Value of Shared Solar in Virginia

Prepared for:

CCSA

dunsky
Energy + Climate

November 2023

Submitted to:

Coalition for Community Solar Access (CCSA)
Charlie Coggeshall
Mid-Atlantic Regional Director
www.communitysolaraccess.org

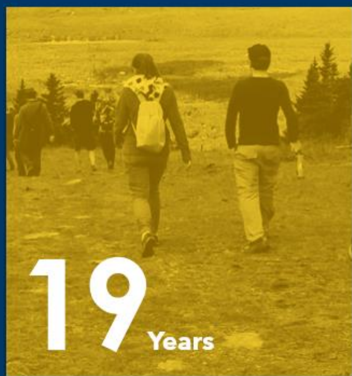
Dunsky Project Number: 23079

Prepared by:

Dunsky Energy + Climate Advisors
50 Ste-Catherine St. West, suite 420
Montreal, QC, H2X 3V4

www.dunsky.com | info@dunsky.com
+ 1 514 504 9030

About Dunsky



Dunsky supports leading governments, utilities, corporations and others across North America in their efforts to accelerate **the clean energy transition**, effectively and responsibly.

With deep expertise across the Buildings, Mobility, Industry and Energy sectors, we support our clients in two ways: through rigorous **Analysis** (of technical, economic and market opportunities) and by designing or assessing **Strategies** (plans, programs and policies) to achieve success.

Dunsky is proudly Canadian, with offices and staff in Montreal, Toronto, Vancouver, Ottawa and Halifax. Visit dunsky.com for more information.

Table of Contents

Executive Summary

Virgnia's Shared Solar Act enabled electric utility customers to benefit from affordable and clean solar electricity by subscribing to new non-utility investments in shared solar facilities. The legislation currently limits the shared solar program to 200 MW in Virginia Electric Power Company's (Dominion Energy) territory. With the program cap approaching through allocated projects, the **Coalition for Community Solar Access (CCSA)** is seeking to expand the program to 2,000 MW across Virginia's two largest investor-owned utilities (Dominion Energy and Appalachian Power Company).

Our analysis found that expanding the Shared Solar Program can offer substantial benefits to Virginia's utility customers, including those utility customers that do not participate in shared solar, by offsetting the utility's transmission charges, deferring transmission and distribution system upgrades, and avoiding generation costs. In aggregate, assuming shared solar capacity of 2,000 MW will be installed by 2035, and following current solar PV projection trends in Virginia, **the expanded program offers $126 million of total benefits over the 2024-2026 period and more than $5 billion in total benefits from 2024 to 2050**.

This study applies values and assumptions put forward by the Virginia utilities in their regulatory filings. It finds that the projected value delivered from the shared solar facilities to the utilities substantially exceeds the net bill credits that Shared Solar Program subscribers would receive on their utility bills. As a result, if 2,000 MW of shared solar were installed, and after accounting for the shared solar credits paid to subscribers and the current minimum bill design, **the utilities are projected to accrue over $64 million in net benefits from 2024-2026 and over $2.4 billion from 2024 to 2050.** This suggests that more value could be returned to subscribers without negatively impacting the utilities, and in turn, without putting additional burden on ratepayers.

For an expanded program to be a success, CCSA seeks to ensure that Shared Solar Program subscribers are fairly compensated for their participation. Currently, customers receive bill credits equal to their retail price of electricity for their portion of shared solar facility energy production, and they are charged back a minimum bill, which is intended to ensure customers pay their fair share for their access to the electric grid. The current minimum bill reduces the value of bill credits issued to subscribers by approximately 40%-60% for a typical residential customer. This arrangement appears not to take into account the concrete benefits shared solar facilities can provide to the utility by avoiding costs associated with generation and infrastructure and by complying with the renewable portfolio standard. As a result, the current minimum bill arrangement appears to significantly under-compensate Shared Solar Program participants.

The study found that the aggregate benefits for shared solar projects are substantial for both major investor-owned utilities:

1. For **Dominion Energy** customers, the study found that the value per kWh of shared solar delivered exceeded the current net compensation (estimated at 7.4 ¢/kWh when the average volumetric minimum bill charges are assessed) to Program subscribers, starting at 11 ¢/kWh in 2024 to 21 ¢/kWh by 2050.
2. For **Appalachian Power Company (APCo)** customers, the projected value of shared solar generation in 2024 is 11 ¢/kWh, rising to 21 ¢/kWh by 2050.

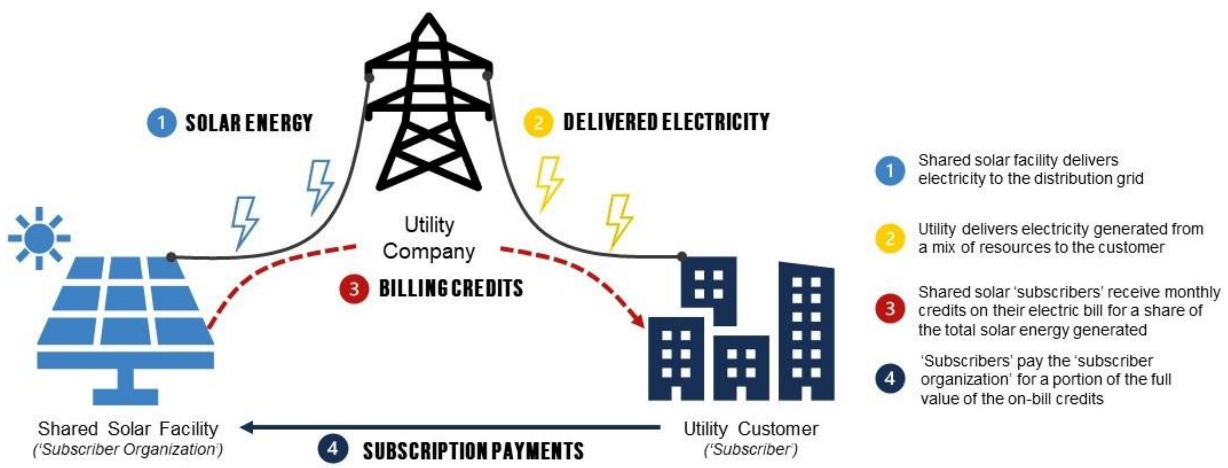
The study found that utilities could reduce the volumetric components of the minimum bill by up to 80% and still reap a net benefit **of $15 million over the 2024-2026 period and $365 million from 2024 to 2050**. Ensuring a more equitable distribution of shared solar benefits would increase the attractiveness of the Shared Solar Program, and, in turn incentivize developers to build more shared solar facilities in the state.

The results of this analysis demonstrate that the expansion of Dominion Energy's Shared Solar Program, and the establishment of a program in APCo's service territory, could create value for all utility ratepayers in excess of the credits provided to program subscribers. Further, increasing compensation to shared solar subscribers appear to be supported by the net benefits that currently accrue to the utilities. **Ultimately, this would be a win-win situation as it would support substantial expansion of the Shared Solar Program and help Virginia mitigate its projected capacity and energy shortfalls.**

1. Introduction

In 2020, the Virginia General Assembly enacted legislation[1] that permitted the development of shared solar facilities that could generate electricity for multiple utility customers at a single site. Under this arrangement, utility customers can subscribe to a shared solar facility, and the electricity generated from their portion of the solar array would result in credits used to lower their electricity bills.

Figure 1: Virginia's Shared Solar Program Schematic[2]



To date, only customers of Dominion Energy have access to the Shared Solar Program. About 150 MW of Shared Solar projects have been approved to date[3]. The 2020 law established a maximum of 200 MW for the Shared Solar Program.[3] The **Coalition for Community Solar Access (CCSA) seeks to expand shared solar in Virginia by adding an additional 1,500 MW of shared solar projects in *Dominion Energy*[1] territory and 300 MW in the *Appalachian Power Company (APCo)* territory**. This proposed expansion would increase Virginia's total shared solar capacity to 2 GW. However, to meet this target, the Program must provide appropriate compensation for shared solar subscribers.

Under current law (SCC § 56-594.3), each subscriber of the Shared Solar Program receives a bill credit based on the subscriber's customer class (residential, commercial, or industrial) and reflects the average retail rate per kWh of electricity delivered from the shared solar facility for that subscriber. The subscribers are also charged a minimum bill fee by Dominion that reduces the bill credit. The rationale of the minimum bill is to ensure subscribers in the Shared Solar Program pay their fair share for the access to the electric grid.

The current minimum bill assumes that distributed solar provides no avoided cost benefits to the utility or ratepayers beyond its energy value. Dominion claims that the minimum bill is designed to capture all the costs of supporting the grid, and any changes to the minimum bill would result in a cost shift from Shared Solar Program participants to non-participants. However, several Value of

Solar studies conducted by public agencies and utilities across the US have identified that, in addition to the cost savings related to avoided energy and generation capacity associated with distributed generation, shared solar also supports avoided line losses and avoided or deferred investment in transmission and distribution capacity.[3, 4, 5] The results of the analysis performed for this report are consistent with the findings of value of solar studies from other markets, and demonstrate that the current minimum bill adopted by the State Corporation Commission (SCC) under-compensates customers for the value of the generation from their projects.

To this end, the CCSA has commissioned this study ***to quantify the generation, transmission, distribution, and environmental value of shared solar to Virginia's two primary electric utilities, Dominion Energy and APCo.*** The study's objective is to determine the value that the Shared Solar Program can deliver to Virginia's electric utility ratepayers over the 2024 to 2050 period. The study will then compare this value with the net compensation received by Shared Solar Program participants after accounting for the current minimum bill under the existing program. This will in turn determine if the current net compensation for shared solar in Dominion accurately reflects the value shared solar brings to Virginia's ratepayers or whether compensation is greater than value and thereby a cost shift is created.

2. Study Approach and Methodology

The following approach was adopted to determine the value of shared solar in Virginia:

1. **Develop technology-neutral value stack components:** A comprehensive framework was developed to identify and quantify the grid benefits that can be attributed to distributed generation resources (a.k,a., the "value stack"). This analysis was conducted by leveraging publicly available information from PJM and utility-specific reports such as integrated resource plans (IRP), annual market outlooks, and solar forecast reports. Appendix A details the methodology to calculate each of the avoided cost components for Dominion and APCo, covering the following value stack components:
    a. **Generation Benefits:** This includes the value of Avoided Energy, Avoided Generation Capacity, Avoided Ancillary Services, Avoided Line Losses, Hedging/ Wholesale Risk Premium, and Wholesale Market Price Suppression Benefits through Demand Reduction Induced Price Effect Benefits (DRIPE).
    b. **Transmission and Distribution (T&D) Benefits:** This includes Avoided Transmission Charges, Avoided Transmission Capacity costs, and Avoided Distribution Capacity costs.
    c. **RPS Benefits:** This includes Avoided Renewable Portfolio Standard (RPS) Compliance Costs.
2. **Develop a representative solar output profile**: NREL PV Watts® was used to generate an hourly solar PV production profile for a 1 kW single-axis tracking system in Richmond, Virginia.

3. Determine shared solar's reliability contribution: PJM's effective load-carrying capability (ELCC) curves serve as a proxy for estimating the contribution of distributed solar to the utilities' capacity and transmission reliability requirements. Several other Value of Solar studies conducted by other public agencies have used this method as well (Appendix C).[5, 7] The ELCC values depend upon the amount of solar deployed within a utility's network. The ELCC analysis for shared solar assumes 2 GW of shared solar would be deployed between 2024 and 2036 in Virginia with about 1.7 GW in Dominion and 300 MW in APCo.

4. Establish the Value of shared solar: The value of shared solar in Virginia was determined using the representative solar output profile and the ELCC values for each utility and applying these to the technology-neutral value stack.

3. Value of Shared Solar in Virginia

The value of shared solar in Dominion and APCo was determined based on the approach outlined in the previous section and in further detail in Appendix B.

3.1 Value of Shared Solar in Dominion

As seen in Figure 2, the value of shared solar increases from 11 ¢/kWh in 2024 to 21 ¢/kWh by 2050. In 2024, the largest component of the value stack is avoided generation benefits, which comprise 64% of the total value. The remaining 36% is split between avoided transmission and distribution costs (24%) and RPS benefits (12%).

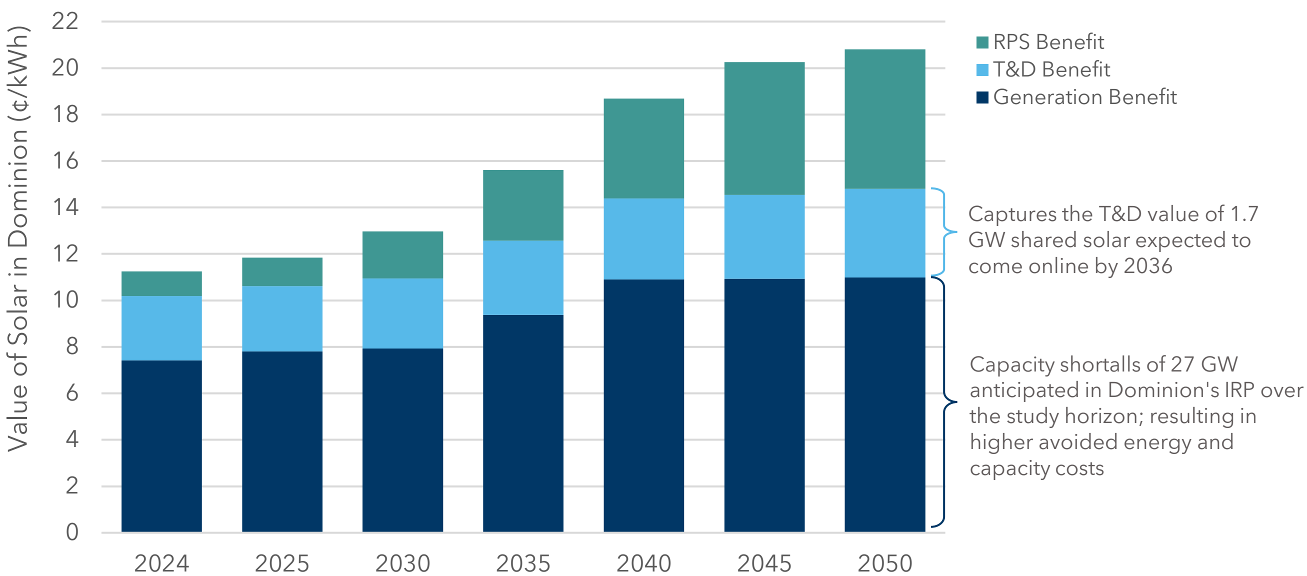


Figure 2: Value of Shared Solar in Dominion

3.1.1 Generation Benefits

The generation benefits attributable to 1.7 GW of shared solar in Dominion Energy increase from 7 ¢/kWh in 2024 to 11 ¢/kWh by 2038, after which it remains stable. Over the study period, the largest drivers of avoided generation costs are avoided energy costs (68%) followed by avoided generation capacity costs (19%).

Avoided Energy Costs: According to Dominion's projection, as presented in their 2023 IRP, by 2048, there will be an energy shortage of 114 TWh due to planned retirement of existing coal-, light fuel oil-, and heavy fuel oil-fired generation plants.[8] Consequently, the energy costs are anticipated to align with higher costs forecasted in Dominion’s IRP, increasing from 48 $/MWh in 2024 to 75 $/MWh by 2038.[8] After 2038, energy costs are expected to remain stable until 2050 (in real $2023).

Avoided Generation Capacity Costs: By 2048, Dominion expects a capacity shortfall of 16 GW, which could increase to 27 GW with the planned retirement of existing coal-, light fuel oil-, and heavy fuel oil-fired generation plants.[8] Given the anticipated capacity constraints in Dominion’s network, generation capacity costs are expected to increase from 99 $/kW-year in 2024 to 134 $/kW-year by 2038 (as determined by PJM’s Net Cone Studies, when including reserves).[9] After 2038, the generation capacity costs are expected to remain stable until 2050 (in real $2023). Although generation capacity costs represent a two-fold increase, the effective contribution of solar to system peak reduces as the peak shifts, resulting in lower avoided generation capacity costs in the later years.

3.1.2 Transmission and Distribution (T&D) Benefits

The T&D benefits attributable to 1.7 GW of shared solar increase from 3 ¢/kWh in 2024 to 4 ¢/kWh by 2050. Over the study period, the largest drivers of avoided T&D costs are avoided transmission charges (45%) followed by avoided transmission and distribution capacity costs (19% and 36%, respectively).

Avoided Transmission Costs: PJM charges Dominion a Network Service Peak Load (NSPL) fee for its contribution to the zonal peak.[10] Given the expected increase in transmission build-out in PJM, the transmission charges are projected to increase at a relatively constant rate, from the current rate of 66 $/kW-year in 2024 to 150 $/kW-year by 2050.[8] Although transmission charges more than double, the effective contribution of distributed solar generation to the system reliability reduces as the timing of the annual peak hour shifts, leading to lower avoided transmission costs per kWh of distributed solar generation with time.

Avoided Transmission and Distribution Capacity Costs: Transmission and distribution capacity costs are projected to remain stable throughout the study period, in line with values provided by Dominion in testimony on the avoided cost value of demand-side management (DSM) programs.[11] The transmission and distribution capacity value is expected to remain constant at 62 $/kW-year throughout the study period.

3.1.3 Renewable Portfolio Standard (RPS) Benefits

Dominion is obligated to meet its RPS requirement, and for every percent of renewable generation they fall short of the RPS, they must pay a Deficiency Payment.[12] Given that the Deficiency Payment increases each year, the avoided RPS compliance costs are projected to increase relatively constantly, from 1 ¢/kWh in 2024 to 6 ¢/kWh in 2050.

3.1.4 Comparison against Current Compensation Structure

Virginia state law says that the credit shall be based on rate class revenues divided by sales to yield a c/kWh credit. Pursuant to this requirement in law, the SCC has determined that residential subscribers of shared solar in Dominion would receive a gross bill credit of 13 ¢/kWh in 2023[13]; this number resets annually based on utility costs and sales. However, subscribers must pay a minimum bill to the utility that is based on the subscribed kWh of generation. The stated intent of the minimum bill is to reflect the overall costs of supporting the grid. Taking into consideration only the volumetric portion of the minimum bill results in a net bill credit of 7.4 ¢/kWh. Apart from the volumetric component, subscribers are also charged a basic customer charge of $6.58/month and a Shared Solar Program administrative charge, which is anticipated to range between $10-20/month. These two fixed charges are not reflected in the minimum bill amount shown in Figure 3, which includes only volumetric components, however they are included in cost assumptions relating to the overall net benefits of the program. As seen in **Figure 3,** the value of shared solar in Dominion exceeds net bill credits today and throughout the entire study period.

Current net bill credit undervalues solar for residential customers

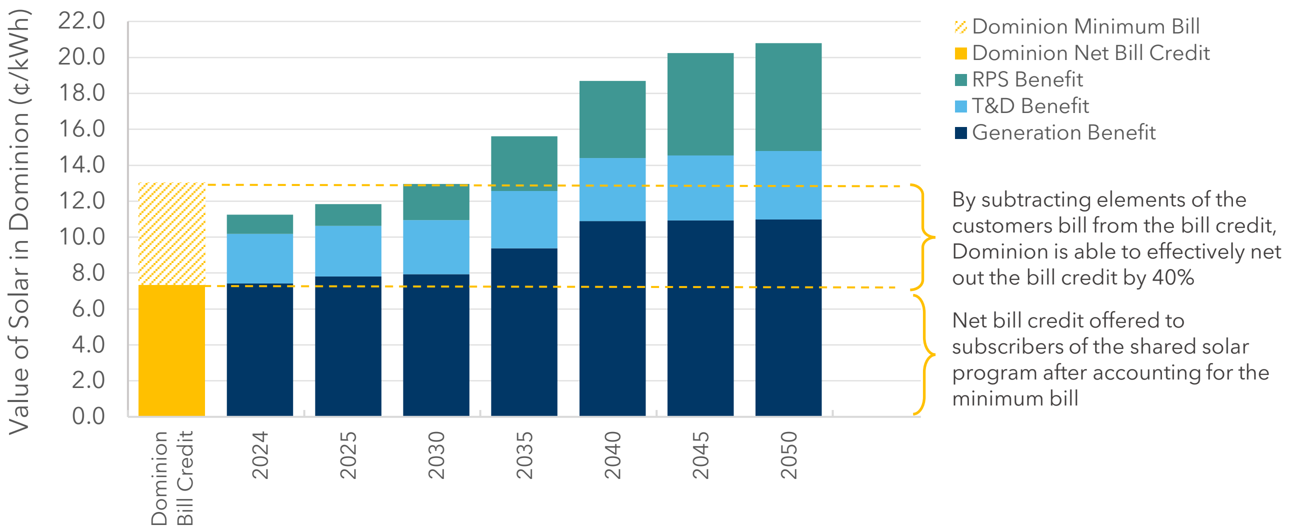


Figure 3: Current Compensation for Shared Solar in Dominion

3.1.5 Present Value of Shared Solar Expansion

To assess the overall value of the shared solar facilities to Dominion Energy, a roll out schedule for achieving an additional 1,700 MW between 2024 and 2036 was assumed. The above value streams were assessed for each kWh of solar produced, and Dominion Energy's weighted average cost of capital (5.2% WACC) was applied to discount future benefits to present values. This results in $109 million of avoided cost value for Dominion Energy and its ratepayers over the 2024-2026 period, and $4.4 billion of total value over the 2024 to 2050 period (see Table 2 in Appendix A for details).

Under the current Shared Solar Program compensation structure, subscribed customers receive a gross bill credit that is effectively equivalent to the retail rate of electricity, for their customer class. Residential customers currently receive 13 ¢/kWh[1] for their portion of the shared solar facility's production. However, Dominion Energy applies fixed charges, such as the basic customer charge and the shared solar administration charge on the monthly bill, as well as volumetric charges (currently 5.5 ¢/kWh) for the customer's portion of the shared solar facility output. When the bill credit offered to subscribers is netted against the minimum bill and deducted from the total avoided cost value for Dominion Energy, it results in $56 million in net benefits accruing to Dominion Energy between 2024 and 2026, and over $2 billion of net utility benefits in the 2024 to 2050 period.

This study found that Dominion Energy could reduce the volumetric minimum bill charges for Shared Solar Program subscribers by up to 80% and still yield a positive net benefit for the utility. This would increase customer compensation by 60%, and could return a net benefit to the utility of $13 million over the 2024 to 2026 period, and $343 Million from 2024 to 2050. This more equitable distribution of shared solar benefits would increase the program's attractiveness to Dominion Energy customers, which in turn would incentivize developers to build more shared solar facilities and ultimately create benefits for all ratepayers within Dominion Energy's territory. This net benefit to the utility could also be used to lower rates for all Dominion customers, including those that don't subscribe to shared solar.

[1] Shared Solar Program Bill Credits and T&D Volumetric Charges are updated annually and are approved by the State Corporation Commission.

3.2 Value of Shared Solar in Appalachian Power Company

As seen in **Figure 4**, the value of shared solar in APCo's territory increases from 11 ¢/kWh in 2024 to 21 ¢/kWh by 2050. In 2024, the largest component of the value stack is avoided generation costs, which make up 58% of the total value. The remaining 42% is split between avoided transmission and distribution costs (33%) and RPS benefits (9%).

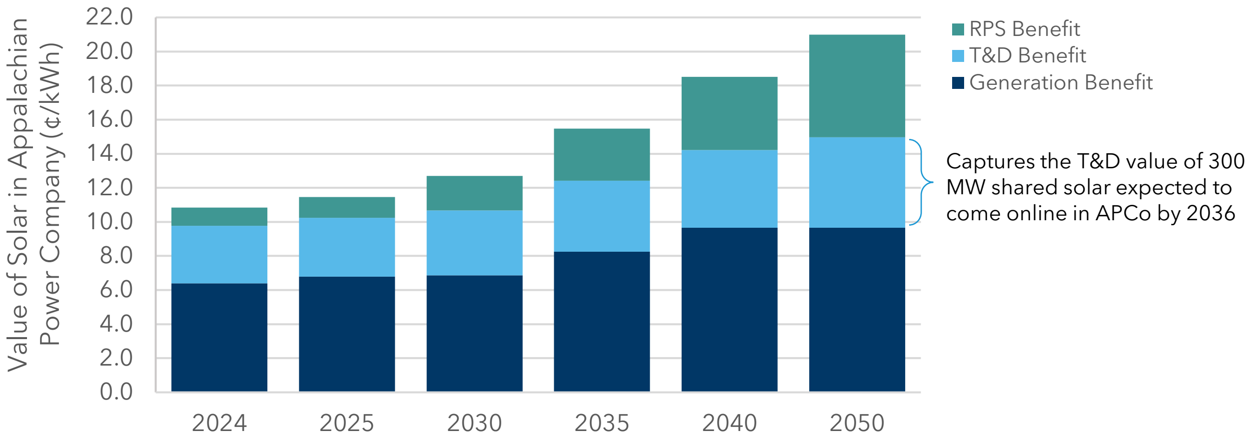


Figure 4: Value of Shared Solar in Appalachian Power Company

3.2.1 Generation Benefits

The generation benefits attributable to the build out of an additional 300 MW of shared solar increase from 6 ¢/kWh in 2024 to 10 ¢/kWh by 2041, after which it remains stable. Over the study period, the largest drivers of generation benefits are avoided energy costs (78%), followed by avoided generation capacity costs (12%).

Avoided Energy Costs: The energy costs outlined in APCo's IRP are considerably lower than PJM market prices and the prices presented in the Dominion IRP.[8,14] Because no rationale for the lower projected energy costs is provided, Dominion's energy price forecasts were used in place of APCo's energy cost projections, as they are more closely aligned with the PJM market price projections and are thus considered to be a more accurate forecast.

Consequently, similar to Dominion, the avoided energy costs increase from the current rate of 46 $/MWh in 2024 to 76 $/MWh by 2038. After 2038, energy costs are assumed to remain stable until 2050 (in real $2023). Note that there is a slight discrepancy between the energy costs for Dominion and APCo. This is because Locational Marginal Pricing (LMP) data for the American Electric Power (AEP) zone in PJM was used as the basis of the analysis.[15]

Avoided Generation Capacity Costs: In line with increasing Regional Transmission Organization (RTO) Capacity Prices outlined in APCo's IRP and their Required Reserve Margin forecasts, the generation capacity costs will increase from the current rate of 60 $/kW-year in 2024 to 116 $/kW-year by 2041.[14] After 2041, the generation capacity costs are expected to remain stable until 2050 (in real $2023).

3.2.2 Transmission and Distribution (T&D) Benefits

The T&D benefits attributable to the build out of an additional 300 MW of shared solar are expected to increase from 3 ¢/kWh in 2024 to 5¢/kWh by 2050. Over the study period, the largest drivers of avoided T&D costs are avoided transmission charges (41%), followed by avoided transmission and distribution capacity costs (20% and 39%, respectively).

Avoided Transmission Costs: PJM charges APCo a Network Service Peak Load (NSPL) fee for its contribution to the zonal peak.[10] Given the expected increase in transmission build-out in PJM, the transmission charges are projected to increase at a relatively constant rate, from the current rate of 38 $/kW-year in 2024 to 127 $/kW-year by 2050. Although transmission charges are projected to rise three-fold, the effective contribution of solar power to the system reliability reduces as the peak is expected to shift throughout the day, leading to lower avoided transmission costs.

Avoided Transmission and Distribution Capacity Costs: Transmission and distribution capacity costs are assumed to remain stable throughout the study period. Since no APCo values for avoided T&D capacity costs were available, Dominion's DSM values, as testimony, were used as a proxy.[11] The transmission and distribution capacity value is expected to remain constant at 62 $/kW-year throughout the study period.

3.2.3 Renewable Portfolio Standard (RPS) Benefits

For every percentage of the RPS requirement that APCo does not meet, the steadily increasing Deficiency Payment must be paid.[12] The avoided RPS costs are projected to increase relatively constantly, from the current rate of 1 ¢/kWh in 2024 to 6 ¢/kWh in 2050.

3.2.4 Present Value of Shared Solar Expansion

To assess the overall value of the shared solar facilities to Appalachian Power Company (APCo), a roll out schedule for achieving 300 MW between 2024 and 2036 was assumed. The above value streams were assessed for each kWh of solar produced, and APCo's weighted average cost of capital (7.4% WACC) was applied to discount future benefits to present values. This results in $18 million of avoided cost value for APCo and its ratepayers over the 2024-2026 period, and about $563 million of total value over the 2024 to 2050 period (see Table 3 in Appendix A for details).

If APCo adopted a compensation structure like Dominion's current Shared Solar Program compensation structure, subscribed customers receive a gross bill credit that is equivalent to the retail rate of electricity, for their customer class. Residential customers would receive 13 ¢/kWh for their portion of the shared solar facility's production. However, APCo would apply fixed charges, such as the basic customer charge and the shared solar administration charge on the monthly bill, as well as volumetric charges (assumed 5.5 ¢/kWh) for the customer's portion of the shared solar facility output. When the net bill credit offered to subscribers is deducted from the total avoided cost value for APCo, it results in $9 million in net benefits accruing to APCo between 2024 and 2026, and over $260 million of net utility benefits in the 2024 to 2050 period.

This study found that APCo could reduce the volumetric charges from the minimum bill for Shared Solar Program subscribers by up to 80% and still yield a positive net benefit for the utility. This reduction in the minimum bill would increase customer compensation by 60%, and return a net benefit to the utility of $2 million over the 2024 to 2026 period, and $22 Million from 2024 to 2050. This more equitable distribution of shared solar benefits would increase the program's attractiveness to APCo customers, which in turn would incentivize developers to build more shared solar facilities and ultimately create benefits for all ratepayers within APCo's territory.

4. Appendix A: Methodology and Assumptions

4.1 Determining Avoided Cost Components

Avoided Cost Component	Rationale	Value of Solar Methodology for Virginia Electric and Power Company	Value of Solar Methodology for Appalachian Power Company
Avoided Energy Costs	Electricity generated by shared solar resources would reduce the amount that would otherwise be generated and procured through the PJM wholesale energy market, resulting in reduced wholesale energy costs.	**Approach:** Historical LMP data for the Dominion Zone forms the cost basis.[15] Projected costs throughout the study period rely on Dominion's 2023 IRP annual on- and off-peak price forecast until 2038.[8] Due to an expected energy shortage in Dominion, energy price forecasts in the base case of the IRP are likely conservative, potentially underestimating energy costs. Therefore, high-case energy cost forecasts are applied.	**Approach:** Historical LMP data for the AEP Zone serves as the basis for avoided energy costs.[15] Although APCo established a 2022 IRP price forecast, it notably falls below recent LMP values in the PJM market.[14, 15] Upon comparing energy prices of APCo and Dominion in PJM, a close match was observed with Dominion's IRP. Therefore, high-case on- and off-peak Dominion energy price forecasts as a proxy for APCo.[8]
Avoided Generation Capacity Costs	The electricity generated by a shared solar resource reduces the generation capacity cost that would otherwise be procured through the PJM Base Residual Auction (BRA) wholesale capacity market.	**Approach:** With an anticipated capacity shortage in the Dominion region, the wholesale capacity costs are expected to align with the cost of a marginal unit.[8] Therefore, PJM's forecasted Net Cost of New Entry is leveraged to determine the avoided capacity costs.[9] After 2038, it is assumed that the net cost of new entry will remain stable without increase. To convert values from $/kW-year to $/kWh, costs are distributed across 24-hour summer and winter periods. Solar PV production normalization is used as a proxy to estimate peak charge timings. A weighted average, factoring Dominion's classification of winter	**Approach:** Avoided generation capacity costs were derived using APCo's 2022 IRP Annual RTO Capacity Price and Required Reserve Margin forecasts until 2041; both held constant thereafter.[14] Unlike the Dominion approach, Net Cone forecasts were not considered due to the absence of a significant capacity shortfall, as indicated in the IRP. The same approach used for Dominion was applied to convert from $/kW-year to $/kWh, but using APCo's classification of winter and summer days.

Avoided Cost Component	Rationale	Value of Solar Methodology for Virginia Electric and Power Company	Value of Solar Methodology for Appalachian Power Company
		and summer days in the year, is then calculated to derive a single $/kWh value.	
Avoided Ancillary Costs	The electricity generated by a shared solar resource can reduces the utility load, resulting in lower ancillary service charges for the utility and an in-state avoided cost.	**Approach:** Avoided ancillary costs were determined using historical ancillary service prices in the Dominion Zone, from the PJM market database.[16, 17] The ancillary price forecast reflects a correlation between ancillary costs and energy prices, meaning ancillary costs rise proportionately with energy cost increases.	**Approach:** The same approach used for Dominion was applied, but with the use of historical ancillary service prices in the AEP Zone from the PJM market database.[16, 17]
Avoided Line Losses	The electricity generated by shared solar resources reduces the energy that would otherwise be distributed through the transmission and distribution network.	**Approach:** Avoided line losses were determined using historical transmission line loss prices in the Dominion Zone from the PJM market database.[15] Throughout the study period, avoided ancillary costs are projected using avoided energy prices, generation capacity, and wholesale market price suppression as scaling factors. Distribution line losses were excluded as shared solar production still flows through the distribution network, resulting in no avoided distribution line loss costs.	**Approach:** The same approach used for Dominion was applied, but with the use of historical transmission line loss prices in the AEP Zone from the PJM market database.[15]
Avoided Risk Premiums	Retail electricity prices typically exceed the sum of wholesale energy, capacity, and ancillary service prices, often due to market risks. The decrease in wholesale energy and capacity obligations resulting from shared solar resources can help lower a	**Approach:** After reviewing existing Value of Solar studies, an appropriate risk premium of 8% was determined for this study, falling within the range considered suitable by Synapse, which spans 5 to 10%.[4] This risk premium was then applied by multiplying it with the avoided energy and generation capacity costs.	**Approach:** The same approach used for Dominion was applied.

Avoided Cost Component	Rationale	Value of Solar Methodology for Virginia Electric and Power Company	Value of Solar Methodology for Appalachian Power Company
	supplier's costs in managing these risks.		
Wholesale Market Price Suppression	The electricity exported by a shared solar resource reduces the overall energy and capacity procured through the wholesale market, resulting in lower market clearing prices. This price suppression, known as Demand Reduction Induced Price Effect (DRIPE), is ultimately passed on to all market participants.	**Approach:** This study factored in the DRIPE linked to reductions in both energy and capacity. The Energy DRIPE was determined by multiplying Dominion's Unhedged Load as a fraction of the PJM Wholesale Load for the Dominion Zone, considering Energy Price, Energy Elasticity, and the effective decay schedule.[4, 8] Meanwhile, the Capacity DRIPE was established using the Dominion Zonal Demand adjusted for reserves, the relevant price shift, and the decay schedule based on the useful life of shared solar.[4, 8]	**Approach:** The same approach used for Dominion was applied, but using APCo-specific data. The Energy DRIPE was determined by multiplying APCo's Unhedged Load as a fraction of the PJM Wholesale Load for the AEP Zone, considering Energy Price, Energy Elasticity, and the effective decay schedule.[4, 8] Meanwhile, the Capacity DRIPE was established using the AEP Zonal Demand adjusted for reserves, the relevant price shift, and the decay schedule based on the useful life of shared solar.[4, 8]
Avoided Transmission Charges	A reduction in annual coincident system peak load, attributed to shared solar production, should lower the allocation of Network Service Peak Load (NSPL) charges imposed. These charges represent the transmission costs that that PJM levies on the utility for its contribution to the zonal peak.	**Approach:** Avoided transmission charges were determined using the PJM Annual Network Integration Transmission Service Revenue Rate based on Dominion's contribution to the Dominion zonal peak. Historical trends from 2018 to 2023 for the Dominion Zone were used to develop a forecast for 2050.[18, 19, 20, 21, 22, 23] The same approach used for Avoided Generation Capacity Costs was applied to convert from $/kW-year to $/kWh.	**Approach:** The same approach used for Dominion was applied, except using the historical trends for the AEP Zone.[18, 19, 20, 21, 22, 23]
Avoided Transmission Capacity Costs	Shared solar resources reducing peak load can diminish the need for certain transmission projects, potentially deferring or avoiding the projects. The avoided capacity costs represent the	**Approach:** The avoided transmission capacity costs were established from a Direct Testimony on the approval for Dominion to implement demand-side management programs.[11] The values were inflated from $2019 to $2023. It is unclear from the Testimony if the	**Approach:** Given the absence of APCo-specific data, the Dominion system costs and approach were used as a proxy.[11]

Avoided Cost Component	Rationale	Value of Solar Methodology for Virginia Electric and Power Company	Value of Solar Methodology for Appalachian Power Company
	potential reductions in utility transmission investments resulting from changes in peak load on the utility systems.	avoided transmission capacity costs include transmission charges. The same approach used for Avoided Generation Capacity Costs was applied to convert from $/kW-year to $/kWh.	
Avoided Distribution Capacity Costs	Shared solar resources reducing peak load can diminish the need for certain distribution projects, potentially deferring or avoiding the projects. The avoided capacity costs represent the potential reductions in utility distribution investments resulting from changes in peak load on the utility systems.	**Approach:** Avoided distribution capacity costs were established from a Direct Testimony on the approval for Dominion to implement demand-side management programs.[11] The values were inflated from $2019 to $2023. The same approach used for Avoided Generation Capacity Costs was applied to convert from $/kW-year to $/kWh.	**Approach:** It was not possible to find APCo-specific data on avoided distribution capacity credits; therefore, the Dominion system costs and approach were used as a proxy.[11] However, distribution costs vary significantly by location; thus, the assumptions being made are very conservative.[24]
Avoided RPS Costs	RPS compliance avoided costs measure the costs attributable to reducing the load used to assess RPS obligations. Each additional unit of shared solar helps the utility in fulfilling its RPS compliance, consequently reducing the total Alternative Compliance Payment (ACP) that would otherwise be necessary if the electricity was not generated from a renewable source.	**Approach:** Dominion has an annual RPS obligation, mandating a specific percentage of its procured electricity to be from renewable sources.[12] This requirement increases annually, targeting 100% by 2045. Falling short leads to Dominion paying an increasing Deficiency Payment. Avoided RPS costs are calculated by multiplying Dominion's RPS requirement with the projected Deficiency Payment.	**Approach:** APCo has an annual RPS obligation, mandating a specific percentage of its procured electricity to be from renewable sources.[12] This requirement increases annually, targeting 100% by 2050. Falling short leads to APCo paying an increasing Deficiency Payment. Avoided RPS costs are calculated by multiplying APCo's RPS requirement with the projected Deficiency Payment.

4.2 Establishing the Effective Load-Carrying Capability (ELCC) for Solar

The Effective Load-Carrying Capability (ELCC) of a generating resource measures its capacity to produce energy during times when the electricity grid is likely to experience shortages. ELCC is usually expressed as a percentage of a resource's capacity. For instance, a 100 MW solar plant with an ELCC of 60% can provide 60 MW to meet reliability requirements. This refers to the requirement where at any given time, utilities must have sufficient resources available to meet customers' demand.

ELCC values were applied from 2022 PJM system forecasts,[25] and Figure 5 presents the projected ELCC values by year applied for this study, along with the projected overall annual incremental solar PV nameplate capacity in Vriginia.[26] It is assumed that the shared solar facilities will make up a portion of the projected solar capacity in each year, but that variability in shared solar additions in Virginia are relatively small compared to the overall projected solar PV additions across the PJM system. Thus, PJM's projected ELCC values are applied without adjustment in this study.

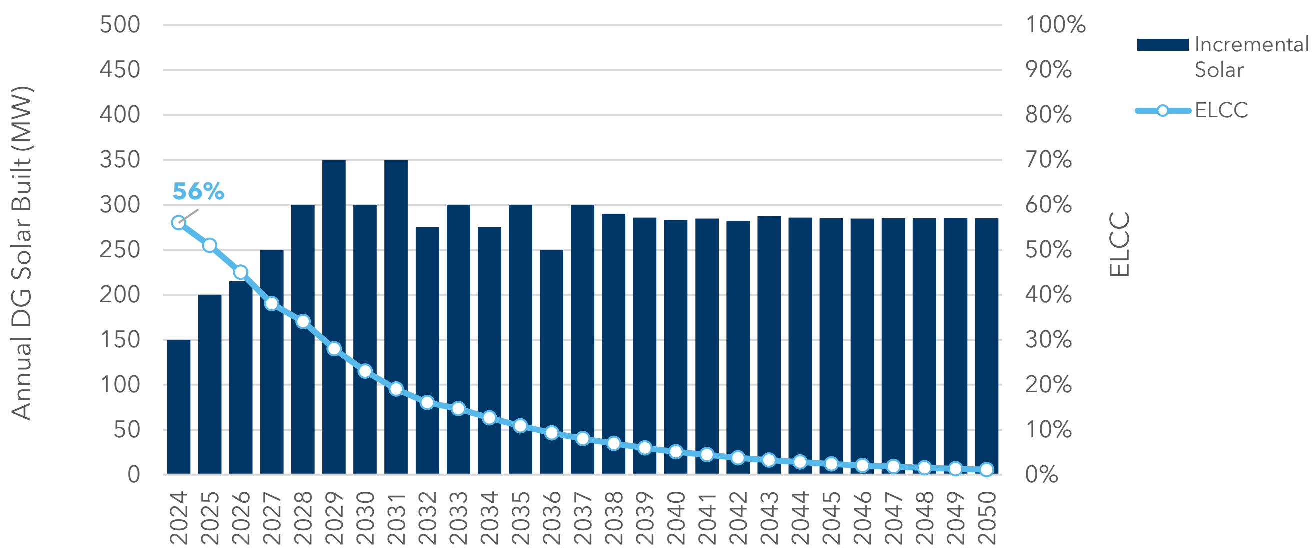


Figure 5: PJM Projected ELCC Derate Values (line) and Projected Solar Deployment in Virginia[26]

As solar is a variable resource, its ELCC will be lower than its nameplate capacity, and as more solar comes onto the system it will shift the timing of annual peak to a later hour, resulting in lower ELCC values for the next solar resources that come online. Therefore, as more solar that is added to the generation system, the smaller the portion of its nameplate capacity that can be expected to contribute to reliability requirements, resulting in a lower ELCC Rating. Overall, it was assumed that distributed solar installed in a given year will retain its ELCC value throughout its useful life, but that it will contribute to a lower ELCC value for the follow-years, as it will contribute to shifting the timing and magnitude of the utility's net peak demand.

To demonstrate this relationship between incremental capacity additions and the ELCC rating, as shown in Figure 4, the ELCC value for the first forecasted 150 MW of solar that comes online in 2024 is 56%, while the ELCC value for the next 200 MW of solar that comes online in 2025 is 51%. Thus, the solar that comes online in 2024 provides higher transmission and generation capacity value to the system than the next incremental solar added. The transmission and generation capacity value from solar that comes online today is based on the marginal value it provides to the system, and it does not degrade over the project's life. Solar projects do not degrade their own value, but they degrade the value of the next project.

Once the ELCC value is established for the installation year of a given system, it can be applied to calculate the following benefits:

- **Generation and Transmission Capacity Value:** The anticipated solar deployment for each year was multiplied by the corresponding ELCC value to derive the effective reliability contribution from the deployed solar.[25, 26] The weighted average of its effective capacity and transmission value was calculated to determine the reliability contribution of the shared solar portfolio.
- **Transmission Charges**: In determining the value of shared solar in offsetting transmission charges, the effective ELCC of the portfolio was calculated and multiplied by the applicable transmission charge for the relevant year. This results in a weighted ELCC value of 28%.

4.3 Net Bill Credit (Dominion)

Under the current Code § 56-594, a shared solar subscriber receives a bill credit for the proportional output of a shared solar facility attributable to that subscriber.[27] This credit is established by the State Corporate Commission and is updated annually. The Commission also established a minimum bill, which is intended to include the costs of all utility infrastructure and services used to provide electric service and administrative costs of the Shared Solar Program. The minimum bill currently includes the following:

- Fixed Costs: Customer Charge and Administrative Charge.
- Volumetric Costs: Statutorily Non-Bypassable Generation Charges, Base Distribution Charges, Distribution RAC Charges, Base Transmission Charges, and Transmission RAC Charges.

Though the minimum bill is a combination of fixed and volumetric charges, only the volumetric charges are considered in the net bill credit calculations in Figure 6. Apart from the volumetric

Net Bill Credit Calculation

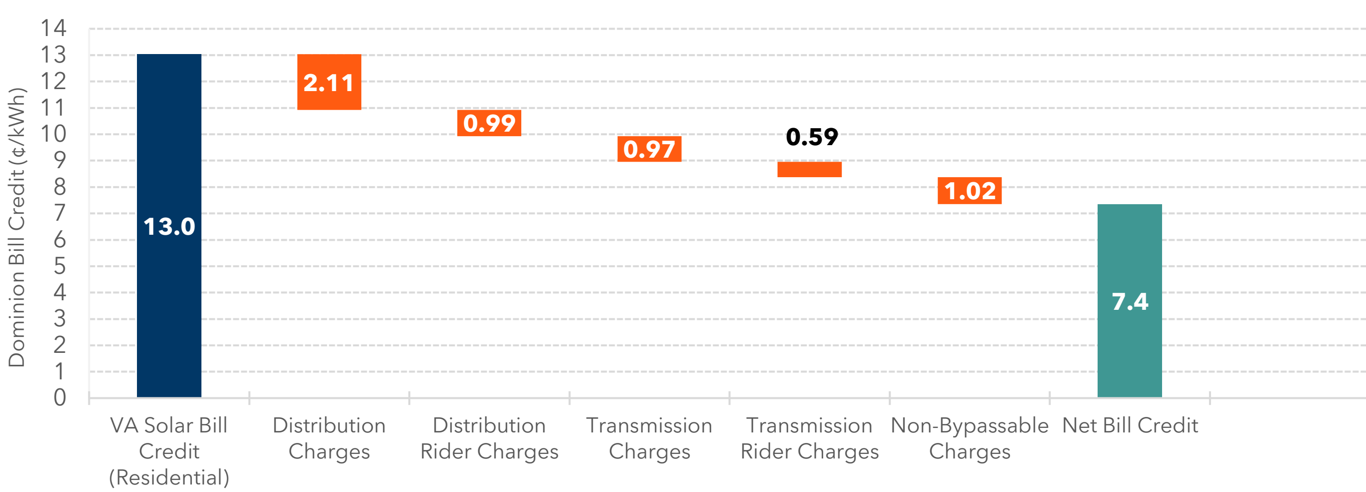


Figure 6: Shared Solar Net Bill Credit Calculation

component, subscribers are charged a basic customer charge of $6.58/month and a Shared Solar Program administrative charge which is estimated to be $10-20/month. These two fixed charges are not reflected in the minimum bill cost assumptions in Figure 6, , however they are included in cost assumptions relating to the overall net benefits of the program.

4.4 Aggregated Value of Solar Benefits

During the study period, the total value of solar benefits was calculated by multiplying the expected solar generation (assuming an annual 18% capacity factor) with the value of solar established by this study. The resulting value was then discounted by the respective utility's WACC.

The solar forecast for each utility was based on the proportion of shared solar proposed for each utility under the program and the projected solar adoption in Virginia. It was assumed that 85% of the solar forecasted in Virginia would be installed in Dominion Energy while the remaining 15% would be installed in Appalachian Power Company.

It was assumed that the total 2000 MW attributable to the expanded Shared Solar Program would be installed over the 2024 to 2035 period, and that annual installations would follow the same trend as is projected for total solar PV installs in Virginia over that period.[25] Table 1 below provides the estimated incremental and cumulative annual shared solar additions by utility.

Table 1: Anticipated Shared Solar by Year in Virginia (MW)

Year	Annual Estimated Shared Solar Forecast in VA	Cumulative Estimated Shared Solar Forecast in VA	Annual Estimated Shared Solar Forecast - Dominion Energy	Annual Estimated Shared Solar Forecast - ApCo
2024	109	109	93	16
2025	139	248	118	21
2026	159	408	135	24
2027	169	577	144	25
2028	189	766	161	28
2029	219	985	186	33
2030	239	1224	203	36
2031	159	1383	135	24
2032	159	1543	135	24
2033	169	1712	144	25
2034	159	1871	135	24
2035	129	2000	110	19

4.4.1 Present Value of Expanded Shared Solar Program Benefits

Table 2 and Table 3 below present the gross and net utility benefits (2023 $) for Dominion Energy and ApCo that result from the expanded Shared Solar Program. The results presented below are based on the assumption that all subscribers to the Shared Solar Program are residential customers who on average subscribe to 100% of their average monthly electric consumption. This equates to 1000 kWh of shared solar energy per month.

The cumulative capacity of shared solar in each utility was based on the prorated program size, with 85% of the 200 MW being installed on Dominion Energy's network and 15% on APCo's network.

- **Gross Benefits:** This is the total benefit that utilities could accrue from the shared solar program. The projected gross savings were determined by factoring in the value of solar, cumulative shared solar capacity, and the resulting annual solar facility output.
- **Gross Bill Credits:** The Virginia State Corporation Commission has determined that a residential customer will receive 13 cents of gross bill credits for every kWh of shared solar subscribed. The credit rate was assumed to increase based on the trends in the value of solar throughout the study period.
- **Fixed Charges:** Includes a fixed customer charge of $6.58 per month and a shared solar admin charge of $15 per month for each subscriber.
- **Volumetric Charges:** Includes the volumetric charges, such as Statutorily Non-Bypassable Generation Charges, Base Distribution Charges, Distribution RAC Charges, Base Transmission Charges, and Transmission RAC Charges, that would be applied to the portion of the shared solar subscription. The volumetric charges are assumed to increase based on the trends in PJM's transmission charges throughout the study period.
- **Net Credit Shared Solar**: To determine the net credits, the total utility charges were deducted from the gross bill credits.
- **Utility Net Benefits**: The net utility savings was determined by deducting the Net Bill Credits from the Gross Savings. This amount was then discounted by the applicable utility WACC: Dom (5.22%) and APCO (7.40%).

It was assumed that the utility's monthly fixed charges would remain constant over the study period. For APCo, we assume that the same bill credit structure is in place, as we see in DOM.

Table 2: Projected Annual Benefits from Expanded Shared Solar Program in Dominion Energy Territory

Year	Value of Solar ($/ kWh)	Gross Bill Credit ($/kWh)	Volumetric Charge ($/kWh)	Cumulative Shared Solar (MW)	Gross Benefit ($Million)	Assumed Number of Residential Subscribers	Gross Bill Credits ($Million)	Fixed Charges ($Million)	Volumetric Charges ($Million)	Total Utility Charge ($Million)	Net Credit Shared Solar ($Million)	Utility Net Benefits ($Million)	Utility Net Benefits (Ex. 80% Volumetric Charges ($Million)
2024	0.11	0.13	0.06	93	$16	12,193	$19	$3	$8	$11	$8	$9	**$2**
2025	0.12	0.14	0.06	211	$39	27,736	$46	$7	$19	$26	$19	$20	**$5**
2026	0.12	0.14	0.06	346	$67	45,514	$77	$12	$33	$45	$33	$34	**$8**
2027	0.12	0.14	0.06	490	$96	64,408	$111	$17	$48	$65	$46	$50	**$11**
2028	0.13	0.15	0.06	651	$129	85,536	$149	$22	$67	$89	$60	$69	**$15**
2029	0.13	0.15	0.07	837	$168	110,015	$194	$28	$89	$117	$76	$91	**$20**
2030	0.13	0.15	0.07	1041	$213	136,727	$246	$35	$114	$150	$96	$117	**$25**
2031	0.13	0.16	0.07	1176	$249	154,505	$288	$40	$134	$174	$114	$135	**$28**
2032	0.14	0.16	0.07	1311	$289	172,282	$333	$45	$154	$199	$134	$154	**$31**
2033	0.14	0.17	0.08	1455	$331	191,176	$383	$50	$177	$227	$156	$175	**$33**
2034	0.15	0.17	0.08	1590	$377	208,953	$435	$54	$200	$254	$181	$195	**$36**
2035	0.16	0.18	0.08	1700	$419	223,380	$484	$58	$220	$278	$206	$213	**$37**
2036	0.16	0.19	0.08	1700	$439	223,380	$507	$58	$227	$285	$223	$216	**$35**
2037	0.17	0.20	0.09	1700	$460	223,380	$531	$58	$233	$291	$240	$220	**$33**
2038	0.18	0.21	0.09	1700	$481	223,380	$556	$58	$240	$298	$258	$223	**$31**
2039	0.18	0.21	0.09	1700	$492	223,380	$569	$58	$246	$304	$264	$228	**$31**
2040	0.19	0.22	0.09	1700	$501	223,380	$579	$58	$253	$311	$268	$233	**$31**
2041	0.19	0.22	0.10	1700	$510	223,380	$589	$58	$260	$318	$272	$238	**$31**
2042	0.19	0.22	0.10	1700	$518	223,380	$598	$58	$266	$324	$274	$244	**$31**
2043	0.20	0.23	0.10	1700	$526	223,380	$608	$58	$273	$331	$277	$249	**$31**
2044	0.20	0.23	0.10	1700	$534	223,380	$617	$58	$279	$337	$280	$254	**$31**
2045	0.20	0.23	0.11	1700	$543	223,380	$627	$58	$286	$344	$283	$260	**$31**
2046	0.20	0.23	0.11	1700	$544	223,380	$629	$58	$293	$351	$278	$266	**$32**
2047	0.20	0.24	0.11	1700	$547	223,380	$632	$58	$299	$357	$275	$272	**$33**
2048	0.20	0.24	0.11	1700	$549	223,380	$635	$58	$306	$364	$271	$278	**$34**
2049	0.21	0.24	0.12	1700	$555	223,380	$641	$58	$313	$370	$270	$284	**$34**
2050	0.21	0.24	0.12	1700	$558	223,380	$644	$58	$319	$377	$267	$290	**$35**

Table 3: Projected Annual Benefits from Expanded Shared Solar Program in APCo Territory

Year	Value of Solar ($/ kWh)	Gross Bill Credit ($/kWh)	Volumetric Charge ($/kWh)	Cumulative Shared Solar (MW)	Gross Benefit ($Million)	Assumed Number of Residential Subscribers	Gross Bill Credits ($Million)	Fixed Charges ($Million)	Volumetric Charges ($Million)	Total Utility Charge ($Million)	Net Credit Shared Solar ($Million)	Utility Net Benefits ($Million)	Utility Net Benefits (Ex. 80% Volumetric Charges ($Million)
2024	0.11	0.13	0.06	16	$3	2,152	$3	$1	$1	$2	$1	$1	**$0**
2025	0.12	0.14	0.06	37	$7	4,895	$8	$1	$3	$5	$3	$3	**$1**
2026	0.12	0.14	0.06	61	$12	8,032	$14	$2	$6	$8	$6	$6	**$1**
2027	0.12	0.14	0.06	87	$17	11,366	$20	$3	$9	$11	$8	$8	**$1**
2028	0.13	0.15	0.06	115	$22	15,095	$27	$4	$12	$16	$11	$11	**$2**
2029	0.13	0.15	0.07	148	$29	19,414	$35	$5	$16	$21	$14	$15	**$2**
2030	0.13	0.15	0.07	184	$37	24,128	$44	$6	$20	$26	$18	$19	**$3**
2031	0.13	0.16	0.07	208	$43	27,266	$52	$7	$24	$31	$21	$22	**$3**
2032	0.14	0.16	0.07	231	$50	30,403	$60	$8	$27	$35	$25	$25	**$3**
2033	0.14	0.17	0.08	257	$58	33,737	$69	$9	$31	$40	$29	$28	**$3**
2034	0.15	0.17	0.08	281	$66	36,874	$79	$10	$35	$45	$34	$32	**$3**
2035	0.16	0.18	0.08	300	$73	39,420	$88	$10	$39	$49	$39	$34	**$3**
2036	0.16	0.19	0.08	300	$77	39,420	$92	$10	$40	$50	$42	$35	**$3**
2037	0.17	0.20	0.09	300	$81	39,420	$97	$10	$41	$51	$45	$35	**$2**
2038	0.18	0.21	0.09	300	$84	39,420	$101	$10	$42	$53	$49	$36	**$2**
2039	0.18	0.21	0.09	300	$86	39,420	$103	$10	$43	$54	$49	$37	**$2**
2040	0.19	0.22	0.09	300	$88	39,420	$105	$10	$45	$55	$50	$37	**$2**
2041	0.19	0.22	0.10	300	$89	39,420	$107	$10	$46	$56	$51	$38	**$2**
2042	0.19	0.22	0.10	300	$91	39,420	$109	$10	$47	$57	$52	$39	**$1**
2043	0.20	0.23	0.10	300	$93	39,420	$111	$10	$48	$58	$53	$40	**$1**
2044	0.20	0.23	0.10	300	$94	39,420	$113	$10	$49	$60	$54	$41	**$1**
2045	0.20	0.23	0.11	300	$96	39,420	$115	$10	$50	$61	$55	$42	**$1**
2046	0.20	0.23	0.11	300	$97	39,420	$116	$10	$52	$62	$54	$43	**$1**
2047	0.20	0.24	0.11	300	$97	39,420	$117	$10	$53	$63	$54	$44	**$1**
2048	0.20	0.24	0.11	300	$98	39,420	$118	$10	$54	$64	$53	$45	**$1**
2049	0.21	0.24	0.12	300	$99	39,420	$118	$10	$55	$65	$53	$46	**$2**
2050	0.21	0.24	0.12	300	$99	39,420	$119	$10	$56	$67	$53	$47	**$2**

5. Appendix B: Value Stack Components of Shared Solar

5.1 Value of Shared Solar in Dominion

Table 4: Value stack Components of Shared Solar in Dominion's Territory (¢/kWh)

Components	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Generation Benefits											
Avoided Energy Costs	4.85	5.19	5.38	5.30	5.26	5.13	5.14	6.39	7.59	7.59	7.59
Avoided Generation Capacity Costs	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78
Avoided Ancillary Costs	0.12	0.13	0.13	0.13	0.13	0.13	0.13	0.16	0.18	0.18	0.18
Avoided Line Losses	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04
Avoided Risk Premiums	0.53	0.56	0.57	0.57	0.56	0.55	0.55	0.65	0.75	0.75	0.75
Wholesale Market Price Suppression	0.11	0.12	0.15	0.17	0.20	0.24	0.30	0.36	0.56	0.59	0.65
Transmission and Distribution (T&D) Benefits											
Avoided Transmission Charges	0.96	1.00	1.05	1.09	1.13	1.17	1.21	1.39	1.69	1.79	2.00
Avoided Transmission Capacity Costs	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61
Avoided Distribution Capacity Costs	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19
Renewable Portfolio Standard (RPS) Benefits											
Avoided RPS Costs	1.07	1.22	1.37	1.53	1.69	1.85	2.02	3.05	4.29	5.71	6.01
Total Avoided Costs	**11.25**	**11.84**	**12.27**	**12.41**	**12.58**	**12.69**	**12.96**	**15.62**	**18.69**	**20.25**	**20.80**

5.2 Value of Shared Solar in Appalachian Company

Table 5: Value stack Components of Shared Solar in APCo's Territory (¢/kWh)

Components	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Generation Benefits											
Avoided Energy Costs	4.76	5.09	5.29	5.24	5.22	5.11	5.14	6.41	7.67	7.67	7.67
Avoided Generation Capacity Costs	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
Avoided Ancillary Costs	0.12	0.13	0.14	0.13	0.13	0.13	0.13	0.16	0.20	0.20	0.20
Avoided Line Losses	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03
Avoided Risk Premiums	0.46	0.49	0.50	0.50	0.50	0.49	0.49	0.59	0.69	0.69	0.69
Wholesale Market Price Suppression	0.06	0.09	0.11	0.16	0.13	0.13	0.12	0.07	0.10	0.10	0.10
Transmission and Distribution (T&D) Benefits											
Avoided Transmission Charges	0.85	0.94	1.02	1.08	1.14	1.21	1.29	1.66	2.04	2.42	2.80
Avoided Transmission Capacity Costs	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Avoided Distribution Capacity Costs	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66
Renewable Portfolio Standard (RPS) Benefits											
Avoided RPS Costs	1.07	1.22	1.37	1.53	1.69	1.85	2.02	3.05	4.29	5.71	6.01
Total Avoided Costs	**10.84**	**11.46**	**11.94**	**12.15**	**12.31**	**12.44**	**12.69**	**15.47**	**18.51**	**20.31**	**20.98**

6. Appendix C: Value of Solar Studies

6.1 Jurisdiction Scan of Value of Solar Assessments

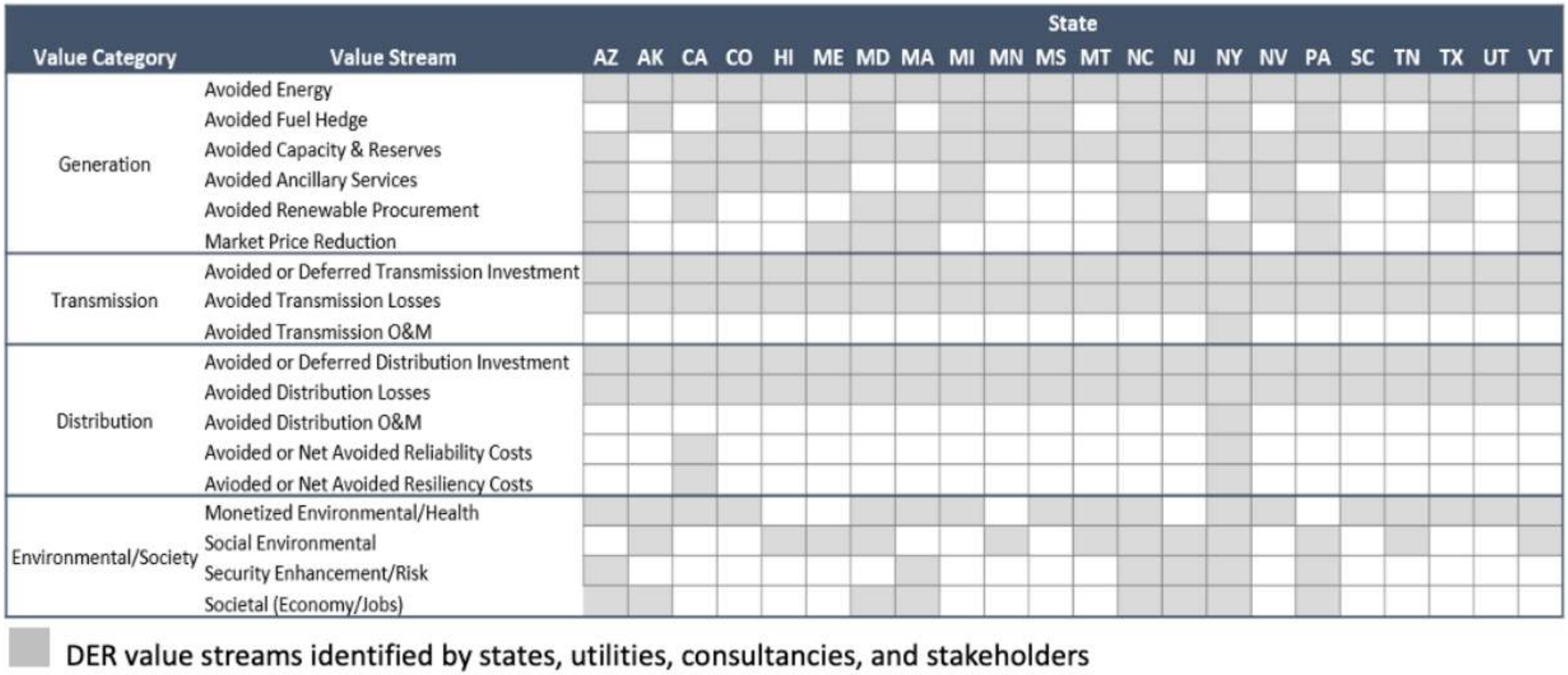


Figure 7: Value Streams for Distributed Energy Resources by Jurisdiction[29]

7. Appendix D: References

[1] Virginia's Legislative Information System. 2020. _2020 Session: SB 629 Shared Solar Programs; Electric Utility Regulation, etc._

[2] Reproduced from Virginia Department of Energy. _Shared Solar and Community Solar_. Accessed November 6, 2023.

[3] Dominion Energy. _Shared Solar Program_. Accessed November 6, 2023.

[4] Synapse Energy Economics, Inc. 2021. _Avoided Energy Supply Components in New England: 2021 Report._

[5] Clean Power Research. January 30, 2014. _Minnesota Value of Solar: Methodology._

[6] National Renewable Energy Laboratory. March 2014. _Value of Solar: Program Design and Implementation Considerations._

[7] Clean Power Research. January 7, 2014. _Value of Solar in Utah: Prepared for Utah Clean Energy._

[8] Dominion Energy. May 2023. _Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan Before the Virginia State Corporation Commission and North Carolina Utilities Commission_. Case No. PUR-2023-00066. Docket No. E-100, Sub 192.

[9] PJM. April 2022. _PJM CONE 2026/2027 Report_.

[10] PJM. _THEO, PLC & NSPL Methodology Inventory_. Accessed November 2, 2023.

[11] Commonwealth of Virginia State Corporation Commission. February 6, 2019. _Application of Virginia Electric and Power Company 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.

[12] PJM Environmental Information Services. _Program Information: Virginia._ Accessed November 3, 2023.

[13] Commonwealth of Virginia State Corporation Commission. October 12, 2023. _Commonwealth of Virginia, ex rel. State Corporation Commission Ex Parte: In the matter of establishing regulations for a shared solar program pursuant to § 56-594.3 of the Code of Virginia_. Case No. PUR-2020-00125

[14] Appalachian Power. May 2022. _Integrated Resource Planning Report to the Commonwealth of Virginia State Corporation Commission_. Case No. PUR-2022-00051.

[15] PJM. _Settlements Verified Hourly LMPs_. Accessed November 3, 2023.

[16] Monitoring Analytics. 2022. _2022 State of the Market Report for PJM_.

[17] PJM. _Real-Time Ancillary Service Market Results_. Accessed November 3, 2023.

[18] PJM. 2018. _Annual Transmission Revenue Requirements and Rates_.

[19] PJM. 2019. _Annual Transmission Revenue Requirements and Rates_.

[20] PJM. 2020. _Annual Transmission Revenue Requirements and Rates_.

[21] PJM. 2021. _Annual Transmission Revenue Requirements and Rates_.

[22] PJM. 2022. *Annual Transmission Revenue Requirements and Rates*.

[23] PJM. 2022. *Annual Transmission Revenue Requirements (ATTR) and Network Integration Transmission Service (NITS) Rates*.

[24] Guidehouse Inc. July 31, 2020. *New Hampshire Locational Value of Distributed Generation Study – Final Report: Prepared for New Hampshire Public Utilities Commission*.

[25] PJM. January 2023. *December 2022 Effective Load Carrying Capability (ELCC) Report*.

[26] S&P Global. November 2022. *PJM Solar and Battery Forecast 2022: Phase II Forecasts*.

[27] Commonwealth of Virginia State Corporation Commission. July 7, 2022. *In the Matter of Establishing Regulations for a Shared Solar Program Pursuant to § 56-594.3 of the Code of Virginia*. Case No. PUR-2020-00125.

[28] U.S. Energy Information Administration. October 2, 2022. *Electricity – Retail sales of electricity to ultimate customers*.

[29] Lawrence Berkely National Laboratory. February 2021. *Locational Value of Distributed Energy Resources.*

“NO DISCLAIMERS” POLICY

This report was prepared by Dunsky Energy + Climate Advisors, an independent firm focused on the clean energy transition and committed to quality, integrity and unbiased analysis and counsel. Our findings and recommendations are based on the best information available at the time the work was conducted as well as our experts' professional judgment.

Dunsky is proud to stand by our work.