Here Comes the Sun: Determining the Future Benefit of Net-Metered Solar

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ABSTRACT

The controversy surrounding current Net Energy Metering (NEM) tariffs is a hot topic in the energy sector, particularly as distributed solar PV plays an increasingly significant role in the clean energy transition. Some argue that NEM places financial strain on utilities, leads to cross-subsidization, and increases grid maintenance costs, which raises fairness concerns for non-solar ratepayers. In response, utilities and governments have been adjusting NEM tariffs and reducing the compensation for distributed solar. This paper dives into the heart of the debate by presenting a comprehensive Value of Solar (VoS) analysis and advocating for fair compensation policies for behind-the-meter (BTM) solar. The aim is to ensure that customer-sited solar is fairly compensated for its full benefits to the electric system, thereby supporting sustainable growth for BTM solar and its contribution to net-zero targets.

This paper outlines the methodology of a comprehensive Value of Solar analysis - a data-driven framework for valuing BTM solar that promotes transparency, consistency and supports better policy and rate design. The paper outlines the rationale & approach behind the framework and demonstrated how a VoS approach can help utilities, regulators, and industry stakeholders establish fair compensation policies for BTM Solar. The practical application of the VoS approach in two case studies, in New Hampshire and Virginia, has shown its potential to resolve contentions around NEM policies and successfully balance the competing interests of BTM solar owners, utilities, policymakers and all ratepayers. This research, therefore, has the potential to significantly impact the future of NEM policies and the compensation for distributed solar.

Introduction

Decarbonizing and expanding electricity production to support net-zero will require deploying new electricity generation and infrastructure at an unprecedented speed and scale. While estimates vary, it is widely recognized that a pathway to net zero will approximately double electricity demand needs by 2050 (CER 2023; McKinsey 2024; Princeton 2021). Distributed Solar Photovoltaic (DPV) systems are crucial in the global shift towards achieving net-zero greenhouse gas emissions targets. These systems, typically installed on rooftops or in small-scale solar farms, offer several advantages that align with the broader goals of decarbonizing our energy systems:

- **Decentralization of Generation**: Distributed solar PV systems play a crucial role in decentralizing energy production. By offsetting load at the customer site, these resources alleviate the constraints of the centralized generation systems, which frequently rely on fossil fuels. This shift towards decentralization not only reduces carbon emissions but also enhances energy security by diversifying our energy sources.

- **Scalability and Flexibility**: Distributed solar PV systems offer scalability and can be tailored to the specific energy needs of individual homes, businesses, or communities. This flexibility allows for a more targeted approach to reducing carbon footprints, as installations can be optimized on end users' available space and energy requirements.
- **Socio-economic Benefits**: Distributed solar PV projects create local jobs and stimulate economic growth. Additionally, they empower consumers to reduce their electricity bills by generating their own power.

Net Energy Metering has been a cornerstone policy in promoting the adoption of rooftop solar panels by allowing solar customers to sell excess electricity generated back to the grid at retail rates. However, there are several reasons why NEM might be considered for replacement or significant modification:

- **Cost Shift to Non-Solar Customers**: NEM enables solar panel owners to offset their electricity bills with the electricity they generate, paying only for their net electricity use. Utility rates, however, encompass more than just the cost of electricity; they also include expenses related to grid maintenance, energy efficiency programs, and other fixed costs. Consequently, solar customers contribute less to these shared utilities. This can lead to a cost shift, where non-solar customers — often including lower-income households — bear a disproportionate share of these fixed costs.
- **Grid Stability and Management Challenges**: As rooftop solar penetration increases, grid management becomes more complex. Unfortunately, NEM does not incentivize solar producers to align their energy production with the grid's demand patterns. This misalignment can lead to challenges such as the infamous "duck curve." During the day, solar energy oversupply occurs, followed by a rapid increase in demand after sunset. This situation poses a balancing act for grid operators as they navigate decreasing solar supply alongside the rising evening demand loads. (Bowers, Fasching & Antonio 2023).
- **Evolution of Energy Markets and Technologies**: The original Net Energy Metering policies were created to support the solar industry during its early stages when solar adoption was low, and panels were expensive. However, as solar panel costs have dropped, adoption has increased, increasing the cost shift. This has resulted in a growing consensus that NEM policies may not accurately reflect the value that solar brings to the grid.

For these reasons, stakeholders and policymakers are considering alternatives to NEM, such as net billing or feed-in tariffs, that aim to distribute costs and benefits more equitably while incentivizing energy storage and supporting renewable energy growth. Many states have switched or are switching away from NEM to address cost-shifting. These include, but are not limited to:

- Austin Energy has replaced its Net Energy Metering program with a Value of Solar tariff (Austin Energy 2017).
- Hawaii has transitioned from NEM rates and introduced new solar programs. Customers have the option to choose between a non-export program and a new “Smart Renewable Energy Export program” where the latter compensates renewable energy based on the time of use rates outlined for exports (Hawaiian Electric 2024).

- New York has moved away from NEM and is replacing it with a "Value Stack" concept as part of Reforming the Energy Vision (REV). The Value Stack, known as Valuing Distributed Energy Resources (VDER) in New York, is a new approach to valuing distributed energy resources (State of New York Public Service Commission 2017).

The paper aims to address the shortcomings of Net Energy Metering policies and their impact on the solar energy market by introducing the Value of Solar framework. It reviews the development of NEM policies, evaluates the costs and benefits of distributed solar PV, and proposes the VoS framework as a solution to NEM. The paper outlines the VoS analysis applied through the New Hampshire and Virginia case studies (Dunsky 2022, 2023). The VoS framework effectively addresses NEM policy debates by providing a quantifiable analysis of distributed solar's benefits, guiding equitable cost distribution, and promoting expanding programs targeted at distributed solar. It highlights the broader implications for utilities, regulators, and stakeholders in adopting VoS for fair solar compensation, emphasizing the importance of data-driven approaches in energy policy formulation. In conclusion, the paper underlines the role of the VoS analysis in fostering the sustainable growth of distributed solar and advancing clean energy transitions.

The Value of Solar Framework

The Value of the Solar framework can be summarized in three key steps:

1. **Establish Technology-Neutral Value Stack Components:** A comprehensive framework was developed to identify and quantify the grid benefits attributed to distributed generation resources.
2. **Develop a Representative Solar Output Profile**: Illustrative net-metered PV production curves are required to assess the value of solar energy. In the New Hampshire Study, the normalized solar production profile published by ISO-NE informed the production profile shape (ISO-NE 2024). In the Virginia study, we leveraged the National Renewable Energy Laboratory (NREL) PV Watts® Calculator to generate an hourly solar PV production profile for a 1 kW single-axis tracking system (NREL 2024).
3. **Establish the Value of Solar for each Component:** The solar output profile is mapped against the technology-neutral avoided costs to calculate the avoided cost value of Distributed Energy Resources (DERs) by system type.

Value Stack Components

Energy

Rationale: This avoided cost criterion represents the cost of energy that would otherwise be generated by dispatching a resource or procured through the wholesale energy market.

Approach: In the New Hampshire study, the avoided energy costs were developed by mapping the hourly solar production profile against the hourly forecasted avoided energy costs developed within the Avoided Energy Supply Costs in New England 2021 ("AESC 2021") Study (Synapse 2021). In the Virginia Study, the hourly solar production profile was mapped against the historical locational marginal prices for Dominion and American Electric Power (AEP) zones, which were used as the basis for the avoided energy costs (PJM 2024a). The avoided energy costs were escalated based on the respective utility Integrated Resource Plans (IRPs) until the end of the study period (Dominion Energy 2023; APCo 2022).

Capacity

Rationale: Solar generation coincident with system peak can offset a portion of generating capacity by the marginal resource procured through the forward market, resulting in avoided capacity costs.

Approach: Two approaches can be considered for developing the avoided capacity costs for solar.

Capacity Price Forecast: In Dunsky's VoS study for New Hampshire, the avoided cost of capacity refers to the cost of generating capacity that would otherwise be obtained through the ISO-NE forward capacity market (FCM). Individual behind-the-meter distributed resources that do not participate in the FCM through DER aggregation indirectly benefit the electricity system by reducing ISO-NE demand - particularly when distributed generation coincides with the system's peak demand.[1] This reduction decreases the generation capacity that needs to be obtained through the market. The AESC 2021 was used to develop a forecast for cleared capacity prices from 2021 to 2035. This forecast considered the impact of reserve margins and was adjusted using the most recent difference between the FCM Regional Net Clearing Price and the Effective Charge-Rate short-term forecast. These costs were spread out over ISO-NE's annual system peak hours to generate hourly avoided cost values.

Net Cost of New Entry: Dunsky's VoS study for the state of Virginia noted that wholesale capacity costs are expected to align with the cost of a marginal unit—a combined-cycle gas turbine (CCGT). Thus, it was determined that a Net Cost of New Entry (Net CONE) approach would be appropriate to calculate the solar avoided cost of capacity. This method estimates the cost to construct and operate a new power generation unit minus the expected revenues from selling electricity in the market over a specified period. It measures the net cost a new entrant would incur when adding new capacity to the market. The Net CONE's capacity

[1] ISO-NE's Order No. 2222 Allows for the participation of DERs to be aggregated and participate in the FCM.

value is then de-rated by solar's capacity contribution to an energy system, measured by its Effective Load Carrying Capability (ELCC) (PJM 2023).

Ancillary Services

Rationale: The electricity generated by a customer-sited solar resource reduces the utility load, resulting in lower ancillary obligations.

Approach: Avoided ancillary service and wholesale load obligation costs can be determined using historical prices in each market. For the historical data, a percentage of these costs relative to wholesale energy prices is calculated for each respective hour. This average historical relationship is then used to forecast the avoided ancillary and load obligation costs.

In the New Hampshire Study, the hourly ancillary prices were obtained from the ISO-NE Market Reports, while for the Virginia Study, they were obtained from the PJM Market Reports. The hourly ancillary service costs were mapped against the hourly solar production profile to obtain the avoided ancillary service costs (PJM 2024b).

RPS Compliance:

Rationale: Renewable Portfolio Standard (RPS) compliance avoided costs measure the costs attributable to reducing the load used to assess RPS obligations. Each additional solar unit helps the utility fulfill its RPS compliance, reducing the total Alternative Compliance Payment (ACP) that would otherwise be incurred if the electricity was not generated from a renewable source.

Approach: The avoided costs for New Hampshire were developed using the RPS compliance costs from the AESC 2021, while the Virginia study used the Alternative Compliance Payment (ACP) as a proxy for the avoided RPS Compliance Costs. The avoided RPS compliance cost was based on the proportion of solar self-consumed behind the customer's meter.

Wholesale Market Suppression:

Rationale: The electricity exported by a solar resource reduces the overall energy and capacity procured through the wholesale market, resulting in lower market clearing prices. This price suppression, the Demand Reduction Induced Price Effect (DRIPE), is passed on to all market participants.

Approach: Studies should consider factoring DRIPE linked to reductions in both energy and capacity. Considering energy price, energy elasticity, and the effective decay schedule, the energy DRIPE can be determined by multiplying the unhedged load by a fraction of the wholesale load for a given market. The capacity DRIPE can be established using zonal/regional demand adjusted for reserves, relevant price shifts, and the decay schedule based on the useful life of solar.

Risk Premium

Rationale: 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 from solar resources can help lower a supplier's costs in managing these risks.

Approach: After reviewing the existing Value of Solar studies available, an appropriate risk premium of 8% was determined for this study. Falling within the range considered suitable by Synapse within the AESC 2021 study, which spans 5 to 10%. The risk premium was then multiplied by the avoided energy and generation capacity costs.

Transmission and Distribution Capacity

Rationale: A reduction in annual coincident system peak load, attributed to solar production, should lower the allocation of Network Service Peak Load (NSPL) or Peak Load Contribution (PLC) charges imposed to states and regions that are part of a greater market system (I.e., ISO-NE, PJM, etc.). These charges represent the transmission costs markets levy on the utility for its contribution to the zonal peak. A state or region that can reduce its peak contribution by deploying solar resources would reduce its proportional share of its peak contribution costs paid to the market. Like transmission capacity, solar generation coincident with system or regional distribution peaks can offset a portion of distribution capacity upgrades, resulting in avoided infrastructure costs.

Approach: If a market possesses forward-looking forecasts for PLC's, these should be used to model avoided transmission charges. Alternatively, utilizing historical trends can also be useful in developing a forecast for market transmission charges. The solar ELCC is applied to the transmission charges to determine the avoided transmission charges applicable to solar. Avoided distribution capacity costs can usually be established based on distribution investment deferral value analyses published by a utility or regional market. The avoided distribution capacity costs can be calculated by de-rating the distribution deferral value by the solar ELCC for that given year.

Transmission and Distribution Line Losses

Rationale: The electricity provided by behind-the-meter solar resources would reduce the marginal energy and capacity-related line losses (LL) within an electricity system. The transmission line losses apply to the entire solar production profile, while the distribution line losses will only apply to the portion of solar generation that is self-consumed and otherwise not exported to the distribution grid.

Approach: The avoided transmission line losses are calculated by taking the sum of solar avoided energy and capacity costs, multiplied by the average transmission line loss published by the market operator and a factor of 1.5 (to gross up to marginal line losses). Avoided distribution line losses are calculated by taking the sum of solar avoided energy and capacity costs, multiplied by the sum of the marginal distribution & substation line losses, multiplied by the portion of self-consumed BTM solar generation and multiplied by a factor of 1.5. The portion of self-consumed solar generation can be calculated by comparing the hourly load for an average solar-generating customer against the hourly generation output of an average solar system for a solar-generating customer. For any given hour where a residential customer's solar generation exceeds its hourly load, this excess energy is assumed to be exported to the grid (and thus not considered self-consumed).

Environmental Externalities

Rationale: The electricity generated from a DG resource may reduce marginal emissions from fossil fuel plants. A portion of the avoided costs of such reduced emissions are already included as environmental program compliance costs embedded in wholesale energy prices. This component evaluates the remaining non-embedded environmental externalities avoided costs resulting from DG resource electricity production.

Approach: This component was only calculated for the New Hampshire Study. The regional marginal emission rates for CO2 and NOx were based on the AESC 2021 study. Next, we established the net societal cost of carbon (SCC) and NOx by calculating the difference between the forecasted gross SCC and forecasted Regional Greenhouse Gas Initiative (RGGI) allowance prices. As RGGI allowance prices are already embedded in wholesale energy market prices, these are subtracted from the gross SCC values to establish a net SCC over the study period. We then multiplied the net SCC by the corresponding AESC 8760 hourly marginal emission rates (short ton per MWh) (2021 to 2035), as outlined in the AESC 2021 study workbooks, to determine the environmental externality avoided cost for CO2.

Study Limitations

- In this study, net-metered DERs are treated as price takers, where the magnitude of their adoption has little or no impact on wholesale market prices. The Demand Reduction Induced Price Effect (DRIPE) is intended to evaluate the price-depressive effects on energy and capacity; however, the potential price impacts of DERs on the value of other avoided cost components, such as Regional Network Service (RNS) and Local Network Service (LNS) transmission charges, Renewable Portfolio Standard (RPS), and environmental externalities, and others, have not been evaluated.
- The avoided cost values calculated in the VDER study are assumed to apply statewide. Actual avoided costs, however, are expected to vary within the state and may be subject to local grid and market conditions.
- Distribution capacity avoided costs only include avoided small-scale system-wide investments. Locational distribution capacity avoided costs are not considered in this study but may be significant; potential avoided costs are locational and time-varying.
- Some value stack cost criterias such as distribution system operating expenses and avoided cost values were determined based on historical trends by using past investments relative to historic load growth. That may not be the case if the utility system experiences unprecedented DER or higher load growth in future years.

Case Studies: New Hampshire and Virginia

New Hampshire Case Study

Background: In recent years, New Hampshire has seen an increase in DER penetration, and this trend is expected to continue. As more DER systems are connected to the grid, there will be significant impacts on both utilities and ratepayers. These impacts include changes in avoided costs and incurred costs. The New Hampshire Public Utilities Commission (PUC) approved the alternative NEM tariff (NEM 2.0) in June 2017. As part of this order, the PUC directed a study to evaluate the value of long-term avoided costs using marginal energy resource values and incorporating test criteria from standard energy efficiency benefit-cost analysis. This study is known as the VDER study, and its findings are expected to shape the development of future NEM tariffs before the PUC.

Analysis and Results: Avoided cost values are modeled for the residential sectors' south and west-facing solar PV arrays.

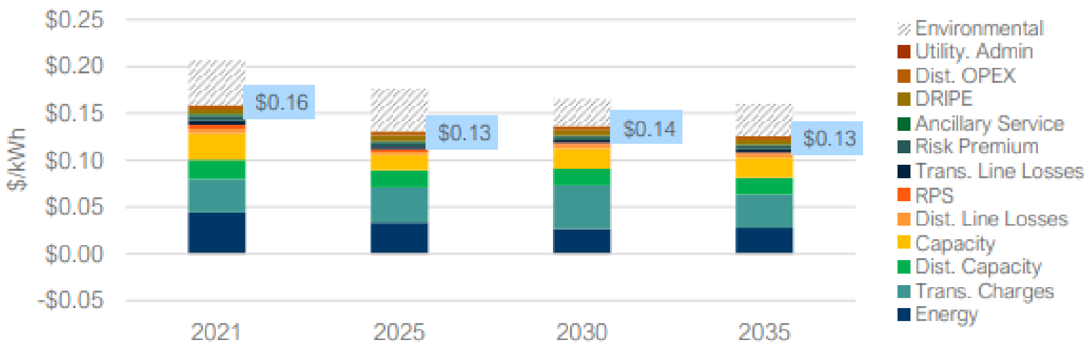

Figure 1: Average Annual Avoided Cost Value for Residential South-Facing Solar PV Array Installed in 2021 (2021$) *Source: Dunsky NH VDER Study (Dunsky 2022)*

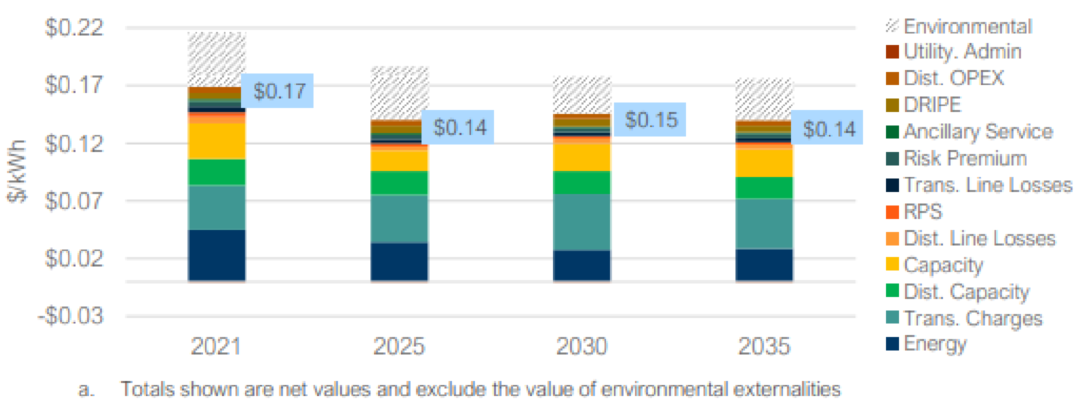

Figure 2: Average Annual Avoided Cost Value for Residential West-Facing Solar PV Array Installed in 2021 (2021$) *Source: Dunsky NH VDER Study (Dunsky 2022)*

As seen in Figure 1 and Figure 2, residential west-facing solar PV generates 5% to 10% more avoided cost value than residential south-facing solar PV throughout the study period. Although south-facing systems have greater overall production, west-facing systems generate energy later in the day, increasing the portion of generated energy that coincides with ISO-NE and New Hampshire-specific peak hours. This allows west-facing systems to generate greater value for those avoided cost categories driven by peak demand.

- Energy is the largest avoided cost criterion for both system types in 2021, representing 28% of the base avoided cost value stack for south-facing systems and 27% for west-facing systems. However, energy value is assumed to decline over time as lower marginal cost resources increasingly participate in the market.
- By 2035, transmission charges – which are assumed to increase over the course of the study period, based on trends seen in short-term forecasts – become the largest avoided cost criteria for both system types, representing 29% of the base value stack for south-facing systems and 31% for west-facing systems.
- Accounting for the non-embedded social costs of carbon and nitrogen oxide as environmental externalities increases the value of each system by \$0.03-\$0.05/kWh (representing 22%-36% of total value for a south-facing system and 22%-34% of total value for a west-facing system).

The previous graphs illustrate the year-over-year variations in avoided cost values. However, as seen in Figure 3, there is also considerable variation throughout a given day and year due to differences in DER production profiles, seasonal changes in demand, congestion, generating resources, and other factors that influence grid conditions.

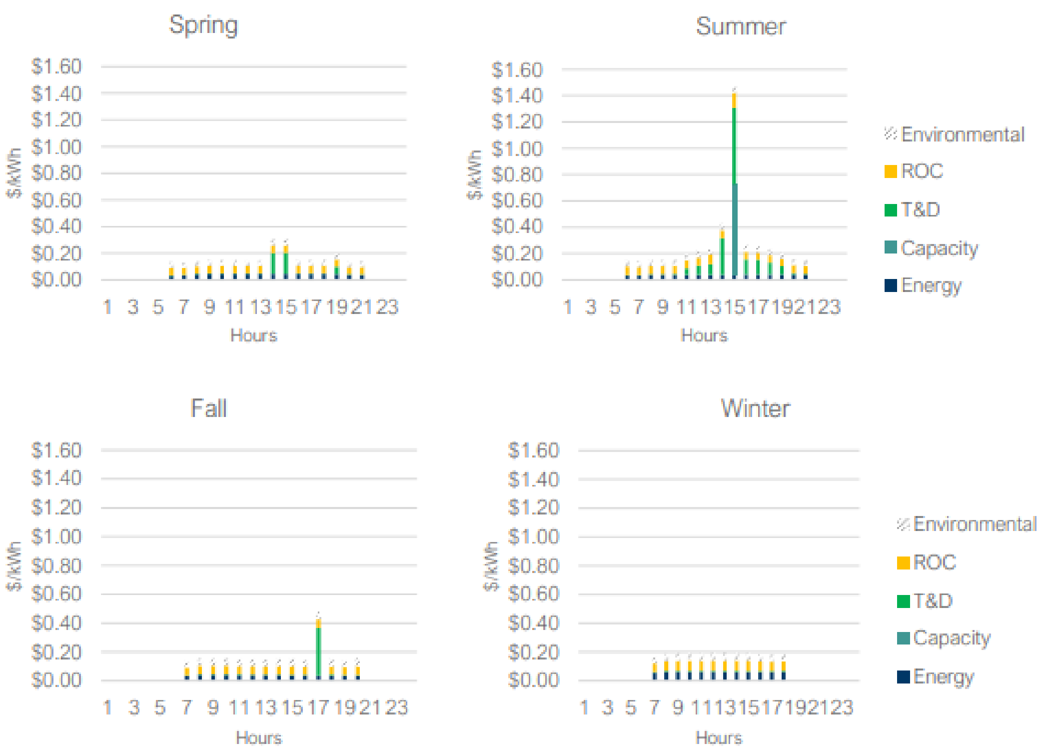

Figure 3: Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Installed in 2021, Year 2021 Shown (2021$) *Source: Dunsky NH VDER Study (Dunsky 2022)*

In most hours, the avoided cost values are lowest during the spring and fall shoulder season days when the ISO-NE system demand is typically at its lowest. A limited number of spring and fall afternoon hours show higher avoided costs due to increased T&D values. These hours coincide with the ISO-NE monthly system peak when the transmission charges levied on New Hampshire utilities are assessed, which increases load reduction value. Transmission charges also cause a spike in summer avoided costs during the afternoon hours. The annual ISO-NE system peak further drives the summer daytime values, leading to sizable capacity avoided costs.

Impact: In addition to the avoided cost analysis, Dunsky conducted a Rate and Bill Impact Assessment to evaluate the high-level analysis of the impacts of future DG deployment in New Hampshire on ratepayers, considering both the benefits and the costs that would be incurred by the utilities and load-serving entities. The overall goal of the assessment was to serve as a future-looking estimate of the direction and magnitude of the impacts of future DG deployment on all ratepayers and any potential cost-shifting between customers with and without DG.

Under the current NEM Tariff scenario[2], forecasted Solar PV adoption is expected to result in slight rate increases relative to a no-PV scenario over the study period (2021-2035) while providing a net bill reduction across all customer bills in aggregate when both Solar PV and non-Solar PV customers are considered within each customer class.

Across the three utilities evaluated, residential customers experience the highest increase (0.7%-1.3%) in rates among the rate classes, followed by small (0.1%-0.7%) and then large (0.0%-0.2%) general service customers. This variation in retail rate increases across the rate classes is a by-product of sector-specific retail rate designs (rates and tariff structures), NEM program administration costs, and the assumed proportion of solar exports relative to the overall customer load. Customers with net-metered DG exports are compensated through monetary credits at the current alternative net-metering tariff rates. Rate classes that exhibit a higher proportion of net exports receive greater compensation through export bill credits. This will increase the utility's program costs, which will be recovered from the retail customer class. Among customers with net metered DG, customers without net metered DG, and the average utility customer, net metered DG customers will experience the largest reduction in monthly bills. Figure 4 below illustrates the findings for customers in Eversource's service territory as an example.

[2] The export credit rate is based on the alternative net metering tariff, under which monthly net exports from residential and small general service customer DG (i.e., those with DG facilities up to 100 kW) are compensated at 25% of the distribution rate component and 100% of the generation and transmission rate components. For exports from customers with DG greater than 100 kW, hourly net exports are compensated at 100% of the generation rate component only.

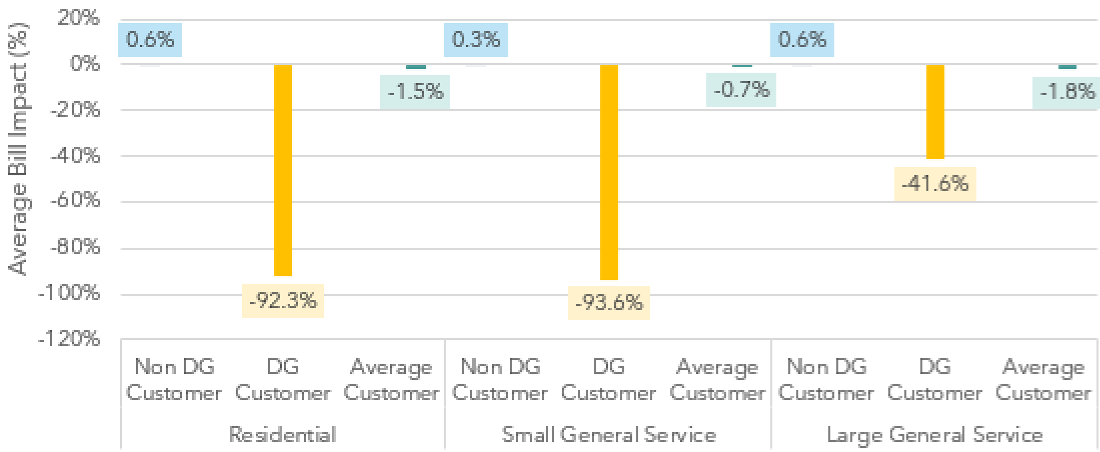

Figure 4: Average Monthly Bill Impacts Across Rate Classes in Eversource Territory Under NEM Scenario (Relative to no-DG Scenario) *Source: Dunsky NH VDER Study (Dunsky 2022)*

Virginia Case Study

Background: In 2020, the Virginia General Assembly enacted legislation that permitted the development of shared solar facilities that could generate electricity for multiple utility customers at a single site (Virginia 2020). Under this arrangement, as seen in Figure 5, 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.

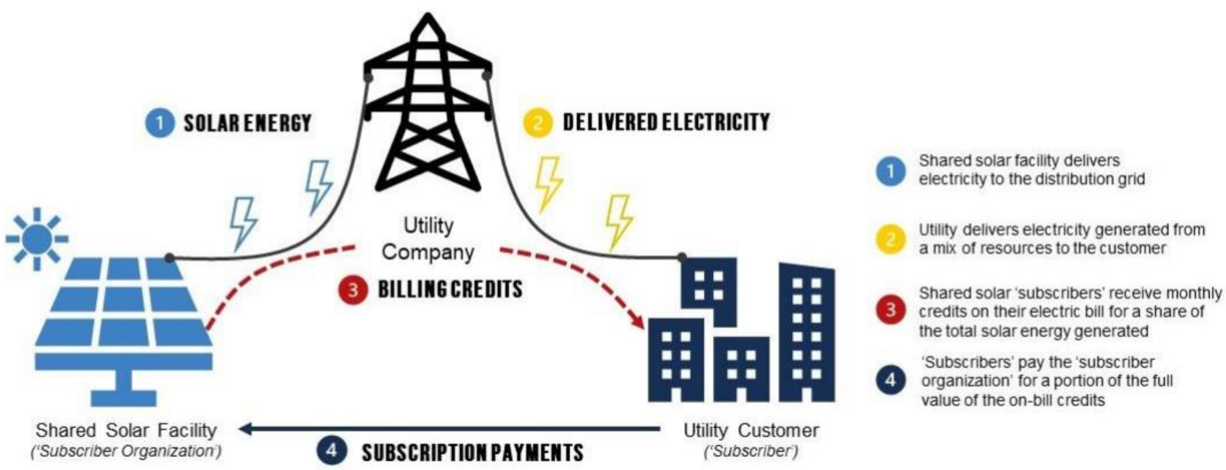

Figure 5: Virginia's Shared Solar Program Schematic (Virginia DOE 2020)

Currently, Dominion Energy customers have access to the Shared Solar Program, and under this program (SCC § 56-594.3), each subscriber receives a bill credit based on the subscriber's customer class (residential, commercial, or industrial) that reflects the average retail rate per kWh of electricity delivered from the shared solar facility for that subscriber. Dominion also charges the subscribers a minimum bill fee, reducing the bill credit. The rationale of the minimum bill is to ensure subscribers in the Shared Solar Program pay their fair share for 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. Our analysis aims to determine the value that the Shared Solar Program can deliver to Virginia's electric utility ratepayers over the 2024 to 2050 period and then compare this value with the net compensation Shared Solar Program participants received 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, thereby creating a cost shift.

Analysis and Results:
The value of shared solar in Dominion and APCo was determined based on the approach outlined in the previous section. Figure 6 shows that 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%).

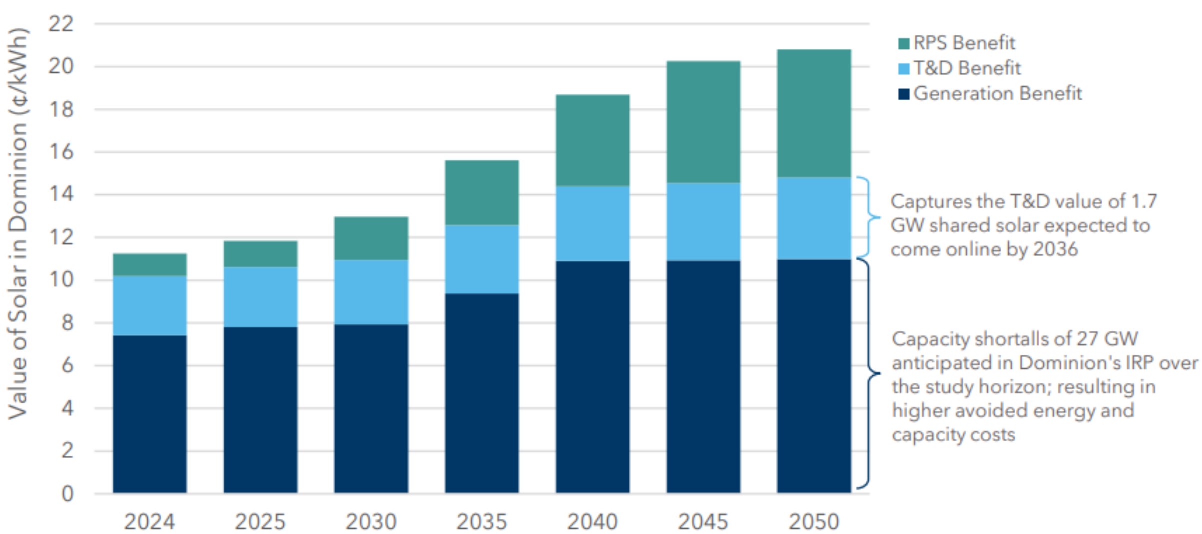

Figure 6: Virginia's Shared Solar Program Schematic *Source*: *(Dunsky 2023)*

Generation Benefits: The generation benefits of 1.7 GW of shared solar in Dominion Energy are projected to rise from 7 cents per kWh in 2024 to 11 cents per kWh by 2038, then stabilize. The primary factors reducing generation costs include avoided energy costs (68%) and avoided generation capacity costs (19%). Dominion's 2023 IRP indicates an energy shortage of 114 TWh by 2048 due to the retirement of specific fossil fuel plants, leading to energy costs increasing from $48/MWh in 2024 to $75/MWh by 2038, before stabilizing until 2050. Moreover, due to capacity constraints and plant retirements, generation capacity costs are projected to increase from $99 per kilowatt-year in 2024 to $134 per kilowatt-year by 2038, remaining stable until 2050.

Transmission and Distribution (T&D) Benefits: The study projects that the transmission and distribution benefits of 1.7 GW of shared solar will increase from 3 cents per kWh in 2024 to 4 cents per kWh by 2050. The main factors reducing T&D costs are avoided transmission charges (45%) and capacity costs for transmission and distribution (19% and 36%, respectively). Despite an increase in PJM's transmission charges from $66 to $150 per kW-year between 2024 and 2050, the effectiveness of distributed solar in reducing these costs decreases over time due to shifts in peak demand hours. Meanwhile, transmission and distribution capacity costs are expected to remain stable at $62 per kW-year throughout the study period, as indicated by Dominion's cost assessments.

Renewable Portfolio Standard (RPS) Benefits: Dominion is required to meet its RPS requirement, and every percentage of renewable generation that falls short of the RPS a Deficiency Payment must be made. As the Deficiency Payment escalates annually, the avoided RPS compliance costs are projected to rise steadily, from 1 ¢/kWh in 2024 to 6 ¢/kWh in 2050.

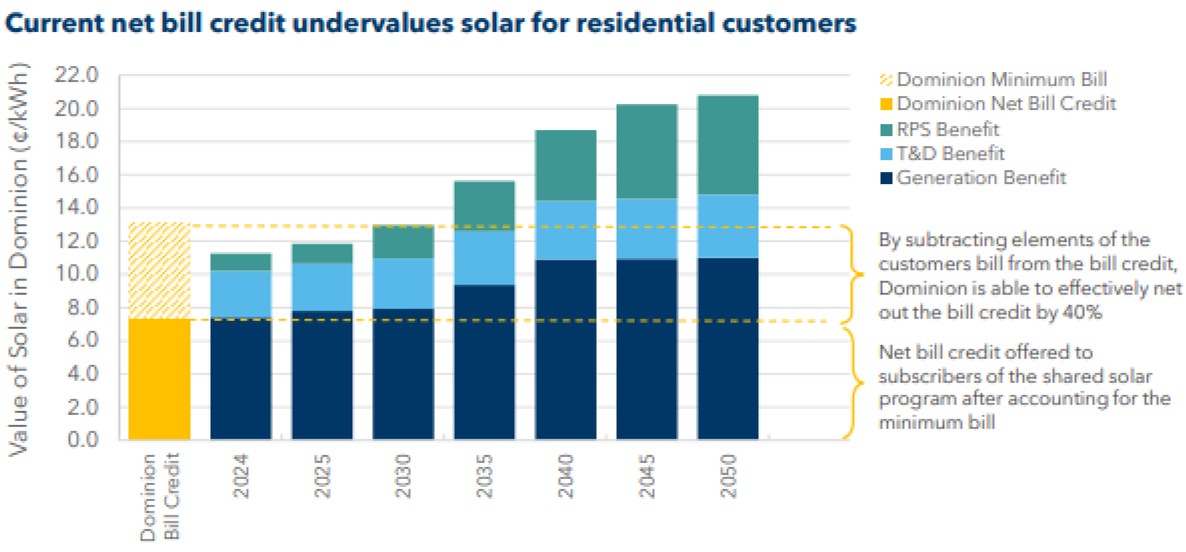

Figure 7: Virginia's Shared Solar Program Schematic *Source: (Dunsky 2023)*

Virginia state law says 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 State Corporation Commission has determined that residential subscribers of shared solar in Dominion would receive a gross bill credit of 13 ¢/kWh in 2023; this number resets annually based on utility costs and sales. Subscribers are required to pay a minimum utility bill based on their subscribed kilowatt-hours (kWh) of generation. The purpose of this minimum bill is to cover the cost of supporting the grid. When considering only the volumetric portion of the minimum bill, subscribers receive a net bill credit of 7.4 cents per kWh. In addition to the volumetric component, subscribers are also subject to a basic customer charge of $6.58 per month and an administrative charge for the

Shared Solar Program, which is expected to range between $10 and $20 per month. While these fixed charges are not reflected in the minimum bill amount shown in Figure 7 (which includes only volumetric components), they are factored into the overall cost assumptions related to the program's net benefits. Figure 7 demonstrates that the value of shared solar in Dominion exceeds net bill credits both currently and throughout the entire study period..

Impact: 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 does not consider the concrete benefits shared solar facilities can provide the utility by avoiding costs associated with generation and infrastructure and complying with the renewable portfolio standard. As a result, the current minimum bill arrangement significantly under-compensates Shared Solar Program participants.

The study revealed that for Dominion Energy customers, the value per kWh of shared solar delivered surpasses the current net compensation (estimated at 7.4 cents per kWh when considering average volumetric minimum bill charges). This compares with the value provided by program subscribers which starts at 11 cents per kWh in 2024 and increases to 21 cents per kWh by 2050.. The study also 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.

This analysis demonstrates that expanding Dominion Energy's Shared Solar Program could create value for all utility ratepayers more than the credits provided to program subscribers. Further, increasing compensation to shared solar subscribers appears 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.

Conclusion

The paper presents a Value of Solar methodology and analysis that addresses the controversy surrounding Net Energy Metering tariffs by providing a comprehensive framework for valuing behind-the-meter solar. The analysis highlights significant benefits of BTM solar for the electric system, including avoided energy costs, capacity costs, transmission and distribution costs, and environmental benefits. By quantifying these benefits, the VoS framework supports fair compensation policies for BTM solar, ensuring that solar owners receive appropriate compensation for their contributions to the grid.

Applying the VoS framework in the New Hampshire and Virginia case studies outlines its potential to resolve NEM policy debates while balancing the interest of solar owners, utilities, policymakers and ratepayers. Under the current NEM tarrif in New Hampshire, the VoS framework was used to demonstrate that non-participants will experience a marginal increase in bills across all utilities and rate classes while benefiting the customer class in aggregate (as shown in Figure 4). In Virginia, the VoS framework demonstrated that shared solar programs subscribers are under-compensated for their grid value.

The VoS framework has significant potential to promote the sustainable growth of distributed solar and contribute to clean energy transition goals. It promotes transparency and consistency in valuing BTM solar, encouraging solar adoption and aligns compensation with the broader goals of decarbonizing the energy system to achieve net-zero. By adopting the VoS framework and embracing data-driven approaches, policymakers and regulators can ensure fair compensation for distributed solar, support sustainable growth, and advance clean energy transition goals.

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