benefits of shared solar extend beyond direct grid benefits and cost savings to reflect broader benefits to the Commonwealth, including societal, environmental, and economic outcomes associated with shared solar deployment. APCo did not include a quantification of these benefits in its analysis. For my analysis, Commonwealth benefits were identified based on established Benefit-Cost Assessment practices, including guidance from the NSPM, as well as Virginia-specific policy objectives.[58] Key Commonwealth benefits include:

1. **Environmental Benefits:** Including reductions in GHG emissions and air pollutant criteria.
2. **Economic Benefits:** Including local job creation and increased economic activity from shared solar project development.

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[55] Petition of Appalachian Power Company for *Approval* of its 2024 RPS Plan *under § 56-585.5* of *the Code of Virginia and Related Requests*, Case No. PUR-2024-00020, Petition at 22 (Apr. 25, 2024).
[56] Va. Code § 56-594.4 D.
[57] *Id*. See also APCo Minimum Bill Proceeding, Order Initiating Proceedings (Feb. 10, 2025).
[58] Va. Code §§ 56-585.5 A, 56-585.5 D, and, 56-585.6 A.

3. **Energy Burden Reductions:** Particularly for low-income customers, who may experience improved affordability and energy cost stability through participation in the Shared Solar Program.

Each category was selected for its relevance to Virginia's clean energy goals and the statutory requirements set forth in Va. Code § 56-594.4 D, requiring the Commission to consider the full range of costs and benefits, including broad benefits "to the Commonwealth," when determining an appropriate minimum bill.

Q. HOW DO THE VCEA AND OTHER STATE POLICIES INFORM THE NON-UTILITY BENEFITS OF THE SHARED SOLAR PROGRAM?

A. The VCEA includes several provisions that support considering non-utility benefits in evaluating the minimum bill. These provisions reflect the Commonwealth's broader clean energy, economic development, affordability, and environmental justice objectives. The key non-utility benefit categories and their corresponding statutory foundations are as follows:

1. **Environmental Benefits:** "The Commonwealth shall achieve 100 percent carbon-free electricity by 2045 for Phase I Utilities and by 2050 for Phase II Utilities."[59] "A Phase I or Phase II Utility shall retire all generating units located in the Commonwealth that emit carbon as a by-product of combusting fuel to generate electricity by December 31, 2045."[60] These provisions affirm Virginia's commitment to GHG emissions reductions and decarbonization, supporting the inclusion of GHG and air pollutant reduction benefits in the assessment of shared solar.

[59] Va. Code § 56-585.5 A.
[60] Va. Code § 56-585.5 D.

2. **Economic Benefits:** "The General Assembly finds that requiring the development of renewable energy generation... will promote job creation and economic development in the Commonwealth."[61] This provision recognizes the economic development potential of clean energy, including net jobs and economic impacts, justifying its inclusion in benefit-cost assessments.
3. **Energy Burden Reduction for Low-Income Customers**: "The Commission shall establish an energy assistance program... designed to limit the electric bills of eligible customers to no more than six percent of the customer's annual household income."[62] Establishing the Percentage of Income Payment Program ("PIPP") reflects the legislature's prioritization of energy affordability, supporting the consideration of reduced energy burdens as a benefit of shared solar participation.

Q. WHAT IS THE APPROPRIATE NET GHG REDUCTION BENEFIT?

A. The Commission should adopt a GHG benefit of $94.73 for a customer subscribing to 1,000 kWh/month from shared solar. The net GHG benefit reflects the reduction in carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions resulting from shared solar generation displacing marginal fossil fuel-based generation on the grid. This displacement reduces emissions at the point of generation and generates climate-related social benefits by mitigating future environmental and public health damages. I determined the GHG benefit by:

1. **Determining Marginal Emission Rates:** I identified the marginal emission intensity of electricity displaced by shared solar generation within the APCo

[61] Va. Code § 56-585.5 A.
[62] Va. Code § 56-585.6 A.

service territory. For this, I utilized non-baseload emission rates specific to Virginia from the EPA's eGRID2022 database, which is commonly used to estimate emissions avoided by renewable energy projects. This source provides marginal emission rates for CO_2, CH_4, and N_2O that are appropriate for projects displacing generation during peak and intermediate hours—typical of solar production. I further validated and refined this data using NREL's Cambium dataset (Cambium 2023, Mid-case, 95% Decarbonization by 2050), focusing on hourly emissions data for PJM East. I extracted emission rates for future years (2025–2050), assuming that Virginia will fully decarbonize by 2045 in line with its RPS. Emissions were set to zero after 2045 to align with that policy.

2. **Superimposing the Solar Production Profile:** I applied the solar production profile from PVWatts (1-kW single-axis tracking system in Roanoke) to the marginal emissions data, producing a time-weighted emissions offset profile. This allowed me to calculate the volume of each greenhouse gas (GHG) (CO_2, CH_4, and N_2O) avoided on an hourly basis by the solar facility across its lifetime.

3. **Applying the Social Cost of GHG**: I then monetized the avoided emissions using the EPA's 2023 Report on the Social Cost of GHG, which provides updated values incorporating the latest findings.[63] I inflated these 2020-dollar values to 2025 dollars using the Consumer Price Index to ensure consistency with other monetized components in the analysis. Importantly, to avoid double-

[63] This analysis assumes a 3% discount rate for valuing carbon-equivalent emissions, consistent with Table ES-1 of the Interagency Working Group's *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990.*

counting Commonwealth-level benefits already captured through compliance with Virginia's RPS, which includes GHG reduction mandates, I netted out the portion of avoided emissions implicitly covered by the RPS policy trajectory. In effect, the estimate reflects the incremental Commonwealth-level benefit of emissions reductions attributable specifically to shared solar, beyond what is already expected from baseline RPS-driven decarbonization.

4. **Determining the GHG Emission Reduction Benefit ($/kWh)**: The total GHG benefit was calculated by multiplying the avoided emissions (in tons) by the corresponding social cost (in $/ton), summed across all three gases. This value was then normalized over total solar production to express the benefit in $/kWh.

Q. HOW DOES THE NET GHG REDUCTION BENEFIT COMPARE TO THE SOCIAL COST OF CARBON?

A. I calculated the GHG reduction benefits of the Shared Solar Program using the most recent estimates of the Social Cost of Greenhouse Gases ("SC-GHG"), including the social costs of carbon dioxide (SC-CO_2), methane (SC-CH_4), and nitrous oxide (SC-N_2O). These SC-GHG values reflect the net harm to society associated with releasing one additional metric ton of greenhouse gas emissions and are recognized by federal agencies as the appropriate values for use in benefit-cost analyses that affect GHG emissions.

Importantly, I recognize that the Commission has directed that the Social Cost of Carbon be incorporated in future RPS filings as part of the policy-making process in Virginia.[64] While this is an important step forward, our analysis goes further by accounting not only for CO_2, but also for CH_4 and N_2O emissions, in line with the

[64] *Petition of Appalachian Power Co. for Approval of its 2024 RPS Plan under § 56-585.5 of the Code of Virginia and Related Requests*, Case No. PUR-2023-00148, Final Order at 4 (Oct. 21, 2024).

broader SC-GHG framework endorsed by the federal Interagency Working Group. This comprehensive accounting provides a fuller understanding of the climate and health benefits of reducing GHG emissions and better aligns with Virginia's clean energy and public health objectives.

The SC-GHG includes a wide range of damages avoided by reducing emissions, such as improvements in human health, increased agricultural productivity, reduced property damage from extreme weather events, and greater ecosystem stability. By incorporating these values, our analysis ensures that the net benefits of the Shared Solar Program are fully captured and reflect the broader Commonwealth-level impacts of clean energy deployment. This more holistic evaluation framework is essential to informing sound regulatory decision-making.

Q. WHAT IS THE APPROPRIATE AIR POLLUTANT BENEFIT?

A. The Commission should adopt an air pollutant benefit of $25.61 for a customer subscribing to 1,000 kWh/month from shared solar. Air pollutant benefits reflect the public health and environmental gains from reducing emissions of harmful criteria air pollutants—specifically nitrogen oxides (NO_x), sulfur dioxide (SO_2), and fine particulate matter ($PM_2.5$)—that are typically released during fossil fuel combustion. Shared solar helps avoid these emissions by displacing marginal generation from fossil-fueled power plants.

To quantify these benefits, I followed a two-step process that combines emission rate data with monetized health damage estimates:

1. **Determining Marginal Emissions Rates:** I used marginal emissions factors for NO_x and SO_2 sourced from the U.S. Environmental Protection Agency's (EPA) eGRID database, which provides regional emissions rates for fossil

generation.[65] These values represent the emissions avoided per unit of displaced energy (1 GWh) and are consistent with Virginia's marginal fuel mix.

2. **Step 2: Monetizing Health Impacts Using EPA's Co-Benefits Risk Assessment ("COBRA") Tool**:[66] I input the marginal emissions rates into EPA's COBRA tool using the following parameters: Location: Virginia, Sector: Fuel Combustion – Electric Utility. COBRA estimates the public health impacts avoided by reducing emissions, including reductions in premature mortality, hospital admissions, and respiratory issues. The COBRA model estimates the monetized health benefits of air pollution reductions, with values ranging from $0.024 to $0.033 per kWh (in 2025 dollars).

I used the midpoint of these two values to represent a reasonable central estimate for each pollutant.

Q. WHAT IMPACTS DOES SHARED SOLAR HAVE ON JOBS AND ECONOMIC FACTORS?

A. The Commission should adopt a job and economic impact credit of $56.65 for a customer subscribing to 1,000 kWh/month from shared solar. Job creation and economic development benefits were estimated using the NREL JEDI (Jobs and Economic Development Impact) model. [67] This model estimates the direct, indirect, and induced jobs per megawatt of solar capacity installed and associated economic output.

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[65] *Emissions & Generation Resource Integrated Database (eGRID)*, ENVIRONMENTAL PROTECTION AGENCY (Jan. 15, 2025), https://www.epa.gov/egrid/download-data.

[66] *UCO-Benefits Risk Assessment (COBRA) Health Impacts Screening and Mapping Tool*, ENVIRONMENTAL PROTECTION AGENCY (last updated Apr. 14, 2025) https://www.epa.gov/cobra.

[67] Job creation and economic value added from shared solar were estimated using the NREL JEDI Photovoltaics (PV) model, based on system deployment in Virginia. The model was run for each year from 2024 to 2028, using inputs for commercial single-axis tracking systems and system sizes aligned with the Shared solar program deployment. Construction-related value added was applied in the year of installation, while operating value added

Q. WHAT IS THE APPROPRIATE ENERGY BURDEN REDUCTION BENEFIT FOR LOW-INCOME CUSTOMERS UNDER THE SHARED SOLAR PROGRAM?

A. We assessed energy burden qualitatively to answer the question of whether Shared Solar can reduce the energy burden for low-income customers. Our assessment shows that by subscribing to shared solar, low-income customers can reduce their overall energy burden by approximately 3.3%. Depending on program size and subscription levels, this reduction could move many households out of the high energy burden category—commonly defined as spending more than 5% of annual income on energy—thereby significantly improving energy affordability for vulnerable communities.

We evaluated the energy burden reduction potential of shared solar for low-income customers by using publicly available data such as the U.S. DOE's Low-Income Energy Affordability Data ("LEAD") Tool:

1. **Estimate Annual Electricity Costs for Low-Income Households**: Using LEAD Tool data filtered by Census Tracts in Virginia, I identified low-income households with a representative % energy burden of 5%.[68] I focused specifically on the electricity portion of the energy burden from this subset, because shared solar only offsets electricity costs. The average electricity energy burden for these households was estimated to be 3.2%. Based on this burden level and typical income levels within the selected tracts, the average

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was accumulated annually beginning the year after installation. This approach allowed us to calculate the cumulative economic impact associated with each 1,000 kWh of shared solar generation. *JEDI: Jobs & Economic Development Impact Models*, NATIONAL RENEWABLE ENERGY LABORATORY, https://www.nrel.gov/analysis/jedi/pv.html (last visited May 12, 2025).

[68] Energy Burden refers to both natural gas and electricity.

annual electricity bill for a low-income household was calculated to be approximately $2,019.

2. **Convert Electricity Costs to Energy Usage:** To estimate total electricity consumption, I divided the annual electricity bill by the average retail electricity rate for residential customers in Virginia. This yielded an estimate of the total kWh consumed annually, which I assumed would be entirely offset by participation in a Shared Solar Program.

3. **Assesses Energy Burden Reduction:** To assess if subscribing to shared solar would reduce a customer's energy burden, I used the following energy burden formula:

Energy Burden = (Post-Solar Annual Electricity Bill − Shared Solar Bill Credit + Remaining Charges (e.g., Minimum Bill)) / Annual Gross Income

This calculation takes into account the bill credits provided under shared solar, any subscription or minimum bill charges, and the resulting impact on the customer's net annual electricity expenses. Thus, subscribing to shared solar allows low-income households to reduce their overall energy burden to below 2% of their household income.

V. VALUE STACK MINIMUM BILL COMPONENT ASSESSMENT

Q. DO YOU SUPPORT APCO'S PROPOSED METHODOLOGY FOR CALCULATING THE MINIMUM BILL APPLICABLE TO SHARED SOLAR SUBSCRIBERS?

A. No, I do not. As discussed above, the Benefit-Cost Assessment supports the Commission adopting a minimum bill of $0, which reflects that the shared solar program provides a net benefit to all APCo customers.

While APCo's proposal identifies the cost components that could be included in a minimum bill, it fails to capture the full scope of the Shared Solar Program's benefits. Indeed, the APCo proposal omits entire categories of benefits, such as avoided energy, generation capacity, transmission capacity, and distribution capacity costs, that shared solar provides to the grid. These omissions result in a minimum bill that undervalues the contributions of shared solar projects to the grid and the Commonwealth, rendering the bill neither fair nor reasonable.

Additionally, APCo's calculation of the transmission credit contains methodological errors that understate the program's contribution to reducing transmission charges. As a result, the proposed minimum bill overstates the costs attributable to shared solar participants, understates the benefits, and does not align with established best practices for evaluating DER benefits.

Finally, APCo fails to account for the net energy and capacity value provided by shared solar projects. Given the incremental value that shared solar offers in terms of reducing both energy procurement needs and generation capacity obligations, I recommend that the Commission revise APCo's methodology to incorporate these benefits directly into the minimum bill calculation. Doing so would produce a more accurate and equitable outcome that better reflects the full value of shared solar, consistent with the statutory framework established by the General Assembly.

Q. BRIEFLY DESCRIBE HOW YOU WOULD MODIFY APCO'S MINIMUM BILL STRUCTURE.

A. If the Commission decides to proceed with a value-stack approach for the minimum bill, the Commission should include all relevant cost components, while ensuring that shared solar's full system benefits are appropriately recognized and included.

As proposed by APCo, the minimum bill would include the fixed customer charge and the Shared Solar Administration Charge of $1 per month. In addition, it would include all applicable non-bypassable riders, including Rider P.I.P.P. (Percentage of Income Payment Program), Rider S.B RAC (System Balancing), Rider A.S RPS RAC, and Rider A.C RPS RAC (for Renewable Portfolio Standard compliance), and Rider P.A.F RAC (Performance Adjustment Factor for capacity). To fully capture the cost of delivering service, the minimum bill would also include the Base Distribution Charges, the Distribution RAC, and the Transmission RAC (Rider T.RAC), which reflect volumetric charges applied to customer usage. To accurately capture the incremental generation benefits, the minimum bill would include the energy generation costs for the subscribing customer based on the applicable tariff. With these inclusions, the gross minimum bill increases to approximately $127 for a 1,000 kWh residential customer, $1,117 for a typical 10,000 kWh/month GS customer, and $42,257 for a 500,000 kWh/month LPS Customer.

On the benefit side, to correct errors in APCo's methods for calculating benefits, the minimum bill should include categories of benefits omitted in its analysis and identify additional categories of benefits recognized in other jurisdictions. Under this Value Stack approach, the minimum bill would start with the same categories of benefits proposed by APCo (with corrected figures, as discussed below):

- APCo's Transmission Credit Calculation
- REC Price Benefit
- Avoided Ancillary Services

Additionally, the minimum bill would include:

- Avoided Energy and Generation Capacity Costs
- Risk Premium Benefits
- Transmission Capacity Deferral Value
- Distribution Capacity Deferral Value
- Avoided Line Losses
- Avoided Hedging Risk Premium

Finally, additional benefits that have been quantified in other jurisdictions should be included:[69]

- DRIPE
- Avoided Distribution Operating Expenses
- Generation Reliability Benefits
- Interconnection Upgrades Funded by Developers
- REC Price Suppression Benefits

Q. BASED ON YOUR ANALYSIS, HOW WOULD APCO'S MINIMUM BILL BE CALCULATED FOR A TYPICAL RESIDENTIAL SHARED SOLAR SUBSCRIBER UNDER THE VALUE STACK APPROACH?

A. In developing the cost components of the minimum bill, I began with APCo's proposed cost components as a starting point. Using this framework, the gross cost of service for a typical residential customer subscribing to 1,000 kWh of shared solar results in a baseline cost of $89.25. However, recognizing that shared solar provides incremental benefits by reducing energy and generation capacity needs, I included the associated energy generation costs based on APCo's applicable tariffs. This brought the gross cost to $127.19 per month.

[69] New Hampshire – New Hampshire Department of Energy. *Value of Distributed Energy Resources (VDER) Study,* https://www.energy.nh.gov/value-distributed-energy-resources-study (last visited May 12, 2025); Maine: Sustainable Energy Advantage, LLC. *Analysis of 2024 Net Benefits of Net Energy Billing Program.* Prepared for the Maine Public Utilities Commission. March 31, 2025. Available at: https://www.maine.gov/mpuc/sites/maine.gov.mpuc/files/inline-files/Maine-NEB-Y2024_CBA_Final.pdf.

On the benefit side, I corrected APCo's understated transmission credit and REC valuation, and included a broader set of utility system benefits, including avoided energy and capacity costs, risk premium, transmission and distribution capacity deferral, DRIPE, interconnection upgrade offsets, and generation reliability enhancements. As seen in the table below, these adjustments bring the total utility benefits to $142.66, resulting in a net benefit of $15.47 per month for the utility from a typical residential shared solar subscriber.

[Table on next page]

Table 5: CCSA and APCo Minimum Bill Framework Comparison (Residential) – all values in real $2025

Cost Component	CCSA	APCo	Benefit Component	CCSA	APCo
Customer Charge	$7.96	$7.96	Transmission Charge Credit	$18.95	$7.20
Rider PIPP	$1.32	$1.32	Ancillary Service Credit	$1.44	$1.50
Rider BC RAC	$0.59	$0.59	REC Credit	$35.00	$31.89
Rider A.5 RPS RAC	$1.03	$1.03	Avoided Energy	$35.94	n/a
Rider PCAP RAC	$0.13	$0.13	Avoided Generation Capacity	$16.39	n/a
Rider A.6 RPS RAC	$0.11	$0.11	Avoided Line Losses	$7.54	n/a
Energy Distribution	$38.28	$38.28	Avoided Hedging Risk Premium	$4.19	n/a
Rider EE RAC	$2.37	$2.37	Avoided Distribution Capacity	$0.19	n/a
Rider T.RAC	$36.46	$36.46	Avoided Transmission Capacity	$3.40	n/a
Administrative Charge	$1.00	$1.00	DRIPE	$7.01	n/a
Energy Generation	$37.94	n/a	Interconnection Upgrade Benefit	$0.21	n/a
			REC Price Suppression Benefit	$8.36	n/a
			Generation Reliability Benefit	$0.32	n/a
			Distribution System Opex Benefit	$3.72	n/a
Total:	$127.19	$89.25	Total	$142.66	$40.59
APCo Shared Solar Net Benefits:		$-48.66	($89.25 - $40.59)		
CCSA Shared Solar Net Benefits:		$15.47	($142.66-$127.19)		

Correcting APCo's minimum bill methodology yields a negative minimum bill, justifying my recommendation that the Commission establish a simple minimum bill of $0. However, if the Commission chooses to adopt APCo's proposal, the same outcome occurs.

Q. BASED ON YOUR ANALYSIS, WHAT ARE YOUR FINDINGS REGARDING THE APPROPRIATE MINIMUM BILL FOR A TYPICAL NON-RESIDENTIAL SHARED SOLAR SUBSCRIBER UNDER THE VALUE STACK APPROACH?

A. Using APCo's proposed framework as a starting point, I assumed a representative customer from the GS class subscribing to 10,000 kWh per month and a LPS Customer subscribing to 500,000 kWh per month. Similar to the residential case, including not only the standard fixed and volumetric charges but also the energy generation costs associated with this level of subscription, results in a gross cost of $1,117 per month for a GS Customer and $42,257 per month for an LPS Customer.

On the benefit side, I corrected APCo's undervaluation of the transmission credit and REC value. I added a comprehensive set of grid benefits, including avoided energy and capacity costs, price stability (risk premium), distribution and transmission capacity deferral, DRIPE, interconnection upgrade offsets, REC price suppression, and generation reliability enhancements. These adjustments yield total utility system benefits of approximately $1,427 from a single GS shared solar subscriber, resulting in a net utility benefit of over $310 per month. For an LPS Customer, the total utility system benefits are approximately $71,328, resulting in a net utility benefit of over $29,071 per month.

Correcting APCo's minimum bill methodology also yields a negative minimum bill for GS and LPS customers, justifying my recommendation that the Commission establish a simple minimum bill of $0.

Table 6: CCSA and APCo Minimum Bill Framework Comparison (GS) – all values in real $2025

Cost Component	CCSA	APCo	Benefit Component	CCSA	APCo
Customer Charge	$14.01	$14.01	Transmission Charge Credit	$189.53	$64.00
Rider PIPP	$13.20	$13.20	Avoided Ancillary Service	$14.43	$15.00
Rider BC RAC Block 1	$5.00	$5.00	REC Credit	$350.00	$318.90
Rider A.5 RPS RAC Block 1	$10.20	$10.20	Avoided Energy	$359.42	n/a
Rider PCAP RAC Block 1	$0.80	$0.80	Avoided Generation Capacity	$163.89	n/a
Rider PCAP Demand	$0.40	$0.40	Avoided Line Losses	$75.40	n/a
Rider A.6 RPS RAC Block 1	$0.70	$0.70	Avoided Hedging Risk Premium	$41.86	n/a
Rider A.6 RPS RAC Demand	$0.40	$0.40	Avoided Distribution Capacity	$1.85	n/a
Energy Distribution Block 1	$392.30	$392.30	Avoided Transmission Capacity	$33.97	n/a
Demand Charge	$44.40	$44.40	DRIPE	$70.10	n/a
Off-Peak Excess Demand Charge	$22.40	$22.40	Interconnection Upgrade Benefit	$2.07	n/a
Rider EE RAC Block 1	$23.70	$23.70	REC Price Suppression Benefit	$83.58	n/a
T-RAC Block 1	$244.00	$244.00	Generation Reliability Benefit	$3.22	n/a
Energy Generation (Forward Prices)	$344.00		Distribution System Opex Benefit	$37.23	n/a
Shared Solar Admin Charge	$1.00	$1.00			
Total:	$1,117	$773	Total	$1,427	$398
APCo Shared Solar Net Benefits:		-$375	($398 - $773)		
CCSA Shared Solar Net Benefits:		$310	($1,427-$1,117)		

Table7: CCSA and APCo Minimum Bill Framework Comparison (LPS) – all values in real $2025

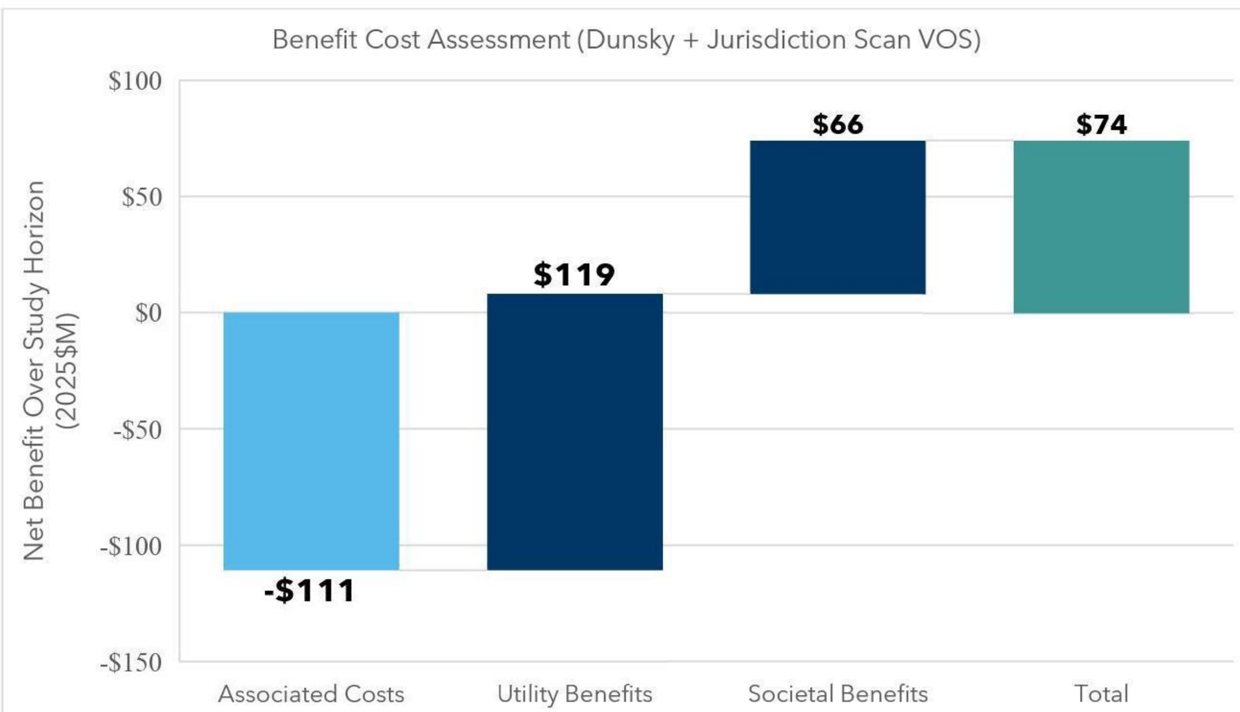
Cost Component	CCSA	APCo	Benefit Component	CCSA	APCo
Customer Charge	$276.49	$276.49	Transmission Charge Credit	$9,476.70	$3050.00
Rider PIPP	$660.00	$660.00	Avoided Ancillary Service	$721.34	$720.00
Rider BC RAC	$50.00	$50.00	REC Credit	$17,500.00	$15,945.00
Rider A.5 RPS RAC	$485.00	$485.00	Avoided Energy	$17,970.83	n/a
Rider A.5 PCAP	$40.00	$40.00	Avoided Generation Capacity	$8,194.68	n/a
Rider A.6 RPS RAC	$30.00	$30.00	Avoided Line Losses	$3,770.17	n/a
Energy Distribution	$0.00	$0.00	Avoided Hedging Risk Premium	$2,093.24	n/a
Demand Charge	$5,550.00	$5,550.00	Avoided Distribution Capacity	$92.73	n/a
Off-Peak Excess Demand Charge	$1,140.00	$1,140.00	Avoided Transmission Capacity	$1,698.63	n/a
Rider EE RAC	$1,125.00	$1,125.00	DRIPE	$3,504.77	n/a
Rider T.RAC Energy	$20.00	$20.00	Interconnection Upgrade Benefit	$103.48	n/a
Rider T.RAC Demand	$9,910.00	$9,910.00	REC Price Suppression Benefit	$4,178.93	n/a
Rider T.RAC Off-Peak kW	$1,020.00	$1,020.00	Generation Reliability Benefit	$160.90	n/a
Energy Generation (Forward Prices)	$21,950.00		Distribution System Opex Benefit	$1,861.69	n/a
Shared Solar Admin Charge	$1.00	$1.00			
Total:	$42,257	$20,307	Total	$71,328	$19,715
APCo Shared Solar Net Benefits:		-$592	($19,715- $20,307)		
CCSA Shared Solar Net Benefits:		$29,071	($71,328 - $42,257)		

VI. SUMMARY AND RECOMMENDATIONS

Q. WHAT ARE THE KEY FINDINGS FROM YOUR BENEFIT-COST ASSESSMENT OF THE SHARED SOLAR PROGRAM?

A. My analysis shows that the Shared Solar Program delivers substantial net benefits to both the electric grid and the Commonwealth of Virginia. When accounting for all associated program costs—including fixed customer charges, administrative costs, and volumetric charges—total program costs over the study horizon (2025–2052) are estimated at $111 million. In contrast, utility system benefits, such as avoided energy, capacity, transmission, distribution, and ancillary services, total $119 million, yielding a net utility savings of $8 million. When Commonwealth benefits such as avoided GHG emissions, avoided air pollutants, local job impact, and economic development are also included, the total benefit to the grid and the Commonwealth of the Shared Solar Program rises to $74 million.

Figure 4: Benefit Cost Assessment of Shared Solar Program (Comprehensive Components) – all values in real $2025



These results demonstrate that when calculating the benefits of shared solar to the electric grid and the Commonwealth and deducting such benefits from other costs, shared solar provides a clear net benefit. This affirms the cost-effectiveness and broader value of the Shared Solar Program.

Q. WHAT ARE THE KEY FINDINGS FROM YOUR MINIMUM BILL ASSESSMENT OF THE SHARED SOLAR PROGRAM?

A. My minimum bill analysis compares the full cost of serving a shared solar customer to the quantifiable utility benefits delivered by their participation. For a typical residential subscriber (1,000 kWh/month), the gross cost is $127, while utility benefits total $142, yielding a net utility benefit of $15/month. For a non-residential GS subscriber (10,000 kWh/month), the gross cost is $1,117, with total utility benefits of $1,427, resulting in a net benefit of $310/month. For a non-residential LPS subscriber (500,000 kWh/month), the gross cost is $42,257, with total utility benefits of $71,328, resulting in a net benefit of $29,071/month.

Table 8: Minimum Bill Calculation for Residential, General Service and Large Primary Service Customers – all in real $2025

	Residential		General Service		Large Primary Service	
	CCSA	APCo	CCSA	APCo	CCSA	APCo
Gross Utility Costs	$127.2	$89.3	$1,117	$773	$42,257	$20,307
Gross Utility Benefits	$142.7	$40.6	$1,427	$398	$71,328	$19,715
Net Utility Benefits	**$15.5**	**-$48.7**	**$310**	**-$375**	**$29,071**	**-$592**
Commonwealth Benefits	$177.0	--	$1,770	--	$88,491	$0
Total Net Benefits	**$192.4**	**-$48.7**	**$2,080**	**-$375**	**$117,562**	**-$592**

Q. WHAT IS YOUR RECOMMENDATION FOR THE MINIMUM BILL?

A. Based on both the benefit-cost assessment and the minimum bill analysis, I recommend that the Commission adopt a cost-reflective, administratively simple minimum bill of $0 for participants in the Shared Solar Program. This recommendation directly supports the goals articulated in the Commission's Order initiating this docket.

By including all relevant utility system costs—such as fixed customer charges, administrative fees, and volumetric rates—this analysis ensures that subscribing customers are paying their fair share of the cost of electric service and eliminates any risk of cost shifting. This approach also ensures that the minimum bill minimizes cost shifting, thereby exceeding the statutory requirement. Incorporating benefits to the Commonwealth further reinforces the cost-effectiveness of the program.

Q. IN THE EVENT THE COMMISSION ADOPTS A MINIMUM BILL STRUCTURE BASED ON THE VALUE STACK APPROACH, HOW DO YOU RECOMMEND THE COMMISSION IMPLEMENT IT?

A. As I demonstrate in the Value Stack analysis above, if APCo's analysis is corrected to include the full set of costs and benefits, the same result is achieved: a $0 minimum bill. This reinforces my primary recommendation that the commission adopt a $0 minimum bill for the program.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes

Table of Exhibits	
Exhibit A	Dunsky Description and Resume
Exhibit B	History of Expert Testimony
Exhibit C	APCo Response to Staff Set 1-2 and CCSA Set 4
Exhibit D	Program Cost Estimates
Exhibit E	Energy – Last 12 Months
Exhibit F	Energy Price Forecast
Exhibit G	BRA Capacity
Exhibit H	Distribution Capacity - Residential and Commercial

EXHIBIT A

Dunsky Description and Resume

dunsky
Energy + Climate

Accelerating the ***Clean Energy*** *Transition*

dunsky
Energy + Climate

ACCELERATING THE CLEAN ENERGY TRANSITION

ANALYSIS + STRATEGY

BUILDINGS | **MOBILITY** | **INDUSTRY** | **ENERGY**

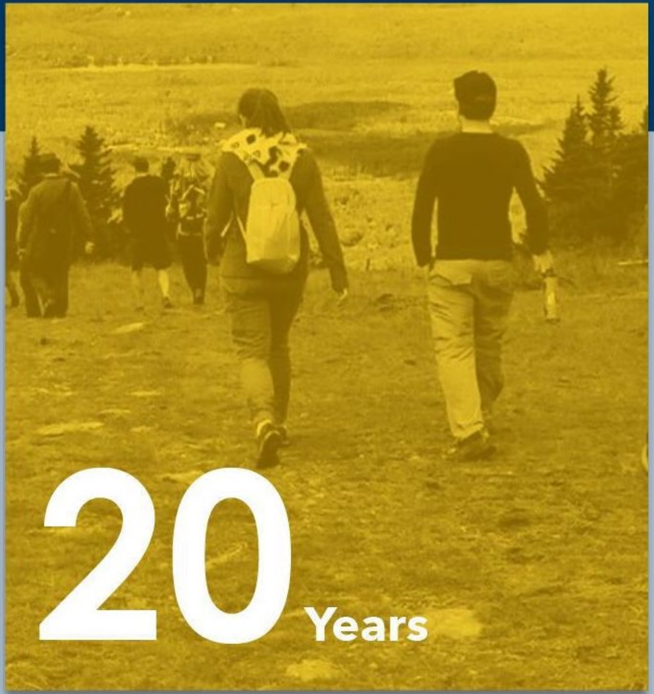


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Exhibit A

dunsky
Energy + Climate

ACCELERATING THE CLEAN ENERGY TRANSITION

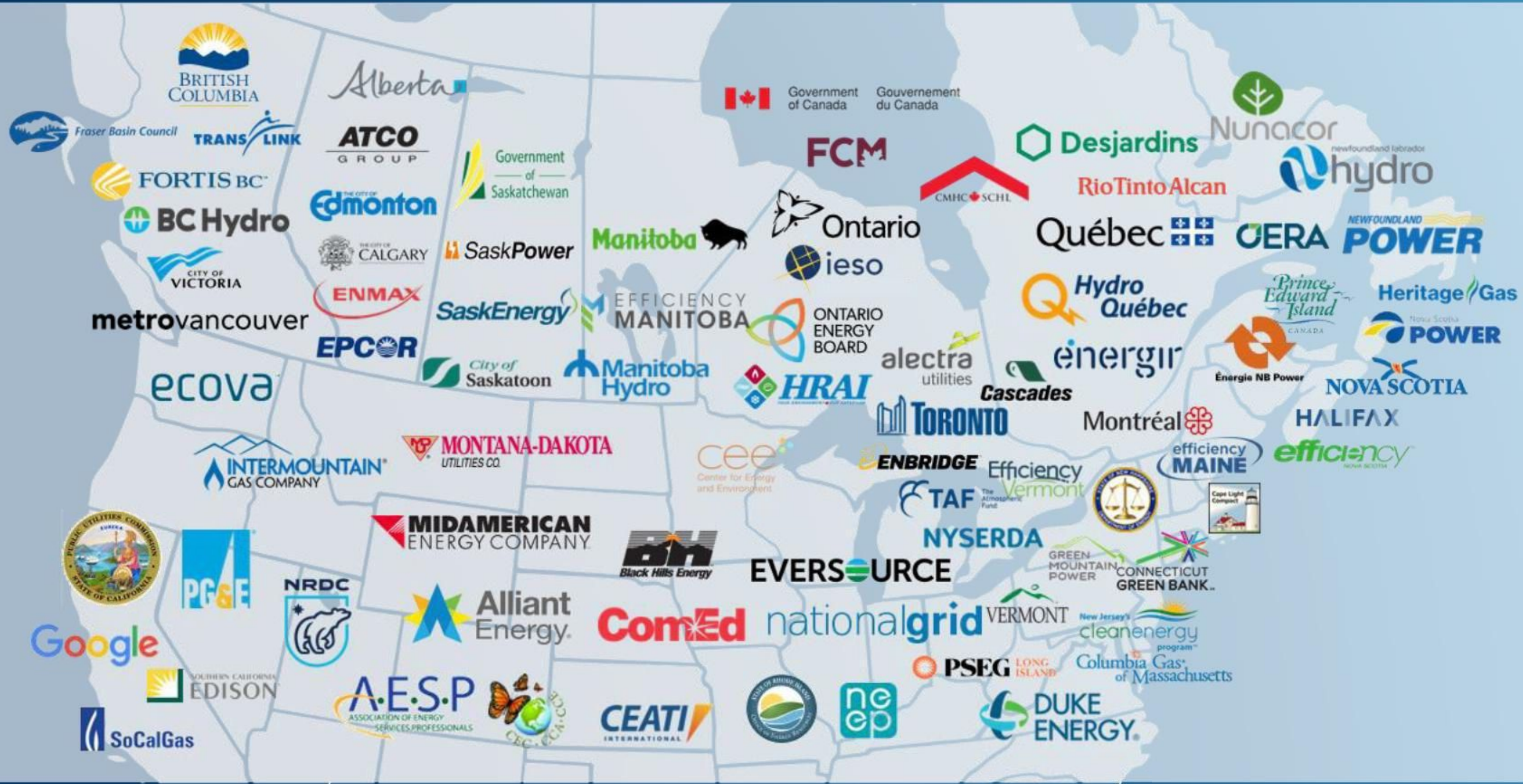
ANALYSIS + STRATEGY

BUILDINGS

MOBILITY

INDUSTRY

ENERGY



GOVERNMENTS

UTILITIES

CORPORATE + NON-PROFIT

Our **Mission**

To accelerate the clean energy transition

Our **Values**

1 Quality

We work tirelessly to ensure that our work is conducted to the highest standards, and that we are either leading, or abreast of, the latest innovations in our field.

2 Integrity

We are duty bound to provide our clients with consistent, honest and unbiased analysis and counsel. Integrity is our North Star.

3 Commitment

We treat both clients and team members as partners, committing ourselves to their objectives, being responsive to needs as they arise, and going the extra mile to help them achieve their goals.

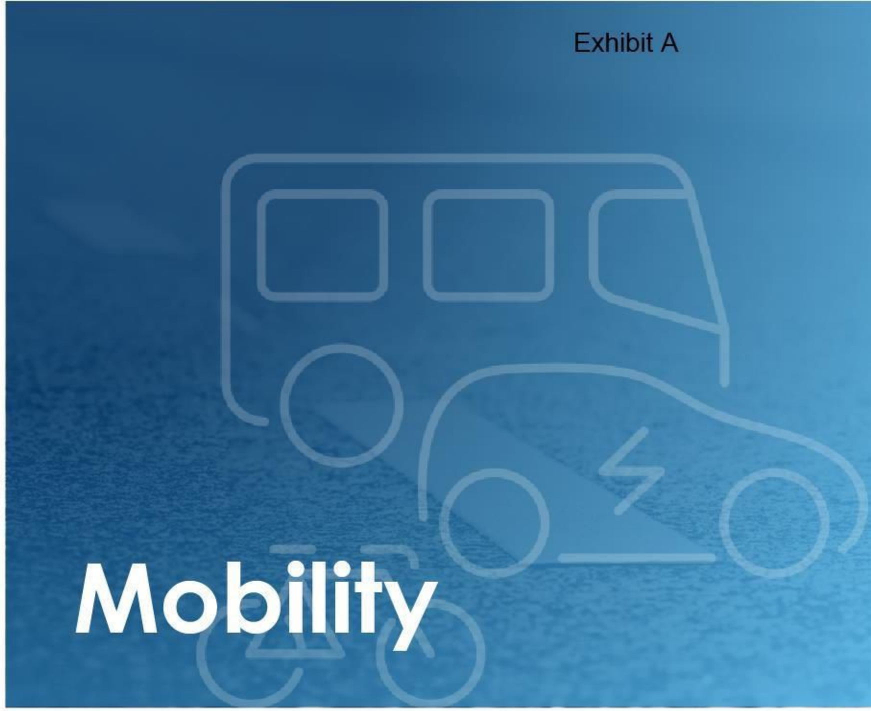
4 Impact

As a mission driven firm, we create positive change by advancing clean energy solutions, minimizing our own environmental footprint, and supporting those who encourage responsible stewardship of the planet.

250520154

Exhibit A

Our Expertise



Buildings

We help our clients deploy efficiency and other demand-side management opportunities, at scale.

Buildings offer large-scale opportunities to improve energy efficiency, reduce peak demand, switch fuel types and achieve energy and climate goals at the lowest possible cost.

At Dunsky, we help our clients to understand – and effectively exploit – the breadth of demand-side energy resources available in homes and buildings.

We assess the costs, savings, cost-effectiveness, and market opportunity for hundreds of options across every sector and market segment; we design market, program and regulatory strategies that accelerate real-world adoption; and we evaluate the effectiveness of programs designed to that end.

In all cases, we bring market research, solid analytics and years of experience to the task.

Mobility

We help our clients slash vehicle emissions at the state/province, municipal and fleet levels.

Moving people and things can use between a quarter and a third of all energy consumed.

At Dunsky, our focus is on the twin challenges of clean mobility: reducing energy demand, and shifting to alternative, low-carbon fuels, notably through electric vehicles (EVs).

We use our in-house models and expertise to help our clients review options, forecast market adoption, assess business cases, address regulatory barriers, and design both regulatory and market-based strategies to accelerate the advent of clean mobility.

Our work, which encompasses light, medium, heavy-duty and specialty vehicles, encompasses all market, economic and technology facets. It further extends to electricity storage, grid integration of EVs, charging infrastructure, peak optimization and more.

Industry

We help clients understand the potential for, and pathways to, cost-efficiently reducing GHG emissions from industrial operations.

How can we slash GHG emissions without harming competitiveness?

That question lies at the heart of our industrial practice. Our team of experts guides clients through the technical, economic and market opportunities to decarbonize industry. Critically, we do it with a view to truly reducing emissions, *not* inadvertently offshoring them.

Our team assesses opportunities in mining, metals, pulp & paper, manufacturing, cement, steel, chemicals, agriculture and others. We know that each sector commands different solutions (and each industrial faces different challenges).

Whether governments, utilities or industrials, our clients are early movers who understand the need to balance risk with reward, and who care about moving to an efficient, world-class, low-carbon industrial economy.

Energy

We help our clients accelerate the transition to clean and renewable energy solutions.

Renewable energy – and its enabler, storage – is critical to achieving a clean energy future.

At Dunsky, we help our clients to assess opportunities for renewable energy resources – both electric and non-electric – and to develop programs and policies to support them effectively, and cost-efficiently.

We use our experience with the full range of renewable energy and storage options – along with proprietary models that provide deep, location-specific insights – to determine both what is possible *and* what is needed to achieve defined goals.

Our work includes assessing technical issues; modelling scenarios, resource potential and markets; designing voluntary programs (incentives, financing and others); building realistic business cases; and advising on regulatory mechanisms and policies.

Our
Services

Services **Overview**

Analysis

What can be achieved?
At what cost (and benefit)?

- Potential studies
- Technology reviews
- Market assessments
- Business case analysis
- Impact evaluations
- Cost-effectiveness analysis
- Fleet electrification studies
- Building portfolio decarbonization studies
- Best practice reviews

Strategy

How to best deliver results?
What outcomes can we expect?

- Policies & frameworks
- Comprehensive plans
- Incentive programs
- Financing mechanisms
- Enabling strategies
- Codes & standards
- Rate design
- Process evaluations
- Strategic evaluations
- Equity analyses

+ *Enabling Strategies* >> strategic counsel | stakeholder engagement | regulatory support | technical support | decision-aid tools

Our Models

Intuition is great, but data is better.

Dunsky's work is supported by sophisticated models that forecast potential market adoption of clean energy solutions under an array of scenarios and technical, economic and market constraints.

DEEP
Energy Efficiency
Potential Model

DROP
Demand Response
Optimized Potential Model

HEAT
Heating Energy
Decarbonization Model

powered by dunsky

SAM
Solar & Storage
Adoption Model

EVA
Electric Vehicles
Adoption Model

EFLEET
Fleet Electrification
Optimization Model

Our keys to success

An approach designed to maximize client value, an incredibly sharp and experienced team, and a deep dedication to our mission.

Our **Approach**

Our work is rooted in solid analytics; in deep experience that informs not only what is best but what is workable; and through clear, compelling communications, with both clients and their stakeholders.

Research & Analysis

In-depth, quantitative and/or qualitative analysis of technical, market and economic issues **that withstand the greatest scrutiny**.

Strategic Counsel

Recommendations rooted in best practices, solid analytics and deep experience help to **avoid common pitfalls and deliver real results**.

Clear Communications

Reports and decision tools are clear, easy to read or use, and employ imagery designed to **tell the story and enable effective decision-making.**

Our **team**

The Dunsky team brings experience and passion to every project.

Comprised of engineers, economists, MBAs, project managers and others, **our team of experts are dedicated to your success.**

Our **reputation**

For years you have contributed to our programs' successes, through strategic support, innovative programs, consistent rigor and exceptional responsiveness to our needs.

Professional, easy to work with and obvious commitment to client service. Deliverables were **high-quality**, and results were presented in a **clear** and reader-friendly format.

Excellent work. Easy to read, and charts illustrate the points. It sets up the **right conversation** about our policy choices going forward to achieve our goals. My compliments to the Dunsky group.

Our **reputation**

The Dunsky team did an excellent job. They produced a **robust analysis** and model,
and were particularly responsive.

The team was collaborative, knowledgeable and always available to help us. The entire team has extensive North American **expertise and credibility**.

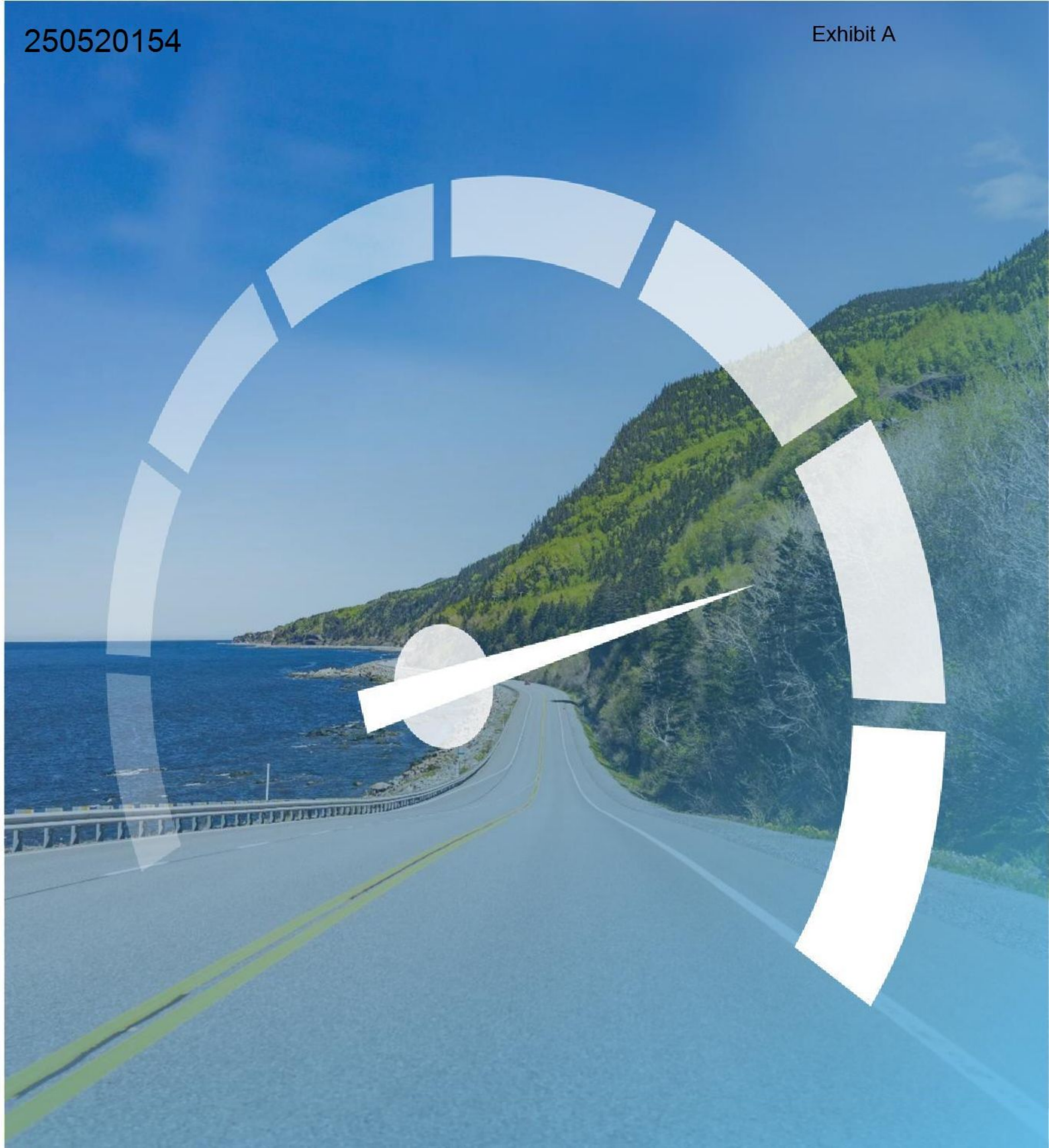
Dunsky was **highly adaptable** to changing and pressing priorities. [They delivered] a program design informed by deep sector engagement that also factored in important internal considerations. We have received great feedback from the sector on the [program] design.

250520154 Exhibit A

Our **mission**

***We are committed to moving the needle on adoption of clean energy solutions**, through quality research, experience-driven insights, and clear communication.*

Because the alternative—guesswork, intuition and reports that gather dust—simply won't get us where we need to go.



Walking the talk

This is *not* why you should hire us.

But for what it's worth, we are deeply committed to walking the talk.

We are headquartered in one of North America's **greenest buildings.**

Certified LEED® NC Platinum, our offices are hyper-insulated, heated and cooled by geothermal wells, and act as a living experiment in how buildings of the future can be built and operated.

We are proud to be a **certified B Corp.**

B Corps are independently certified, mission-driven corporations that, in addition to shareholder returns, produce demonstrable benefits for staff, communities and our shared environment.

We believe in **giving back.**

We donate 2% of our *gross* revenue to charities involved in building a better world. To share in the pleasure of giving, we invite our clients and staff to choose charities that are near to their hearts.

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Contact

Montréal
Toronto
Ottawa
Halifax
Vancouver

We'll connect you to the right person

(not a salesperson; we don't have any)

info@dunsky.com

Anirudh Kshemendranath

Senior Consultant

Email: anirudh.kshemendranath@dunsky.com **Telephone:** 1-416-947-8599 x4269

Anirudh Kshemendranath is an adept consultant with over a decade of experience in the energy sector, specializing in energy storage, regulatory services, market entry strategy, and electricity wholesale markets. Anirudh has a proven track record of leading complex projects and providing strategic insights to support the clean energy transition. At Dunsky, Anirudh leads analytical and strategic consultations on energy storage, solar adoption, distributed energy resources (DERs), utility planning, and rate design. He has been instrumental in guiding regulatory processes, including expert witness testimony in high-profile cases such as the New Hampshire Value of Distributed Energy Resources (VDER) study. His work spans across North America, where he has conducted assessments of solar compensation frameworks, provided due diligence for utility-scale storage projects, and developed innovative rate design methodologies.

Anirudh's expertise extends to strategic planning, where he has led studies on Canada's hydrogen export potential, clean energy transition plans, and long-duration energy storage opportunities. His work has informed policy decisions, supported the development of renewable energy legislation, and advanced the understanding of emerging technologies in the energy sector. Before joining Dunsky, Anirudh worked at Strategen Consulting in Berkeley, California, where he helped policymakers create clean energy roadmaps and assisted energy developers in evaluating project financial viability. Anirudh holds a Master of Science in Energy Science, Technology, and Policy from Carnegie Mellon University, Pittsburgh, and a Bachelor of Technology in Metallurgy and Material Science from the National Institute of Technology, Nagpur, India.

PROFESSIONAL EXPERIENCE

Dunsky Energy + Climate Advisors — 2019–PRESENT

Senior Consultant

Regulatory Services

- **Expert Witness Testimony in NH VDER and RBI Study**: Led the New Hampshire Value of Distributed Energy Resources study, developing a comprehensive framework to assess the benefits and costs of solar and hydro within three utility service territories. Created a user-friendly tool for government, regulators, and stakeholders. The study included a rate and bill impact assessment, evaluating cost-shifting impacts under the current Net Energy Metering tariff. Provided expert testimony, technical presentations, and additional analysis to support the NH Department of Energy (NH-DOE) in **Docket 022-060**, building confidence in their rate filing.
- **Assessment of Solar Compensation Frameworks**: Led the assessment of the Value of Shared Solar in Virginia, recommending program modifications to support community solar expansion for the Coalition for Community Solar Access (CCSA). As a result, the Virginia State Corporation Commission initiated a docket to review the minimum bill framework. Report: **Value of Shared Solar Report**. Additionally, led value of solar studies for utilities in New Brunswick and British Columbia, and the industry association in Texas, re-examining compensation structures for customer-sited solar.
- **Default Service Procurement**: Led analysis and testimony development for Earthjustice, advocating for a portfolio-based approach to default service supply with long-term renewable contracts. Developed a detailed model estimating savings for residential customers in Philadelphia Electric Company (PECO).
- **Rate Design**: Established the rate design methodology and approach to design an EV DCFC rate that meets specific objectives and conduct appropriate analyses needed to inform decision-making and/or seek New Brunswick Energy and Utilities Board (NBEUB) approval. Supporting the Maine Renewable Energy Association in formulating a stranded cost rate design under the Maine PUC initiated investigation.
- Supporting a Non-Wires Solution regulatory process, including the development of a cost benefit assessment framework, for PURA in Connecticut.

Project Due Diligence

- **Utility Storage Procurement**: Developed a framework to evaluate the costs and benefits of utility-scale storage projects for the electric grid, which was used to assess Nova Scotia's procurement of 150 MW of battery storage. Conducted technical and economic due diligence on a long-duration storage pilot project for a utility in eastern Canada.
- **Due Diligence of Customer-Sited Solar PV**: Led multiple studies to assess the technical and economic potential for on-site solar PV on client rooftops, including economic analyses within investment thresholds and business case development for high-potential sites.

Strategy

- **Canada's Hydrogen Export Opportunity Assessment**: Led a study evaluating hydrogen export potential to Europe, focusing on production in eastern Canada using wind and Small Modular Reactors. The study's recommendations contributed to establishing the transatlantic hydrogen corridor between Germany and Canada.
- **Review Clean Energy Transition Plans**: Supported the Provincial Auditor of Saskatchewan in reviewing SaskPower's transition plan to low-emission energy sources, including an evaluation of load forecasting methodology and resource planning.
- **Competitive Assessment**: Led a benchmarking study to enhance NRCan's knowledge of long-duration energy storage (LDES) innovations, providing policy recommendations to strengthen Canadian companies' market leadership.
- **Vehicle to Grid Application**: Supported the assessment of the value and potential applications of bidirectional electric vehicle charging for BC Hydro. The study was focused on gaining understanding of key barriers and opportunities for vehicle-to-grid and other bidirectional charging applications in the province.

Resource Planning and Opportunity Assessment

- **Solar Adoption Market Forecasts**: Spearheaded the python development of Dunsky's Solar Adoption Model to forecast distributed solar adoption under business-as-usual conditions as well as a variety of policy and market scenarios, including incentive/rebate and financing programs, alternative rate designs, compensation mechanisms as well as PV costs and electricity rate uncertainty. Leveraged this model to,
    - Produce the first comprehensive national market outlook for rooftop and on-site solar in Canada that called for policy and program actions to scale up rooftop solar by 20-40 times to help Canada achieve net-zero targets. Report: **BTM Solar Canada Market Outlook**
    - Forecast the market potential and adoption of solar and battery storage in and Platte River Power Authority's (PRPA) service territory and conduct a load impact analysis to help the utility discern the impact of emerging technologies on their grid.
    - Contribute to several distributed solar PV technical, economic and market potential studies for Rhode Island, Ontario, Alberta, New Brunswick, Manitoba and Nova Scotia among other jurisdictions across North America.
- **Renewable and Storage Cost Forecasts**: Led and supported studies on forecasting the cost of storage and generating resources (solar, wind and combined cycle gas turbines) in Quebec, Alberta, and Ontario through a bottom-up modelling for multiple clients including Clean Energy Canada's study. Report: **A Renewables Powerhouse - Clean Energy Canada**.
- **Long Duration Energy Storage Opportunity Assessment**: Led studies to benchmark emerging energy storage technologies, identify potential LDES applications, and assess their cost-effectiveness, providing recommendations for utility system planning in eastern Canada and Ontario. Report: https://www.energystoragecanada.org/blog-3-1/unlocking-ontarios-sustainable-energy-future-with-long-duration-energy-storage **Long Duration Opportunity Assessment**
- **Clean Energy Opportunities in Remote Communities**: Led evaluations of LDES and hydrogen opportunities in remote and Indigenous communities, focusing on reducing diesel dependency and enhancing winter reliability through clean energy solutions.
- **Municipal Payment Structures**: Conducted a jurisdictional scan comparing municipal payment structures for wind projects.
- **Demand Response Opportunity Assessment**: Conducted evaluation of measure characterizations for commercial customers for major utilities in North America which includes both electricity and fuels. Supported demand response assessments, including those for North Carolina and South Carolina (Duke Energy), Prince Edward Island, and Massachusetts.

Strategen Consulting LLC — 2015–2018

Consultant

ANALYZING PROPOSALS FOR PUBLIC PROCEEDINGS

Maryland Office of People's Council (Mar. 2018–July 2018)

- Evaluated the cost-effectiveness of the PC44 EV charger proposal through a total resource cost test, a ratepayer impact test, and a societal cost test.

New York Reforming the Energy Vision (Mar. 2017–May 2018)

- Developed models to evaluate the economics and project risks of BTM resources under the new Value of Distributed Energy Resources tariff.

Utility Rate Payer Advocates, Multiple Clients (Mar. 2016–July 2018)

- Developed models to evaluate rate design options for testimony in states such as Arizona, New Hampshire, Maine, Massachusetts.

ENERGY STORAGE ROADMAPS FOR GOVERNMENT

Massachusetts Clean Energy Center & Department of Energy Resources (Nov. 2015–Mar. 2016)

- Evaluated the value proposition, revenue generation and potential market size for energy storage for different customers at various grid locations. The recommendations from this analysis are now a part of the Massachusetts State of Charge report.

European Union, Roadmap for battery-based energy storage (BATSTORM) (Ma. 2016–Dec. 2016)

- Analysis of energy storage pilot projects, applications and current trends to develop an RD&D strategy focused on battery-based energy storage for the EU.

ECONOMIC ANALYSIS

Large-scale system integrator, Multiple Clients (Mar. 2016–Nov. 2018)

- Developed a business model for multiple nodes in CAISO by analyzing the historic wholesale market prices and forecasting future trends. The mode allowed the client to identify key factors that affect current revenue streams for standalone storage participation.

City and County of San Francisco (Nov. 2016–Mar. 2018)

- Evaluated the economic viability of solar and storage for wholesale market participation using Energy Storage Valuation Tool and by developing ingenious models.

City of Portland, Maine (Oct. 2016–Feb. 2018)

- Performed an in-depth analytical review of an energy-related investment. This included a financial and economic risk assessment by modelling future scenarios and an evaluation of the general terms and conditions to ensure investment viability.

MARKET ENTRY STRATEGIES FOR CORPORATIONS

EV company (Mar. 2016–Nov. 2016)

- Developed a holistic business strategy for residential storage through policy analysis, tariff modelling, incentive research and market forecasting of Behind the Meter (BTM) residential energy storage systems.

Automotive innovation company (Sept. 2016–Nov. 2016)

- Developed a business model for optimizing residential loads using BTMs. Analyzed the value proposition and developed a business model optimizing residential loads using BTM systems and EVs.

Large-scale energy developers, Multiple Clients (Nov. 2015–Nov. 2018

- Developed a BTM go-to-market strategy for the US market based on a model that identified the optimal system configuration and system size for commercial customers.

Solar rooftop developer (Nov. 2015–Mar. 2016)

- Conducted market research and competitive assessment to identify the market gap and develop a business model to consolidate the client's position as a holistic smart home developer.

EDUCATION

M.Sc Energy Science Technology & Policy
Carnegie Mellon University – USA

B.Tech Metallurgy and Material Science
National Institute of Technology – India

EXHIBIT B

History of Expert Testimony

Exhibit B: Expert Testimony List

Date	Matter	Docket Number	Regulatory Agency	Witness
April 15, 2024	Maine Public Utility Commission Investigation Into Allocation of Benefits of Distributed Generation Under NEB	Docket No. 2024-00149	Maine Public Utility Commission	Samuel C. Ross, Ben Kujala, Anirudh Kshemendranath
September 27, 2024.	Maine Public Utility Commission Follow-On Proceeding to Further Investigate Stranded Cost Rate Design	Docket No. 2024-00137	Maine Public Utility Commission	Samuel C. Ross, Ben Kujala, Anirudh Kshemendranath
December 6, 2024	Electric Distribution Utilities Consideration of Changes to the Current Net Metering Tariff Structure, Including Compensation of Customer Generator	DE 22-060	State of New Hampshire Public Utilities Commission	Alex Hill and Anirudh Kshemendranath
January 30, 2024	Electric Distribution Utilities Consideration of Changes to the Current Net Metering Tariff Structure, Including Compensation of Customer Generator	DE 22-060	State of New Hampshire Public Utilities Commission	Alex Hill and Anirudh Kshemendranath

Case No. PUR-2025-00028

CCSA - Direct Testimony of Anirudh Kshemendranath

EXHIBIT C

APCo Responses to Staff Set 1-2 and CCSA Set 4

	PAGE
APCo Response to Staff 1-2	1
APCo Attachment to Staff 1-2, Workpaper NMC-1 "Sheet 1"	2
APCo Response to CCSA 4-1	3
APCO Attachment 1 to CCSA 4-1	4

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2025-00028
Interrogatories and Requests for the Production
of Documents by the STAFF OF THE STATE CORPORATION COMMISSION
Staff Set 1
To Appalachian Power Company

Interrogatory Staff 1-2:

Please provide workpapers used in this proceeding and note if the workpaper is original to this case or if it originated in and had been provided in Case No. PUR-2024-00161 prior to the Company's filing in this case on April 1, 2025.

Response Staff 1-2:

Workpaper NMC 1 is original to this case. NMC 2 and NMC 3 are sourced from PUR-2024-00161 but were modified for the scope of this case. All workpapers are available on iManage.

The foregoing response is made by William K. Castle, Dir Regulatory Svcs, and Nicole M. Coon, Regulatory Consultant Prin, on behalf of Appalachian Power Company.

Residential			Usage kWh	1,000
Charge Type	**Charge name**	**Amount**	**Unit**	**Total Charge**
Cust Charge	Cust Charge	$ 7.96	Fixed	$ 7.96
Non-Bypassable Charges	Rider PIPP	$ 0.00132	kWh	$ 1.32
	Rider BC RAC	$ 0.00059	kWh	$ 0.59
	Rider A.5 RPS RAC	$ 0.00103	kWh	$ 1.03
	Rider PCAP RAC	$ 0.00013	kWh	$ 0.13
	Rider A.6 RPS RAC	$ 0.00011	kWh	$ 0.11
Base Distribution Charge	Energy Distribution	$ 0.03828	kWh	$ 38.28
Distribution RAC Charge	Rider EE RAC	$ 0.00237	kWh	$ 2.37
Trans. RAC Chgs.	Rider T.RAC	$ 0.03646	kWh	$ 36.46
Benefit Credits	Shifted Transmission Credit	$ (0.00720)	kWh	$ (7.20)
	Ancilliary Service Credit	$ (0.00150)	kWh	$ (1.50)
	REC Credit	$ (0.03189)	kWh	$ (31.89)
Admin Charge	Admin. Charge	$ 1.00	Fixed	$ 1.00
		Total		$ 48.66

Energy Credit	-0.0372	-37.2
Capacity Credit	-0.0015	-1.5
		$ 9.96

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2025-00028
Interrogatories and Requests for the Production
of Documents by the Coalition for Community Solar Access
CCSA Set 4
To Appalachian Power Company

Interrogatory CCSA 4-1:

Under APCo's proposed calculation, what is the resulting minimum bill for the industrial and commercial rate classes? Please provide all workpapers related to APCo's calculation.

Response CCSA 4-1:

Please see CCSA 4-1 Attachment 1 for an illustrative minimum bill for a General Service - secondary customer and a Large Primary Service – Primary customer.

The foregoing response is made by Nicole M. Coon, Regulatory Consultant Prin, on behalf of Appalachian Power Company

Exhibit C

			Total Usage kWh	**10,000**
			Load Factor	**47%**
			kVAR	**0**
			kw	**40**
GS Secondary			**Shared Solar Allocation**	**5,000**
Charge Type	**Charge Name**	**Amount**	**Unit**	**Total Charge**
Cust Charge	Cust Charge	$ 14.01	Fixed	$ 14.01
Non-Bypassable Charges	Rider PIPP	$ 0.00132	kWh	$ 6.60
	Rider BC RAC Block 1	$ 0.00050	kWh	$ 2.50
	Rider BC RAC Block 2	$ 0.00002	kWh	$ -
	Rider A.5 RPS RAC Block 1	$ 0.00102	kWh	$ 5.10
	Rider A.5 RPS RAC Block 2	$ 0.00102	kWh	$ -
	Rider A.5 RPS RAC Block 3	$ 0.00102	kWh	$ -
	Rider PCAP RAC Block 1	$ 0.00008	kWh	$ 0.40
	Rider PCAP RAC Block 2	$ 0.00006	kWh	$ -
	Rider PCAP RAC Block 3	$ 0.00003	kWh	$ -
	Rider PCAP Demand	$ 0.01000	kW	$ 0.40
	Rider A.6 RPS RAC Block 1	$ 0.00007	kWh	$ 0.35
	Rider A.6 RPS RAC Block 2	$ 0.00005	kWh	$ -
	Rider A.6 RPS RAC Block 3	$ 0.00002	kWh	$ -
	Rider A.6 RPS RAC Demand	$ 0.01000	kW	$ 0.40
Base Distribution Charge	Energy Distribution Block 1	$ 0.03923	kWh	$ 196.15
	Energy Distribution Block 2	$ 0.01563	kWh	$ -
	Energy Distribution Block 3	$ -	kWh	$ -
	Demand Charge	$ 1.11000	kW	$ 44.40
	Off-Peak Excess Demand Charge	$ 0.56000	kW	$ 22.40
Distribution RAC Charges	Rider EE RAC Block 1	$ 0.00237	kWh	$ 11.85
	Rider EE RAC Block 2	$ 0.00237	kWh	$ -
	Rider EE RAC Block 3	$ 0.00237	kWh	$ -
Trans. RAC Chgs.	T-RAC Block 1	$ 0.02440	kWh	$ 122.00
	T-RAC Block 2	$ 0.01515	kWh	$ -
	T-RAC Block 3	$ 0.00005	kWh	$ -
Benefit Credits	Shifted Transmission Credit	$ (0.00640)	kWh	$ (32.00)
	Ancilliary Service Credit	$ (0.00150)	kWh	$ (7.50)
	REC Credit	$ (0.03189)	kWh	$ (159.45)
Admin Charge	Admin Service Charge	$ 1.00000	Fixed	$ 1.00
		Total		$ 228.61

			Total Usage kWh	**10,000**
			Load Factor	**74%**
			kVAR	**120**
			kW	**1,000**
LPS Primary			**Shared Solar Allocation**	**5,000**
Charge Type	**Charge Name**	**Amount**	**Unit**	**Total Charge**
Cust Charge	Cust Charge	$ 276.49	Fixed	$ 276.49
Non-Bypassable Charges	Rider PIPP	$ 0.00132	kWh	$ 6.60
	Rider BC RAC	$ 0.05000	kWh	$ 250.00
	Rider A.5 RPS RAC	$ 0.00097	kWh	$ 4.85
	Rider A.5 PCAP	$ 0.04000	kW	$ 40.00
	Rider A.6 RPS RAC	$ 0.03000	kW	$ 30.00
Base Distribution Charge	Energy Distribution	$ -	kWh	$ -
	Demand Charge	$ 5.55000	kW	$ 5,550.00
	Off-Peak Excess Demand Charge	$ 1.14000	kW	$ 1,140.00
Distribution RAC Charges	Rider EE RAC	$ 0.00225	kWh	$ 11.25
Trans. RAC Chgs.	Rider T.RAC Energy	$ 0.00004	kWh	$ 0.20
	Rider T.RAC Demand	$ 9.91000	kW	$ 9,910.00
	Rider T.RAC Off-Peak kW	$ 1.02000	kW	$ 1,020.00
Benefit Credits	Shifted Transmission Credit	$ (0.00610)	kWh	$ (30.50)
	Ancilliary Service Credit	$ (0.00144)	kWh	$ (7.20)
	REC Credit	$ (0.03189)	kWh	$ (159.45)
Admin Charge	Admin. Charge	$ 1.00000	Fixed	$ 1.00
		Total		$ 18,043.24

EXHIBIT D

Program Cost Estimates

Exhibit D

250520154

Program Cost Estimates

VoS - APCo

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Shared Solar Program Size (MW	50
Residential	60%
Non Residential (Secondary)	40%

	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	2051	2052
Shared Solar Deployment (MW)	5	15	30	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	45	35	20
Total Program Costs	$0.85	$2.64	$5.27	$8.73	$8.64	$8.64	$8.64	$8.64	$8.64	$8.64	$8.64	$8.64	$8.64	$8.64	$8.64	$8.64	$8.64	$8.64	$8.64	$8.64	$8.64	$8.64	$8.64	$8.64	$8.64	$7.78	$6.05	$3.46
Energy Cost Correction	100%	109%	109%	107%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%

Residential

Percentage of Shared Solar	60%	
Program Size (MW)	30	
Annual Production (MWh)	44308	
Monthly Shared Solar Subscription (kWh	1000	
Number of Customers	3692	

Program Costs (Per Customer)				Monthly	Annual	Lifetime
Customer Charge	$	7.9600	Fixed	$7.96	$96	$4.51
Rider PIPP	$	0.0013	kWh	$1.32	$16	$0.75
Rider BC RAC	$	0.0006	kWh	$0.59	$7	$0.33
Rider A.5 RPS RAC	$	0.0010	kWh	$1.03	$12	$0.58
Rider PCAP RAC	$	0.0001	kWh	$0.13	$2	$0.07
Rider A.6 RPS RAC	$	0.0001	kWh	$0.11	$1	$0.06
Energy Distribution	$	0.0383	kWh	$38.28	$459	$21.71
Rider EE RAC	$	0.0024	kWh	$2.37	$28	$1.34
Rider T.RAC	$	0.0365	kWh	$36.46	$438	$20.68
Shared Solar Admin Charge	$	1.0000	Fixed	$1.00	$12	$0.57
Energy Generation (Forward Prices)	$	0.0379	kWh	$37.94	$455	$22.46
Total				**$127.19**	**$1,526**	$73.07

Residential

	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	2051	2052
Number of Subscribers	369	1108	2215	3692	3692	3692	3692	3692	3692	3692	3692	3692	3692	3692	3692	3692	3692	3692	3692	3692	3692	3692	3692	3692	3692	3323	2585	1477

Program Costs (Program $M)	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	2051	2052
Customer Charge	$0.04	$0.11	$0.21	$0.35	$0.35	$0.35	$0.35	$0.35	$0.35	$0.35	$0.35	$0.35	$0.35	$0.35	$0.35	$0.35	$0.35	$0.35	$0.35	$0.35	$0.35	$0.35	$0.35	$0.35	$0.35	$0.32	$0.25	$0.14
Rider PIPP	$0.01	$0.02	$0.04	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.05	$0.04	$0.02
Rider BC RAC	$0.00	$0.01	$0.02	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.02	$0.02	$0.01
Rider A.5 RPS RAC	$0.00	$0.01	$0.03	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.04	$0.03	$0.02
Rider PCAP RAC	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.00	$0.00
Rider A.6 RPS RAC	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Energy Distribution	$0.17	$0.51	$1.02	$1.70	$1.70	$1.70	$1.70	$1.70	$1.70	$1.70	$1.70	$1.70	$1.70	$1.70	$1.70	$1.70	$1.70	$1.70	$1.70	$1.70	$1.70	$1.70	$1.70	$1.70	$1.70	$1.53	$1.19	$0.68
Rider EE RAC	$0.01	$0.03	$0.06	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.09	$0.07	$0.04
Rider T.RAC	$0.16	$0.48	$0.97	$1.62	$1.62	$1.62	$1.62	$1.62	$1.62	$1.62	$1.62	$1.62	$1.62	$1.62	$1.62	$1.62	$1.62	$1.62	$1.62	$1.62	$1.62	$1.62	$1.62	$1.62	$1.62	$1.45	$1.13	$0.65
Shared Solar Admin Charge	$0.00	$0.01	$0.03	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.03	$0.02
Energy Generation (Forward Pri	$0.17	$0.55	$1.09	$1.80	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$1.57	$1.22	$0.70
Total	**$0.56**	**$1.74**	**$3.47**	**$5.75**	**$5.70**	**$5.70**	**$5.70**	**$5.70**	**$5.70**	**$5.70**	**$5.70**	**$5.70**	**$5.70**	**$5.70**	**$5.70**	**$5.70**	**$5.70**	**$5.70**	**$5.70**	**$5.70**	**$5.70**	**$5.70**	**$5.70**	**$5.70**	**$5.70**	**$5.13**	**$3.99**	**$2.28**

General Service

Percentage of Shared Solar	20%	
Program Size (MW)	10	
Annual Production (MWh)	14769	
Monthly Shared Solar Subscription (kWh	10000	
Number of Customers	123	
Monthly Demand (kW)	40	kW

Program Costs (Per Customer)				Monthly	Annual	Lifetime
Customer Charge	$	14.0100	Fixed	$14.01	$168	$0.26
Shared Solar Admin Charge	$	1.0000	Fixed	$1.00	$12	$0.02
Rider PIPP	$	0.0013	kWh	$13.20	$158	$0.25
Rider BC RAC Block 1	$	0.0005	kWh	$5.00	$60	$0.09
Rider A.5 RPS RAC Block 1	$	0.0010	kWh	$10.20	$122	$0.19
Rider PCAP RAC Block 1	$	0.0001	kWh	$0.80	$10	$0.02
Rider PCAP Demand	$	0.0100	kW	$0.40	$5	$0.01
Rider A.6 RPS RAC Block 1	$	0.0001	kWh	$0.70	$8	$0.01
Rider A.6 RPS RAC Demand	$	0.0100	kW	$0.40	$5	$0.01
Energy Distribution Block 1	$	0.0392	kWh	$392.30	$4,708	$7.42
Demand Charge	$	1.1100	kW	$44.40	$533	$0.84
Off-Peak Excess Demand Charge	$	0.5600	kW	$22.40	$269	$0.42
Rider EE RAC Block 1	$	0.0024	kWh	$23.70	$284	$0.45
T-RAC Block 1	$	0.0244	kWh	$244.00	$2,928	$4.61
Energy Generation (Forward Prices)	$	0.0344	kWh	$344.00	$4,128	$6.79
Total				**$1,116.51**	**$13,398**	**$21.39**

General Service

	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	2051	2052
Number of Subscribers	12	37	74	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123	111	86	49

Program Costs (Program $M)	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	2051	2052
Customer Charge	$0.00	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.01	$0.01
Shared Solar Admin Charge	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Rider PIPP	$0.00	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.01	$0.01
Rider BC RAC Block 1	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.00
Rider A.5 RPS RAC Block 1	$0.00	$0.00	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.01	$0.01	$0.01
Rider PCAP RAC Block 1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Rider PCAP Demand	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Rider A.6 RPS RAC Block 1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Rider A.6 RPS RAC Demand	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Energy Distribution Block 1	$0.06	$0.17	$0.35	$0.58	$0.58	$0.58	$0.58	$0.58	$0.58	$0.58	$0.58	$0.58	$0.58	$0.58	$0.58	$0.58	$0.58	$0.58	$0.58	$0.58	$0.58	$0.58	$0.58	$0.58	$0.58	$0.52	$0.41	$0.23
Demand Charge	$0.01	$0.02	$0.04	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.06	$0.05	$0.03
Off-Peak Excess Demand Charg	$0.00	$0.01	$0.02	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.02	$0.01
Rider EE RAC Block 1	$0.00	$0.01	$0.02	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.03	$0.02	$0.01
T-RAC Block 1	$0.04	$0.11	$0.22	$0.36	$0.36	$0.36	$0.36	$0.36	$0.36	$0.36	$0.36	$0.36	$0.36	$0.36	$0.36	$0.36	$0.36	$0.36	$0.36	$0.36	$0.36	$0.36	$0.36	$0.36	$0.36	$0.32	$0.25	$0.14
Energy Generation (Forward Pri	$0.05	$0.17	$0.33	$0.54	$0.53	$0.53	$0.53	$0.53	$0.53	$0.53	$0.53	$0.53	$0.53	$0.53	$0.53	$0.53	$0.53	$0.53	$0.53	$0.53	$0.53	$0.53	$0.53	$0.53	$0.53	$0.48	$0.37	$0.21
Total	**$0.16**	**$0.51**	**$1.02**	**$1.68**	**$1.67**	**$1.67**	**$1.67**	**$1.67**	**$1.67**	**$1.67**	**$1.67**	**$1.67**	**$1.67**	**$1.67**	**$1.67**	**$1.67**	**$1.67**	**$1.67**	**$1.67**	**$1.67**	**$1.67**	**$1.67**	**$1.67**	**$1.67**	**$1.67**	**$1.50**	**$1.17**	**$0.67**

LPS Primary

Percentage of Shared Solar	20%	
Program Size (MW)	10	
Annual Production (MWh)	14769	
Number of Customers	2	
Monthly Shared Solar Subscription (kWh	500,000	
Monthly Demand (kW)	1,000	kW

Program Costs (Per Customer)				Monthly	Annual	Lifetime
Customer Charge	$	276.49	Fixed	$276.49	$3,318	$0.10
Shared Solar Admin Charge	$	1.00	Fixed	$1.00	$12	$0.00
Rider PIPP	$	0.00132	kWh	$660.00	$7,920	$0.25
Rider BC RAC	$	0.05000	kW	$50.00	$600	$0.02
Rider A.5 RPS RAC	$	0.00097	kWh	$485.00	$5,820	$0.18
Rider A.5 PCAP	$	0.04000	kW	$40.00	$480	$0.02
Rider A.6 RPS RAC	$	0.03000	kW	$30.00	$360	$0.01
Energy Distribution	$	-	kWh	$0.00	$0	$0.00
Demand Charge	$	5.55000	kW	$5,550.00	$66,600	$2.10
Off-Peak Excess Demand Charge	$	1.14000	kW	$1,140.00	$13,680	$0.43
Rider EE RAC	$	0.00225	kWh	$1,125.00	$13,500	$0.43
Rider T.RAC Energy	$	0.00004	kWh	$20.00	$240	$0.01
Rider T.RAC Demand	$	9.91000	kW	$9,910.00	$118,920	$3.75
Rider T.RAC Off-Peak kW	$	1.02000	kW	$1,020.00	$12,240	$0.39
Energy Generation (Forward Prices)	$	0.04390	kWh	$21,950.00	$263,400	$8.66
Total				**$42,257**	**$507,090**	**$16.34**

LPS Primary

	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	2051	2052
Number of Subscribers	0	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1

Program Costs (Program $M)	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	2051	2052
Customer Charge	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.00
Shared Solar Admin Charge	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Rider PIPP	$0.00	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.01	$0.01
Rider BC RAC	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Rider A.5 RPS RAC	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Rider A.5 PCAP	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Rider A.6 RPS RAC	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Energy Distribution	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Demand Charge	$0.02	$0.05	$0.10	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.15	$0.11	$0.07
Off-Peak Excess Demand Charg	$0.00	$0.01	$0.02	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.02	$0.01
Rider EE RAC	$0.00	$0.01	$0.02	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.02	$0.01
Rider T.RAC Energy	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Rider T.RAC Demand	$0.03	$0.09	$0.18	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.29	$0.26	$0.20	$0.12
Rider T.RAC Off-Peak kW	$0.00	$0.01	$0.02	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.02	$0.01
Energy Generation (Forward Pri	$0.06	$0.21	$0.42	$0.69	$0.67	$0.67	$0.67	$0.67	$0.67	$0.67	$0.67	$0.67	$0.67	$0.67	$0.67	$0.67	$0.67	$0.67	$0.67	$0.67	$0.67	$0.67	$0.67	$0.67	$0.67	$0.61	$0.47	$0.27
Total	**$0.12**	**$0.39**	**$0.78**	**$1.29**	**$1.27**	**$1.27**	**$1.27**	**$1.27**	**$1.27**	**$1.27**	**$1.27**	**$1.27**	**$1.27**	**$1.27**	**$1.27**	**$1.27**	**$1.27**	**$1.27**	**$1.27**	**$1.27**	**$1.27**	**$1.27**	**$1.27**	**$1.27**	**$1.27**	**$1.15**	**$0.89**	**$0.51**

EXHIBIT E

Energy – Last 12 Months

Exhibit E

250520154

Energy

VoS - APCo

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Calculate value of energy based on trailing twelve month RT LMP

Calculation Steps:

1) Avg Month-Hour solar Production * Avg Month-Hour Energy Price

2) Multiply the product from step 1) with # of days for each respective month to obtain total $ value

3) Sum Monthly Values and divide by monthly solar production for each respective month to obtain $/kWh

4) Sum Annual Value and divide by total

Step 1&2

TB Energy Calc

Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.01	0.09	0.17	0.12	0.12	0.07	0.05	0.00	0.00	0.00
7	0.00	0.04	0.36	0.31	0.33	0.23	0.25	0.23	0.24	0.34	0.05	0.00
8	0.45	0.51	0.58	0.33	0.38	0.28	0.35	0.26	0.27	0.47	0.27	0.26
9	0.73	0.55	0.44	0.35	0.46	0.36	0.42	0.37	0.34	0.32	0.33	0.38
10	0.55	0.51	0.50	0.36	0.47	0.40	0.42	0.40	0.33	0.35	0.34	0.26
11	0.48	0.67	0.47	0.35	0.48	0.59	0.76	0.45	0.37	0.32	0.32	0.28
12	0.42	0.49	0.38	0.36	0.55	0.54	0.70	0.48	0.36	0.32	0.28	0.28
13	0.41	0.41	0.40	0.38	0.53	0.60	0.64	0.55	0.47	0.31	0.30	0.28
14	0.38	0.43	0.41	0.35	0.52	0.66	0.76	0.74	0.46	0.30	0.31	0.28
15	0.37	0.41	0.35	0.34	0.56	0.57	0.73	0.59	0.52	0.29	0.24	0.25
16	0.20	0.29	0.32	0.28	0.55	0.52	0.85	0.78	0.48	0.22	0.11	0.07
17	0.00	0.07	0.16	0.20	0.56	0.56	0.81	0.52	0.28	0.03	0.00	0.00
18	0.00	0.00	0.00	0.03	0.20	0.27	0.34	0.16	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Step 3

Monthly VoS	1	2	3	4	5	6	7	8	9	10	11	12
$/kWh	**$ 0.050**	**$ 0.047**	**$ 0.036**	**$ 0.025**	**$ 0.037**	**$ 0.034**	**$ 0.045**	**$ 0.037**	**$ 0.034**	**$ 0.029**	**$ 0.028**	**$ 0.033**

Step 4

Annual Vos	2025																									
$/kWh	**$0.0359**	$0.03918	$0.03902	$0.03844	$0.03735	$0.03735	$0.03735	$0.03735	$0.03735	$0.03735	$0.03735	$0.03735	$ 0.03735	$ 0.03735	$0.03735	$0.03735	$0.03735	$0.03735	$0.03735	$0.03735	$0.03735	$0.03735	$0.03735	$0.03735	$0.03735	$0.03735
		109%	109%	107%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%	104%
Solar Weighted Avg Price	$ 48.98	$ 53.40	$ 53.17	$ 52.38	$ 50.90	$ 50.90	$ 50.90	$ 50.90	$ 50.90	$ 50.90	$ 50.90	$ 50.90	$ 50.90	$ 50.90	$ 50.90	$ 50.90	$ 50.90	$ 50.90	$ 50.90	$ 50.90	$ 50.90	$ 50.90	$ 50.90	$ 50.90	$ 50.90	$ 50.90

EXHIBIT F

Energy Price Forecast

Template

VoS - APCo

#N/A

⬆ ⬅ ➡

Calculate value of energy based on forward prices and long-term inflation expectations (2% beyond 2029).

Calculation Steps:

1) Aggregate On/OffPeak Futures Data from NYMEX & weighted On/Offpeak solar generation (completed in other sheets)

(first 3 months of 2025 based on actual market pricing)

2) Develop solar weighted avg avoided energy price by multiplying forecasted prices and solar weighted generation

Avoided Solar Energy Cost

TB_Energy_Calc	[2025$/kWh]	[2025$/kWh]	[2025$/kWh]
Year	**On-Peak Price**	**Off-Peak Price**	**Solar Weighted Avg Price**
2025	53.03	40.90	48.98
2026	58.66	42.90	53.40
2027	58.24	43.06	53.17
2028	57.16	42.84	52.38
2029	55.61	41.49	50.90
2030	55.61	41.49	50.90
2031	55.61	41.49	50.90
2032	55.61	41.49	50.90
2033	55.61	41.49	50.90
2034	55.61	41.49	50.90
2035	55.61	41.49	50.90
2036	55.61	41.49	50.90
2037	55.61	41.49	50.90
2038	55.61	41.49	50.90
2039	55.61	41.49	50.90
2040	55.61	41.49	50.90
2041	55.61	41.49	50.90
2042	55.61	41.49	50.90
2043	55.61	41.49	50.90
2044	55.61	41.49	50.90
2045	55.61	41.49	50.90
2046	55.61	41.49	50.90
2047	55.61	41.49	50.90
2048	55.61	41.49	50.90
2049	55.61	41.49	50.90
2050	55.61	41.49	50.90

EXHIBIT G

BRA Capacity

Exhibit G

250520154

PJM Capacity Price

VoS - APCo

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Notes

Notes:

2022 APCo IRP data input:
https://rga.lis.virginia.gov/Published/2022/RD206/PDF

Exhibit E: Fundamentals
pg. 146 out of 150

Steps:
- Converted $/MW-day to $/kW-yr by dividing by 1000 and multiplying by 365
- Assuming capacity follow outlined trend from 2022 APCo IRP trajectory

Starting Capacity Price:
In July 2024, PJM released its newBRA Resource Clearing Prices for the Dominion & RTO zones, which are effective for 2025/2026.

To forecast the capacity price, we will leverage the RTO Zone price in 2025 and use the price 2022 APCo price trajectory

From 2041 onwards, we assume costs increase with inflation.

Source:

PJM 2025/2026 Base Residual Auction Report (2025 prices).

https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx

2024 Dominion IRP: Appendix 5B-10

https://www.dominionenergy.com/-/media/pdfs/global/company/IRP/2024-IRP-w_o-Appendices.pdf

PJM BRA Resource Clearing Price

TB_PJM_Capacity_2025_26

Year	Zone	$/MW-day	$/kW-yr
2025	RTO	269.92	98.52

Auction Adjustment Factor
1.47

Forecasted Capacity Price - Using latest Dominion IRP

Check TRUE

TB_CapacityPrice

	[$/MW-day]	[$/kW-year]	[$/kW-year]		[$/kW-year]	[2025$/kW-year]		[2025$/kW-year]
Year	2022 APCo IRP /day	2022 APCo IRP /yr	Latest Auction Price	Adjustment Factor	Modelled BRA Price $/kW-yr	Marginal Net CONE (CT)	Select BRA	Modelled BRA Price Real $/kW-yr
2025	183.53	66.99	98.52	1.47	99	117	1	99
2026	202.6	73.95	0.00	0.00	109	117	-	117
2027	215.63	78.70	0.00	0.00	116	117		117
2028	218.54	79.77	0.00	0.00	117	117		117
2029	224.05	81.78	0.00	0.00	120	117		117
2030	227.32	82.97	0.00	0.00	122	117		117
2031	232.06	84.70	0.00	0.00	125	117		117
2032	236.06	86.16	0.00	0.00	127	117		117
2033	242.04	88.34	0.00	0.00	130	117		117
2034	245.37	89.56	0.00	0.00	132	117		117
2035	252.27	92.08	0.00	0.00	135	117		117
2036	255.8	93.37	0.00	0.00	137	117		117
2037	261.59	95.48	0.00	0.00	140	117		117
2038	264.76	96.64	0.00	0.00	142	117		117
2039	268.97	98.17	0.00	0.00	144	117		117
2040	273.6	99.86	0.00	0.00	147	117		117
2041	278.12	101.51	0.00	0.00	149	117		117
2042	283.68	103.54	0.00	0.00	152	117		117
2043	289.36	105.61	0.00	0.00	155	117		117
2044	295.14	107.73	0.00	0.00	158	117		117
2045	301.05	109.88	0.00	0.00	162	117		117
2046	307.07	112.08	0.00	0.00	165	117		117
2047	313.21	114.32	0.00	0.00	168	117		117
2048	319.47	116.61	0.00	0.00	171	117		117
2049	325.86	118.94	0.00	0.00	175	117		117
2050	332.38	121.32	0.00	0.00	178	117		117

EXHIBIT H

Distribution Capacity – Residential and Commercial

Distribution Capacity - Residential

VoS - APCo

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Calculation Steps:

1) Outline **Max** Res Demand Profile (Month-hour)

2) Calculate Average Solar production (Month-hour)

3) Calculate Net Demand due to solar generation

4) Calculate Max demand Pre & Post solar gen to find net demand reduction due to solar

5) Net Demand Reduction/Avg System Size to develop % distribution benefit for solar, multiply against avoided

Max Residential Demand Profile

Step 1

Hour	1	2	3	4	5	6	7	8	9	10	11	12	Avg
0	2.63	2.86	2.65	1.33	1.08	1.11	1.62	1.36	1.35	1.13	2.78	2.86	1.90
1	2.82	2.94	2.53	1.34	1.07	1.05	1.37	1.24	1.12	1.08	2.87	2.81	1.85
2	2.70	3.03	2.63	1.32	1.07	0.91	1.32	1.09	1.08	1.17	3.02	2.90	1.85
3	2.89	3.23	2.71	1.33	1.03	0.83	1.15	0.96	0.96	1.21	3.14	3.06	1.87
4	3.00	3.32	2.72	1.41	1.13	0.79	1.05	0.95	0.92	1.42	3.02	3.02	1.90
5	2.96	3.51	3.03	1.64	1.24	0.86	1.05	1.01	0.95	1.64	3.30	3.27	2.04
6	3.16	3.32	3.23	1.97	1.54	1.01	1.16	1.12	1.02	1.88	3.24	3.47	2.18
7	3.17	3.54	3.38	2.25	1.65	1.04	1.22	1.18	1.10	1.92	3.48	3.74	2.31
8	3.38	3.43	3.00	2.21	1.42	1.23	1.44	1.39	1.27	1.70	3.09	3.41	2.25
9	3.01	3.21	2.81	1.94	1.56	1.31	1.62	1.66	1.42	1.59	2.67	2.96	2.15
10	2.72	2.93	2.57	1.73	1.48	1.42	1.80	1.78	1.55	1.51	2.41	2.59	2.04
11	2.44	2.58	2.60	1.69	1.42	1.61	2.06	2.00	2.00	1.32	2.23	2.44	2.03
12	2.40	2.44	2.73	1.43	1.56	1.78	2.27	2.16	2.17	1.38	2.12	2.38	2.07
13	2.39	2.40	2.62	1.54	1.70	1.85	2.43	2.44	2.36	1.52	1.97	2.24	2.12
14	2.43	2.35	2.54	1.58	1.74	1.97	2.73	2.42	2.46	1.60	2.06	2.10	2.16
15	2.35	2.44	2.63	1.57	1.90	2.08	2.82	2.52	2.69	1.71	2.03	2.15	2.24
16	2.49	2.36	2.58	1.56	2.02	2.17	2.85	2.66	2.80	1.75	2.35	2.28	2.32
17	2.69	2.42	2.49	1.63	2.01	2.28	2.96	2.80	2.90	1.68	2.71	2.78	2.45
18	2.81	2.73	2.54	1.62	1.95	2.33	2.75	2.57	2.69	1.65	2.78	2.74	2.43
19	2.76	2.77	2.69	1.66	1.71	2.09	2.67	2.54	2.55	1.63	2.83	2.93	2.40
20	2.84	2.82	2.68	1.80	1.64	1.91	2.45	2.21	2.44	1.67	3.05	2.77	2.36
21	2.74	2.94	2.70	1.78	1.48	1.79	2.26	2.07	2.05	1.67	2.86	2.80	2.26
22	2.99	2.92	2.64	1.53	1.39	1.59	1.96	1.79	1.78	1.54	2.78	2.83	2.14
23	2.92	2.99	2.61	1.50	1.14	1.27	1.78	1.55	1.54	1.39	2.78	2.82	2.02

Max Pre	
July	December
2.96	3.74
2.96	3.74
2.96	3.74
2.96	3.74
2.96	3.74
2.96	3.74
2.96	3.74
2.96	3.74
2.96	3.74
2.96	3.74
2.96	3.74
2.96	3.74
2.96	3.74
2.96	3.74
2.96	3.74
2.96	3.74
2.96	3.74
2.96	3.74
2.96	3.74
2.96	3.74
2.96	3.74
2.96	3.74
2.96	3.74
2.96	3.74

Avg Residential Solar Generation (based on system size)

Step 2

TB_Avg_Res_Solar_Gen

Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.1	0.3	0.1	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.9	2.0	2.1	1.7	1.0	0.6	0.0	0.0	0.0
7	0.0	0.3	1.6	3.2	3.7	3.6	3.2	3.3	2.8	2.0	0.5	0.0
8	1.5	2.7	3.6	4.2	3.7	4.4	4.4	4.2	4.0	4.2	2.6	1.4
9	3.3	3.8	4.1	4.4	4.4	5.1	4.4	4.9	4.3	4.2	3.8	2.9
10	3.6	3.5	4.4	4.8	5.0	5.1	4.8	4.9	4.3	4.3	4.0	2.7
11	3.1	4.1	4.1	4.8	5.0	5.5	5.0	4.8	4.1	4.2	3.8	2.8
12	3.1	4.0	4.1	5.0	5.0	5.4	4.8	4.4	4.0	3.9	3.5	2.9
13	3.3	3.7	4.1	5.0	4.7	5.1	4.7	4.7	4.2	3.9	3.6	3.0
14	3.2	3.7	4.1	5.0	4.3	5.1	4.7	4.7	3.9	3.7	3.8	3.2
15	3.2	3.9	3.8	4.7	4.3	4.4	4.3	4.2	3.9	3.4	3.1	2.7
16	1.6	2.8	3.3	3.8	3.8	3.8	4.1	4.0	3.1	2.3	1.2	0.8
17	0.0	0.6	1.5	2.4	3.1	3.5	3.3	2.7	1.5	0.2	0.0	0.0
18	0.0	0.0	0.0	0.3	1.1	1.6	1.6	0.7	0.0	0.0	0.0	0.0
19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Net Demand

Step 3

Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	2.63	2.86	2.65	1.33	1.08	1.11	1.62	1.36	1.35	1.13	2.78	2.86
1	2.82	2.94	2.53	1.34	1.07	1.05	1.37	1.24	1.12	1.08	2.87	2.81
2	2.70	3.03	2.63	1.32	1.07	0.91	1.32	1.09	1.08	1.17	3.02	2.90
3	2.89	3.23	2.71	1.33	1.03	0.83	1.15	0.96	0.96	1.21	3.14	3.06
4	3.00	3.32	2.72	1.41	1.13	0.79	1.05	0.95	0.92	1.42	3.02	3.02
5	2.96	3.51	3.03	1.64	1.11	0.53	0.93	1.01	0.95	1.64	3.30	3.27
6	3.16	3.32	3.18	1.07	-0.43	-1.12	-0.53	0.11	0.40	1.87	3.24	3.47
7	3.17	3.28	1.76	-0.94	-2.02	-2.57	-2.01	-2.16	-1.69	-0.08	2.96	3.74
8	1.92	0.75	-0.64	-2.03	-2.30	-3.21	-2.94	-2.82	-2.73	-2.53	0.50	2.05
9	-0.26	-0.63	-1.26	-2.47	-2.88	-3.79	-2.81	-3.24	-2.86	-2.62	-1.10	0.02
10	-0.86	-0.60	-1.84	-3.03	-3.53	-3.71	-2.95	-3.08	-2.78	-2.77	-1.59	-0.10
11	-0.63	-1.50	-1.48	-3.08	-3.61	-3.89	-2.90	-2.81	-2.06	-2.84	-1.60	-0.35
12	-0.71	-1.56	-1.36	-3.55	-3.42	-3.57	-2.58	-2.19	-1.86	-2.49	-1.39	-0.53
13	-0.87	-1.29	-1.49	-3.46	-3.01	-3.24	-2.28	-2.24	-1.87	-2.40	-1.66	-0.72
14	-0.75	-1.39	-1.58	-3.39	-2.52	-3.09	-1.97	-2.28	-1.40	-2.09	-1.77	-1.06
15	-0.81	-1.46	-1.17	-3.16	-2.39	-2.34	-1.51	-1.71	-1.19	-1.72	-1.04	-0.59
16	0.91	-0.46	-0.68	-2.23	-1.79	-1.62	-1.21	-1.35	-0.34	-0.51	1.19	1.50
17	2.68	1.83	0.99	-0.76	-1.05	-1.24	-0.31	0.13	1.41	1.50	2.71	2.78
18	2.81	2.73	2.54	1.31	0.86	0.75	1.10	1.89	2.67	1.65	2.78	2.74
19	2.76	2.77	2.69	1.66	1.71	2.08	2.65	2.54	2.55	1.63	2.83	2.93
20	2.84	2.82	2.68	1.80	1.64	1.91	2.45	2.21	2.44	1.67	3.05	2.77
21	2.74	2.94	2.70	1.78	1.48	1.79	2.26	2.07	2.05	1.67	2.86	2.80
22	2.99	2.92	2.64	1.53	1.39	1.59	1.96	1.79	1.78	1.54	2.78	2.83
23	2.92	2.99	2.61	1.50	1.14	1.27	1.78	1.55	1.54	1.39	2.78	2.82

Max Post	
July	December
2.65	3.74
2.65	3.74
2.65	3.74
2.65	3.74
2.65	3.74
2.65	3.74
2.65	3.74
2.65	3.74
2.65	3.74
2.65	3.74
2.65	3.74
2.65	3.74
2.65	3.74
2.65	3.74
2.65	3.74
2.65	3.74
2.65	3.74
2.65	3.74
2.65	3.74
2.65	3.74
2.65	3.74
2.65	3.74
2.65	3.74
2.65	3.74

Max Demand Reduction

Step 4

	Jan	Feb	March	April	May	June	July	Aug	Sep	Oct	Nov	Dec	Year-Round
Pre-Solar	3.38	3.54	3.38	2.25	2.02	2.33	**2.96**	2.80	2.90	1.92	3.48	**3.74**	3.7446
Post-Solar	3.17	3.51	3.18	1.80	1.71	2.08	2.65	2.54	2.67	1.87	3.30	3.74	3.7373

Max Pre	3.74	3.74	3.74	3.74	3.74	3.74	3.74	3.74	3.74	3.74	3.74	3.74
Max Post	3.74	3.74	3.74	3.74	3.74	3.74	3.74	3.74	3.74	3.74	3.74	3.74

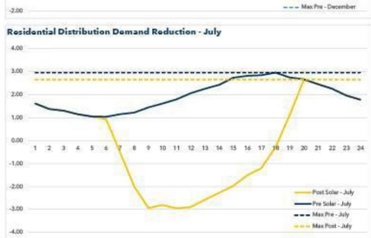
Demand Reduction (kW)
0.01

Step 5

Equivalent Distribution Capacity Reduction
0.1%

Distribution Capacity Cost
31.07 $/kW-yr

Value of Distribution Capacity
0.02 $/kW-yr
0.000015 $/kWh



Distribution Capacity - Commercial

VoS - APCo

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Calculation Steps:

1) Outline **Max** Comm Demand Profile (Month-hour)

2) Calculate Average Solar production (Month-hour)

3) Calculate Net Demand due to solar generation

4) Calculate Max demand Pre & Post solar gen to find net demand reduction due to solar

5) Net Demand Reduction/Avg System Size to develop % distribution benefit for solar, multiply against avoided

Max Commercial Demand Profile

Step 1

Hour	1	2	3	4	5	6	7	8	9	10	11	12	Avg
0	36.22	37.73	36.72	26.65	26.24	28.55	32.94	30.96	31.71	25.33	35.72	36.71	32.12
1	36.43	38.41	36.95	25.94	25.87	27.79	32.07	30.29	31.20	25.37	35.88	37.02	31.93
2	36.65	39.08	36.78	25.76	25.87	27.53	31.54	30.33	30.68	25.50	36.06	37.31	31.93
3	39.24	41.18	39.29	27.66	27.46	28.85	32.38	31.10	31.51	27.10	37.70	38.81	33.52
4	41.99	42.87	42.14	31.08	30.20	30.46	34.24	33.43	33.53	29.78	41.04	42.50	36.11
5	49.16	45.75	49.13	37.48	35.07	35.02	39.42	39.98	38.74	36.50	47.67	48.79	41.89
6	53.35	50.46	54.14	42.91	39.76	40.33	44.61	44.75	43.51	42.50	51.21	53.59	46.76
7	53.67	50.76	54.79	43.32	41.29	43.82	48.97	47.03	47.01	43.24	51.62	52.88	48.20
8	52.29	50.54	53.66	42.39	43.58	46.56	51.31	48.88	50.42	42.52	50.24	51.98	48.70
9	49.80	49.86	53.10	44.34	44.38	47.97	53.87	51.44	52.85	43.63	49.73	50.55	49.29
10	48.61	48.81	52.24	44.76	45.34	48.80	54.80	52.55	53.78	44.95	48.10	47.82	49.21
11	47.93	48.66	51.14	45.47	46.39	50.37	56.09	53.56	55.54	46.09	47.10	46.59	49.58
12	48.82	48.92	49.58	46.29	46.95	51.60	57.55	55.18	57.59	48.17	46.58	46.63	50.32
13	47.82	47.83	47.98	46.59	47.81	51.84	57.84	55.79	57.65	48.74	45.46	45.65	50.08
14	45.36	45.11	45.51	45.59	46.12	50.96	56.13	54.47	55.76	47.23	43.13	43.71	48.26
15	41.29	41.17	42.09	42.39	42.46	47.85	52.09	50.52	51.78	43.60	40.60	41.18	44.75
16	40.86	39.56	39.91	38.71	38.93	44.13	47.99	46.14	47.81	39.32	40.04	39.63	41.92
17	40.38	40.32	39.82	35.96	35.88	41.12	45.66	43.54	45.93	36.86	39.36	39.47	40.36
18	39.32	40.27	40.12	34.67	34.35	38.78	44.13	41.51	43.24	35.31	38.69	39.36	39.15
19	39.23	40.64	40.71	33.49	33.35	37.13	42.01	39.93	41.33	33.00	38.44	39.51	38.23
20	37.80	39.64	40.23	31.70	31.74	35.04	39.48	37.53	38.20	30.67	37.52	38.13	36.47
21	37.17	38.94	39.18	29.92	29.62	33.11	36.83	35.10	35.80	29.04	37.13	37.89	34.98
22	36.24	38.22	38.48	28.43	28.07	31.05	35.06	33.51	34.34	28.14	37.05	37.31	33.83
23	36.34	37.51	37.79	27.32	27.25	29.49	33.83	31.85	32.96	27.32	36.15	37.02	32.90

Max Pre	
July	December
57.84	53.59
57.84	53.59
57.84	53.59
57.84	53.59
57.84	53.59
57.84	53.59
57.84	53.59
57.84	53.59
57.84	53.59
57.84	53.59
57.84	53.59
57.84	53.59
57.84	53.59
57.84	53.59
57.84	53.59
57.84	53.59
57.84	53.59
57.84	53.59
57.84	53.59
57.84	53.59
57.84	53.59
57.84	53.59
57.84	53.59
57.84	53.59

Avg Residential Solar Generation (based on system size)

Step 2

TB_Avg_Res_Solar_Gen

Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	2.6	6.6	2.5	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	1.0	18.1	39.7	42.9	34.0	20.4	12.4	0.2	0.0	0.0
7	0.0	5.3	32.8	64.2	74.0	72.8	65.1	67.4	56.4	40.4	10.5	0.1
8	29.5	54.1	73.4	85.4	74.9	89.5	88.4	84.8	80.4	85.2	52.3	27.4
9	65.9	77.4	82.0	88.8	89.5	102.6	89.3	98.7	86.3	85.0	76.0	59.3
10	72.0	71.0	88.8	95.9	100.9	103.5	95.8	98.0	87.3	86.3	80.6	54.4
11	61.7	82.2	82.1	96.2	101.4	110.8	99.9	97.0	81.9	83.8	77.2	56.1
12	62.8	80.7	82.5	100.4	100.4	107.8	97.7	87.7	81.2	78.0	70.7	58.5
13	65.6	74.4	82.9	100.7	94.9	102.6	94.9	94.2	85.4	79.0	73.2	59.6
14	64.0	75.4	83.0	100.0	85.7	102.0	94.9	94.7	77.8	74.4	77.3	63.6
15	63.6	78.5	76.7	95.2	86.5	89.0	87.2	85.1	78.1	69.2	61.9	55.2
16	32.0	56.9	65.6	76.5	76.8	76.4	81.9	80.8	63.3	45.7	23.3	15.7
17	0.1	11.9	30.1	48.1	61.6	71.0	65.8	53.7	30.0	3.6	0.0	0.0
18	0.0	0.0	0.0	6.3	21.9	31.8	33.2	13.6	0.5	0.0	0.0	0.0
19	0.0	0.0	0.0	0.0	0.0	0.2	0.3	0.0	0.0	0.0	0.0	0.0
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Net Demand

Step 3

Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	36.22	37.73	36.72	26.65	26.24	28.55	32.94	30.96	31.71	25.33	35.72	36.71
1	36.43	38.41	36.95	25.94	25.87	27.79	32.07	30.29	31.20	25.37	35.88	37.02
2	36.65	39.08	36.78	25.76	25.87	27.53	31.54	30.33	30.68	25.50	36.06	37.31
3	39.24	41.18	39.29	27.66	27.46	28.85	32.38	31.10	31.51	27.10	37.70	38.81
4	41.99	42.87	42.14	31.08	30.20	30.46	34.24	33.43	33.53	29.78	41.04	42.50
5	49.16	45.75	49.13	37.48	32.50	28.38	36.96	39.98	38.74	36.50	47.67	48.79
6	53.35	50.46	53.14	24.85	0.04	-2.60	10.60	24.34	31.09	42.30	51.21	53.59
7	53.67	45.49	22.01	-20.83	-32.72	-28.98	-16.14	-20.42	-9.35	2.86	41.09	52.73
8	22.81	-3.51	-19.71	-43.02	-31.32	-42.91	-37.09	-35.91	-30.03	-42.71	-2.05	24.57
9	-16.10	-27.56	-28.90	-44.46	-45.08	-54.65	-35.41	-47.30	-33.46	-41.33	-26.22	-8.77
10	-23.43	-22.17	-36.56	-51.13	-55.58	-54.66	-41.02	-45.42	-33.48	-41.39	-32.50	-6.56
11	-13.76	-33.58	-30.96	-50.76	-54.96	-60.44	-43.80	-43.40	-26.35	-37.74	-30.06	-9.55
12	-13.99	-31.74	-32.91	-54.09	-53.47	-56.22	-40.11	-32.50	-23.64	-29.84	-24.09	-11.92
13	-17.83	-26.53	-34.93	-54.09	-47.08	-50.81	-37.09	-38.44	-27.73	-30.27	-27.69	-13.92
14	-18.65	-30.27	-37.51	-54.46	-39.61	-51.00	-38.75	-40.26	-22.01	-27.13	-34.14	-19.93
15	-22.26	-37.36	-34.61	-52.79	-44.00	-41.19	-35.13	-34.54	-26.32	-25.57	-21.30	-14.03
16	8.90	-17.33	-25.69	-37.77	-37.82	-32.30	-33.88	-34.68	-15.49	-6.35	16.76	23.95
17	40.28	28.42	9.73	-12.17	-25.72	-29.91	-20.17	-10.12	15.97	33.27	39.36	39.47
18	39.32	40.27	40.09	28.34	12.45	6.98	10.92	27.90	42.78	35.31	38.69	39.36
19	39.23	40.64	40.71	33.49	33.35	36.96	41.70	39.93	41.33	33.00	38.44	39.51
20	37.80	39.64	40.23	31.70	31.74	35.04	39.48	37.53	38.20	30.67	37.52	38.13
21	37.17	38.94	39.18	29.92	29.62	33.11	36.83	35.10	35.80	29.04	37.13	37.89
22	36.24	38.22	38.48	28.43	28.07	31.05	35.06	33.51	34.34	28.14	37.05	37.31
23	36.34	37.51	37.79	27.32	27.25	29.49	33.83	31.85	32.96	27.32	36.15	37.02

Max Post	
July	December
41.70	53.59
41.70	53.59
41.70	53.59
41.70	53.59
41.70	53.59
41.70	53.59
41.70	53.59
41.70	53.59
41.70	53.59
41.70	53.59
41.70	53.59
41.70	53.59
41.70	53.59
41.70	53.59
41.70	53.59
41.70	53.59
41.70	53.59
41.70	53.59
41.70	53.59
41.70	53.59
41.70	53.59
41.70	53.59
41.70	53.59
41.70	53.59

Max Demand Reduction

Step 4

	Jan	Feb	March	April	May	June	July	Aug	Sep	Oct	Nov	Dec	Year-Round
Pre-Solar	**53.67**	50.76	54.79	46.59	47.81	51.84	**57.84**	55.79	57.65	48.74	51.62	**53.59**	57.84
Post-Solar	**53.67**	50.46	53.14	37.48	33.35	36.96	**41.70**	39.98	42.78	42.30	51.21	**53.59**	53.67

Max Pre	57.84	57.84	57.84	57.84	57.84	57.84	57.84	57.84	57.84	57.84	57.84	57.84
Max Post	53.67	53.67	53.67	53.67	53.67	53.67	53.67	53.67	53.67	53.67	53.67	53.67

Demand Reduction (kW)

4.17

Step 5

Equivalent Distribution Capacity Reduction

2.1%

Distribution Capacity Cost

31.07 $/kW-yr

Value of Distribution Capacity

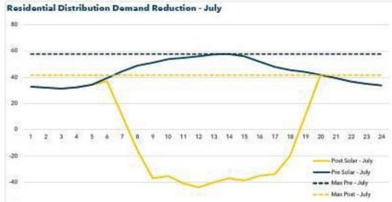
0.65 $/kW-yr 0.04404545 cent/kWh

0.000440 $/kWh 28.5131 *times larger than res*

Commercial Distribution Demand Reduction

Residential Distribution Demand Reduction - December

Residential Distribution Demand Reduction - July



CERTIFICATE OF SERVICE

I certify that on this 12th day of May, 2025, I caused a true and correct copy of the foregoing to be delivered to the following recipients via electronic mail:

Raymond L. Doggett, Jr., Esq.
Arlen Bolstad, Esq.
Office of General Counsel
Virginia State Corporation Commission
1300 E. Main Street, 10th Floor
Post Office Box 1197
Richmond, VA 23218
Raymond.doggett@scc.virginia.gov
Arlen.bolstad@scc.virginia.gov

Andrew J. Flavin, Esq.
Chelsey B. Noble, Esq.
Troutman Pepper Locke LLP
1001 Haxall Point
Richmond, VA 23219
andyflavin@troutman.com
chelsey.noble@troutmcm.com

Josephus M. Allmond, Esq.
E. Grayson Holmes, Esq.
Southern Environmental Law Center
120 Garrett St.
Ste 400
Charlottesville, Virginia 22902
jallmond@selc.org
gholmes@selcva.org

Noelle J. Coates, Esq.
Christen M. Blend, Esq.
American Electric Power Service Corp.
3 James Center
1051 E. Cary St.
Ste 1100
Richmond, Virginia 22902
njcoates@aep.com
cblend@aep.com

C. Meade Browder, Jr., Esq.
Commonwealth of Virginia
Office of the Attorney General
Division of Consumer Counsel
202 N. Ninth Street
Richmond, VA 23219
mbrowder@oag.state.va.us

/s/ Eric J. Wallace
Eric J. Wallace