DELAWARE VALUE OF SOLAR:

A Study of the Costs and Benefits of Net Metering

Prepared for: Delaware Sustainable Energy Utility
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About

Gabel Associates, Inc. (gabelassociates.com) is an energy, environmental and public utility consulting firm with its principal office located in Highland Park, New Jersey and satellite offices in Philadelphia, Pennsylvania; Denver, Colorado; Baton Rouge, Louisiana; and Miami, Florida. For over 30 years, the firm has provided quality consulting services and strategic insight to hundreds of clients throughout the United States. The firm has successfully assisted public and private sector clients with implementing energy plans and projects that reduce costs and enhance environmental quality, with a diverse staff that possesses strong economic, financial, project development, technical, and regulatory knowledge and expertise.

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Executive Summary

This Report evaluates the costs and benefits of behind-the-meter solar and net metering in Delaware, commissioned by the Delaware Sustainable Energy Utility following Senate Joint Resolution 3.

Net metering is a form of valuing the production from customer-located solar: production generated on site avoids the cost of utility-delivered power, with the excess of on-site usage "turning the meter backwards," allowing the customer to realize value for the excess energy.

One of the principal arguments used by critics of continuing net metering is an allegation that it provides a subsidy to customers who have solar projects installed on their home or business at the expense of customers who do not. To determine whether such a subsidy exists, it is necessary to consider whether the benefits of net metered solar energy exceed the cost of paying the retail net metering credit. As with any product or service, if the benefits realized by all other users of the system exceed the costs, there is no subsidy.

This Report addresses this issue by carefully assessing the value of net metering relative to the value that solar energy provides: a) to the grid and all customers attached to the grid (entitled "direct benefits"); and b) broader benefits provided to all residents of Delaware (entitled "societal benefits"). Direct benefits accrue to all ratepayers and include lower costs due to reduced fossil fuel-based power generation and the avoidance of forward-looking transmission and distribution expenditures. Societal benefits accrue to the public at large and are not reflected in customer rates. This includes environmental and health benefits from reduced emissions as well as economic benefits from increased jobs, consumer spending, and tax revenues caused by investments in solar capacity. Additionally, net metered solar supports the overall reliability and resiliency of Delaware's power grid, helping the economy and avoiding the potential health and safety harms of blackouts.

Key Findings

The analysis demonstrates that net metered solar provides substantial value to Delaware, with benefits significantly outweighing costs. This Report finds that:

- Net metered solar customers can reduce their energy charges ($/kWh) by 22% and demand charges ($/kW) by 2%, all else being equal. This highlights the fact that distributed behind-the-meter solar creates direct customer savings that do not occur with utility-scale solar: whereas a utility-scale project sells at market prices and retains those revenues, a behind-the-meter project provides direct cost savings for customers through lower utility bills. This unique benefit represents real savings for Delaware ratepayers.
- Based on status quo expectations for customer demand growth over the next 10 years, net metered solar is projected to provide Delaware with $1.8 billion in *gross* total benefits (present value), including $614 million in *gross* direct benefits and $1.2 billion in *gross* societal benefits.

- Even after accounting for net metering bill credits, there would still be significant net benefits remaining for the State, with more than $1.4 billion in *net* total benefits (present value) and $136 million in *net* direct benefits.
- When measured as a ratio of benefits-to-costs, the total benefits of net metered solar are nearly 4 times greater than its costs. Further, for every dollar spent on net metering, net metered solar generates $1.28 in direct benefits. Accordingly, there is no subsidy flowing from other ratepayers to net metered solar customers. Quite the reverse, Delaware's net metering policy realizes greater financial benefits than costs for all customers by reducing the overall cost of energy, improving grid resilience, and creating additional economic and societal benefits as detailed in this Report.
- If Delaware expands its net metering cap to a level that aligns with neighboring states, Delaware could realize benefits for all customers that are more than 2 times greater than those under the status quo, with $3.8 billion in total gross benefits and $2.8 billion in total net benefits (present value).

Another benefit of continuing this policy is that it permits the continued expansion of solar development in accord with the State's broader energy, economic development and sustainability goals. It simplifies the messaging to customers who are considering installing solar projects on their sites, as the net metering approach of "letting the meter spin backwards" can be easily understood by customers and sends a clear price signal to invest in clean energy. When homeowners can visualize their excess solar power literally reversing their electric meter and reducing their bill in a one-to-one relationship, it removes much of the complexity from the decision-making process. Instead of trying to understand complicated rate structures or time-of-use calculations, customers can grasp this straightforward value proposition. The direct relationship between solar generation and bill reduction makes it easier for customers to calculate their potential savings and return on investment. When excess generation is valued at the same rate as consumption, the math becomes much simpler for the average homeowner. Ultimately, this helps drive faster adoption of on-site solar by removing barriers to customer understanding and decision-making.

This approach has been highly successful throughout the United States and Delaware in supporting expansion of solar energy, furthering clean energy development, improving reliability, reducing air pollution, and promoting economic growth. Net metering's simplicity and transparency helps reduce barriers to solar adoption by: (1) minimizing customer confusion during the sales process; (2) reducing the perceived risk of investment; and (3) making it easier for solar installers to communicate value to potential customers. This straightforward approach has historically been a significant driver of residential solar adoption in markets where it's available, supporting the expansion of distributed solar energy systems and allowing states like Delaware to achieve their clean energy goals.

Looking forward, accelerating the integration of net metered solar resources in Delaware can further enhance the State's electrical grid flexibility while creating a more resilient energy ecosystem through the deployment of advanced inverters, co-located battery storage resources, microgrids, and other grid modernization improvements that maximize the value of behind-the-meter solar. Taken together, these resources can make electricity more reliable, clean, efficient, and flexible for all Delawareans.

Based on the analysis in this Report, the State's net metering policy should be expanded beyond the current cap of 8%, as the benefits of this policy clearly outweigh its costs, with these benefits increasing with higher deployments of net metered solar. This will not cause a subsidy of on-site solar energy as it reflects the full range of net benefits caused by solar and does not require the program to be underwritten by non-participating customers.

Recommendations

- Increase the current 8% net metering cap to capture the full range of direct and societal benefits.
- Expand access to net metering through targeted incentives and financing programs for underserved communities.
- Encourage solar-plus-storage deployments through additional incentives that reflect enhanced grid benefits.

This analysis provides strong evidence that expanding BTM solar deployment in Delaware would create substantial value for all residents and businesses while supporting the State's clean energy objectives.

1 Background

On February 28, 2024, the Delaware Senate passed Senate Joint Resolution 3 (SJR 3), directing all electric utilities in the State that offer net metering to solar customers to participate in a cost-benefit analysis of net metering in Delaware.[1] Under current State law, utilities may restrict net metering for new customers once the total number of net metering customers in the State reaches 8% of the utilities' total peak demand. SJR 3 notes that the current net metering cap may pose a significant detriment to the growth and health of the solar industry in the State, as utilities may exercise their right to reject new requests for net metering once the cap is reached. SJR 3 seeks to address this risk by exploring ways to improve the State's net metering framework in a manner that is equitable and properly accounts for the value of net metered solar in Delaware.

On June 7, 2024, the Delaware Sustainable Energy Utility (DESEU) issued a request for proposals (RFP) to conduct a statewide value-of-solar (VOS) study (Report) entailing a quantification of the estimated costs and benefits of net metering in Delaware. After a competitive selection process, DESEU awarded the contract to Gabel Associates, Inc. (Gabel) on September 9, 2024.

The purpose of this Report is to provide an independent analysis of the full range of benefits provided by distributed solar energy in Delaware and establish a transparent basis for setting the solar net metering credit that is fair to customers, including both those with net metered solar and those without.

1.1 DESEU Overview

The DESEU, a 501(c)(3) nonprofit organization, is dedicated to advancing affordable, reliable clean energy and energy efficiency for Delawareans through its Energize Delaware initiatives. Energize Delaware connects energy consumers to opportunities that help reduce energy costs, improve environmental outcomes, and promote energy independence. These initiatives encompass a wide range of programs focused on clean energy generation, energy efficiency, and air pollution reduction. These programs include funding and educational resources to support both residential and commercial energy consumers. Energize Delaware's role is also supported by DESEU's ability to issue tax-exempt bonds, use Regional Greenhouse Gas Initiative (RGGI) funds, and manage solar renewable energy credits (SREC). Through these efforts, DESEU applies its expertise to help individuals, businesses, and institutions reduce energy consumption and emissions, thereby driving Delaware's clean energy transition.

1.2 Gabel Associates Overview

Gabel, headquartered in Highland Park, New Jersey, is an established energy, environmental, and public utility consulting firm with over 30 years of experience. Gabel has a strong track record of providing strategic advice and consulting services to public and private sector clients across the United States. The firm has extensive expertise in energy planning, cost reduction, environmental quality enhancement, and project implementation. Gabel's work spans economic, financial, regulatory, technical, and project

[1] Senate Joint Resolution 3, 152nd Gen. Assemb. (Del. 2024).

development areas, equipping Gabel with the holistic knowledge to assist clients in achieving their energy and environmental goals.

1.3 Delaware Electric Sector Overview

Delaware's electrical sector is primarily served by three companies (Companies): Delmarva Power (DPL), Delaware Electric Cooperative (DEC), and Delaware Municipal Electric Corporation (DEMEC), which includes nine municipal utilities. DPL, founded in 1909, is a public utility serving over 532,000 electric customers across Delaware and Maryland, plus 138,000 natural gas customers in northern Delaware. DEC, established in 1936, is a member-owned electric distribution company serving rural communities in Kent and Sussex Counties. DEMEC, formed in 1979, is a public corporation constituted as a Joint Action Agency and a wholesale electric utility serving nine municipalities covering more than 140,000 residents and businesses. Each Company maintains distinct operational models – DPL as a traditional electric utility, DEC as a cooperative, and DEMEC as a municipal joint action agency – creating a diverse energy landscape that serves Delaware's varied communities.

1.4 Net Metering Background

Net metering is a billing arrangement that allows residential and non-residential customers with solar panels installed on their homes and businesses to send excess electricity back to the power grid in exchange for a credit on their utility bills. When a customer’s solar panels produce more electricity than the customer needs, the excess power flows back to the grid. This reduces strain on the grid and provides the customer with a bill credit to offset some electricity charges. This system has become a cornerstone policy for promoting solar adoption among households and businesses throughout Delaware and across the U.S.

Under Delaware’s current net metering framework, customers that produce excess energy receive a bill credit for their surplus energy. The value of the bill credit is based on the Companies’ Supply Service and Distribution Service Charges.[2] If the bill credits exceed the customer’s usage in a billing period, the remaining credits will carry over until the annualized billing period, continuing to reduce costs.

The debate around cost burdens and cost shifting in net metering centers on how to fairly compensate solar customers while maintaining grid infrastructure and protect ratepayers who do not have solar. Opponents of net metering argue that customers who reduce their bills through net metering still rely on the grid but pay less toward its fixed maintenance and infrastructure investment costs, shifting these costs to non-solar customers. The literature on cost shifting shows mixed results, however, with some studies noting the potential for cost shifts, with others finding minimal to no impacts, particularly when considering the net benefits provided by solar power such as avoided transmission system upgrades, lower emissions, and incremental economic impacts from building distributed energy resources in lieu of large-scale generators.

[2] DPL excludes charges for societal benefits programs from its net metering credits. DEC and DEMEC do not.

For example, an analysis of the benefits and costs of net metering in Washington concluded that the costs of net metered solar may exceed its benefits.[3] However, this analysis does not account for many of the potential benefits created by net metered solar.[4] Conversely, comprehensive meta-analyses of multiple VOS studies[5] [6] demonstrate that the benefits of net metered solar almost always exceed its costs for all utility customers.

VOS studies can be used to overcome these challenges by evaluating the full range of costs and benefits net metered solar provides to the grid, customers, and society. This comprehensive approach considers factors beyond just electricity generation, including transmission and distribution cost savings, environmental benefits, and avoided capacity costs, among many other avoidable costs and incremental benefits made possible by BTM solar. While net metering offers a simple, understandable mechanism for customers, VOS studies suggest it may undervalue solar's total grid contributions.

1.5 Report Overview

This Report encompasses three groups of analyses. First, it provides a cost-benefit analysis of net metering in Delaware, tailored to each of the Companies. Second, it explores the value of net metered solar using a range of different scenarios to illustrate key value drivers and potential opportunities for the State to maximize benefits. Third, it evaluates the potential for cost-shifting and implications for net metering in Delaware.

The remainder of the Report elaborates on these issues in greater detail and is organized as follows:

- *Solar Value Stack Overview and Valuation Methodology*: examines the potential sources of value to Delaware from deploying more BTM solar;
- *Solar Value Stack Scenario Analysis:* summarizes the results of two scenarios comparing the potential range of benefits when using different assumptions for load growth and the number of BTM solar deployments through 2035;
- *Solar Value Stack Sensitivity Analysis:* summarizes the results of two sensitivity analyses testing the impact of using alternative discounting assumptions to value emissions-related benefits and, separately, the incremental reliability-related benefits of pairing battery storage with Delaware's BTM solar installations;
- *Solar Value Stack Cost-Benefit Analysis*: evaluates the ratio of BTM solar's benefits to its costs for each of the scenarios and sensitivity analyses; and

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[3] Energy and Environmental Economics, Inc. (2023). Benefits and Costs of Net Energy Metering in Washington. (E3 Report)

[4] See Figure 7 of the E3 Report.

[5] ICF. (2018). Review of recent cost-benefit studies related to net metering and distributed solar. Prepared for the U.S. Department of Energy.

[6] Brookings Institution. (2016). Rooftop solar: Net metering is a net benefit.

- *Solar Value Stack Cost-Shift Analysis:* evaluates the potential cost impacts on the State's customers who do not have access to net metered resources.

2 Solar Value Stack Overview and Methodology

The solar "value stack" represents the total monetary value of the benefits solar power provides to the grid, economy, and environment. It can include multiple sources of value such as avoided infrastructure costs, lower market prices, improvements to grid reliability, reduced emissions, and local economic value-added. Utilities and regulators can use the value stack to determine the compensation rate for solar projects.

This Report segments the value stack into two primary categories (direct and societal benefits) and four secondary categories (avoidable utility expenses, market price savings, economic benefits, and societal benefits). This approach provides a comprehensive framework for identifying key value drivers by separating direct financial benefits that accrue to utilities and ratepayers from broader economic and societal impacts. **Direct benefits** include avoidable utility expenses, market price savings, and targeted economic benefits (e.g., tax credits). **Societal benefits** include environmental and health benefits realized by reduced air emissions as well as economic benefits realized by the jobs, spending, and increased economic activity caused by solar investments.

Figure 1: Solar Value Stack Components

Primary Category	Secondary Category	Benefit Type
Direct	Avoidable Utility Expense	Energy Generation Fixed Costs
Direct	Avoidable Utility Expense	Energy Generation Variable Costs
Direct	Avoidable Utility Expense	Energy Generation Hedge Costs
Direct	Avoidable Utility Expense	Purchased Power Costs
Direct	Avoidable Utility Expense	RPS Compliance Costs
Direct	Avoidable Utility Expense	T&D Costs
Direct	Market Price Impacts	Energy DRIPE
Direct	Market Price Impacts	Energy Redispatch Costs
Direct	Market Price Impacts	Capacity DRIPE
Direct	Market Price Impacts	Ancillary Services DRIPE
Direct	Economic Benefits	Tax Credits
Societal	Economic Benefits	Local Value Added
Societal	Avoidable Societal Damages	Emissions Scopes 1 & 2 Costs
Societal	Avoidable Societal Damages	Emissions Scope 3 Costs
Societal	Avoidable Societal Damages	Value of Lost Load

2.1 Avoidable Utility Expenses

Avoidable utility expenses represent the cost savings from customers who generate their own power using on-site solar. This includes costs savings from BTM solar's ability to avoid or defer (1) building new grid infrastructure; (2) operating and maintaining existing generation, transmission, and distribution capacity; (3) securing power supply hedges that would otherwise be necessary to mitigate exposure to volatile and unpredictable swings in fuel and power prices; and (4) procuring renewable energy credits (RECs) needed to comply with renewable portfolio standards (RPS). When customers generate their own power, utilities can defer or avoid these expenses, creating real savings for customers throughout the State.

2.1.1 Energy Generation Fixed Costs

Energy generation fixed costs represent the power plant investments and fixed operating costs that utilities can avoid when customers generate their own electricity through distributed resources like BTM solar. When customers generate their own power, they can reduce the overall system demand for electricity that utilities need to serve. Lower customer loads mean that utilities may not need to build as much generation capacity. For example, if rooftop solar produces electricity on hot summer afternoons when air conditioning use is high, the utility might avoid having to construct or maintain peaking power plants that would otherwise be needed to run during these high-demand periods.

To quantify the Companies' avoidable fixed generation capacity costs, we relied on recent estimates for the cost of building new generation capacity resources in the PJM Interconnection (PJM) Eastern Mid-Atlantic Area Council (EMAAC) region, which includes the Companies' service territories. Specifically, we relied on PJM's most recent Cost of New Entry (CONE) study.[7]

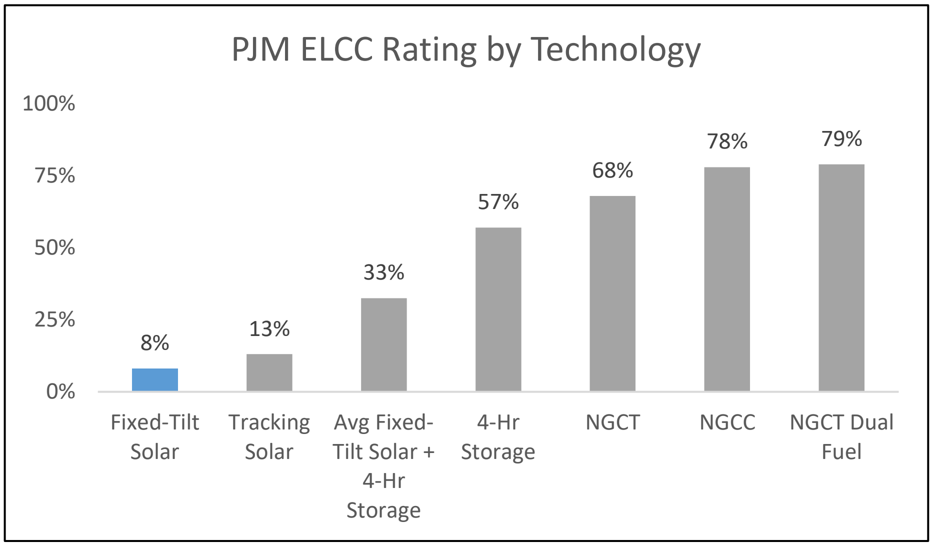
CONE represents the estimated cost of building a new power generation unit to meet system demand in a specific market. CONE plays a crucial role in capacity markets, where power plants earn fixed revenues in exchange for agreeing to ensure that they will be available to generate electricity in the future. Grid operators also use CONE to set price caps in competitive capacity auctions and to determine how much capacity is needed to ensure reliable electricity supply. For example, if capacity prices consistently reach CONE, it signals that the market needs to build new power plants to meet customer demand. If prices stay well below CONE, it suggests the market has adequate supply.

The development of CONE involves calculating the cost of building a new power plant, referred to as the "reference resource," considering the costs of construction, operations and maintenance (O&M), and financing that are specific to the type of generation technology. Historically, PJM used natural gas combustion turbines (CTs) as the reference resource. However, in recent studies, PJM has recommended switching to combined cycle gas plants (CCs) as a more economic option for merchant developers in PJM's market.

To quantify the share of the reference resource capacity costs that BTM solar can avoid, we relied on PJM's Effective Load Carrying Capability (ELCC) ratings for fixed-tilt solar:

[7] The Brattle Group. "PJM CONE 2026/2027 Report" (April 21, 2022). Prepared for PJM.

Figure 2: ELCC Ratings Comparison[8]



ELCC represents the share of system demand that each resource type can reliably support, considering the predictability of its fuel supply and operational characteristics. Note that BTM solar, which is represented by the "fixed-tilt solar" scenario in the figure above, has the lowest ELCC rating. This is because solar generation may not produce power as consistently throughout the day or during peak demand periods as other generation and storage technologies.

We account for this variability by reducing the reference resource CONE value using solar's ELCC rating, ensuring that solar's avoided capacity costs are scaled to its expected contribution to grid reliability.

We then divide the solar ELCC-adjusted CONE by the estimated annual generation from a Delaware-based BTM solar installation using projections from the National Renewable Energy Laboratory's (NREL) PVWatts tool. PVWatts is an open-source online calculator used to estimate how much electricity a solar array may produce over the course of a weather-normalized year. It uses decades of weather data and solar radiation measurements to make representative predictions of solar generation based on historical location-specific weather patterns, the size of the solar array, how the panels are mounted, and their orientation. For this analysis, we simulated the generation output for a roof-mounted solar array located in Delaware. Roof-mounted solar serves as the most representative proxy for BTM solar because it aligns with the typical physical and operational characteristics of BTM installations, which are often fixed, roof-mounted systems rather than the larger-scale, open-rack and solar-tracking systems.

[8] PJM Interconnection, LLC. ELCC Class Ratings for the 2026/2027 Base Residual Auction.

Lastly, to account for the fact that the Companies own little to no generation capacity,[9] [10] we further reduce the output from the prior step by multiplying it by the ratio of each Company's owned generation capacity output to its total customer sales. The higher the ratio, the higher the avoidable costs, all else being equal. This approach provides a transparent and reproduceable basis for quantifying avoidable fixed generation costs that is specific to the load-carrying capability of BTM solar and each Company's generation fleet.

2.1.2 Energy Generation Variable Costs

Avoidable variable energy generation costs represent the fuel and variable O&M (VOM) that a utility or power generator can avoid by not producing electricity at a particular time. These costs are typically associated with the operation of conventional fossil-fuel-powered generation resources, which incur more costs as they generate more power – unlike BTM solar and other renewable generation resources, which rely on "free" sources of power like the sun. When BTM solar generates power, it can reduce the need for traditional power plants to generate electricity to serve the same demand. As a result, the variable costs of operating fossil fuel-powered power plants, like the cost of fuel, equipment maintenance, chemicals, and other consumable materials that vary with the output of the generator, can be avoided.

To determine if the Companies' fossil fuel-powered generation resources would be displaced by BTM solar, we developed a simplified energy market-style "supply stack," comparing the variable generation costs of all resources in the PJM marketplace. In PJM, all load-serving entities (LSE) across each of the 13 member states and D.C. pay the same price for energy under PJM's locational marginal pricing (LMP) construct, which sets the system-wide price for energy based on the cost of serving the next increment of load across the entire PJM region.[11] In PJM's energy market, power plants are ranked in order of their costs to produce electricity, starting with the cheapest resources and ending with the most expensive. When the market needs electricity, the plants with the lowest fuel and VOM costs are selected to produce energy first. The last plant needed to meet system demand is referred to as the "marginal unit." Its variable production costs set the market price for energy. Any resource that is more expensive to operate than the marginal unit will not clear the market or be dispatched to serve customer demand. This ensures that all resources needed to supply customer demand can fully recover their costs in generating power and that customer demand is met using the cheapest available mix of generation resources.

To develop the proxy supply stack, we relied on historical power plant operations data from the U.S. Energy Information Administration's (EIA) Form 923, which provides fuel consumption and net generation data for individual generating units, and technology-specific fuel costs and heat rate assumptions from a

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[9] U.S. Energy Information Administration. Annual Electric Power Industry Report, Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only).

[10] U.S. Energy Information Administration. (2024, January 17). Delaware State Profile and Energy Estimates.

[11] PJM Interconnection, LLC. PJM Manual 11: Energy & Ancillary Services Market Operations Revision: 110. Effective Date: October 28, 2020.

range of additional resources.[12] Multiplying the proxy heat rates by the corresponding fuel prices yields plant-specific fuel costs per megawatt-hour (MWh) of generation. For VOM costs, we relied on a combination of EIA and PJM data, depending on availability.[13] Total variable production costs equal the sum of fuel and VOM costs for each generating unit.

We then ranked all units by their total variable production costs from most to least expensive. Inefficient generators with higher fuel and variable operations and maintenance costs would be at the top of the supply stack. Solar, which has no fuel costs and little to no variable operations and maintenance costs, would be at the bottom of the supply stack.

Next, we added more solar to the supply stack of available generators in PJM to determine if any of the Companies' generation resources would no longer be needed to meet customer demand, given the addition of solar resources at the bottom of the supply stack. If the Companies' generation resources are displaced from the supply stack, then they would not be dispatched to serve customer demand. If they are not dispatched to serve demand, then they will not operate or incur any variable production costs. Therefore, the extent to which the Companies may be able to avoid variable production costs depends on (1) if the Companies own any generators that participate in the PJM energy market; (2) if the generators incur high enough fuel and variable operations and maintenance costs to be at risk of being pushed out of the supply stack once lower-cost solar generators are added to the system; and (3) if enough new solar is added to displace the Companies' generation resources from the supply stack.

The analysis indicates that there would be no avoidable variable production costs under the status quo projections (Scenario A) because the Companies do not own any resources with high enough variable production costs to be displaced from the market using the assumed amount of BTM solar generation included in this Report. However, when using higher estimates for BTM solar capacity additions (Scenario B), there would be some cost savings, as detailed later in this Report.

2.1.3 Energy Generation Hedge Costs

Avoidable hedge costs represent the savings from reducing the need to pay for risk-mitigation services due to BTM solar, which can reduce system demand and the need to buy potentially costly forms of insurance to protect against volatility in commodity prices. For purposes of this Report, we evaluated two types of avoidable hedge expenses: (1) avoidable fuel price hedges; and (2) avoidable electricity price hedges.

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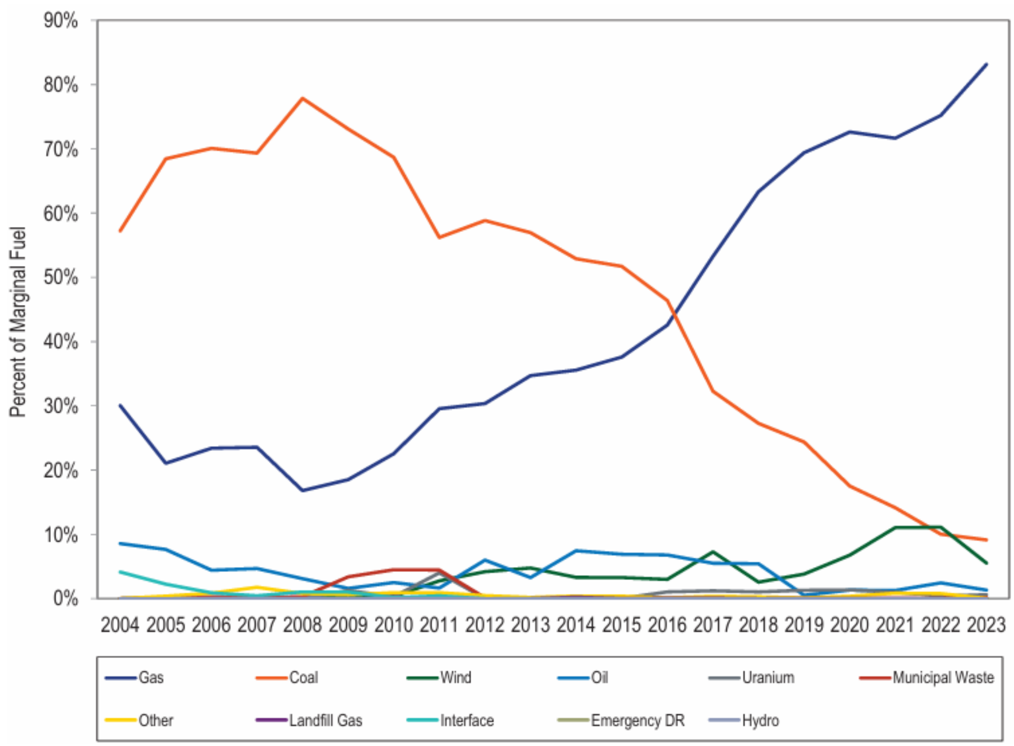
[12] Natural gas prices were based on Delaware City Gate prices from EIA's state profile for Delaware. Due to limited data availability for Delaware, petroleum product prices were based on average delivered costs for electricity generation in the Middle Atlantic and South Atlantic regions, sourced from EIA Table 4.11A. Coal prices were based on the average delivered cost for electric power sector from EIA Table 34. Similar EIA data sources were used for other fuel types.

[13] Specifically, we relied on variable O&M costs for combined cycles, combustion turbines, steam turbines, and coal units from PJM's Independent Market Monitor State of the Market Report. For all other generation types, we used variable O&M costs from EIA's Annual Energy Outlook 2023 technology characteristics.

Avoidable fuel price hedges represent the costs that utilities and power generators typically incur to protect themselves against future volatility in natural gas prices. Natural gas plays a significant role in determining electricity prices because it is typically the last and most expensive fuel source used to meet power demand. Therefore, the variable production costs of natural gas-powered generators typically set the market price that all resources receive. This occurs because electricity markets operate based on a system where all generators receive the price set by the most expensive plant needed to meet demand at any given time. Power plants are brought online in order of their operating costs, with nuclear, hydroelectric, wind and solar generally running first since they have very low variable costs or are otherwise needed to provide "baseload" generation. Coal plants usually come next, followed by natural gas plants which have the highest operating costs. Even if the most expensive resources provide a fraction of total power generation, their higher costs end up determining the market price that all generators receive.

This means that when natural gas prices rise, electricity prices tend to increase across the board, even if more power is coming from other sources. This dynamic has become more pronounced as natural gas has grown to play a larger role in the power system:

Figure 3: PJM Marginal Unit Fuel Trends[14]



This figure illustrates that natural gas (dark blue line) is the predominant fuel type used by resources that set the market-clearing price in PJM, supplanting coal (orange line) as the last and most expensive

[14] Monitoring Analytics, LLC. (2024). State of the Market Report for PJM. Volume 2: Detailed Analysis. March 2024.

resource able to clear the market. Many coal plants have retired over the past decade, replaced primarily by natural gas generation. At the same time, the increasing share of renewable energy has made natural gas plants even more important as a flexible source of backup power when wind and solar output is low. The combination of these factors means that natural gas prices have a larger influence on electricity costs than in the past.

Similarly, avoidable wholesale electricity price hedge expenses represent the cost savings for LSEs that can reduce the amount of insurance needed to manage electricity price volatility. When LSEs add solar generation to their resource mix, they can reduce their exposure to natural gas price fluctuations, thereby avoiding some hedging expenses. When customers generate their own electricity through distributed resources like BTM solar, they reduce the amount of electricity LSEs need to purchase from wholesale markets to serve their customers. This reduction in required wholesale purchases means LSEs can scale back some of their hedging activities. The associated cost savings are considered "avoidable" because they represent expenses LSEs can reduce or would no longer need to incur.

For example, according to DPL's SEC 10-K investor report, Note 15, the company procures electric and natural gas supply through competitive procurement processes and reduces its exposure to energy and natural gas price volatility from these purchases by entering into physical and financial derivative contracts. Specifically, the company states that it mitigates its exposure to (1) natural gas price fluctuations by purchasing exchange-traded futures contracts for up to 50% of its estimated monthly requirements; and (2) electricity price volatility using fixed price contracts covering the entirety of its standard offer service (SOS) requirements. The costs associated with these contracts are fully recovered from customers through electric tariff mechanisms.

To quantify the avoidable fuel price hedge expense for DPL, we compared the difference between current spot prices and futures contract prices for natural gas at Henry Hub.[15] This price spread reflects the market's collective view of future price risk and the premium traders are willing to pay for price certainty. This premium, multiplied by the volume of natural gas that would have been needed for generation, yields the avoidable hedge expense. Given that DPL's investor report states that it hedges "up to" 50% of its estimated purchase requirements, we used a simplifying assumption that the Companies would hedge 25% of their requirements, on average. We further reduced the estimated fuel price hedge amounts by multiplying the 25% assumption by PJM's current ELCC rating for fixed-tilt solar. This additional step helps to account for the intermittency of solar generation and its reduced ability to provide an equivalent hedge against natural gas price volatility that a firm resource could provide. These steps result in a composite adjustment factor of 2%, meaning this analysis assumes that only 2% of the fuel price hedge expense would be avoidable.

To quantify the avoidable electricity price hedge expense for DPL, we compared current spot prices with futures contract prices for wholesale electricity at the Delmarva Hub in PJM. The difference between

[15] Henry Hub is a key natural gas pricing point located in Louisiana, where multiple pipelines converge. It serves as a benchmark for natural gas prices in the U.S. and is widely used in contracts and trading.

futures prices and spot prices represents the risk premium market participants are willing to pay to avoid price uncertainty. This premium directly reflects the cost of hedging. Unlike the natural gas price hedge analysis, which assumes that only 25% of the company's requirements would be hedged, this analysis assumes that 100% of the company's requirements would be hedged, consistent with DPL's SEC 10-K. Like the natural gas price hedge analysis, however, this analysis also reduces the total hedge amount using PJM's ELCC rating for BTM solar. Both metrics essentially measure reliability of delivery – ELCC for capacity contribution and hedging for price protection. Since price spikes may correlate with system stress conditions that ELCC considers, a resource's limited reliability during critical demand periods would likely also diminish its effectiveness as a price hedge. While this simplification does not perfectly capture all price-generation relationships, it provides a practical approach that acknowledges the intermittency of renewable energy resources. This analysis results in a composite adjustment factor of 8%, meaning the analysis assumes that only 8% of the power price hedge expense would be avoidable.

DEC and DEMEC were excluded from this analysis, as these companies do not maintain comparable hedge policies.

2.1.4 Purchased Power Costs

Avoidable purchased power costs represent the savings to the Companies and ratepayers resulting from the ability of BTM Solar to reduce customer demand for grid-supplied energy. This issue is of particular relevance to the Companies because they rely heavily on power purchases from wholesale power markets to meet their customer demand for energy, capacity, and ancillary services. For example, historical records for the Companies' customer sales obtained using EIA reports indicate that, on average from 2019 through 2023, more than 90% of the Companies' total customer sales were supplied using wholesale market purchases.[16] This means that a large portion of the Companies' customer charges can be avoided by deploying more BTM solar.

We quantified the value of the Companies' avoidable energy power purchases using an average of 3 methods covering the DPL zone in PJM:

- Linear regression of historical hourly energy prices and system demand;
- Futures contract prices; and
- Production cost model[17] forecast of energy prices.

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[16] U.S. Energy Information Administration. Annual Electric Power Industry Report, Form EIA-861 detailed data files. Operational_Data.

[17] The production cost model forecast reflects a market fundamentals-driven view of long-term energy market prices based on expected changes to generator costs, resource supply mix, transmission limitations, and load patterns. The forecast was developed using EnCompass, which is an investment-grade production cost model that simulates wholesale electricity market operations by determining the least-cost solution for dispatching power plants to meet demand while respecting system constraints. This model is described in greater detail below under the Energy DRIPE overview.

Each method offers complementary insights, making them most valuable when used together. The regression reflects a normalized view of steady-state market conditions based on recent historical outcomes. The futures contracts analysis reflects current expectations for near-term market conditions, as trading liquidity decreases for longer-dated contracts. The production cost model analysis reflects expected long-term changes in system operations and costs. Together, these three approaches provide a comprehensive view of market dynamics across different time horizons—historical patterns, current expectations, and long-term structural changes.

For the capacity and ancillary services components, we escalated recent historical market-clearing prices using the CBO's Long-Term Budget Outlook expectation for inflation over the next 10 years. The sum of the average energy market costs and capacity and ancillary service market costs represents the total avoidable purchased power costs for each of the Companies.

2.1.5 RPS Compliance Costs

Renewable Portfolio Standards (RPS) compliance costs represent the charges incurred by utilities to meet state-mandated renewable energy requirements. These costs stem from the purchase of Renewable Energy Certificates (RECs), which represent the environmental attributes of renewable energy generation. Each REC typically equals one MWh of renewable electricity production.

Delaware's RPS specifies that renewable energy (including solar) must comprise an increasing share of total retail electrical energy[18] sales to end-use customers in the State, increasing from 25% of total retail energy sales in 2024 to 40% by 2035.

[18] Energy (measured in watt-hours) represents electricity generated over time, while power (measured in watts) refers to capacity or maximum potential output. This distinction is crucial for Renewable Portfolio Standards (RPS), which require utilities to generate a percentage of their electricity from renewable sources. RPS requirements are expressed in energy terms (e.g., MWh), not power capacity. Because renewable sources have lower capacity factors than conventional generation, more installed capacity is needed to fulfill these requirements. For example, with a typical capacity factor of 20%, a 5 MW solar installation will produce approximately 8,760 MWh/year (5 MW × 24 hours × 365 days × 0.2) rather than the 43,800 MWh/year that would result from continuous maximum output.

Figure 4: Delaware RPS Requirements[19]

SCHEDULE I		
Compliance Year (beginning June 1st)	Minimum Cumulative Percentage from Eligible Energy Resources	Minimum Cumulative Percentage from Solar Photovoltaics*
2018	**17.50%**	**1.75%**
2019	19.00%	2.00%
2020	20.00%	2.25%
2021	21.00%	2.50%
2022	22.00%	2.75%
2023	23.00%	3.00%
2024	24.00%	3.25%
2025	25.00%	3.50%
2026	25.50%	3.75%
2027	26.00%	4.00%
2028	26.50%	4.25%
2029	27.00%	4.50%
2030	28.00%	5.00%
2031	30.00%	5.80%
2032	32.00%	6.60%
2033	34.00%	7.40%
2034	37.00%	8.40%
2035	40.00%	10.00%

* Minimum Percentage from Eligible Energy Resources Includes the Minimum Percentage from Solar Photovoltaics.

Electricity suppliers in PJM pass RPS compliance costs on to customers through retail electricity rates. Cost recovery mechanisms for RPS charges typically appear as a separate line item on customer bills but may also be embedded within the generation portion of the rate. For residential and small commercial customers, suppliers spread these costs evenly across their customer base on a per-kWh basis. Large industrial customers may negotiate different cost allocation arrangements based on their usage patterns and specific state regulations.

Avoidable RPS compliance costs represent the reduction in REC procurement obligations that LSEs can achieve through customer-sited solar generation. When customers generate their own electricity through BTM solar, they reduce their net consumption from the grid. Since RPS compliance obligations are calculated as a percentage of retail electricity sales, this reduction in retail sales directly decreases the number of RECs that suppliers must procure to maintain compliance.

The Companies' RPS compliance charges range from $0.18/MWh (DEC, DEMEC) to $6.37/MWh (DPL), with a load-weighted average of $4.55/MWh across Delaware.

[19] Delaware Code, Title 26, Chapter 1, Subchapter III-A. (n.d.). Renewable Energy Portfolio Standards.

2.1.6 Transmission and Distribution Costs

Avoidable transmission and distribution (T&D) system costs represent the investment costs and O&M expenses that utilities can reduce or eliminate through the deployment of BTM solar. T&D system costs may become avoidable when BTM solar reduces the customer demand that drives T&D capacity requirements. The reduced stress on these assets can also extend their operational life, defer capacity upgrades, and lower maintenance requirements.

This issue is of particular importance to grid planners, who manage momentary variations in supply and demand throughout the day and night and plan for the long-term needs of the power grid. When solar power fluctuates during periods of peak demand, the T&D system may become strained as voltage levels fluctuate, power flows change directions, or system congestion increases.[20] Though evidence supporting the cost of integrating solar power and managing these constraints is sparse, at least one study estimates that these costs may range from $1-10/MWh for transmission-related upgrades[21] and $1-5/MWh for distribution-related upgrades.[22] However, these estimates do not account for the benefits provided by solar in avoiding costly upgrades to the T&D system.

As an example, a recent meta-analysis of multiple studies exploring the costs and benefits of distributed solar across 15 states found that avoidable T&D costs represent one of the most common sources of *value* provided by solar power.[23] Moreover, the potential cost impacts can be mitigated through smart inverter controls, battery storage integration, and grid modernization. For example, DPL and DEC are pursuing Department of Energy-funded demonstration projects for utility-managed inverters that could enable higher solar adoption while strengthening grid stability. While Delaware's utilities have implemented some mitigation strategies such as improved power factor requirements to strengthen grid voltage and new load management programs to improve grid flexibility during periods of high demand, the State lags in advancing more robust solutions such as incentivizing the deployment of battery storage systems and microgrids that have proven successful in other regions. Additional modernization of Delaware's grid infrastructure, along with the expanded use of advanced metering and inverter control technologies, can help integrate more solar and unlock greater benefits for the State.[24]

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[20] Kim, A. Y. (2021). California's grid modernization: Report to the Governor and Legislature. California Public Utilities Commission.

[21] Gorman, W., Mills, A., & Wiser, R. (2019). Improving estimates of transmission capital costs for utility-scale wind and solar projects to inform renewable energy policy. Electricity Markets and Policy Group, Energy Analysis and Environmental Impacts Division, Lawrence Berkeley National Laboratory.

[22] ICF. (2018). Review of recent cost-benefit studies related to net metering and distributed solar. Prepared for the U.S. Department of Energy.

[23] ICF. (2018). Review of recent cost-benefit studies related to net metering and distributed solar. Prepared for the U.S. Department of Energy.

[24] Hegedus, S. (2023, June 19). Statewide survey of Delaware's electric utility grid modernization status: Current activities and future readiness (Report prepared for the Delaware Sustainable Energy Utility). Institute of Energy Conversion & Department of Electrical and Computer Engineering, University of Delaware.

To estimate the avoidable T&D costs in Delaware, we relied on the Companies' historical T&D costs and system demand data from regulatory filings, EIA reports, and information requests. We converted the Companies' T&D costs to $/MW values to determine the typical T&D investment and operating costs per unit of system demand. We then scaled these values down to a level that approximates BTM solar's ability to reliably meet peak demand based on PJM's ELCC rating for fixed-tilt solar. Lastly, we divided the ELCC-adjusted T&D $/MW values by the estimated generation for a 1-MW BTM solar array in Delaware using NREL's PVWatts tool. This approach produces a representative $/MWh estimate for each of the Companies' avoidable T&D costs.

2.2 Market Price Effects

Market price effects represent the cost savings from lower wholesale electricity market prices due to lower demand for electricity. This phenomenon is also referred to as "Demand Reduction-Induced Price Effects" (DRIPE). When BTM solar generates power, it reduces overall electricity demand. Lower demand can drive down prices in three key electricity markets: (1) energy markets, which secure power to meet near-term customer demand on a day-ahead and real-time basis; (2) capacity markets, which ensure sufficient power to meet long-term peak demand up to three years in advance; and (3) ancillary services markets, which ensure sufficient short-term reserves and fast-responding resources to stabilize current grid conditions.

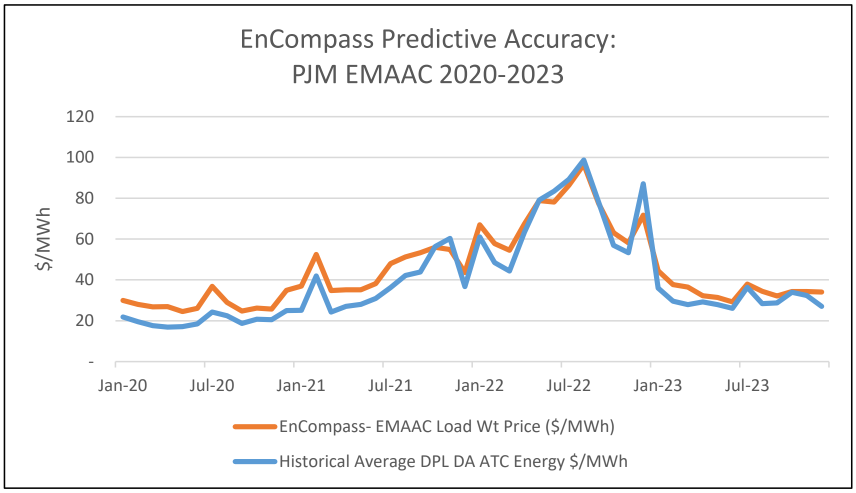
2.2.1 Energy Market Demand-Reduction Induced Price Effects

Energy market DRIPE represents the potential cost savings from lower energy market prices due to BTM solar's impact on system demand. As explained in Section 2.1.2, when demand for energy decreases, power plants with higher operating costs may be displaced from the market by plants with lower operating costs. Adding more solar generation resources to the energy market supply curve reduces market-clearing prices, benefiting all consumers in the market – not just those who reduce their demand.

Energy DRIPE-related cost savings are typically estimated using either a linear regression of historical market outcomes or forecasts of potential market outcomes. To estimate the Energy DRIPE for this Report, we employed both approaches to develop a composite average that accounts for observable market trends as well as projected changes to market fundamentals over the long-term.

For the forecast component, we used EnCompass, which is an investment-grade production cost model that simulates wholesale electricity market operations by determining the least-cost solution for dispatching power plants to meet demand while respecting system constraints. The model incorporates detailed data on generation units, transmission networks, fuel prices, and demand patterns. EnCompass performs chronological simulations of power market operations to account for changing market conditions across hours, days, and seasons. The model accounts for generator operational constraints, maintenance schedules, and transmission limits to produce realistic estimates of market clearing prices and power plant operations.

Figure 5: EnCompass Back Test Results



This chart illustrates the predictive accuracy of EnCompass using a "back test." A back test involves running a forecast using historical data to see if the model would have accurately predicted actual prices. The results of this back test indicate that EnCompass' forecasts are 98% correlated with actual historical outcomes. In simple terms, this means that the model is highly reliable because its predictions for wholesale electricity prices for the EMAAC zone closely match actual historical outcomes.

To estimate the avoidable energy market costs in Delaware, we performed two forecasts: a Base Case scenario assuming no new BTM solar and a Change Case including new BTM solar. The difference in market prices between these scenarios represents the energy DRIPE from BTM solar.

The primary assumptions used for this analysis include the following:

- natural gas prices
- resource mix
- renewable procurement targets
- capacity accreditation constraints
- long-term demand growth

Natural Gas Prices

Natural gas prices are a critical factor in forecasting energy market dispatch and prices in wholesale power markets like PJM. When natural gas prices increase, the cost of producing electricity rises, which can lead to higher electricity prices for consumers. Conversely, a decrease in natural gas prices can reduce generation costs and lower market prices.

For this analysis, we relied on a composite forecast that accounts for near-term market signals based on futures contract prices and long-term market fundamentals to create a balanced outlook over the ten-year study period.

The near-term forecast consists of settlement prices for Henry Hub natural gas futures contracts traded on the CME/NYMEX exchange, accessed through S&P Capital IQ. Futures prices represent the market's current expectations of natural gas prices and incorporate real-time information about supply, demand, storage levels, and other factors affecting the natural gas market. These prices reflect the aggregate views of market participants who have financial exposure to natural gas prices, making them a robust indicator of near-term price expectations.

For the longer-term forecast horizon, the methodology incorporates price projections from EIA. The EIA projections are based on fundamentals-driven analysis of natural gas supply and demand, including anticipated production trends, infrastructure development, demand growth across sectors, and long-term macroeconomic conditions. These projections provide a structured view of long-term market dynamics that may not be fully captured in shorter-term futures prices.

To create a smooth transition between the market-based near-term prices and fundamental long-term projections, we gradually shifted the weighting from futures prices to EIA projections. This approach recognizes that futures market liquidity and price discovery decrease at longer tenors, while fundamental factors become more relevant for price formation.

Resource Mix

Resource mix refers to the different types of power generation and energy storage resources used to meet electricity demand in a market or region. This typically includes fossil fuels like coal and natural gas, nuclear power, and renewable sources such as wind and solar. As new resources are built and existing resources are retired, the resource mix can shift from fossil fuels to cleaner alternatives, depending on policy goals, technology costs, and grid-related constraints. The pace and extent of resource mix changes can have significant impacts on grid reliability, electricity prices, and emissions levels.

For this analysis, we relied on data from EIA 860, Yes Energy Infrastructure Insights, the PJM interconnection queue, and forecasted changes in PJM’s resource supply mix developed using a long-term capacity expansion simulation in EnCompass.

Renewable Energy Procurement Targets

Renewable energy procurement targets require LSEs to procure a specific percentage of their electricity from renewable sources. These targets can influence the dispatch of renewable resources within the PJM region by creating incentives for investment in wind, solar, and other renewable technologies. Meeting renewable procurement targets can help reduce carbon emissions and increase the share of clean energy in the market.

For this analysis, we relied on RPS requirements for different markets across the PJM region, aggregating the state-level requirements into a single market (unless they have a state requirement to fulfill the requirement in state).

Capacity Accreditation Constraints

Capacity accreditation constraints refer to the limits placed on the amount of generation capacity that can be counted toward meeting system reliability requirements. In PJM, capacity accreditation is measured through ELCC, which represents the share of system demand that can be reliably supported by specific types of generation and storage technologies, considering the predictability of its fuel supply and operational characteristics. Intermittent renewable resources like solar and wind typically receive lower ELCC ratings than non-intermittent fossil fuel resources like gas and coal. These standards impact the amount of available capacity to meet peak demand, which, in turn, impacts market prices, emissions, and grid reliability.

For this analysis, we relied on PJM's ELCC class ratings. As noted previously, ELCC accounts for resource availability and plays a crucial role in capacity expansion simulations by determining the percentage of system demand that each resource type can reliably support and, therefore, how much capacity of each resource type is needed and can be added to meet demand growth over time.

Long-Term Demand Growth

Long-term demand growth refers to the anticipated increase in electricity consumption due to population growth, economic expansion, technological advancements, and changing consumption patterns. Understanding demand growth trends is critical in planning for long-term investment needs in generation capacity, transmission capacity, and related grid infrastructure, ensuring that PJM can reliably meet future energy needs.

For this analysis, we relied on PJM's 2024 load forecast, which entails a 15-year forecast of monthly customer energy usage and peak demand based on regressions of historical customer loads, weather, economic drivers, end-use equipment trends, and load management programs. The forecasts support capacity obligations, reliability studies, and transmission expansion planning.

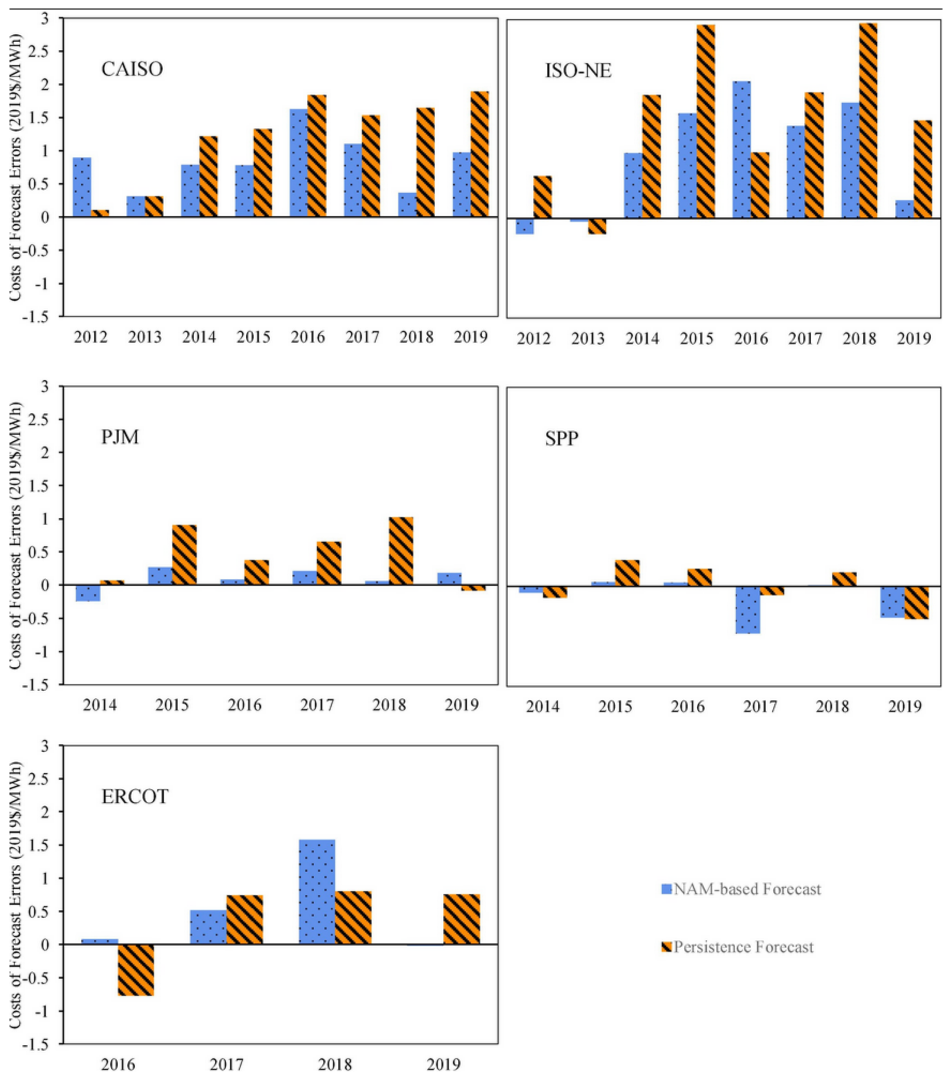
2.2.2 Energy Market Redispatch Impacts

Generation forecast errors occur when the predicted amount of power generation from a resource differs from the actual amount it can produce. This issue is relevant in the context of competitive energy markets that rely on a two-stage process to match electricity supply with demand ahead of the time at which customers will eventually be served. In the day-ahead market, generators submit offers to provide electricity at a specific price for each hour of the next operating day. PJM then runs a market clearing process that selects the lowest-cost combination of resources to meet the projected demand. This process creates binding financial commitments – generators must either deliver the promised power or pay for the cost of replacement generation.

The real-time market operates continuously during the operating day to address differences between planned and actual conditions. When a solar generator produces less power in real-time than it agreed to provide when submitting its day-ahead offer, it must purchase replacement power at real-time prices. This discrepancy represents the “forecast error” between the day-ahead and real-time markets. The difference between the planned cost and the actual cost of serving electricity demand represents an incremental or avoidable cost – depending on the direction of the price change.

For this analysis, we relied on a recent report by Lawrence Berkeley Laboratory (LBL) that examined how errors in day-ahead solar generation forecasts impacted electricity system costs across major U.S. power markets from 2012-2019[25]:

Figure 6: Cost of forecast errors by ISO in the context of growing solar deployments



The research revealed that the cost of solar forecast errors in PJM is negligible. This contrasts with markets like California ISO and ISO New England, where the cost of forecast errors averaged approximately $1/MWh over the same period.

[25] Lawrence Berkeley National Laboratory. "The cost of day-ahead solar forecasting errors in the United States." January 2024.

The lower cost in PJM may stem from its comparatively low solar penetration rate. The research found that in regions with low solar penetration, the relationship between forecast errors and price impacts was largely random, sometimes even resulting in revenue increases rather than costs.

Based on these findings, we assigned a value of $0/MWh for this component.

2.2.3 Capacity Market Purchases

Avoidable capacity market costs represent the savings from reducing or eliminating a utility's need to purchase capacity from wholesale markets like PJM. In PJM, the regional grid operator determines capacity obligations for utilities based on their expected peak demand. When customers install BTM solar, they reduce the amount of electricity they need from the grid during peak times. This reduction in peak demand results in lower capacity obligations for utilities serving those customers. Lower demand, in turn, reduces capacity auction clearing price, all else being equal, benefiting ratepayers across the PJM region.

To quantify the avoidable capacity market costs due to BTM solar, we performed a linear regression of historical and counterfactual market outcomes using PJM data. For historical data, we relied on actual capacity market-clearing prices and cleared capacity for the EMAAC zone in PJM, which encompasses Delaware. For counterfactual data, we relied on scenario analyses developed by PJM showing the estimated clearing-price impact resulting from adding or removing supply from the bottom of PJM's capacity supply stack. Specifically, we relied on data for the most recent capacity auction as of the date of this analysis, which is the Base Residual Auction for the 2025/2026 Delivery Year, as this auction is more representative of market dynamics over the next ten years than prior auctions. For example, the 2025-2026 auction experienced a significant increase in clearing prices due to supply constraints, increasing customer demand, interconnection delays, and a reduction in PJM's capacity accreditation ratings for all resource types. Each of these factors is projected to persist over the foreseeable future, as PJM's fleet of aging generators will continue to retire, customer demand is projected to rise, interconnection constraints continue to impede the integration of new generators, and PJM's ELCC ratings are projected to decline over time.[26]

This analysis produces a $/MW-day value representing the average change in capacity market prices per MW of avoided capacity. We then convert this value to $/MWh to align the results with those developed for the other component of the supply stack analysis.

2.2.4 Ancillary Services Market Purchases

Avoidable ancillary service market purchases represent the savings from reducing or eliminating a utility's need to purchase specialized grid support services from wholesale markets like PJM. In PJM, ancillary service markets provide the following services:

- Voltage support ensures that the grid has sufficient power resources available to stabilize the electrical "pressure" in power lines needed to move electricity from generators to customers. Power plants and specialized equipment inject or absorb reactive power to regulate voltage

[26] PJM Interconnection, LLC. (April 2024). Preliminary ELCC Class Ratings for Period 2026-2027 through 2034-2035.

levels, similar to how a water pump maintains pressure in pipes. Without proper voltage support, power quality can degrade and electrical equipment may not function correctly.

- Black start ensures that the grid has sufficient power resources available to start up and deliver electricity without an outside source of power. Black start units help energize larger generators and gradually restore power to customers during grid outages.
- Frequency regulation refers to the continuous adjustment of power output to maintain the electrical system's frequency at a target level, typically 60 hertz in the United States. The grid requires precise matching of power supply and demand at all times to maintain this frequency. When demand exceeds supply, system frequency drops below 60 hertz. When supply exceeds demand, frequency rises above 60 hertz. Resources providing frequency regulation respond to signals from grid operators, adjusting their output up or down within seconds to correct these deviations and maintain the required system frequency.
- Synchronized reserves are power plants that are online, synchronized to the grid, and able to quickly increase their output if needed. These plants operate below their maximum capacity so they can ramp up within minutes in response to sudden changes in demand and supply.
- Non-synchronized reserves are power plants that are not currently running but can start up and inject power into the grid within 10 to 30 minutes. While slower to respond than synchronized reserves, they are less expensive since the plants don't need to run continuously. Grid operators maintain a mix of both reserve types to balance cost and response speed.

BTM solar installations may be able to reduce the grid's need for some of these ancillary services. When BTM solar generates power during periods of high electricity demand, it reduces the total load on the system and, in turn, the need to procure these services from traditional resources.

To estimate avoidable ancillary service costs, we performed a linear regression of historical hourly ancillary service requirements and prices for frequency regulation and synchronized reserves, as these markets are priced on an hourly basis based on supply and demand, rather than voltage support and black start, which are priced on a fixed annual basis.

The analysis entails two scenarios. The first scenario estimates the annual hourly ancillary services costs across PJM based on actual historical load and assumes that no new BTM solar has been added to the grid. The second scenario estimates the annual hourly ancillary services costs across PJM based on actual historical load but assumes that 1 MW of new BTM solar has been added to the grid. The reduction in load between the two scenarios results in lower ancillary service prices and costs.

We note that reliance on PJM-wide data was necessary because PJM's public datasets for historical ancillary service market outcomes are provided on a consolidated market-wide basis rather than on a state- or utility-specific basis. To isolate Delaware's share of the PJM total, we developed a composite allocation factor consisting of two ratios: (1) Delaware's share of total PJM load; and (2) DPL Delaware's share of DPL's overall load, which includes Delaware and Maryland. This produces an allocation factor of 1.5%, which means that the analysis assumes that only 1.5% of the total avoidable ancillary services costs are attributable to Delaware load.

2.3 Economic Benefits

Economic benefits represent the additional financial savings or value added from building renewable energy resources – specifically small-scale, distributed solar projects in lieu of alternative large-scale fossil fuel projects. BTM solar can create significant local economic value through tax credits, job creation, tax revenue, and increased economic activity.

2.3.1 Investment Tax Credits

The investment tax credit (ITC) is a federal incentive that allows solar project owners to reduce their tax liability based on a percentage of their solar installation costs. The tax credit percentage depends on the type of entity (e.g., residential homeowner, business, etc.), whether it satisfies specific requirements for labor and low-income criteria, and the year in which construction began. The current base tax credit for most BTM solar owners is 30% but can be as high as 70% for some qualifying projects. This value will decline over time, falling to 26% by 2033, 22% by 2034, and 0% thereafter.[27]

Figure 7: Projected ITC % (2026-2035)

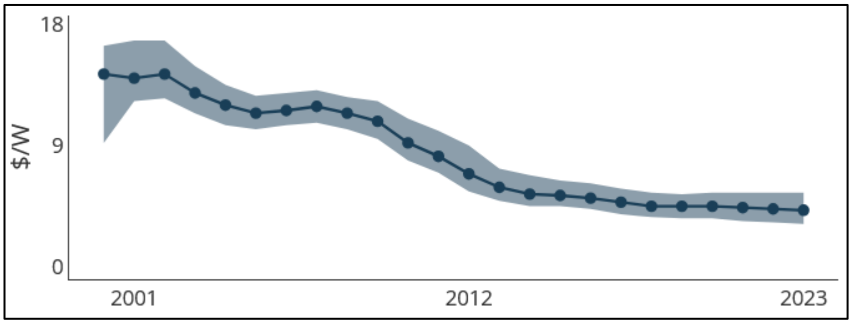
Stdy Period	Year	Capex $/W	ITC %	ITC % w/ 1-Yr Lag	ITC $/W
1	2026	3.99	30%	30%	1.20
2	2027	3.92	30%	30%	1.18
3	2028	3.85	30%	30%	1.16
4	2029	3.79	30%	30%	1.14
5	2030	3.72	30%	30%	1.12
6	2031	3.66	30%	30%	1.10
7	2032	3.60	30%	30%	1.08
8	2033	3.53	26%	30%	1.06
9	2034	3.47	22%	26%	0.90
10	2035	3.41	0%	22%	0.75

Our analysis assumes that BTM solar owners will earn the base tax credit in line with the planned phase-out schedule. However, because the tax credit is based on the year in which construction of the solar resource begins rather than when it is completed, the analysis also includes an assumed one-year lag to account for the time needed to construct new BTM solar installations.

The analysis also assumes that the tax credit value will be based on the median installed cost of residential solar as of 2023, with future costs declining each year through 2035 based on historical price trends:

[27] U.S. Department of Energy. (December 2024). Federal solar tax credits for businesses. Energy.gov; U.S. Department of Energy. (April 2024) Homeowner's Guide to the Federal Tax Credit for Solar Photovoltaics.

Figure 8: Historical Median Installed Cost ($/W) of Residential Solar[28]



We note that the inclusion of the ITC in VOS studies is necessary to evaluate the full range of costs and benefits of net metered solar.

First, the ITC represents federal – not state – resources flowing into state economies. These federal tax credits are not drawn from state treasuries or budgets. Without the ITC incentivizing the deployment of new solar projects in a particular state, these dollars would not automatically be redirected to that state through other channels.

Second, the ITC creates an economic multiplier effect by allowing households and businesses to retain more of their income. When taxpayers reduce their federal tax liability through the ITC, the increased disposable income can circulate within local economies as consumers purchase goods and services from local businesses. This spending can trigger subsequent rounds of economic activity – retailers hire additional staff, suppliers increase production, and service providers expand operations – creating a multiplier effect where each dollar saved generates more economic output, further amplifying the credit's local economic impact.

Third, including the ITC provides a more accurate representation of the actual economics facing solar adopters by substantially reducing upfront installation costs. Reducing the upfront burden of purchasing a solar resource makes it easier for a larger group of people and businesses to add BTM solar.

Fourth, the ITC represents established federal energy policy specifically designed to accelerate renewable energy adoption nationwide. Excluding the ITC from a solar-specific cost-benefit analysis would disregard these congressionally enacted policies and dramatically understate the true benefits created by net metered solar and lead to flawed policy decisions based on incomplete financial information.

2.3.2 Local Economic Value Added

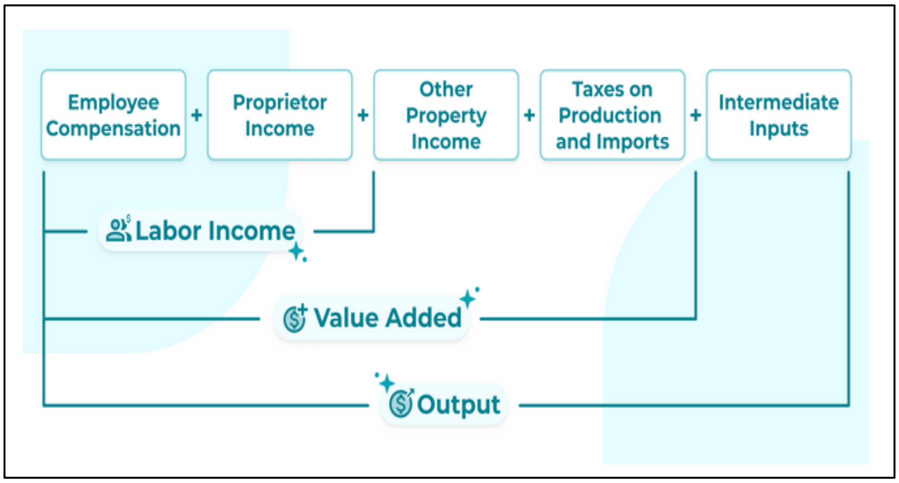
Value added refers to the increased spending on local goods and services created by BTM solar. The additional economic activity is driven by increased hiring to build and maintain customer-sited solar and manufacturing of components (if done locally), which, in turn, increases local tax revenues and consumer spending throughout the local economy. The value added comes from both the initial project

[28] Lawrence Berkeley National Laboratory. (2024). *Tracking the sun: Pricing and design trends for distributed photovoltaic systems in the United States* (2024 ed.).

development and the long-term reduction in external energy purchases, keeping more money circulating within the local economy rather than flowing to external service providers.

To measure the potential value added from building more BTM solar in Delaware, we relied on IMPLAN, which is an economic impact analysis and planning model designed to evaluate how economic activities ripple through regional and national economies. It maps the relationships between industries, showing how spending in one sector affects others through supply chains and consumer spending.

Figure 9: IMPLAN Value Added Components[29]



In an IMPLAN analysis, value-added represents the difference between an industry's total output and the cost of its intermediate inputs. This includes employee compensation, business owner income, other property income, and tax payments. Value-added effectively measures an activity's contribution to the regional gross domestic product. The model also accounts for regional differences in supply chains, labor markets, and spending patterns to provide realistic economic estimates for specific locations.

IMPLAN's analysis for BTM solar's value-added is based on detailed cost breakdowns of installation components and regional economic data. Key inputs include hardware costs (modules, inverters, racking), labor costs (installation, electrical work), soft costs (permitting, customer acquisition), and regional economic multipliers specific to the Report location. The modeling process maps these costs to relevant NAICS/IMPLAN[30] sectors and applies regional multipliers to calculate direct effects (immediate economic activity from installation), indirect effects (supply chain impacts), and induced effects (household spending impacts). Key outputs include employment impacts, labor income, value added (GDP contribution), tax revenues, and total economic output.

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[29] IMPLAN. (n.d.). Understanding Output.

[30] The North American Industry Classification System (NAICS) is the standard used by Federal statistical agencies in classifying business establishments for the purpose of collecting, analyzing, and publishing statistical data related to the U.S. business economy. U.S. Census Bureau. (n.d.). Introduction to NAICS. U.S. Department of Commerce.

For BTM solar, direct effects primarily come from construction and installation activities, while indirect effects stem from equipment manufacturing and professional services. BTM solar typically generates higher value-added impacts because more of the project spending occurs locally compared to utility-scale installations. BTM projects require more local labor for site assessment, design, installation, and maintenance since they involve many small distributed systems rather than a single large facility. These projects often engage local contractors, electricians, and other service providers, leading to higher local employment multipliers.

Additionally, BTM solar installations frequently involve local supply chains for equipment distribution and project management, whereas utility-scale projects tend to procure materials and specialized services from national or international suppliers. The distributed nature of BTM projects also means that more of the ongoing maintenance and operational spending remains within the local economy, contributing to sustained economic impacts over time through both direct and indirect effects in IMPLAN analysis.

The IMPLAN analysis indicates that **each additional MW of BTM solar supports 22 local jobs and creates $2.1 million in total value-added benefits** (present value) for the local economy in Delaware.

2.4 Societal Benefits

Societal benefits represent the economic value of reducing fossil-fuel emissions and power outages. Generating power from BTM solar reduces emissions from fossil fuel-power generation resources, including both direct emissions from generating electricity and indirect emissions from activities like fuel extraction and transportation. Solar can also improve grid reliability by reducing strain on the electric system during peak usage times, which can help reduce the risk of power outages and associated costs of reduced productivity and economic output.

2.4.1 Social Cost of Emissions (Scopes 1 and 2)

The social cost of emissions refers to a range of harmful consequences from climate change (e.g., reduced agricultural yields, health impacts from extreme weather, infrastructure damage, etc.). BTM solar can mitigate the costs of these harms by reducing the need for energy supplied by fossil fuel-powered generation resources.

Avoidable emissions costs can represent a significant portion of BTM solar's total value stack. Quantifying avoidable emissions costs enables policymakers to properly value BTM solar's contribution to meeting state and federal emissions reduction targets. Without including these costs, VOS studies would undervalue one of solar's primary benefits. As grid decarbonization targets become more ambitious, the proper valuation of avoided emissions will become increasingly important for accurate resource planning and policy development. As explained previously, however, our analysis separates the value of avoided emissions from the other value stack components to provide a clear delineation of the direct and societal benefits.

Emissions Types

The primary types of emissions and pollutants caused by generating energy from fossil fuels include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), particulate matter ($PM_{2.5}$), sulfur dioxide (SO_2), and nitrogen oxides (NO_x).

CO_2 is the primary greenhouse gas produced when burning fossil fuels. It traps heat in the atmosphere and can persist for hundreds of years, making it the leading driver of long-term climate change. CH_4 is released during natural gas extraction and transport. Though it breaks down faster than CO_2, CH_4 traps significantly more heat within the atmosphere. N_2O is another potent greenhouse gas that forms during fossil fuel combustion. $PM_{2.5}$ consists of microscopic particles released during combustion that can penetrate deep into lungs, causing respiratory and cardiovascular issues. SO_2 and NO_x are produced when burning fossil fuels that contain sulfur, which can cause acid rain, respiratory problems, and contribute to smog formation.

These pollutants are widespread due to the dominance of fossil fuels in power generation. While some pollutants like $PM_{2.5}$ settle relatively quickly, others like CO_2 persist in the atmosphere over decades. Transitioning from fossil fuel power plants to clean energy would directly reduce all emissions, however, as renewable sources produce no direct air pollutants during operation. This would improve both climate and public health outcomes, with benefits occurring at local, national, and global scales.

Emissions Classifications

The Greenhouse Gas Protocol classifies emissions into three "scopes":

- Scope 1 emissions refer to direct emissions from sources that an organization owns or controls directly. These include emissions from company-owned vehicles, on-site fuel combustion in boilers or furnaces, and any industrial processes or chemical production within the organization's facilities.

- Scope 2 emissions encompass indirect emissions from purchased electricity, steam, heating, and cooling that the organization consumes. While these emissions occur at facilities owned by utilities or energy providers, they are attributed to the organizations that use this energy. This classification helps companies understand and manage their energy consumption's carbon footprint, even though if they do not directly produce these emissions.

- Scope 3 emissions comprise all other indirect emissions that occur throughout an organization's value chain. This includes upstream emissions from suppliers, purchased goods and services, and downstream emissions from the use and disposal of products, investments, and leased assets. Scope 3 emissions can represent a significant portion of a company's carbon footprint but can be challenging to measure because they occur outside the company's direct control and may not be tracked with the same precision or consistency as Scopes 1 and 2 emissions.

This classification system serves several important purposes. It prevents double-counting of emissions across organizations, establishes clear boundaries for carbon accounting, and helps companies identify where they have the most significant opportunities for emissions reduction. The system also enables organizations to prioritize their climate action efforts based on where they have the most control and influence over emissions sources.

Our analysis groups Scope 1 and Scope 2 emissions together because both relate to emissions from fossil fuel combustion for power generation. As solar capacity increases, it replaces or reduces reliance on fossil-fuel-based power plants, which are major sources of CO2 and other harmful pollutants. This reduction in fossil fuel consumption leads to lower overall emissions, contributing to a decrease in the social costs associated with climate change, such as health impacts and environmental damage. Scope 3 emissions are evaluated separately, as these emissions cover indirect upstream and downstream impacts like fuel extraction and decommissioning, while Scopes 1 and 2 cover direct operational emissions.

Social Costs

To estimate the avoidable emissions costs (Scopes 1 and 2) for CO2, CH4, and N2O, we relied on the EPA's November 2023 report, "Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances." For PM2.5, SO2, and NOX, we relied on the EPA's September 2023 report, "Estimating the Benefit per Ton of Reducing Directly-Emitted PM2.5, PM2.5 Precursors and Ozone Precursors from 21 Sectors." These reports include estimates for the long-term economic damage caused by each category of emissions and pollutants.

Figure 10: EPA Social Cost of GHG[31]

Table ES.1: Estimates of the Social Cost of Greenhouse Gases (SC-GHG), 2020-2080 (2020 dollars)

	SC-GHG and Near-term Ramsey Discount Rate								
	$SC\text{-}CO_2$ *(2020 dollars per metric ton of CO_2)*			$SC\text{-}CH_4$ *(2020 dollars per metric ton of CH_4)*			$SC\text{-}N_2O$ *(2020 dollars per metric ton of N_2O)*		
Emission	Near-term rate			Near-term rate			Near-term rate		
Year	2.5%	2.0%	1.5%	2.5%	2.0%	1.5%	2.5%	2.0%	1.5%
2020	120	190	340	1,300	1,600	2,300	35,000	54,000	87,000
2030	140	230	380	1,900	2,400	3,200	45,000	66,000	100,000
2040	170	270	430	2,700	3,300	4,200	55,000	79,000	120,000
2050	200	310	480	3,500	4,200	5,300	66,000	93,000	140,000
2060	230	350	530	4,300	5,100	6,300	76,000	110,000	150,000
2070	260	380	570	5,000	5,900	7,200	85,000	120,000	170,000
2080	280	410	600	5,800	6,800	8,200	95,000	130,000	180,000

Values of $SC\text{-}CO_2$, $SC\text{-}CH_4$, and $SC\text{-}N_2O$ are rounded to two significant figures. The annual unrounded estimates are available in Appendix A.5 and at: https://www.epa.gov/environmental-economics/scghg.

[31] U.S. Environmental Protection Agency. "EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances." November 2023.

Figure 11: EPA Social Cost of Pollutants (2019$, 3% Discount Rate)[32]

Sector	PM2.5-Related Benefits				Ozone-Related Benefits	
	Directly emitted $PM_{2.5}$	*SO_2*	*NO_x*	*NH_3*	*NO_x*	*VOC*
Brick kilns	$223,000	$43,100	$26,600	$128,000	$83,700	$11,400
Cement kilns	$153,000	$41,400	$14,300	$63,100	$73,200	$17,900
Coke ovens	$280,000	$52,300	$25,300	--	$65,300	$35,500
Electric arc furnaces	--	$44,700	$18,700	--	$77,800	$6,820
Ferroalloy facilities	$148,000	$44,200	$15,300	--	$102,000	$7,680
Gasoline distribution	--	--	--	--	--	$6,800
Industrial Boilers	$188,000	$41,300	$14,900	$84,400	$68,900	$14,000
Integrated iron & steel	$375,000	$52,500	$23,200	$188,000	$74,300	$14,200
Internal Combustion Engines	$162,000	$37,700	$10,500	$73,400	$58,200	$9,040
Iron and steel foundries	$257,000	$53,100	$23,600		$90,000	$7,860
Oil and natural gas	$95,900	$18,900	$7,900	$23,600	$47,700	$1,780
Oil and natural gas transmission	$136,000	$29,000	$13,400	$72,700	$65,000	$7,960
Paint stripping	--	--	--	--	--	$6,820
Primary copper smelting	--	$9,830	$4,080	--	$52,600	--
Pulp and paper	$141,000	$38,200	$10,900	$50,000	$80,400	$2,260
Refineries	$358,000	$49,600	$22,500	$109,000	$61,100	$12,200
Residential woodstoves	$465,000	$33,900	$32,400	$197,000	$41,400	$13,000
Secondary lead smelters	--	$43,200	$23,000	--	$96,400	--
Synthetic organic chemical	$137,000	$41,600	$16,600	$69,300	$74,600	$5,890
Taconite mining	$60,800	$32,400	$9,150	--	$48,600	$31,500
EAF & IIS (combined)	$368,000	$51,300	$22,400	$188,000	$74,900	$12,100
Electricity generating units	$110,000	$55,200	$7,470	--	$95,500	--

[32] U.S. Environmental Protection Agency. "Technical Support Document Estimating the Benefit per Ton of Reducing Directly-Emitted PM2.5, PM2.5 Precursors and Ozone Precursors from 21 Sectors" September 2023.

Figure 12: EPA Social Cost of Pollutants (2019$, 7% Discount Rate)[33]

Sector	PM2.5-Related Benefits				Ozone-Related Benefits	
	Directly emitted $PM_{2.5}$	*SO_2*	*NO_x*	*NH_3*	*NO_x*	*VOC*
Brick kilns	$200,000	$38,800	$23,900	$115,000	$75,000	$10,200
Cement kilns	$138,000	$37,200	$12,800	$56,700	$65,500	$16,000
Coke ovens	$252,000	$47,000	$22,700	--	$58,500	$31,800
Electric arc furnaces	--	$40,200	$16,800	--	$69,600	$6,110
Ferroalloy facilities	$133,000	$39,700	$13,700	--	$91,300	$6,880
Gasoline distribution	--	--	--	--	--	$6,080
Industrial Boilers	$169,000	$37,200	$13,400	$75,800	$61,700	$12,500
Integrated iron & steel	$337,000	$47,200	$20,800	$169,000	$66,500	$12,700
Internal Combustion Engines	$145,000	$33,900	$9,400	$66,000	$52,100	$8,090
Iron and steel foundries	$231,000	$47,700	$21,200		$80,600	$7,040
Oil and natural gas	$86,100	$17,000	$7,100	$21,200	$42,700	$1,590
Oil and natural gas transmission	$122,000	$26,100	$12,000	$65,300	$58,200	$7,120
Paint stripping	--	--	--	--	--	$6,100
Primary copper smelting	--	$8,830	$3,670	--	$47,000	--
Pulp and paper	$127,000	$34,400	$9,780	$44,900	$72,000	$2,030
Refineries	$322,000	$44,500	$20,200	$97,800	$54,600	$10,900
Residential woodstoves	$418,000	$30,500	$29,200	$177,000	$37,100	$11,700
Secondary lead smelters	--	$38,800	$20,700	--	$86,300	--
Synthetic organic chemical	$123,000	$37,400	$15,000	$62,300	$66,800	$5,270
Taconite mining	$54,600	$29,100	$8,220	--	$43,500	$28,200
EAF & IIS (combined)	$331,000	$46,100	$20,100	$169,000	$67,100	$10,900
Electricity generating units	$98,400	$49,700	$6,710	--	$85,400	--

We note that EPA's analysis includes multiple valuations using different discount rate assumptions: 1.5%, 2.0%, and 2.5% for the emissions costs estimates and 3.0% and 7.0% for the pollutants costs estimates. The EPA uses different discount rates to account for how we value future climate impacts compared to present-day costs. A lower discount rate places more value on future impacts, resulting in higher cost estimates. Higher discount rates reduce the present value of future damages, leading to lower cost estimates.

The choice of discount rate reflects a moral and practical judgment about how much weight to give to impacts on future generations versus present-day costs of emissions reductions. For environmental policy, this is particularly significant because climate change impacts unfold over long time horizons. The discount rate chosen can dramatically affect whether climate policy appears cost-effective. Lower rates tend to justify more aggressive near-term action, while higher rates suggest a more gradual approach. By providing multiple scenarios, the EPA allows decision-makers to understand these tradeoffs while acknowledging the underlying uncertainty and ethical considerations in valuing future climate impacts.

For this Report, we selected EPA's 2.0% discount rate scenario as our Base Case scenario because it represents a balanced approach to valuing future environmental impacts. Given that the reports rely on different discount rates, we standardized the EPA's cost estimates using a 2.0% discount rate to ensure methodological consistency for all emissions and pollutants. This involved performing linear and

[33] U.S. Environmental Protection Agency. "Technical Support Document Estimating the Benefit per Ton of Reducing Directly-Emitted PM2.5, PM2.5 Precursors and Ozone Precursors from 21 Sectors" September 2023.

logarithmic interpolations of the relationship between discount rates and social costs and then averaging these results to generate a composite valuation consistent with the EPA’s 2.0% discount rate scenario.

We also developed an inflation adjustment factor to escalate the EPA's valuations to the current year dollar values using the U.S. Bureau of Labor Statistics (BLS) Consumer Price Index (CPI). This approach ensures that the emissions costs reflect current economic conditions and EPA’s latest scientific understanding of greenhouse gas impacts.

Emissions Rates

Emissions rates relate to the amount of greenhouse gases released per unit of electricity produced by different types of electricity generation resources. Less efficient resources tend to have higher emissions rates than more efficient resources. Given that the Companies purchase energy from the PJM marketplace, the avoidable emissions from BTM solar in Delaware depend on the emission rates for the mix of power sources (e.g., coal, natural gas, renewables, etc.) used throughout the PJM region at different times.

To identify a representative emissions rate for this Report, we relied on historical emissions data from the EPA’s eGRID database for the PJM region. We chose to use PJM-wide emissions rates rather than Delaware-specific data because PJM operates as an integrated power market that dispatches and moves power across state boundaries. When BTM solar reduces electricity demand in Delaware, it affects the marginal generator that PJM would have dispatched to meet that demand – a unit that could be located anywhere within PJM's footprint based on economic dispatch principles. Delaware's relatively small generation fleet and state-specific average emissions rates would not accurately capture these cross-border dispatch effects or represent the true emissions impact.

Next, we calculated average emissions rates using the most recent three years of EPA data. This timeframe strikes a balance between capturing recent grid trends and maintaining statistical validity by minimizing the impact of extremes in emissions from one year to the next. A single year of data could be distorted by temporary anomalies such as unusual weather events or fuel price volatility, while using longer periods risks relying on an outdated resource mix that no longer reflects current conditions, particularly given the rapid pace of the energy transition in the region.

The final step involved converting EPA's emissions rates from pounds per megawatt-hour (lb/MWh) to metric tons per megawatt-hour (mt/MWh). This conversion aligns our analysis with the EPA's social cost metrics for greenhouse gases, which are denominated in dollars per metric ton ($/mt).

Cost Analysis

We estimated the total avoidable emissions by multiplying the emissions rates (mt/MWh) by the assumed amount of generation from BTM solar in the State (MWh/yr). Next, we multiplied this total by the emissions costs ($/mt). This produces annual dollar totals ($/yr) for the total avoidable emissions from BTM solar over the ten-year study period.

2.4.2 Social Cost of Emissions (Scope 3)

Avoided Scope 3 emissions represent the indirect greenhouse gas emissions that can be reduced throughout the energy supply chain when customers generate their own power using BTM solar. These emissions are distinct from those caused by power generation for self-supply (Scope 1) and purchased electricity (Scope 2).

The primary avoidable Scope 3 emissions are those associated with fuel extraction, processing, and transportation that would otherwise be needed to support traditional power generation resources. When customers generate solar power on-site, they reduce the need for fossil fuels to be extracted, refined, and delivered to power plants. This includes emissions from activities like coal mining, natural gas drilling and processing, pipeline operations, and fuel transportation by truck, rail, or ship.

Our analysis relies on data from NREL's study of "Life Cycle Emissions Factors for Electricity Generation Technologies,"[34] which evaluates lifecycle emissions across multiple power plant technologies, from initial construction through final decommissioning, with results normalized to grams of CO2 per kilowatt-hour (gCO2/kWh). NREL's findings are based on a review of approximately 3,000 published studies on utility-scale power generation and energy storage technologies.

Using NREL's findings, we identified the total lifecycle emissions for three key generation types: roof-mounted solar photovoltaic arrays, natural gas combined cycle plants, and natural gas combustion turbines. To prevent double-counting with the Scope 1 and 2 analysis, we excluded ongoing combustion-related emissions by subtracting these values from the total lifecycle emissions for each resource type.

We then calculated an average of the adjusted lifecycle emissions totals for the two natural gas generation types. This approach reflects a simplifying assumption that either a combined cycle or combustion turbine would be the most likely utility-scale resource used to meet system demand in the absence of BTM solar. As explained earlier in this Report, combined cycle and combustion turbine facilities are the predominant choice for new thermal generation capacity.

To align with the EPA's framework on the social cost of greenhouse gases, which values the social costs of emissions on a $/mt basis, we converted the emissions data from grams of CO2 equivalent per kilowatt-hour (gCO2/kWh) to metric tons per megawatt-hour (mtCO2/MWh). Lastly, we calculated the avoidable emissions costs by applying the same methodology and data used in the Scopes 1 and 2 analysis outlined above.

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[34] Nicholson, Scott, and Garvin Heath. 2021. "Life Cycle Emissions Factors for Electricity Generation Technologies." NREL Data Catalog. Golden, CO: National Renewable Energy Laboratory. Last updated: January 21, 2025. DOI: 10.7799/1819907.

This approach provides a standardized comparison of emissions impacts while maintaining consistency with established frameworks for emissions cost evaluation. Additionally, it accounts for the full environmental impact of different generation options while avoiding any double-counting of emissions between scope categories.

2.4.3 Value of Lost Load

Value of Lost Load (VOLL) represents the cost that electricity customers are willing to pay to avoid a power outage. Grid operators and regulators use VOLL to make decisions about power system investments and operations, cap energy and reserve market prices when the grid experiences supply shortfalls, and set reliability standards and reserve requirements by quantifying the economic value of grid reliability.

We use VOLL as the starting point for estimating the avoidable cost of power system outages due to generation supply shortfalls. Though BTM solar can help reduce these types of outages, its ability to do so is constrained by the intermittency of solar irradiance and limitations of common inverter technologies that are unable to operate during power outages. To account for these limitations, we scale down the VOLL estimate using an adjustment factor that approximates the (A) probability outages caused by power system failures rather than external factors and (B) ability of BTM solar to reliably support critical system demand.

VOLL Estimate

For the VOLL component, our analysis relies on a composite average of recent VOLL estimates developed by MISO and ERCOT. Reliance on these RTOs is necessary because PJM does not have an internal VOLL estimate. Instead, it relies on "shortage pricing" to incentivize resources to quickly respond to reserve shortages and prevent power system failures. For example, in a January 2024 fact sheet on shortage pricing, PJM notes that in some instances, emergency demand response, emergency purchases, and demand resources can set the price of energy up to $2,000/MWh.[35] PJM is also investigating whether VOLLs developed by other ISOs can be used to strengthen PJM's long-term system needs and maintain system reliability. For example, in a November 2024 report addressing recent shortage pricing efforts, PJM notes that MISO recommended increasing its VOLL from $3,500/MWh to $10,000/MWh.[36] Separately, in a January 2024 report, ERCOT notes that a recent review of its outage and customer data supports VOLLs ranging from $5,122/MWh for residential customers to $102,490/MWh for small commercial and industrial customers.[37] The average of these benchmarks yields a composite VOLL of $39,204/MWh.

[35] PJM Interconnection, LLC. Shortage Pricing Fact Sheet. 2024.

[36] PJM Interconnection, LLC. Recent Shortage Pricing Efforts, Update to PJM Reserve Certainty Senior Task Force. November 2024.

[37] Electric Reliability Council of Texas. Value of Lost Load (VOLL) Study Update. January 2024.

Outage Probability Estimate

To estimate the probability of experiencing a generation supply shortfall-related outage, we relied on historical records for outages using data provided by EIA and the North American Electric Reliability Corporation (NERC).[38] [39]

The EIA data includes the total number of minutes of distribution system-related electric interruptions Delaware customers experienced over the past 10 years, grouped into one of three categories: events with major event days, events without major event days, and events with loss of supply removed. The first category, events with major event days, includes events that are beyond the design and/or operational limits of utilities (e.g., major weather events, catastrophes, etc.). The second category, events without major event days, excludes these extreme events but may include events caused by the loss of supply from the high-voltage/bulk power system. The third category, events with loss of supply removed, excludes events caused by the loss of supply from the high-voltage/bulk power system. Our analysis relies on the lesser of the minutes for events without major event days and those for events with loss of supply removed. We excluded major event days because they represent events that cannot be avoided by typical grid management practices. We also excluded events without major event days when the number of event minutes exceeded those for events with loss of supply removed. Using the lesser of these two event categories mitigates the potential for double-counting event minutes with the second phase of this analysis, which includes events caused by the loss of supply from the high-voltage/bulk power system.

The NERC data includes historical transmission system outage hours by year, cause, and region. For the year component, we included data from 2019 through 2023, which matches the time horizon used to develop the distribution-related outages addressed above. For the outage cause component, we included only outages that were labeled as being caused by "power system conditions." Other categories of causes include equipment failures, fires, human error, weather, vandalism, and vegetation. We excluded these categories because they are less representative of potential power system-related supply-demand imbalances. Over the past five years, power system conditions have driven less than 1% of the total transmission-related outages included in the NERC dataset. For the region component, we excluded all outages outside of the Reliability First (RF) region, which includes Delaware. To isolate Delaware's share of RF outages, we multiplied the average annual RF outages due to power system conditions by the ratio of Delaware's historical average customer sales to those of the entire RF region using EIA data. On average, Delaware's customer sales represent less than 2% of the RF region sales.

Taken together, this analysis indicates that the probability of generation supply-related electric interruptions impacting the transmission and distribution in Delaware is just 0.09%.

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[38] U.S. Energy Information Administration. Table 11.4 SAIDI Values (Minutes Per Year) of U.S. Distribution System by State, 2013 – 2023.

[39] North American Electric Reliability Corporation. Transmission Availability Data System (TADS). TADS Dashboard Supporting Data.

<u>BTM Solar Reliability Contribution Estimate</u>

To estimate the probability of BTM solar being online and operational during critical demand periods, we rely on PJM's ELCC rating for fixed-tilt solar. As noted previously, ELCC reflects the resource's contribution to system reliability, considering not just its capacity, but also its availability during critical times like hot summer afternoons when electricity demand peaks and the risk of supply-demand imbalances may be highest. PJM's ELCC rating for fixed-tilt solar, 8%, means that for every 100 MW of installed BTM solar capacity, only 8 MW can be relied on to meet critical system demand.

<u>DE BTM Solar-Adjusted VOLL</u>

Lastly, we multiply the outage probability (0.09%) by solar's ELCC rating (8.00%). This produces a composite outage mitigation factor (0.01%) unique to net metered solar in Delaware. Applying this factor to the value customers would pay to avoid outages ($39,204/MWh) indicates that BTM solar's contribution to preventing outages is worth $3.51/MWh on a levelized basis over the next ten years. This represents the real-world value of BTM solar in helping to prevent power supply disruptions, accounting for both how rarely these specific types of outages occur and how often solar power is actually available when needed.

3 Scenario Analysis

This section of the Report summarizes how we quantified the total BTM solar value stack over the next 10 years for two scenarios:

- Scenario A: Status Quo Net Metering Deployment Case
- Scenario B: Accelerated Net Metering Deployment Case

3.1 Scenario A: Status Quo Net Metering Deployment Case

Scenario A establishes a central reference point that aligns with current regulatory and market conditions, providing decision-makers with a realistic assessment of BTM solar's value proposition under "business-as-usual" conditions. The scenario assumes Delaware's net metered solar capacity reaches the current regulatory cap of 8% of the State's total peak demand by 2035,[40] with peak demand growing at a compound annual growth rate (CAGR) of 0.5% based on PJM's long-term forecast for the DPL zone.[41] We note that the projections begin with actual historical data from 2023, as this is the most recent year in which EIA has published data for the Companies.[42] All subsequent years are projected using the growth assumptions noted above.

[40] We note that discovery responses provided as part of this analysis indicates that DEC has already reached the 8% cap. Therefore, we assume DEC's ratio of installed net metered capacity to peak demand remains fixed at the same value observed in the historical data provided by DEC.

[41] PJM Interconnection, LLC. PJM Load Forecast Report. January 2024.

[42] U.S. Energy Information Administration. Annual Electric Power Industry Report, Form EIA-861 detailed data files.

Figure 13: Peak Demand MW Projections (Scenario A)

Stdy Period	Year	Total	DPL	DEC	DEMEC
1	2026	4,990	4,036	478	475
2	2027	5,015	4,056	481	478
3	2028	5,039	4,076	483	480
4	2029	5,064	4,097	485	482
5	2030	5,089	4,117	488	485
6	2031	5,115	4,137	490	487
7	2032	5,140	4,158	493	490
8	2033	5,165	4,178	495	492
9	2034	5,191	4,199	498	494
10	2035	5,217	4,220	500	497

Figure 14: Net Metered Solar Capacity Share of Peak Demand (Scenario A)

Stdy Period	Year	Total	DPL	DEC	DEMEC
1	2026	4.04%	3.74%	8.01%	3.52%
2	2027	4.48%	4.22%	8.01%	4.02%
3	2028	4.92%	4.69%	8.01%	4.52%
4	2029	5.36%	5.16%	8.01%	5.01%
5	2030	5.80%	5.64%	8.01%	5.51%
6	2031	6.24%	6.11%	8.01%	6.01%
7	2032	6.68%	6.58%	8.01%	6.51%
8	2033	7.12%	7.05%	8.01%	7.00%
9	2034	7.56%	7.53%	8.01%	7.50%
10	2035	8.00%	8.00%	8.01%	8.00%

Figure 15: Installed Net Metered Solar Capacity MW (Scenario A)

Stdy Period	Year	Total	DPL	DEC	DEMEC
1	2026	206	151	38	17
2	2027	229	171	39	19
3	2028	252	191	39	22
4	2029	275	211	39	24
5	2030	298	232	39	27
6	2031	321	253	39	29
7	2032	345	274	39	32
8	2033	369	295	40	34
9	2034	393	316	40	37
10	2035	417	338	40	40

These projections serve as the basis for quantifying the BTM solar value stack benefits, with higher amounts of BTM solar generally resulting in higher benefits.

The tables below summarize the total value stack benefits for Scenario A:

Figure 16: Scenario A (Status Quo) Solar Value Stack 10-Yr Levelized Value ($/kWh)

Primary Category	Secondary Category	Benefit Type	DE Wtd Avg	DPL	DEC	DEMEC
Direct	Avoidable Utility Expense	Energy Generation Fixed Costs	0.0002	-	0.0001	0.0022
Direct	Avoidable Utility Expense	Energy Generation Variable Costs	-	-	-	-
Direct	Avoidable Utility Expense	Energy Generation Hedge Costs	0.0021	0.0029	-	-
Direct	Avoidable Utility Expense	Purchased Power Costs	0.0766	0.0766	0.0766	0.0766
Direct	Avoidable Utility Expense	RPS Compliance Costs	0.0056	0.0078	0.0002	0.0002
Direct	Avoidable Utility Expense	T&D Costs	0.0059	0.0062	0.0063	0.0032
Direct	Market Price Impacts	Energy DRIPE	0.0013	0.0013	0.0013	0.0013
Direct	Market Price Impacts	Energy Redispatch Costs	-	-	-	-
Direct	Market Price Impacts	Capacity DRIPE	0.0376	0.0376	0.0376	0.0376
Direct	Market Price Impacts	Ancillary Services DRIPE	0.0006	0.0006	0.0006	0.0006
Direct	Economic Benefits	Tax Credits	0.0615	0.0615	0.0615	0.0615
Societal	Economic Benefits	Local Value Added	0.0847	0.0847	0.0847	0.0847
Societal	Avoidable Societal Damages	Emissions Scopes 1 & 2 Costs	0.2918	0.2918	0.2918	0.2918
Societal	Avoidable Societal Damages	Emissions Scope 3 Costs	0.0047	0.0047	0.0047	0.0047
Societal	Avoidable Societal Damages	Value of Lost Load	0.0035	0.0035	0.0035	0.0035
Direct Total			**0.1913**	**0.1944**	**0.1841**	**0.1832**
Societal Total			**0.3848**	**0.3848**	**0.3848**	**0.3848**
Overall Total			**0.5761**	**0.5792**	**0.5689**	**0.5680**

Figure 17: Scenario A (Status Quo) Solar Value Stack 10-Yr NPV ($000)

Primary Category	Secondary Category	Benefit Type	DE Total	DPL	DEC	DEMEC
Direct	Avoidable Utility Expense	Energy Generation Fixed Costs	678	-	41	637
Direct	Avoidable Utility Expense	Energy Generation Variable Costs	-	-	-	-
Direct	Avoidable Utility Expense	Energy Generation Hedge Costs	7,261	7,261	-	-
Direct	Avoidable Utility Expense	Purchased Power Costs	244,820	190,787	32,063	21,970
Direct	Avoidable Utility Expense	RPS Compliance Costs	19,491	19,338	91	62
Direct	Avoidable Utility Expense	T&D Costs	19,006	15,454	2,631	921
Direct	Market Price Impacts	Energy DRIPE	4,039	3,148	529	362
Direct	Market Price Impacts	Energy Redispatch Costs	-	-	-	-
Direct	Market Price Impacts	Capacity DRIPE	120,330	93,773	15,759	10,798
Direct	Market Price Impacts	Ancillary Services DRIPE	1,940	1,512	254	174
Direct	Economic Benefits	Tax Credits	196,621	153,226	25,751	17,644
Societal	Economic Benefits	Local Value Added	270,831	211,057	35,470	24,304
Societal	Avoidable Societal Damages	Emissions Scopes 1 & 2 Costs	933,368	727,369	122,240	83,758
Societal	Avoidable Societal Damages	Emissions Scope 3 Costs	15,168	11,820	1,986	1,361
Societal	Avoidable Societal Damages	Value of Lost Load	11,222	8,746	1,470	1,007
Direct Total			**614,188**	**484,499**	**77,120**	**52,569**
Societal Total			**1,230,588**	**958,992**	**161,167**	**110,430**
Overall Total			**1,844,776**	**1,443,490**	**238,287**	**162,999**

The Scenario A total value stack benefits for the State equal $1.8 billion on a present value basis over the next 10 years ($0.58/kWh), with approximately $614 million in direct benefits ($0.19/kWh) and $1.2 billion in societal benefits ($0.38/kWh). This distinction illustrates that even when excluding the broader societal benefits, the value of expanding net metering through BTM solar can still yield significant value to the State.

The primary drivers of the value are avoidable power purchases, local economic value added, and avoidable emissions costs (Scopes 1 and 2).

Avoidable emissions comprise the largest share of the total value stack due to the extensive harms and costly impacts of emissions on health outcomes, agricultural productivity, property damage, and infrastructure losses.

Local economic value added also comprises a large portion of the total value stack due to BTM solar's distributed workforce of local installers, electricians, sales representatives, and project managers who live and spend their wages in the community. Each project needs custom design, permitting, and ongoing maintenance, creating sustained local jobs. Additionally, BTM solar's building-by-building approach can generate recurring business opportunities for local contractors and may require partnerships with Energize Delaware residential and commercial loan programs, community banks, credit unions, and other local financial institutions for project financing. This distributed model may also keep more of the project soft costs – such as customer acquisition, system design, and permitting – within the local economy rather than flowing to external engineering firms or corporate headquarters, which may be more likely to occur with centralized, utility-scale projects.

Avoidable power purchases and tax credits also comprise a relatively large portion of the direct benefits. As noted previously, the Companies rely heavily on purchased power to supply customer demand, meaning that a large portion of the Companies' customer charges can be avoided from BTM solar. And because solar power generation typically coincides with periods of on-peak system demand when power prices are high, installing more BTM solar provides the additional benefit of avoiding costlier on-peak energy prices.

3.2 Scenario B: Accelerated Net Metering Deployment Case

Scenario B reflects the potential upside of deploying higher amounts of BTM solar in Delaware consistent with the levels achieved in neighboring states. This scenario also reflects higher load growth to account for potential increases in electrification, data center deployments, electric vehicles, and other factors driving load growth across PJM. Our findings are intended to provide stakeholders with an expanded foundation to understand the potential upside from accelerated BTM solar deployments beyond the current regulatory constraints.

This scenario models a comparatively stronger BTM solar adoption pathway where Delaware's net metered capacity reaches 18% of its total peak demand by 2035. This benchmark reflects the average penetration rates observed in the neighboring states of New Jersey and Maryland as of 2023.[43]

[43] U.S. Energy Information Administration. Annual Electric Power Industry Report, Form EIA-861 detailed data files.

Figure 18: Peak Demand MW Projections (Scenario B)

Stdy Period	Year	Total	DPL	DEC	DEMEC
1	2026	5,062	4,096	483	482
2	2027	5,112	4,137	488	487
3	2028	5,162	4,178	493	492
4	2029	5,214	4,219	498	497
5	2030	5,265	4,261	503	502
6	2031	5,317	4,303	507	507
7	2032	5,370	4,346	513	512
8	2033	5,423	4,389	518	517
9	2034	5,477	4,432	523	522
10	2035	5,531	4,476	528	527

Figure 19: Net Metered Solar Capacity Share of Peak Demand (Scenario B)

Stdy Period	Year	Total	DPL	DEC	DEMEC
1	2026	6.59%	6.30%	9.87%	6.07%
2	2027	7.88%	7.62%	10.79%	7.42%
3	2028	9.18%	8.94%	11.72%	8.77%
4	2029	10.47%	10.27%	12.65%	10.12%
5	2030	11.76%	11.59%	13.57%	11.47%
6	2031	13.05%	12.92%	14.50%	12.82%
7	2032	14.34%	14.24%	15.43%	14.17%
8	2033	15.63%	15.56%	16.36%	15.51%
9	2034	16.92%	16.89%	17.28%	16.86%
10	2035	18.21%	18.21%	18.21%	18.21%

Figure 20: Installed Net Metered Solar Capacity MW (Scenario B)

Stdy Period	Year	Total	DPL	DEC	DEMEC
1	2026	335	258	48	29
2	2027	404	315	53	36
3	2028	475	374	58	43
4	2029	546	433	63	50
5	2030	620	494	68	58
6	2031	694	556	74	65
7	2032	770	619	79	72
8	2033	848	683	85	80
9	2034	927	749	90	88
10	2035	1,007	815	96	96

Based on these alternative assumptions, Scenario B demonstrates that Delaware can create significant additional value by expanding its net metering cap beyond the current limit of 8%:

Figure 21: Scenario B (Accelerated Net Metering Growth) Solar Value Stack ($/kWh)

Primary Category	Secondary Category	Benefit Type	DE Wtd Avg	DPL	DEC	DEMEC
Direct	Avoidable Utility Expense	Energy Generation Fixed Costs	0.0002	-	0.0001	0.0022
Direct	Avoidable Utility Expense	Energy Generation Variable Costs	0.0003	-	-	0.0017
Direct	Avoidable Utility Expense	Energy Generation Hedge Costs	0.0021	0.0029	-	-
Direct	Avoidable Utility Expense	Purchased Power Costs	0.0759	0.0759	0.0759	0.0759
Direct	Avoidable Utility Expense	RPS Compliance Costs	0.0056	0.0078	0.0002	0.0002
Direct	Avoidable Utility Expense	T&D Costs	0.0059	0.0062	0.0063	0.0032
Direct	Market Price Impacts	Energy DRIPE	0.0020	0.0020	0.0020	0.0020
Direct	Market Price Impacts	Energy Redispatch Costs	-	-	-	-
Direct	Market Price Impacts	Capacity DRIPE	0.0376	0.0376	0.0376	0.0376
Direct	Market Price Impacts	Ancillary Services DRIPE	0.0006	0.0006	0.0006	0.0006
Direct	Economic Benefits	Tax Credits	0.0615	0.0615	0.0615	0.0615
Societal	Economic Benefits	Local Value Added	0.0847	0.0847	0.0847	0.0847
Societal	Avoidable Societal Damages	Emissions Scopes 1 & 2 Costs	0.2918	0.2918	0.2918	0.2918
Societal	Avoidable Societal Damages	Emissions Scope 3 Costs	0.0047	0.0047	0.0047	0.0047
Societal	Avoidable Societal Damages	Value of Lost Load	0.0035	0.0035	0.0035	0.0035
Direct Total			**0.1917**	**0.1945**	**0.1842**	**0.1850**
Societal Total			**0.3848**	**0.3848**	**0.3848**	**0.3848**
Overall Total			**0.5765**	**0.5793**	**0.5690**	**0.5698**

Figure 22: Scenario B (Accelerated Net Metering Growth) Solar Value Stack 10-Yr NPV ($000)

Primary Category	Secondary Category	Benefit Type	DE Total	DPL	DEC	DEMEC
Direct	Avoidable Utility Expense	Energy Generation Fixed Costs	1,452	-	73	1,379
Direct	Avoidable Utility Expense	Energy Generation Variable Costs	1,077	-	-	1,077
Direct	Avoidable Utility Expense	Energy Generation Hedge Costs	15,546	15,546	-	-
Direct	Avoidable Utility Expense	Purchased Power Costs	507,865	404,941	55,748	47,176
Direct	Avoidable Utility Expense	RPS Compliance Costs	41,698	41,403	159	135
Direct	Avoidable Utility Expense	T&D Costs	39,697	33,087	4,615	1,995
Direct	Market Price Impacts	Energy DRIPE	13,668	10,898	1,500	1,270
Direct	Market Price Impacts	Energy Redispatch Costs	-	-	-	-
Direct	Market Price Impacts	Capacity DRIPE	251,797	200,768	27,640	23,389
Direct	Market Price Impacts	Ancillary Services DRIPE	4,059	3,236	446	377
Direct	Economic Benefits	Tax Credits	411,440	328,057	45,164	38,219
Societal	Economic Benefits	Local Value Added	566,726	451,874	62,209	52,643
Societal	Avoidable Societal Damages	Emissions Scopes 1 & 2 Costs	1,953,117	1,557,299	214,393	181,425
Societal	Avoidable Societal Damages	Emissions Scope 3 Costs	31,739	25,307	3,484	2,948
Societal	Avoidable Societal Damages	Value of Lost Load	23,483	18,724	2,578	2,181
Direct Total			**1,288,298**	**1,037,937**	**135,344**	**115,017**
Societal Total			**2,575,066**	**2,053,204**	**282,664**	**239,198**
Overall Total			**3,863,364**	**3,091,141**	**418,008**	**354,215**

The Scenario B total value stack benefits for the State equal $3.9 billion on a present value basis over the next 10 years ($0.58/kWh), with approximately $1.3 billion in direct benefits ($0.19/kWh) and $2.6 billion in societal benefits ($0.38/kWh). These results indicate that if Delaware expands its net metering cap to a level that aligns with neighboring states, Delaware could realize benefits for all customers that are 2 times higher than those under the status quo (Scenario A).

4 Sensitivity Analysis

We also performed two sensitivity analyses focusing on quantifying the impact of using different assumptions for the emissions and reliability-related components of the value stack. Unlike the scenario analyses, which illustrate how using different load growth and BTM deployment assumptions impact each component of the value stack, the sensitivities modify just one component of the overall value stack to help stakeholders understand how these factors drive the overall results.

4.1 Sensitivity Analysis 1: High Emissions Benefits

The first sensitivity analysis examines how different approaches to valuing future emissions reductions affect the total benefits. This analysis compares the sensitivity of the avoidable emissions benefits when using a lower discount rate – 1.5% versus the baseline rate of 2.0% – while maintaining all other assumptions and steps from our core analysis.

The discount rate assumption is a crucial component of VOS analyses because avoidable emissions typically represent one of the largest drivers of the overall value stack and because the discount rate determines how we value future benefits in today's terms, with a lower discount rate placing greater value on future emissions reductions. The 1.5% discount rate reflects a plausible but pessimistic scenario that assumes emissions damages will be more costly in today's dollars than when valued using the baseline 2.0% discount rate assumption.

Figure 23: Sensitivity Case 1 (SC GHG @ 1.5%) 10-Yr Levelized Value ($/kWh)

Primary Category	Secondary Category	Benefit Type	DE Wtd Avg	DPL	DEC	DEMEC
Direct	Avoidable Utility Expense	Energy Generation Fixed Costs	0.0002	-	0.0001	0.0022
Direct	Avoidable Utility Expense	Energy Generation Variable Costs	-	-	-	-
Direct	Avoidable Utility Expense	Energy Generation Hedge Costs	0.0021	0.0029	-	-
Direct	Avoidable Utility Expense	Purchased Power Costs	0.0766	0.0766	0.0766	0.0766
Direct	Avoidable Utility Expense	RPS Compliance Costs	0.0056	0.0078	0.0002	0.0002
Direct	Avoidable Utility Expense	T&D Costs	0.0059	0.0062	0.0063	0.0032
Direct	Market Price Impacts	Energy DRIPE	0.0013	0.0013	0.0013	0.0013
Direct	Market Price Impacts	Energy Redispatch Costs	-	-	-	-
Direct	Market Price Impacts	Capacity DRIPE	0.0376	0.0376	0.0376	0.0376
Direct	Market Price Impacts	Ancillary Services DRIPE	0.0006	0.0006	0.0006	0.0006
Direct	Economic Benefits	Tax Credits	0.0615	0.0615	0.0615	0.0615
Societal	Economic Benefits	Local Value Added	0.0847	0.0847	0.0847	0.0847
Societal	Avoidable Societal Damages	Emissions Scopes 1 & 2 Costs	0.4272	0.4272	0.4272	0.4272
Societal	Avoidable Societal Damages	Emissions Scope 3 Costs	0.0081	0.0081	0.0081	0.0081
Societal	Avoidable Societal Damages	Value of Lost Load	0.0035	0.0035	0.0035	0.0035
Direct Total			**0.1913**	**0.1944**	**0.1841**	**0.1832**
Societal Total			**0.5235**	**0.5235**	**0.5235**	**0.5235**
Overall Total			**0.7148**	**0.7179**	**0.7076**	**0.7067**

Figure 24: Sensitivity Case 1 (SC GHG @ 1.5%) Solar Value Stack 10-Yr NPV ($000)

Primary Category	Secondary Category	Benefit Type	DE Total	DPL	DEC	DEMEC
Direct	Avoidable Utility Expense	Energy Generation Fixed Costs	678	-	41	637
Direct	Avoidable Utility Expense	Energy Generation Variable Costs	-	-	-	-
Direct	Avoidable Utility Expense	Energy Generation Hedge Costs	7,261	7,261	-	-
Direct	Avoidable Utility Expense	Purchased Power Costs	244,820	190,787	32,063	21,970
Direct	Avoidable Utility Expense	RPS Compliance Costs	19,491	19,338	91	62
Direct	Avoidable Utility Expense	T&D Costs	19,006	15,454	2,631	921
Direct	Market Price Impacts	Energy DRIPE	4,039	3,148	529	362
Direct	Market Price Impacts	Energy Redispatch Costs	-	-	-	-
Direct	Market Price Impacts	Capacity DRIPE	120,330	93,773	15,759	10,798
Direct	Market Price Impacts	Ancillary Services DRIPE	1,940	1,512	254	174
Direct	Economic Benefits	Tax Credits	196,621	153,226	25,751	17,644
Societal	Economic Benefits	Local Value Added	270,831	211,057	35,470	24,304
Societal	Avoidable Societal Damages	Emissions Scopes 1 & 2 Costs	1,366,375	1,064,810	178,950	122,615
Societal	Avoidable Societal Damages	Emissions Scope 3 Costs	25,850	20,145	3,385	2,320
Societal	Avoidable Societal Damages	Value of Lost Load	11,222	8,746	1,470	1,007
Direct Total			**614,188**	**484,499**	**77,120**	**52,569**
Societal Total			**1,674,278**	**1,304,757**	**219,275**	**150,246**
Overall Total			**2,288,466**	**1,789,256**	**296,396**	**202,815**

The Sensitivity Case 1 total value stack benefits for the State equal $2.3 billion on a present value basis over the next 10 years ($0.71/kWh), with approximately $614 million in direct benefits ($0.19/kWh) and $1.7 billion in societal benefits ($0.52/kWh). This analysis shows that using a lower discount rate, 1.5% instead of 2.0%, to value the social costs of emissions can increase the overall value of BTM solar to Delaware by $674 million on a present value basis over the next 10 years when compared with the status quo (Scenario A).

This approach places a higher value on the potential costs and societal harms from climate change, emphasizing the importance of mitigating future climate risks. A lower discount rate increases the value of avoided emissions and long-term environmental benefits, thus justifying stronger incentives for renewable energy adoption and an expanded net metering cap. In contrast, using a higher discount rate (e.g., 2.0%) could undervalue these long-term benefits, potentially slowing down the transition to a cleaner, more sustainable energy system.

4.2 Sensitivity Analysis 2: Battery Storage Reliability Benefits

The second sensitivity analysis evaluates how pairing BTM solar with battery storage affects power system reliability benefits. Testing the impact of including battery storage in the analysis helps quantify the additional grid reliability value that hybrid solar-plus-storage systems provide, which is an increasingly important consideration as extreme weather events become more common.

Pairing battery storage with BTM solar can improve the ability of net metered resources to mitigate power outages, particularly during times when solar power alone may not be sufficient. Battery storage allows residents and business with BTM solar to store excess energy generated during the day when the sun is shining and then use this stored energy in later periods as solar irradiance wanes but consumption of electricity remains high. This helps bridge the gap between solar generation and periods of critical system demand, ensuring that customer loads continue to be served even if the grid is down or unable to supply enough electricity.

To quantify the incremental reliability-related benefits, we modified two of the assumptions used in the Scenario analyses outlined previously in this Report. First, we replaced the ELCC rating for standalone roof-mounted solar with an average rating for solar-storage hybrid resources. Whereas standalone solar's ELCC rating is just 8%, standalone battery storage's ELCC rating is 57%. Averaging these values produces a composite rating of approximately 33%, which is 4 times greater than the value for standalone BTM solar. Second, we replaced the assumed operating capacity factor for standalone solar resources with a higher value that accounts for the ability of battery storage resources to augment the operational capabilities of co-located solar resources. According to NREL’s 2024 ATB, pairing battery storage with solar yields a capacity factor that is approximately 5% greater than that for standalone solar resources.

Apart from these two changes, the analysis followed the same approach, inputs, and assumptions from Scenario A.

Figure 25: Sensitivity Case 2 (PV+BESS) 10-Yr Levelized Value ($/kWh)

Primary Category	Secondary Category	Benefit Type	DE Wtd Avg	DPL	DEC	DEMEC
Direct	Avoidable Utility Expense	Energy Generation Fixed Costs	0.0002	-	0.0001	0.0022
Direct	Avoidable Utility Expense	Energy Generation Variable Costs	-	-	-	-
Direct	Avoidable Utility Expense	Energy Generation Hedge Costs	0.0021	0.0029	-	-
Direct	Avoidable Utility Expense	Purchased Power Costs	0.0766	0.0766	0.0766	0.0766
Direct	Avoidable Utility Expense	RPS Compliance Costs	0.0056	0.0078	0.0002	0.0002
Direct	Avoidable Utility Expense	T&D Costs	0.0059	0.0062	0.0063	0.0032
Direct	Market Price Impacts	Energy DRIPE	0.0013	0.0013	0.0013	0.0013
Direct	Market Price Impacts	Energy Redispatch Costs	-	-	-	-
Direct	Market Price Impacts	Capacity DRIPE	0.0376	0.0376	0.0376	0.0376
Direct	Market Price Impacts	Ancillary Services DRIPE	0.0006	0.0006	0.0006	0.0006
Direct	Economic Benefits	Tax Credits	0.0615	0.0615	0.0615	0.0615
Societal	Economic Benefits	Local Value Added	0.0847	0.0847	0.0847	0.0847
Societal	Avoidable Societal Damages	Emissions Scopes 1 & 2 Costs	0.2918	0.2918	0.2918	0.2918
Societal	Avoidable Societal Damages	Emissions Scope 3 Costs	0.0047	0.0047	0.0047	0.0047
Societal	Avoidable Societal Damages	Value of Lost Load	0.0143	0.0143	0.0143	0.0143
Direct Total			**0.1913**	**0.1944**	**0.1841**	**0.1832**
Societal Total			**0.3955**	**0.3955**	**0.3955**	**0.3955**
Overall Total			**0.5868**	**0.5899**	**0.5797**	**0.5787**

Figure 26: Sensitivity Case 2 (PV+BESS) Solar Value Stack 10-Yr NPV ($000)

Primary Category	Secondary Category	Benefit Type	DE Total	DPL	DEC	DEMEC
Direct	Avoidable Utility Expense	Energy Generation Fixed Costs	680	-	42	639
Direct	Avoidable Utility Expense	Energy Generation Variable Costs	-	-	-	-
Direct	Avoidable Utility Expense	Energy Generation Hedge Costs	7,283	7,283	-	-
Direct	Avoidable Utility Expense	Purchased Power Costs	245,555	191,366	32,152	22,037
Direct	Avoidable Utility Expense	RPS Compliance Costs	19,550	19,397	91	62
Direct	Avoidable Utility Expense	T&D Costs	19,063	15,501	2,639	924
Direct	Market Price Impacts	Energy DRIPE	4,051	3,157	530	364
Direct	Market Price Impacts	Energy Redispatch Costs	-	-	-	-
Direct	Market Price Impacts	Capacity DRIPE	120,691	94,057	15,803	10,831
Direct	Market Price Impacts	Ancillary Services DRIPE	1,945	1,516	255	175
Direct	Economic Benefits	Tax Credits	197,211	153,691	25,822	17,698
Societal	Economic Benefits	Local Value Added	271,643	211,697	35,568	24,378
Societal	Avoidable Societal Damages	Emissions Scopes 1 & 2 Costs	936,167	729,574	122,578	84,015
Societal	Avoidable Societal Damages	Emissions Scope 3 Costs	15,213	11,856	1,992	1,365
Societal	Avoidable Societal Damages	Value of Lost Load	45,728	35,637	5,987	4,104
Direct Total			**616,031**	**485,968**	**77,333**	**52,730**
Societal Total			**1,268,751**	**988,764**	**166,126**	**113,862**
Overall Total			**1,884,782**	**1,474,731**	**243,459**	**166,592**

The Sensitivity Case 2 total value stack benefits for the State equal $1.9 billion on a present value basis over the next 10 years ($0.59/kWh), with approximately $616 million in direct benefits ($0.19/kWh) and $1.3 billion in societal benefits ($0.40/kWh). This analysis indicates that accelerating the deployment of battery storage resources can provide significant value to all customers because everyone benefits from grid reliability – not just those with net metered solar.

5 Cost-Benefit Analysis

This section of the Report examines the estimated net benefits to Delaware by comparing the total value stack of BTM solar benefits with the estimated net metering bill credits. If this calculation produces a positive result, then there would be a net benefit to the State from accelerating the deployment of net metered solar, as the total benefits provided by BTM solar would exceed the costs of compensating owners of these resources through net metering payments. Conversely, if the results produce a negative result, there would be a net cost. Our analysis demonstrates that there would be significant net benefits to all customers throughout Delaware.

For the benefits component, we used the 10-year levelized value of the total BTM solar benefits from Scenario A (Base Case). This includes the total benefits for avoidable utility expense, market price effects, economic benefits, and societal benefits.

For the cost component, we used the 10-year levelized value of the residential bill credit for the Companies.[44] The net metering bill credit includes volumetric charges for energy, capacity, ancillary services, and distribution service. Notably, this excludes volumetric charges for societal benefits programs and demand-based charges for transmission service. Despite these exclusions, using the residential bill credit for this analysis provides the strongest test of the estimated net benefits when compared with using the bill credits for other customer groups, as residential charges exceed those for other customer classes – meaning it shows a higher "cost" of net metering. Additionally, residential customers comprise the largest share of customers with net metered solar, making this group more representative of the overall pool of net metered customers and the associated costs and benefits.

Figure 27: 10-Yr Levelized $/kWh Gross Benefits (Scenario A)

Metric	DE	DPL	DEC	DEMEC
Direct Benefits	0.1913	0.1944	0.1841	0.1832
Societal Benefits	0.3848	0.3848	0.3848	0.3848
Total Benefits	0.5761	0.5792	0.5689	0.5680

Figure 28: 10-Yr Levelized $/kWh Net Benefits (Scenario A)

Metric	DE	DPL	DEC	DEMEC
Costs	0.1495	0.1493	0.1499	0.1496
Direct Benefits Remaining	0.0418	0.0451	0.0342	0.0336
Total Benefits Remaining	0.4266	0.4299	0.4190	0.4184

[44] The bill credits for the Companies reflects the average of the DPL and DEC tariffs due to a lack of publicly available information on the DEMEC company tariffs.

Figure 29: 10-Yr NPV $000 Gross Benefits (Scenario A)

Metric	DE	DPL	DEC	DEMEC
Direct Benefits	614,188	484,499	77,120	52,569
Societal Benefits	1,230,588	958,992	161,167	110,430
Total Benefits	1,844,776	1,443,490	238,287	162,999

Figure 30: 10-Yr NPV $000 Net Benefits (Scenario A)

Metric	DE	DPL	DEC	DEMEC
Costs	478,012	372,062	62,784	42,931
Direct Benefits Remaining	136,176	112,437	14,336	9,637
Total Benefits Remaining	1,366,764	1,071,428	175,503	120,068

This analysis demonstrates that even after accounting for the bill credit, there would still be significant net benefits remaining for each of the Companies, with $136 million in net direct benefits and $1.4 billion in net total benefits over the next 10 years on present value terms.

When measured as a ratio of benefits-to-costs, the analysis demonstrates that the overall benefits of net metered solar are nearly 4 times greater than its costs. Further, for every dollar spent on net metering, BTM solar generates $1.28 in direct benefits.

Figure 31: 10-Yr Levelized Benefits-to-Costs Ratio (Scenario A)

Metric	DE	DPL	DEC	DEMEC
Direct Benefits-to-Costs Ratio	1.28	1.30	1.23	1.22
Societal Benefits-to-Costs Ratio	2.57	2.58	2.57	2.57
Total Benefits-to-Costs	3.85	3.88	3.80	3.80

Importantly, these results likely understate the full net benefits from net metered solar, as they are based on the residential bill credit rather than a weighted average that includes the lower value of the bill credits for other customer classes.

6 Cost-Shift Analysis

This section of the Report evaluates the potential bill impacts of net metering on customers without net metered solar. Non-solar customers may argue that customers with net metered solar may not pay for their full share of fixed grid infrastructure costs as BTM solar reduces – but not eliminates – their need to consume grid-supplied power. The continued reliance on the grid for energy needed to meet the customers' demand or to sell the excess BTM generation back to the grid suggests that net metered customers still bear some responsibility to pay for the investments in and operations and maintenance of the T&D system. If net metered solar customers continue to benefit from the grid but can reduce their contributions towards sustaining the grid, some may argue that this creates a "cost shift" from customers with net metered solar to those without it. Though this argument ignores the numerous benefits provided by net metered solar to all customers, it highlights a persistent concern of net metered solar that warrants a closer examination.

To address this concern, we developed a simplified method for projecting the potential T&D bill impacts on customers without net metered solar based on historical T&D costs, customer counts, and system demand along with the BTM solar projections developed for Scenarios A and B in this Report.

The methodology involves four main components: First, it estimates how solar generation reduces T&D system demand based on historical hourly load and projections of the expected generation output for a customer with net metered solar in Delaware. Second, it calculates baseline T&D charges using Company-specific data obtained through regulatory filings, EIA reports, and information requests. Third, it escalates the starting T&D charges using inflation estimates from the CBO's long-term budget outlook. Fourth, it compares two scenarios – a Reference Case with no solar growth and a Change Case with solar growth – to quantify the potential cost shift impact on customers without net metered solar.

For the first component, we estimate the ability of BTM solar to reduce customer peak demand and total load. The analysis begins by gathering hourly load data for the DPL zone in PJM and normalizing these data to a 1-kilowatt peak demand baseline to facilitate an "apples to apples" comparison with hourly BTM solar generation estimates for a typical 1-kW rooftop system developed using NREL's PVWatts calculator. By comparing the timing of solar generation to system loads on a normalized 1-kW baseline, this method allows for a straightforward estimate of the maximum potential reduction in average monthly peak demand and total load.

Figure 32: Example Peak Demand Reduction from BTM Solar

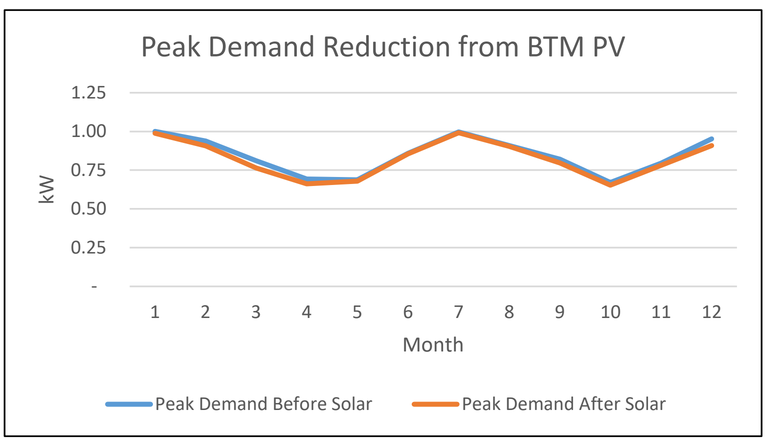
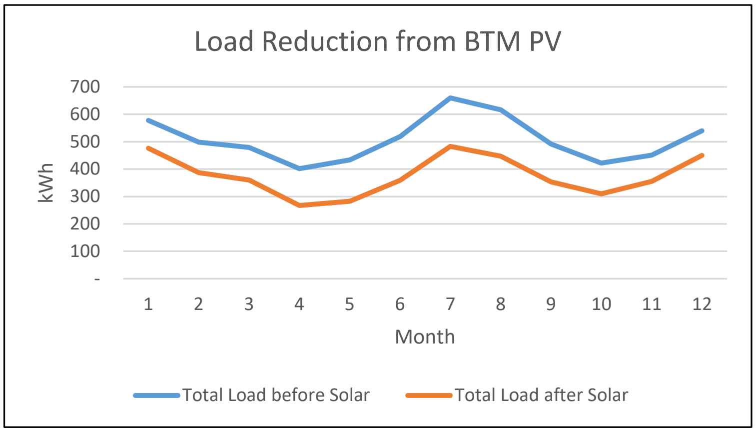


Figure 33: Example Load Reduction from BTM Solar



This analysis indicates that a customer with an annual peak demand of 1 kW and a 1-kW BTM solar array can reduce its average monthly peak demand by approximately 2% and overall load by approximately 22%. This means that customers with onsite solar can reduce their demand charges ($/kW) by 2% and energy charges ($/kWh) by 22%, all else being equal. This highlights the fact that BTM solar creates direct customer savings that do not occur with utility-scale solar: whereas a utility-scale project sells at market prices and retains those revenues, a BTM project provides direct cost savings for customers through lower utility bills. This unique benefit from net metered solar represents real savings for Delaware ratepayers.

For the second component, we developed estimates for the Companies' starting (2023) T&D costs using a combination of historical data from FERC Form 1 filings, EIA reports, and information requests.[45] The total T&D revenue requirements are then projected forward using inflation projections from the CBO's long-term budget forecast.

For the third component, we developed a Reference Case to establish a baseline scenario with no future growth in BTM solar capacity. By using a baseline projection that assumes no new BTM solar capacity will be added to Companies' customer base, we can measure the maximum potential cost shift that could result from accelerated BTM solar deployments. The Reference Case analysis begins with 2023 EIA data to determine the current number of customers with and without net metered solar in Delaware. We assume that the total number of customers grows at a pace that aligns with PJM's long-term load forecast for the DPL zone.

For the fourth component, we estimate T&D cost allocations based on each of the Companies' tariffs. For DPL, we allocate transmission costs based on monthly peak demand and distribution costs based on total monthly energy consumed. For DEC, we allocate all T&D costs based on total energy consumed. For DEMEC, which does not own T&D infrastructure, we apply the same method used for DEC as a simplifying assumption, given that (1) the DEMEC member company electric rate tariffs generally exclude demand

[45] DEMEC is excluded from this analysis as it owns no transmission or distribution assets.

charges for residential customers and (2) DEMEC's net metering capacity is dominated by residential installations.[46]

The analysis first determines a per-customer transmission charge by dividing the total projected transmission costs by the total customer count. We calculate the total estimated transmission charges paid by customers with net metered solar by multiplying the total number of customers in this group by the total company transmission charge per customer by the estimated kW-reduction percentage developed in the prior step. We assign all remaining transmission costs to customers without net metered solar. We then repeat this analysis for distribution charges using the total kWh-reduction percentage instead of the kW-reduction percentage.

Fifth, we repeat each of these steps using BTM solar growth projections developed for Scenarios A and B. and then calculate the change in total T&D charges for customers without net metered solar versus the Reference Case. This produces estimates for the T&D cost shift impact per customer ($/cust) for the two BTM solar growth scenarios.

Figure 34: Example Levelized 10-Year Cost Shift Impact per Customer (DPL)

T&D Charges for Customers without NM PV	Units	PMT (26-35)
Reference Case	$000	311,766
Change Case (Scenario A)	$000	300,509
Change Case (Scenario B)	$000	279,166
Total Customers without NM PV		
Reference Case	count	336,147
Change Case (Scenario A)	count	322,246
Change Case (Scenario B)	count	295,919
T&D Charges per Customer without NM PV		
Reference Case	$/cust	927
Change Case (Scenario A)	$/cust	933
Change Case (Scenario B)	$/cust	946
Change in T&D Charges per Customer without NM PV		
Reference Case	$/cust	-
Change Case (Scenario A)	$/cust	5.96
Change Case (Scenario B)	$/cust	19.20

[46] For example, the Town of Smyrna's utility fees & rates excludes demand charges for residential and commercial customers but includes demand charges for industrial customers. The Town of Middletown's utility rates, on the other hand, include demand charges for large commercial customers.

Figure 35: Example Levelized 10-Year Cost Shift Impact per Customer (DEC)

	Units	PMT (26-35)
T&D Charges for Customers without NM PV		
Reference Case	$000	56,024
Change Case (Scenario A)	$000	55,723
Change Case (Scenario B)	$000	54,618
Total Customers without NM PV		
Reference Case	count	116,592
Change Case (Scenario A)	count	115,786
Change Case (Scenario B)	count	112,898
Total T&D Charges per Customer without NM PV		
Reference Case	$/cust	480
Change Case (Scenario A)	$/cust	481
Change Case (Scenario B)	$/cust	484
Change in T&D Charges per Customer without NM PV		
Reference Case	$/cust	-
Change Case (Scenario A)	$/cust	0.75
Change Case (Scenario B)	$/cust	3.60

Figure 36: Example Levelized 10-Year Cost Shift Impact per Customer (DEMEC)

	Units	PMT (26-35)
T&D Charges for Customers without NM PV		
Reference Case	$000	54,294
Change Case (Scenario A)	$000	52,552
Change Case (Scenario B)	$000	49,402
Total Customers without NM PV		
Reference Case	count	56,959
Change Case (Scenario A)	count	54,656
Change Case (Scenario B)	count	50,496
T&D Charges per Customer without NM PV		
Reference Case	$/cust	953
Change Case (Scenario A)	$/cust	962
Change Case (Scenario B)	$/cust	981
Change in T&D Charges per Customer without NM PV		
Reference Case	$/cust	-
Change Case (Scenario A)	$/cust	9.19
Change Case (Scenario B)	$/cust	28.50

These examples indicate that under Scenario A (status quo net metering growth), customers without net metered solar could see an increase in their utility bills ranging from approximately $1 to $9 per year.

Under Scenario B (accelerated net metering growth), customers could see an increase ranging from approximately $4 to $29 per year.

Next, we translate the cost impact of increased solar adoption into a $/kWh metric to serve as a more direct comparison with the value stack analysis developed previously in this Report. This analysis begins with Delaware's total electricity demand starting in 2023 based on EIA data, projected forward using PJM's long-term load forecast for the DPL zone. For the Reference Case and Change Cases, we estimate the electricity demand for customers without net metered solar by multiplying the total projected demand by the ratio of customers without net metered solar to total customers. Dividing the total T&D charges for customers without net metered solar developed in the prior steps by the projected demand for this customer group produces a $/kWh T&D charge estimate. The difference between the Reference Case and Change Case results reveals how increased solar adoption affects T&D charges on an energy consumption basis for customers without net metered solar.

Figure 37: Example Levelized 10-Year Cost Shift Impact vs Total Customer Charges (DPL)

Customer Demand	Units	PMT (26-35)
Total System Demand	GWh	7,720
Customers without NM (Reference Case)	GWh	7,515
Customers without NM (Scenario A)	GWh	7,204
Customers without NM (Scenario B)	GWh	6,616
T&D Charges for Customers without NM PV		
Customers without NM (Reference Case)	$/kWh	0.0415
Customers without NM (Scenario A)	$/kWh	0.0417
Customers without NM (Scenario B)	$/kWh	0.0423
Change in T&D Charges for Customers without NM PV		
Change Case (Scenario A)	$/kWh	0.0003
Change Case (Scenario B)	$/kWh	0.0009
T&D Charge Impacts / T&D Charges for Customers without NM PV		
Change Case (Scenario A)	%	0.64%
Change Case (Scenario B)	%	2.03%

Figure 38: Example Levelized 10-Year Cost Shift Impact vs Total Customer Charges (DEC)

Customer Demand	Units	PMT (26-35)
Total System Demand	GWh	1,570
Customers without NM (Reference Case)	GWh	1,531
Customers without NM (Scenario A)	GWh	1,520
Customers without NM (Scenario B)	GWh	1,482
T&D Charges for Customers without NM PV		
Customers without NM (Reference Case)	$/kWh	0.0366
Customers without NM (Scenario A)	$/kWh	0.0366
Customers without NM (Scenario B)	$/kWh	0.0369
Change in T&D Charges for Customers without NM PV		
Change Case (Scenario A)	$/kWh	0.0001
Change Case (Scenario B)	$/kWh	0.0003
T&D Charge Impacts / T&D Charges for Customers without NM PV		
Change Case (Scenario A)	%	0.16%
Change Case (Scenario B)	%	0.74%

Figure 39: Example Levelized 10-Year Cost Shift Impact vs Total Customer Charges (DEMEC)

Customer Demand	Units	PMT (26-35)
Total System Demand	GWh	1,639
Customers without NM (Reference Case)	GWh	1,603
Customers without NM (Scenario A)	GWh	1,539
Customers without NM (Scenario B)	GWh	1,421
T&D Charges for Customers without NM PV		
Customers without NM (Reference Case)	$/kWh	0.0338
Customers without NM (Scenario A)	$/kWh	0.0342
Customers without NM (Scenario B)	$/kWh	0.0349
Change in T&D Charges for Customers without NM PV		
Change Case (Scenario A)	$/kWh	0.0003
Change Case (Scenario B)	$/kWh	0.0010
T&D Charge Impacts / T&D Charges for Customers without NM PV		
Change Case (Scenario A)	%	0.96%
Change Case (Scenario B)	%	2.90%

These examples indicate that under Scenario A (status quo net metering growth), customers without net metered solar could see an increase in their utility bills ranging from approximately $0.0001/kWh to $0.0003/kWh, which equates to bill increase of less than 1%. Under Scenario B (accelerated net metering growth), customers could see an increase ranging from approximately $0.0003/kWh to $0.0010/kWh, which equates to a bill increase of 1% to 3%, respectively.

Lastly, we compare the hypothetical cost shift impacts to the total net metering benefits and, separately, to the direct benefits:

Figure 40: Example Levelized 10-Year Cost Shift Impact (DPL)

Scenario A (Base Case BTM PV Growth)	Units	Impacts vs Total Benefits	Impacts vs Direct Benefits
Gross Benefits	$/kWh	0.5761	0.1913
Net Metering Credit	$/kWh	0.1495	0.1495
Net Benefits	$/kWh	0.4266	0.0418
Cost Shift Impact	$/kWh	0.0003	0.0003
Value Remaining	$/kWh	0.4264	0.0416
Scenario B (High Case BTM PV Growth)			
Gross Benefits	$/kWh	0.5765	0.1917
Net Metering Credit	$/kWh	0.1495	0.1495
Net Benefits	$/kWh	0.4270	0.0422
Cost Shift Impact	$/kWh	0.0009	0.0009
Value Remaining	$/kWh	0.4261	0.0414

Figure 41: Example Levelized 10-Year Cost Shift Impact (DEC)

Scenario A (Base Case BTM PV Growth)	Units	Impacts vs Total Benefits	Impacts vs Direct Benefits
Gross Benefits	$/kWh	0.5761	0.1913
Net Metering Credit	$/kWh	0.1495	0.1495
Net Benefits	$/kWh	0.4266	0.0418
Cost Shift Impact	$/kWh	0.0001	0.0001
Value Remaining	$/kWh	0.4266	0.0418
Scenario B (High Case BTM PV Growth)			
Gross Benefits	$/kWh	0.5765	0.1917
Net Metering Credit	$/kWh	0.1495	0.1495
Net Benefits	$/kWh	0.4270	0.0422
Cost Shift Impact	$/kWh	0.0003	0.0003
Value Remaining	$/kWh	0.4267	0.0419

Figure 42: Example Levelized 10-Year Cost Shift Impact (DEMEC)

Scenario A (Base Case BTM PV Growth)	Units	Impacts vs Total Benefits	Impacts vs Direct Benefits
Gross Benefits	$/kWh	0.5761	0.1913
Net Metering Credit	$/kWh	0.1495	0.1495
Net Benefits	$/kWh	0.4266	0.0418
Cost Shift Impact	$/kWh	0.0003	0.0003
Value Remaining	$/kWh	0.4263	0.0415
Scenario B (High Case BTM PV Growth)			
Gross Benefits	$/kWh	0.5765	0.1917
Net Metering Credit	$/kWh	0.1495	0.1495
Net Benefits	$/kWh	0.4270	0.0422
Cost Shift Impact	$/kWh	0.0010	0.0010
Value Remaining	$/kWh	0.4260	0.0412

This analysis indicates that even when relying on more aggressive assumptions for long-term increases in net metering customers, T&D charge growth rates, and load growth rates, customer bill impacts would be minimal and would not exceed the net benefits BTM solar provides to all customers in the State.

7 Conclusion

This Report examines the costs and benefits of BTM solar in Delaware for the 10-year period from 2026 through 2035. The Report begins with an examination of the potential sources of value created by BTM solar, referred to as the solar "value stack," followed by a quantification of the projected financial savings and incremental value added associated with each of the benefits comprising the value stack. The analysis includes two customer demand scenarios and two value-specific sensitivity analyses. Lastly, the Report provides an evaluation of the potential cost impacts of expanded net metering on customers without net metering.

Solar Value Stack

The solar value stack represents the combined financial benefits that BTM solar installations provide to utilities, ratepayers, and the broader electric grid. These benefits include reduced energy costs, lower transmission and distribution costs, avoided capacity investments, environmental advantages like decreased emissions, and enhanced grid reliability. Utilities and regulators can use the value stack framework to establish fair compensation rates for solar energy exported to the grid that accurately reflects solar's full economic and system-wide contributions beyond just the wholesale price of electricity.

This Report focuses on four categories of potential benefits: avoided utility costs, market price reductions, economic growth, and societal improvements.

- *Avoidable utility expenses* represent direct cost savings when customers generate their own power. These include reduced generation costs, purchased power costs, transmission and distribution costs, hedging costs, and RPS compliance costs. The ability to defer or eliminate these expenses creates immediate savings for utilities and their customers.
- *Market price effects* capture how BTM solar reduces costs in PJM's wholesale markets. By decreasing overall electricity demand, solar generation helps lower prices in energy, capacity, and ancillary services markets. These price reductions benefit all customers in the region, not just customers with BTM solar.
- *Economic benefits* stem from federal tax incentives and increased local economic activity. The continued availability of the federal investment tax credit makes solar more affordable for property owners over the next 10 years. Solar installations also create jobs and economic value through construction, maintenance, and related services within Delaware.
- *Societal benefits* reflect solar's environmental and reliability value. Solar reduces harmful emissions from power plant emissions and supply chain impacts. It also enhances grid reliability by reducing strain during on-peak system demand periods.

Scenario Analysis

Scenario A (Status Quo) assumes BTM solar reaches 8% of the State's peak demand by 2035. This scenario demonstrates that expanding BTM solar in Delaware creates substantial value through both direct utility benefits and broader societal impacts. Under current regulatory conditions with an 8% cap on net metering capacity, BTM solar delivers $0.58/kWh in total benefits on a levelized basis over the next decade ($1.8 billion on a present value basis). Direct benefits make up approximately 30% of this value, primarily through avoided purchased power costs and tax credits.

Scenario B (Accelerated Net Metering Deployment Case) demonstrates the significant value potential of expanding Delaware's net metering program on par with regional benchmarks. This scenario projects net metered capacity reaching 18% of peak demand by 2035, matching the average historical penetration rates observed in neighboring states, while incorporating higher load growth of 0.99% per year, driven by increased electrification, data center growth, and EV adoption. If Delaware expands its net metering cap to a level that aligns with neighboring states, Delaware could realize benefits for all customers that are 2 times greater than those under the status quo, with $3.9 billion in total gross benefits and $2.9 billion in total net benefits (present value).

Sensitivity Analysis

Sensitivity Analysis 1 (High Emissions Benefits) demonstrates that lowering the discount rate used to value the avoidable social costs of emissions from 2.0% to 1.5% increases the value of BTM solar by 24% ($444 million on present value terms) over the next 10 years. The lower discount rate recognizes the imperative of responding to climate change by assigning a higher value to long-term climate-related damages. A lower discount rate increases the value of avoided emissions and long-term environmental benefits, thus justifying stronger incentives for renewable energy adoption and an expanded net metering cap.

Sensitivity Analysis 2 (Solar-plus-Storage Reliability Benefits) indicates that pairing net metered solar with battery storage can generate an additional $40 million in benefits for the State over the next 10 years on present value terms. Though the additional benefits comprise a relatively minor portion of the overall value stack, the analysis indicates that accelerating the deployment of battery storage resources can provide significant value to all customers because everyone benefits from grid reliability – not just those with net metered solar. To accelerate deployment of these hybrid systems, the State should consider installation targets, incentive programs to include storage components, and accessible financing options. These policy measures, in addition to the potential for utility load control of storage, will help drive adoption of solar-plus-storage deployments and enhance overall grid reliability.

Cost-Benefit Analysis

The cost-benefit analysis provides additional support for the substantial economic gains the State could realize from accelerating BTM solar deployments. This analysis demonstrates that even after accounting for the net metering bill credit, there would still be significant net benefits remaining for the Companies, with $136 million in net direct benefits and $1.4 billion in net total benefits over the next 10 years on present value terms. When measured as a ratio of benefits-to-costs, the analysis demonstrates that the overall benefits of net metered solar are nearly 4 times greater than its costs. Further, for every dollar spent on net metering, BTM solar generates $1.28 in direct benefits.

Cost Impact Analysis

The cost impact analysis demonstrates that expanded solar adoption in Delaware would have minimal impacts on T&D charges for customers without BTM solar. This section of the Report entails the development of a 10-year projection comparing baseline T&D costs against scenarios with increased BTM solar adoption. The model incorporates historical data from regulatory filings and EIA reports. Results show that under Scenario A, customers without net metered solar could see an increase in their utility bills of approximately $1 to $9 per year ($0.0001/kWh to $0.0003/kWh). Under Scenario B, customers could see an increase of approximately $4 to $29 per year ($0.0003/kWh to $0.0010/kWh). However, even under aggressive growth scenarios for solar adoption, T&D costs, and load growth, the potential cost shift to non-solar customers remains less than 3% of customer charges – a marginal impact that is less than the broader benefits that BTM solar provides to all Delaware ratepayers.

Key Takeaways and Recommendations

The analysis reveals that BTM solar provides substantial value to all residents of the State, evident through the significant return on investment and minimal potential for cost shifts. These findings support expanding Delaware's net metering program to ensure these benefits can be realized and distributed throughout the State. Based on these findings, we identified the following policy recommendations:

- **Increase the net metering cap**: The Report's cost-benefit analysis supports increasing the overall cap on net metering compensation. The benefits BTM solar provides to the grid and society justify an expanded cap to ensure that the State can capture the full range of potential benefits provided by BTM solar. This recommendation is supported by the finding that the solar value stack substantially exceeds its costs across all projections and scenarios.
- **Expand access to net metering**: The economic benefits analysis suggests BTM solar creates substantial local value through job creation and economic activity. Consider policies to expand access to these benefits, particularly for low- and moderate-income residents. This could include:
    - Creating targeted incentive programs for underserved communities;
    - Supporting community solar initiatives by improving access to affordable solar energy, especially for renters, lower-income households, and residents who are unable to install solar on their own property; and
    - Developing Energize Delaware, and other, financing programs to reduce upfront cost barriers.
- **Encourage solar-plus-storage customer deployments**: The Report's findings support policies that would encourage combining solar panels with battery storage systems. The analysis shows that adding batteries to solar systems creates significant additional value. First, it allows solar energy to be used after sunset or during cloudy weather. Second, it provides backup power during blackouts, making the electric grid more reliable for everyone. The State can encourage expanded deployments of solar-plus-storage systems through targeted incentives for adding batteries to new or existing solar installations with the potential for future utility load control. This could include upfront rebates, performance-based payments, and/or net metering incentive adders that reflect the added grid benefits these systems provide.

These findings highlight that the expansion of net metering in Delaware can create substantial value for residents and businesses throughout the State while ensuring equitable outcomes that advance Delaware's clean energy objectives.

8 Index of Acronyms and Abbreviations

$/MW-d	Dollars per Megawatt-Day
BLS	U.S. Bureau of Labor Statistics
CAGR	Compound Annual Growth Rate
CC	Combined Cycle
CH4	Methane
CO2	Include Carbon Dioxide
CONE	Cost of New Entry
CPI	Consumer Price Index
CT	Combustion Turbines
DEC	Delaware Electric Cooperative
DEMEC	Delaware Municipal Electric Company
DESEU	Delaware Sustainable Energy Utility
DPL	Delmarva Power
DRIPE	Demand-Reduction-Induced Price Effects
EIA	U.S. Energy Information Administration
ELCC	Effective Load Carrying Capability
EMAAC	Eastern Mid-Atlantic Area Council
EPA	U.S. Environmental Protection Agency
gCO2/kWh	Grams of CO2 Equivalent per Kilowatt-Hour
ITC	Investment Tax Credit
kWh	Kilowatt-Hour
LBL	Lawrence Berkeley Laboratory
LMP	Locational Marginal Pricing
LOLP	Loss of Load Probability
LSE	Load-Serving Entity
mt/MWh	Metric Tons to Megawatt-Hours
mtCO2/MWh	Metric Tons per Megawatt-Hour
MW	Megawatt
MWh	Megawatt-Hour
N2O	Nitrous Oxide
NERC	North American Electric Reliability Corporation
NOx	Nitrogen Oxides
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
PJM	PJM Interconnection
PM2.5	Particulate Matter
RF	Reliability First
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standards
SC CO2	Social Cost of Carbon
SC GHG	Social Cost of Greenhouse Gases
SJR 3	Senate Joint Resolution 3
SO2	Sulfur Dioxide
SOS	Standard Offer Service
SREC	Solar Renewable Energy Credits
TADS	Transmission Availability Data System

VOLL	Value of Lost Load
VOM	Variable O&M
VOS	Value-of-Solar

TO: Delaware Public Service Commission Staff
FROM: Gabel Associates, Inc.
DATE: March 26, 2025
SUBJECT: Responses to Stakeholder Comments Relating to the February 2025 Value of Solar Report

In February 2024, Delaware Senate passed SJR 3, directing the State's electric utilities to participate in a cost-benefit analysis of net metering in Delaware. Following this directive, the Delaware Sustainable Energy Utility (DESEU) issued a request for proposal in June 2024 for a statewide value-of-solar study, ultimately awarding the contract to Gabel Associates, Inc. (Gabel) in September 2024. Gabel delivered a draft version of the study in February 2025. This memo responds to the Delaware Public Service Commission Staff's (DE PSC) comments received on February 28, 2025.

DE PSC.1

COMMENT: Staff is supportive of DEC's comments that the report needs to calculate separately for each utility. Averaging such vastly different numbers doesn't represent a fair picture.

RESPONSE: We note that the draft report included company-specific estimates for all elements of the solar value stack (see figures 26-29 on pages 45-47 of the report). However, we understand that two elements of the value stack, avoidable RPS charges and hedge costs, could benefit from further segmentation. To address the stakeholder comments on these issues, we have updated the report to (1) exclude the avoidable hedge cost benefit for DEC and DEMEC and (2) replace the weighted average RPS charges with company-specific values. We have also updated the cost-shift analysis to use energy-only charges rather than a combination of energy and demand charges for DEC and DEMEC.

417 Denison Street, Highland Park, New Jersey 08904
Phone (732) 296-0770
www.gabelassociates.com

TO: Delaware Electric Cooperative
FROM: Gabel Associates, Inc.
DATE: March 26, 2025
SUBJECT: Responses to Stakeholder Comments Relating to the February 2025 Value of Solar Report

In February 2024, Delaware Senate passed SJR 3, directing the State's electric utilities to participate in a cost-benefit analysis of net metering in Delaware. Following this directive, the Delaware Sustainable Energy Utility (DESEU) issued a request for proposal in June 2024 for a statewide value-of-solar study, ultimately awarding the contract to Gabel Associates, Inc. (Gabel) in September 2024. Gabel delivered a draft version of the study in February 2025. This memo responds to Delaware Electric Cooperative's (DEC) comments received on February 28, 2025.

DEC.1

COMMENT: As a general matter, the Value of Solar ("VOS") considers all of Delaware's electric distribution entities – DEC, Delmarva Power, and DEMEC – through a single lens (referencing them collectively as the "Companies") which fails to account for (i) DEC's ownership of and contracts for utility scale solar and (ii) access to conventional and renewable energy generation through DEC's membership in Old Dominion Electric Cooperative ("ODEC"), a member-owned generation and transmission (G&T) cooperative.

RESPONSE: The report evaluates the statewide costs and benefits of net metered solar in Delaware, segmented by utility. The report does not evaluate the estimated costs and benefits of non-net metered resources such as DEC's utility-scale solar assets or ODEC-sourced renewable generation. Including these additional resources could distort the analysis by showing greater benefits to the State without any connection to net metering.

DEC.2

COMMENT: The VOS study – instead of using DEC's actual RPS compliance charge of $0.18/MWh – uses a load-weighted average of $4.55/MWh derived primarily from Delmarva Power's higher RPS compliance cost of $6.37 MWh. This over-inflated cost value skews the resulting cost/benefit calculation as to DEC. The VOS study should, instead, calculate the cost and benefits of solar for each utility on an individual basis

RESPONSE: The report has been updated to reflect the requested change. Specifically, the update replaces the prior weighted average statewide calculation with a company-specific calculation, starting with the referenced value of $0.18/MWh.

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DEC.3

COMMENT: The VOS study indicates (P. 5, footnote 2) that net metering Excess kWh Credits excludes charges for societal benefit programs, which is accurate as to Delmarva Power but inaccurate as to DEC. DEC credits all NEM system generation at the full kWh value.

RESPONSE: The report has been updated to reflect the requested change.

DEC.4

COMMENT: DEC purchases 95% of the electricity it supplies to its members through an all-requirements wholesale power contract with ODEC. The remaining 5% DEC self-supplies through in-state renewable energy resources. DEC's power supplier owns substantial generating assets in PJM (approximately 2700 MW) that act as a physical hedge against rising capacity prices. DEC does not have any Energy Generation Hedge Costs and DEC does not purchase energy in the PJM wholesale market. Instead, DEC pays a set wholesale supply rate to ODEC, which meets the energy needs of its member electric cooperative through a portfolio of owned generating assets, long-term and short-term power purchase agreements, and some PJM spot market purchases.

RESPONSE: The report has been updated to reflect the requested change. Specifically, the update eliminates the avoidable hedge expense benefit for DEC.

DEC.5

COMMENT: ITCs reduce the taxes an NEM system owner would otherwise be required to pay. The effect of the ITC is a reduction in the financial resources available for spending on social services, education, or other beneficial government programs. The benefit of the ITC to the NEM system owner comes at a cost in terms of how those tax dollars could otherwise have been spent. Consequently, while the ITC may have value to the NEM system owner, its value to society as whole is offset by the corresponding reduction in tax revenue.

RESPONSE: Inclusion of the ITC in VOS studies is necessary to evaluate the full range of costs and benefits of net metered solar.

First, the ITC represents federal — not state — resources flowing into state economies. These federal tax credits are not drawn from state treasuries or budgets. Without the ITC incentivizing the deployment of new solar projects in a particular state, these dollars would not automatically be redirected to that state through other channels.

Second, the ITC creates an economic multiplier effect by allowing households and businesses to retain more of their income. When taxpayers reduce their federal tax liability through the ITC, this increased disposable income circulates within local economies as consumers purchase goods and services from local businesses. This spending can trigger subsequent rounds of economic activity - retailers hire additional staff, suppliers increase production, and service providers expand operations - creating a cascading effect where each dollar saved generates more economic output. Additionally, businesses that utilize the ITC can direct their tax savings toward expansion, workforce development, and community reinvestment, further amplifying the credit's local economic impact.

Third, including the ITC provides a more accurate representation of the actual economics facing solar adopters by substantially reducing upfront installation costs. This accelerates deployments of new solar installations by both individuals and businesses, creating an additional multiplier effect that generates additional economic activity within the State. More installations mean more local jobs, increased energy savings, and enhanced environmental benefits that accumulate over decades.

Fourth, the ITC represents established federal energy policy specifically designed to accelerate renewable energy adoption nationwide. Excluding the ITC from a solar-specific cost-benefit analysis would disregard these congressionally enacted policies and dramatically understate the true benefits created by net metered solar and lead to flawed policy decisions based on incomplete financial information.

DEC.6

COMMENT: The VOS study contains the following statement which is inaccurate as to DEC - "...net metered solar creates direct customer savings that do not occur with utility-scale solar: whereas a utility-scale project sells at market prices and retains those revenues, a net metered project provides direct cost savings for customers through lower utility bills. This unique benefit represents real savings for Delaware ratepayers." DEC owns 7 MWs of utility scale solar. The energy from DEC's solar farm is installed behind-the-meter and directly offsets DEC's energy supply requirements, i.e. it provides the same direct cost savings for all DEC members that an NEM system provides an individual system owner. Utility scale solar also allows individuals who cannot afford the upfront costs of an NEM system to participate in community solar programs at a lower cost of entry.

RESPONSE: Please see the response to DEC.1 for explanation addressing why the report evaluates distributed net metered resources rather than utility-scale resources. For the avoidance of doubt, however, we note that the referenced citation has been updated in the report to replace the term "net metered solar" with "behind-the-meter solar."

DEC.7

COMMENT: The VOS study states on page 4 that current Delaware law restricts Delaware utilities from accepting new net metering customers once the installed NEM capacity reaches 8% of the utilities peak demand. This is not entirely correct. The 8% threshold is a voluntary cap after which a utility may prohibit additional NEM interconnections. DEC is currently at or above the voluntary cap but has not restricted additional NEM interconnections. Expansion of NEM solar installations will for DEC be driven more by system limitations than voluntary cap considerations.

RESPONSE: The report has been updated to acknowledge that utilities can accept new NEM customers once the 8% cap is reached.

DEC.8

COMMENT: The Avoidable Societal Damages from Emissions value stack methodology also starts with the flawed assumption that DEC and Delmarva Power are the same (Emissions Rates – P. 34) Instead of looking at the PJM resource mix, a DEC-specific calculation must look at ODEC's resource mix and DEC's renewable resources to calculate potential avoidable emissions. Calculations of societal benefits are also highly influenced by the discount rate applied.

RESPONSE: While ODEC has an all-requirements contract with DEC, this does not mean DEC customers physically receive electricity directly from ODEC's generation resources. In the interconnected PJM grid, electricity from all generators – including ODEC's resources – flows into a shared pool from which all customers draw power. When DEC incentivizes the expansion of net metered solar installations, this reduces overall demand on the grid, displacing the least efficient generators currently operating in the PJM resource mix. The emissions benefits from these solar installations therefore depend on which resources are displaced across the entire PJM system, not just within ODEC's portfolio. This is why using the PJM resource mix for emissions calculations provides a more accurate assessment of the physical emissions impact from changes in DEC customers' electricity consumption patterns.

Regarding discount rates for societal benefits calculations, this is a valid consideration that is noted in the draft report. Please see Section 2.4.1 of the report for an overview of the role of the discount rate and influence on the valuation of emissions-related costs. See also Section 4.1, which summarizes the sensitivity analysis impacts of using a different discount rate.

DEC.9

COMMENT: The VOS' Status Quo Scenario A (Figure 18) attributes value stack benefits (approximately $185 million) to DEC based on the inaccurate assumption that DEC will not reach 8% installed NEM capacity until 2035 (Figure 15). DEC's installed NEM capacity is currently 8.4% and, therefore, DEC has, through its support for NEM solar, already helped Delaware achieve and surpass the projected overall benefits under the VOS' Status Quo Scenario.

RESPONSE: The projections are based on public EIA data (Form 861), which indicates that, as of 2023, DEC had 24 MW of installed NEM capacity and 438 MW of peak demand, equating to a 5.5% share in 2023. The projections start with this percentage in 2023 and then escalate the percentage each year using a fixed growth rate needed to reach the 8.0% cap by 2035.

FOLLOW-UP INFORMATION REQUESTS:

1. Please provide a breakdown of the installed NEM generation capacity and peak demand by year from 2019 through the present date. Please also include a brief explanation for any discrepancies with the EIA-861 data.

TO:	Delaware Municipal Electric Corporation
FROM:	Gabel Associates, Inc.
DATE:	March 26, 2025
SUBJECT:	Responses to Stakeholder Comments Relating to the February 2025 Value of Solar Report

In February 2024, Delaware Senate passed SJR 3, directing the State's electric utilities to participate in a cost-benefit analysis of net metering in Delaware. Following this directive, the Delaware Sustainable Energy Utility (DESEU) issued a request for proposal in June 2024 for a statewide value-of-solar study, ultimately awarding the contract to Gabel Associates, Inc. (Gabel) in September 2024. Gabel delivered a draft version of the study in February 2025. This memo responds to Delaware Municipal Electric Corporation's (DEC) comments received on February 28, 2025.

DEMEC.1

COMMENT: DEMEC represents the 9 cities and towns that operate community-owned electric utilities and serve a total population of over 143,000 people and businesses. While they have a combined peak of over 472MW, individually, they range from around 7MW to 161MW. Our 9 members have over 18MW of customer-sited behind the meter solar and own over 28MW of utility scale solar currently connected to the grid. We are also in the process of finalizing the contract for an additional 3MW of floating solar in Middletown.

RESPONSE: We note that the report includes a brief description of DEMEC that is consistent with the comment. Please see Section 1.3 of the report for further details.

DEMEC.2

COMMENT: The assumption that each utility is hedged at 100% and beholden to the PJM market misrepresents the value DEMEC brings to our membership. DEMEC's power supply is nearly 50% from self-supply assets and 50% bilateral contracts with PJM market participants, with staggered contract lengths.

RESPONSE: The analysis relies on the simplifying assumption that 100% of DEMEC's energy needs would be hedged and that 8% of this amount would be avoidable, based on estimates for the effective load carrying capability of fixed-tilt solar resources located in the PJM footprint. Please see Section 2.1.3 of the report for further information. Regarding the actual amount of hedged capacity, we understand that the assumption used in the report may not align with DEMEC's historical hedging practices. We have provided a follow-up information request below to address this discrepancy.

Regarding the comment relating to DEMEC's exposure to PJM, we note that bilateral contracts that do not include a physical behind-the-meter connection between a buyer and seller would rely on PJM's grid infrastructure to move power from the generation resource to customer loads. Sellers under these arrangements account for wholesale market prices and volatility by pricing these projections into their requested contract price. If the wholesale market price for energy is expected to be higher than the fixed contract price requested by the buyer, then the seller would be unlikely to accept the buyer's terms because doing so would mean selling below market value, all else being equal. Therefore, even if the buyer is not directly exposed to the wholesale marketplace, it may be indirectly exposed if the seller relies on expectations for wholesale market prices and volatility to evaluate the tradeoffs between a bilateral contract and wholesale market sales. This makes the wholesale market price a reasonable proxy for bilateral contract prices, particularly when the contracts are based on staggered lengths, which increases the buyer's exposure to changes in wholesale market prices. Though the weighted average annual contract price may not perfectly match the wholesale market price, replacing one with the other is unlikely to have a material impact on the analysis, given the dynamics explained above. With that being said, we are amenable to reviewing updated information relating to DEMEC's power supply sources and costs. Please see the follow-up data request below in response to this issue.

FOLLOW-UP INFORMATION REQUESTS

1. Please provide a brief description of DEMEC's hedge policies and costs. To the extent that DEMEC does not hedge its fuel or power supply needs, please explain how it accounts for the risk of price and power supply volatility.
2. Please specify the percentage of DEMEC's annual fuel and power supply needs that are hedged.
3. Please specify the historical annual costs associated with DEMEC's fuel and power supply hedges.
4. Please provide historical annual load totals from 2019 through the present.
5. Please provide historical annual power purchase volumes and costs from 2019 through the present.

DEMEC.3

COMMENT: The study also assumes that if net-metering is added to the system that the utility will not have to make investments in power supply or infrastructure. As stated during the initial review call, this may work scientifically in a silo, however, in the reality we face on the peninsula, transmission infrastructure costs continue to go up 11 and 12% in the last two years, distribution system upgrades are required for grid modernization and increased DERs, and power supply contracts and investments in generation will still be in place given that we cannot control the customer-sited generation output. Also, with the increased need for capacity in the region, we are going to see infrastructure costs rise regardless of customer-sited solar.

RESPONSE: The objective of the report is to assess the value of net metered solar rather than forecast exogenous factors such as grid infrastructure cost inflation or grid modernization upgrades that may occur regardless of changes in net metering capacity. Though evaluating these issues could provide helpful insights for a separate analysis, they do not change the underlying logic that utilities make investments in power supply and infrastructure based, in part, on the assumed amount of peak demand and total customer load the utilities will need to serve in the future, all else being equal. Additionally, we are unaware of any publicly available data showing that deploying higher amounts of net metered solar will directly cause a specific and quantifiable increase in costs associated with these exogenous factors. Absent this information, revising the report to include such costs would reflect unsupported and speculative assumptions that are inconsistent with the scope and intent of the study. Nevertheless, we appreciate the importance of this issue to DEMEC and would consider evaluating additional data, as available. Please see the follow-up information request below.

FOLLOW-UP INFORMATION REQUEST

6. As available, please provide historical cost records, studies, or other support showing that deploying higher amounts of net metered solar will directly cause a specific and quantifiable increase in costs associated with grid infrastructure cost inflation and grid modernization upgrades.

DEMEC.4

COMMENT: DEMEC is to our members as ODEC is to DEC. We are the wholesale provider. DEMEC's full-requirements members get 100% of their power supply through DEMEC not the market. The City of Dover is an associate member and hedges 75% of its power supply on average.

RESPONSE: The purpose of this comment is unclear. Please see the follow-up information request below.

FOLLOW-UP INFORMATION REQUEST:

7. Please clarify which issue in the report DEMEC requires clarification and why. This information will help us provide a direct response and determine if and to what extent revisions to the report and analysis should be made.

DEMEC.5

COMMENT: We agree with the statement on the investment tax credits made by DEC, as well. These credits should not be included in the calculation as the benefits are already accounted for when giving the customer the credit.

RESPONSE: Inclusion of the ITC in VOS studies is necessary to evaluate the full range of costs and benefits of net metered solar.

First, the ITC represents federal — not state — resources flowing into state economies. These federal tax credits are not drawn from state treasuries or budgets. Without the ITC incentivizing the deployment of new solar projects in a particular state, these dollars would not automatically be redirected to that state through other channels.

Second, the ITC creates an economic multiplier effect by allowing households and businesses to retain more of their income. When taxpayers reduce their federal tax liability through the ITC, this increased disposable income circulates within local economies as consumers purchase goods and services from local businesses. This spending can trigger subsequent rounds of economic activity - retailers hire additional staff, suppliers increase production, and service providers expand operations - creating a cascading effect where each dollar saved generates more economic output. Additionally, businesses that utilize the ITC can direct their tax savings toward expansion, workforce development, and community reinvestment, further amplifying the credit's local economic impact.

Third, including the ITC provides a more accurate representation of the actual economics facing solar adopters by substantially reducing upfront installation costs. This accelerates deployments of new solar installations by both individuals and businesses, creating an additional multiplier effect that generates additional economic activity within the State. More installations mean more local jobs, increased energy savings, and enhanced environmental benefits that accumulate over decades.

Fourth, the ITC represents established federal energy policy specifically designed to accelerate renewable energy adoption nationwide. Excluding the ITC from a solar-specific cost-benefit analysis would disregard these congressionally enacted policies and dramatically understate the true benefits created by net metered solar and lead to flawed policy decisions based on incomplete financial information.

DEMEC.6

COMMENT: DEMEC's member-owned solar assets that total over 28MW provide value to all customers they serve. DEMEC member customers do not receive a demand charge like DPL customers. The energy we provide through these facilities provides the same cost savings for all customers as NEM provides individual customers and allows those benefits to flow to low- and moderate-income customers that typically would not be able to benefit.

RESPONSE: The report has been updated to reflect the requested change. Specifically, the cost-shift analysis described in Section 6 of the report has been updated to treat all charges for DEMEC as energy-related rather than energy- and demand-related.

DEMEC.7

COMMENT: In addition, with the new calculation for the net-metering cap, DEMEC has several members already above the 8% threshold. They have continued to receive and process applications.

RESPONSE: The projections for DEMEC are based on public EIA data (Form 861), which indicates that, as of 2023, DEMEC had 9 MW of installed NEM capacity and 372 MW of peak demand, equating to a 2.6% share in 2023. The projections start with this percentage in 2023 and then escalate the percentage each year using a fixed growth rate need to reach the 8.0% cap by 2035.

FOLLOW-UP INFORMATION REQUESTS:

8. Please provide a breakdown of the installed NEM generation capacity and peak demand by year from 2019 through the present date. Please also include a brief explanation for any discrepancies with the EIA-861 data.

DEMEC.8

COMMENT: DEMEC already has a power supply mix that is 92.5% low to no emissions. The amount of renewables in our portfolio covers roughly 26% of our power supply. The assumptions made in the value stack of the study do not account for the mix in our current supply.

RESPONSE: The report evaluates the potential emissions reductions resulting from deploying more net metered solar. Even if DEMEC's power supply mix emits little to no emissions, this would not change the analysis unless DEMEC's power supply resources are directly interconnected with DEMEC's member loads. Without a direct, physical connection between generation resource and customer load, the customer loads will be supplied by power from the PJM marketplace. And because PJM cannot dictate the path along which electrons flow from generators to load, this means that the electricity received by DEMEC's member loads originates from the mixed pool of generators feeding the PJM grid at any given moment, which includes more than just DEMEC's resource mix. In reality, all electricity in PJM flows through the shared grid regardless of contractual arrangements. Electrons from all generators mix together and customers physically receive power from this combined pool, not from specific generators. Therefore, using PJM's overall resource mix for emissions calculations (rather than DEMEC's specific mix) is appropriate for determining physical emissions impacts from DEMEC customers' electricity consumption.

DEMEC.9

COMMENT: We know that solar peaks and system peaks do not directly line up, as well as when the system peaks in the winter time as we are starting to see more of this year. Assuming that they perfectly align and that as more solar goes on the system the peak continues to rise skews the benefits of these systems.

RESPONSE: The critique raises a valid general concern about methodological approaches to solar valuations but appears to overlook that our analysis specifically accounts for hourly peak shifting. The analysis recognizes that reducing load at the original peak time can cause a different hour with less solar generation to become the new peak. In fact, we found that peak demand shifts each month in which BTM solar operates. This shift occurs because we do not make the simplistic assumption that peak reduction occurs at a static time. Instead, our methodology normalizes historical hourly load data spanning multiple years to a 1-kW baseline, compares this with solar generation hour-by-hour, recalculates the new peak time after accounting for solar generation, and quantifies the actual achievable peak reduction based on this dynamic analysis. This approach yields a more realistic assessment of peak demand reduction potential than methods that fail to account for temporal shifts in peak demand. Please see Section 6 of the report for further information.

DEMEC.10

COMMENT: Finally, on page 9 of the draft, an estimation for the ELCC adjusted CONE for a Delaware BTM solar installation assumed a 1MW rooftop mounted system. The calculation for that is extremely high considering the average rooftop solar installation on homes is around 7.7kW.

RESPONSE: While we understand the confusion relating to the typical size of the roof-mounted solar array and the referenced assumption in the report, we note that the 1-MW value was used instead of a smaller value to align with the market data we used to perform the analysis. It does not have any impact on the results of the analysis because the inputs were unitized in terms of $/MWh and $/kWh. For example, the avoidable generation fixed costs analysis relies on PJM's estimates for CONE, which is expressed in terms of $/MW-year. We then multiply this by the solar ELCC rating, 8%, and then divide the result by the estimated generation output from 1 MW of solar. This yields a $/MWh value that can be applied consistently to varying levels of net metered capacity.

DEMEC.11

COMMENT: As originally stated, a report that summarizes all utility business models together will misrepresent the real data each utility's regulatory bodies should consider and misguide legislation going forward. This study should be used as a foundation for each utility to consider their unique cost/benefits, not drive industry assumptions for policymaking.

RESPONSE: The objective of the report was to conduct a statewide value of solar study analyzing the costs and benefits of net metering in Delaware, consistent with the June 7, 2024, RFP: "The purpose of this study is to determine the value of net metered solar as a cost-benefit study and analysis of net metering including cost burdens and cost shifting, if any. This study will provide an analysis across all electric utilities that offer net metering to solar customers in Delaware." See page 3 of the RFP.

The draft report is consistent with this objective and accounts for differences across each utility in terms of customer demand, installed generation capacity, T&D expenditures, along with a range of other company-specific factors. Further, based on stakeholder feedback, we've updated the report to reflect additional company-specific differences in RPS compliance costs, avoidable hedge expenses, and tariff charges. Lastly, all assumptions relied on the report are based on publicly available sources like EIA, utility tariffs, and FERC Form 1 filings, which are developed using input directly from the companies.

TO: Delmarva Power & Light Company
FROM: Gabel Associates, Inc.
DATE: March 26, 2025
SUBJECT: Responses to Stakeholder Comments Relating to the February 2025 Value of Solar Report

In February 2024, Delaware Senate passed SJR 3, directing the State's electric utilities to participate in a cost-benefit analysis of net metering in Delaware. Following this directive, the Delaware Sustainable Energy Utility (DESEU) issued a request for proposal in June 2024 for a statewide value-of-solar study, ultimately awarding the contract to Gabel Associates, Inc. (Gabel) in September 2024. Gabel delivered a draft version of the study in February 2025. This memo responds to Delmarva Power & Light Company's (DPL) comments received on February 28, 2025.

DPL.1.A

COMMENT: Delmarva Power recommends an additional sensitivity analysis considering higher NM adoption scenarios beyond the ones modeled.

RESPONSE: While the requested supplemental analysis could be valuable in highlighting the sensitivity of the study findings when using alternative assumptions or scenarios, this would exceed the original scope of work for the VOS study. We have documented this suggestion for potential future analysis and would be happy to provide a separate proposal with time and budget estimates should stakeholders wish to pursue this supplemental work.

DPL.1.B

COMMENT: Alternative cost recovery mechanisms, such as demand-based charges, should be evaluated to ensure that NM customers contribute fairly to maintaining grid infrastructure.

RESPONSE: Please see response to DPL.1.A

DPL.1.C

COMMENT: The study does not fully account for the fixed costs of grid maintenance and modernization, which must still be recovered from all customers.

RESPONSE: Fixed costs for grid maintenance and modernization are captured in the avoidable transmission and distribution (T&D) expense analysis and the cost-shift analysis. The avoidable T&D expense analysis quantifies the change in total T&D capital expenditures and operations and maintenance expenses resulting from increased deployments of behind-the-meter (BTM) solar. The cost-shift analysis quantifies the extent to which customers without on-site solar may bear a higher share of grid maintenance and modernization costs over time as more BTM solar is added to the system.

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DPL.2.A

COMMENT: The study should more explicitly separate fixed vs. variable T&D costs and analyze whether the assumed cost savings are realistic.

RESPONSE: The approach used to estimate avoidable T&D costs is grounded in actual utility cost records encompassing all T&D costs rather than just fixed or variable costs. By converting historical T&D costs to $/kW values based on system demand data from regulatory filings and EIA reports, it establishes a baseline of real-world investment and operating costs. The approach then scales these values using PJM's Effective Load Carrying Capability rating for fixed-tilt solar, which accounts for solar's intermittency and actual contribution to peak demand reduction. The final conversion to $/MWh using NREL's PVWatts tool ensures the estimate reflects local generation conditions in Delaware. This methodology balances analytical rigor with practical considerations, acknowledging both the documented benefits of BTM solar in deferring T&D investments (as confirmed by the 15-state meta-analysis cited in the report) and the integration challenges that utilities face, while producing estimates directly tied to utility-specific costs and operations.

DPL.2.B

COMMENT: [The avoidable T&D costs analysis] should evaluate whether a demand-based cost allocation model would be more appropriate than using volumetric reductions alone.

RESPONSE: Please see response to DPL.1.A

DPL.3.A

COMMENT: A key issue with this assumption is that peak demand reduction is often based on the probability that peak occurs during solar output. Many studies incorrectly assume that a lower system peak at time (t=a) due to solar guarantees a new system peak at the same time, rather than shifting peak to another period (t=b) when solar output is lower.

RESPONSE: The critique raises a valid general concern about methodological approaches to solar valuation but appears to overlook that our analysis specifically accounts for hourly peak shifting. The analysis recognizes that reducing load at the original peak time can cause a different hour with less solar generation to become the new peak. This shift occurs because we do not make the simplistic assumption that peak reduction occurs at a static time. Instead, our methodology normalizes hourly load data to a 1-kW baseline, compares this with solar generation hour-by-hour, recalculates the new peak time after accounting for solar generation, and quantifies the actual achievable peak reduction based on this dynamic analysis. This approach yields a more realistic assessment of peak demand reduction potential than methods that fail to account for temporal shifts in peak demand. Please see Section 6 of the report for further information.

DPL.3.B

COMMENT: The study should incorporate a more granular hourly analysis of solar generation vs. system peak demand to reflect real-world impacts.

RESPONSE: Please see response to DPL.3.A.

DPL.3.C

COMMENT: A separate winter peak demand analysis should be included to ensure reliability planning accounts for seasonal variations.

RESPONSE: Please see responses to DPL.1.A and DPL.3.A.

DPL.4.A

COMMENT: Delmarva Power recommends recalculating avoided emissions costs using PJM market-based CO_2 pricing, rather than national averages, to provide a more accurate estimate.

RESPONSE: The analysis indirectly accounts for Regional Greenhouse Gas Initiative (RGGI) allowance costs through the energy market demand reduction-induced price effects (DRIPE) analysis. When demand for energy decreases, power plants with higher operating costs can be displaced from the market by power plants with lower operating costs. This reduces market-clearing prices that already incorporate RGGI allowance costs. Under RGGI, power plants that emit CO_2 must pay for allowances to cover their CO_2 emissions. These power plants price the cost of CO_2 allowances into their energy market offers to ensure that will receive sufficient revenues to cover their fuel costs, variable operations and maintenance costs, and RGGI costs if they clear the market and generate electricity.

DPL.4.B

COMMENT: The study should clearly distinguish between direct utility benefits and broader societal benefits to avoid overstating the financial benefits of NM solar to ratepayers.

RESPONSE: The distinction between direct and societal benefits is already reflected the report. For example, page 1 of the report notes this distinction in stating the following: "This Report addresses this issue by carefully assessing the value of net metering relative to the value that solar energy provides: a) to the grid and all customers attached to the grid (entitled '**direct benefits**'); and b) broader benefits provided to all residents of Delaware (entitled '**societal benefits**'). Direct benefits are benefits that accrue directly to all ratepayers and include the reduction in costs due to reduced fossil fuel-based power generation on the grid and the avoidance of forward-looking transmission and distribution expenditures made possible by solar generation. Societal benefits include broader benefits that accrue to the public at large and are not reflected in customer rates. This includes environmental and health benefits realized by reduced air emissions as well as economic benefits realized by the jobs, spending, and increased economic activity caused by investments in solar capacity." Similarly, Figures 1, 17-18, 24-34, and 39 each separate direct benefits from societal benefits.

DPL.5.A

COMMENT: Delmarva Power recommends aligning NM compensation with wholesale energy costs rather than full retail rates to prevent cross-subsidization.

RESPONSE: Please see response to DPL.1.A

DPL.5.B

COMMENT: The study should explore alternative compensation structures, such as time-of-use credits or declining block tariffs, to better reflect the true value of distributed solar.

RESPONSE: Please see response to DPL.1.A

DPL.6.A

COMMENT: Delmarva Power requests alignment with its internal load forecasting models to ensure consistency.

RESPONSE: Please see response to DPL.1.A. Please also note that the report relies on load growth projections developed by PJM in its 2024 load forecast report. This report represents the most current publicly available source of load projections that are developed through rigorous stakeholder review processes and incorporate regional economic factors, weather patterns, and demand trends, including those applicable to the Delmarva zone. Reliance on the PJM load forecast report also ensures consistency with regional planning assumptions used by multiple utilities and regulators within the PJM marketplace.

DPL.6.B

COMMENT: Additional scenarios should be included to account for potential winter demand spikes from electrification.

RESPONSE: Please see response to DPL.1.A

DPL.6.C

COMMENT: The study should include an additional cost-benefit analysis specifically for battery storage integration.

RESPONSE: Please see response to DPL.1.A

DPL.6.D

COMMENT: Compensation mechanisms for storage should be distinct from net metering credits and instead aligned with demand response incentives.

RESPONSE: Please see response to DPL.1.A

TO: University of Delaware Institute of Energy Conversion
FROM: Gabel Associates, Inc.
DATE: March 26, 2025
SUBJECT: Responses to Stakeholder Comments Relating to the February 2025 Value of Solar Report

In February 2024, Delaware Senate passed SJR 3, directing the State's electric utilities to participate in a cost-benefit analysis of net metering in Delaware. Following this directive, the Delaware Sustainable Energy Utility (DESEU) issued a request for proposal in June 2024 for a statewide value-of-solar (VOS) study, ultimately awarding the contract to Gabel Associates in September 2024. Gabel delivered a draft version of the study in February 2025. This memo responds to the University of Delaware Institute of Energy Conversion's (UD IEC) comments received on February 28, 2025.

UD IEC.1

COMMENT: Page 1. Net metered solar customers can reduce their energy charges ($/kWh) by 22% and demand charges ($/kW) by 2%, all else being equal. Why only 22% or 2%? Why can't they reduce energy charges by 100%? What assumptions go into this? It gives impression that PV can't make a significant impact on customer bill.

RESPONSE: The analysis finds that customers with on-site solar in Delaware can reduce their total energy demand by 22% **on average** across all hours of the year. This can rise to a reduction of 100% in some hours of the year when solar irradiance is highest. The analysis was based on several years of historical hourly load data for the Delmarva Power and Light Company (DPL) zone in PJM and hourly behind-the-meter (BTM) solar generation estimates for a typical 1-kW rooftop system developed using NREL's PVWatts calculator. Please see pages 49-50 of the report for more information.

UD IEC.2

COMMENT: Page 5. It needs some references in several places to justify claims. Like "The literature on cost shifting shows mixed results, however, with some studies noting the potential for cost shifts, with others finding minimal to no impact.

RESPONSE: The updated report adds a paragraph to section 1.4 addressing this issue. Specifically, the addition includes citations to multiple studies.

UD IEC.3

COMMENT: This sentence is gobbly gook [sic]. No idea what it means. The presence of the Companies' owned generation units in the displaced portion of the supply curve indicates whether they would be able to avoid variable production costs from increased solar adoption

RESPONSE: The report has been updated to reflect the requested change. Specifically, the updated report revises Section 2.1.2 (Energy Generation Variable Costs) to use simpler terms when describing the process of evaluating potential changes to PJM supply stack.

UD IEC.4

COMMENT: Section 2.1.5 or somewhere else. You need to clarify that these percentages are for the AC POWER rating relative to the peak or average power for that utility. Most people think it means this is energy - Example in 2025 this is 3.5% of the relative power capacity not that solar made 3.5% of the energy. Please encourage the author to clarify when power or energy are the relevant concept under discussion. Given PV's 20% capacity factor the amount of energy is 5 times less than the installed power.

RESPONSE: Though the text in section 2.1.5 is consistent with the Delaware Code on the State's RPS (Title 26, Chapter 1, Subchapter III-A), we have added the following footnote to this section to help clarify the distinction between energy and power:

> Energy (measured in watt-hours) represents electricity generated over time, while power (measured in watts) refers to capacity or maximum potential output. This distinction is crucial for Renewable Portfolio Standards (RPS), which require utilities to generate a percentage of their electricity from renewable sources. RPS requirements are expressed in energy terms (e.g., MWh), not power capacity. Because renewable sources have lower capacity factors than conventional generation, more installed capacity is needed to fulfill these requirements. For example, with a typical capacity factor of 20%, a 5 MW solar installation will produce approximately 8,760 MWh/year (5 MW × 24 hours × 365 days × 0.2) rather than the 43,800 MWh/year that would result from continuous maximum output.