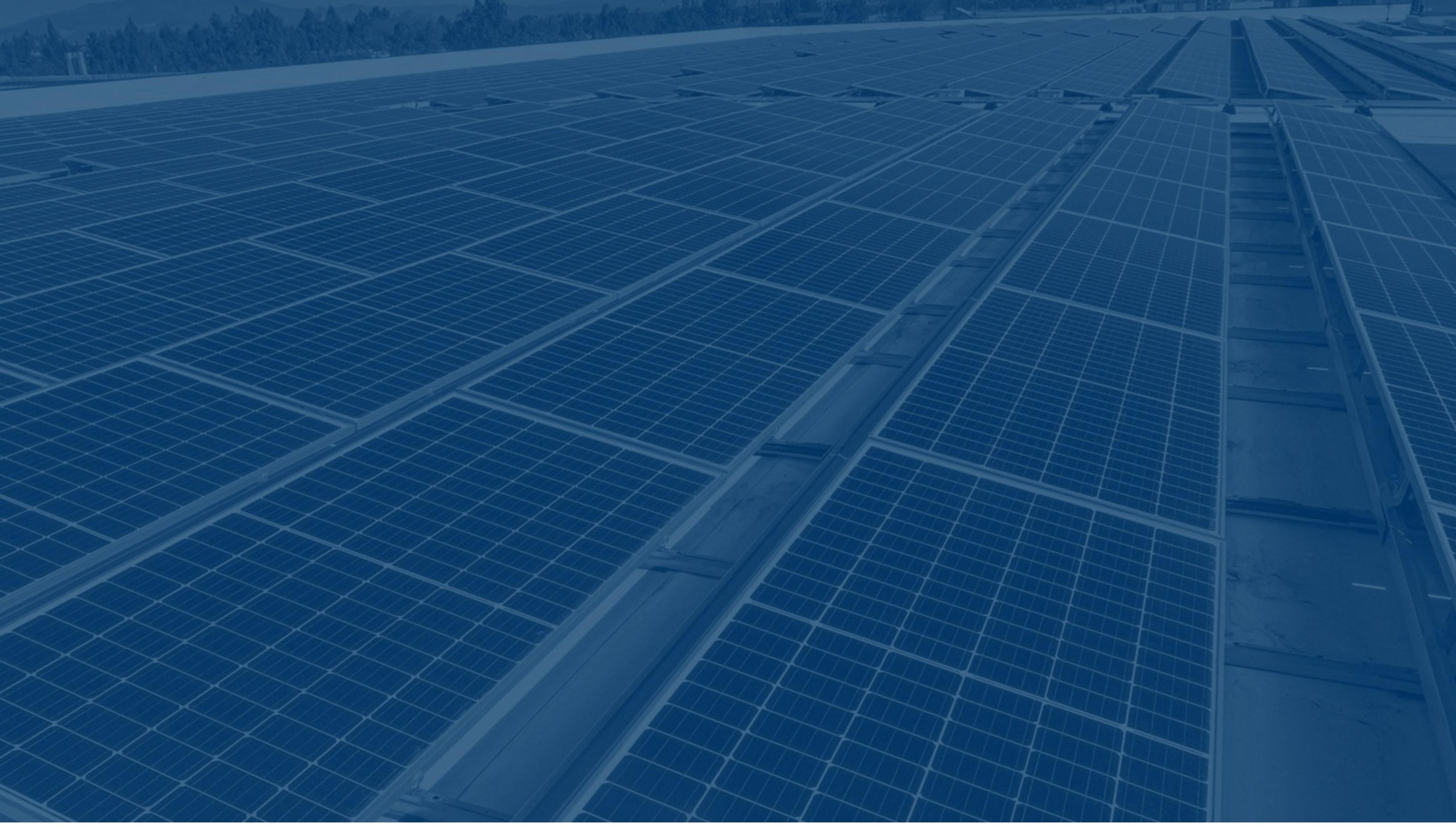

New Hampshire Value of Distributed Energy Resources

Final Report

Submitted to:

New Hampshire Department of Energy

www.energy.nh.gov

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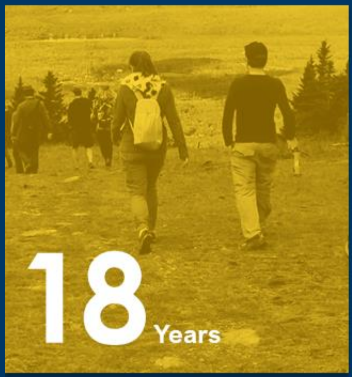
With support from Power Advisory

About Dunsky



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Working across buildings, industry, energy and mobility, we support our clients through three key services: we **quantify** opportunities (technical, economic, market); **design** go-to-market strategies (plans, programs, policies); and **evaluate** performance (with a view to continuous improvement).

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List of Acronyms

AESC	Avoided Energy Supply Costs
BTM	Behind-the-Meter
CO_2	Carbon dioxide
DER	Distribution Energy Resource
DG	Distributed Generation
DRIPE	Demand Reduction Induced Price Effect
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
GHG	Greenhouse Gas
HE	Hour Ending
HLGS	High Load Growth Scenarios
ISO-NE	Independent System Operator – New England
kWh	Kilowatt-hour
LGHC	Large Group Host Commercial
LMP	Locational Marginal Price
LNS	Local Network Service
LSEs	Load Serving Entities
MRVS	Market Resource Value Scenario
MW	Megawatt
NEM	Net Energy Metering
NO_x	Nitrogen oxide
PTF	Pool Transmission Facilities
PUC	Public Utilities Commission
RGGI	Regional Greenhouse Gas Initiative
RNS	Regional Network Service
ROC	Rest of Criteria
RPS	Renewable Portfolio Standard
SO_2	Sulfur dioxide
T&D	Transmission and Distribution
VDER	Value of Distributed Energy Resources

EXECUTIVE SUMMARY

Introduction

The New Hampshire Value of Distributed Energy Resources (VDER) study assesses the value of behind-the-meter (BTM) Distributed Energy Resources (DERs) that are owned by customers-generators and are eligible to participate in net energy metering (NEM) programs in New Hampshire. Statewide value is assessed from the perspective of the utility system and – through a rate and bill impact analysis – from the perspective of New Hampshire ratepayers, both NEM participants and non-participants.

This report answers the following key questions (with relevant study component indicated in brackets):

- **What are the system-wide avoided cost values of net-metered DERs installed during the 15-year study period to the utility system in New Hampshire?** (base value stack)
- **How does this value change if environmental externalities are considered?** (environmental externalities sensitivity)
- **How does this value change if system-wide loads increase?** (high load growth scenarios)
- **How does this value change with participation in the ISO-NE regional wholesale markets?** (market resource value scenario)
- **How do net-metered DERs impact ratepayers under the current NEM tariff structure and how would that impact change under an alternate compensation structure?** (rate and bill impacts analysis)

Methodology Overview

The VDER study methodology framework can be summarized by five high-level steps, outlined below:

1. Establish **Technology Neutral Value Stack** → 2. Develop **DER Production Profiles** → 3. Assess **DER Avoided Cost Value** → 4. Test **Avoided Cost Sensitivities** → 5. Assess **Rate and Bill Impacts**

First, baseline technology-neutral avoided cost values are established (step 1). Next, DER production curves are developed for each resource type (step 2) and mapped against the technology-neutral avoided costs to calculate the avoided cost value of DERs by system type (step 3). Avoided cost values are also calculated under sensitivity cases, including consideration of environmental externalities, high load growth scenarios, and a market resource value scenario (step 4). Finally, the rate and bill impacts are assessed, determining how DER deployment and compensation will affect New Hampshire rates and customer bills (step 5).

Key Findings

The results provided in this section are illustrative. The values presented below are calculated using specific sample system types, which were selected to be representative of common systems installed in the state. Specifically, the system types modeled were: residential and commercial south-facing solar PV (with and without storage), residential and commercial west-facing solar PV, large group host commercial (LGHC) solar PV, and micro hydro. The system specifications can be found in the 'Establishing DER Production Profiles' section of this report.

Although this approach is useful in highlighting trends, it does not generate values that can be applied to other system types. The model that accompanies this report allows users to generate results specific to other system types using a custom production profile.

In New Hampshire, the DER systems modeled for this study are expected to have provided a total system-wide net avoided cost value of **$0.11 to $0.18 per kWh energy produced in 2021** (Figure 1) and are forecasted to provide **$0.10 to $0.23 per kWh produced in 2035** (Figure 2), varying by DER system type:

Figure 1. Average Annual Value Stack with Environmental Externalities Sensitivity by DG System Type, 2021 (2021$)

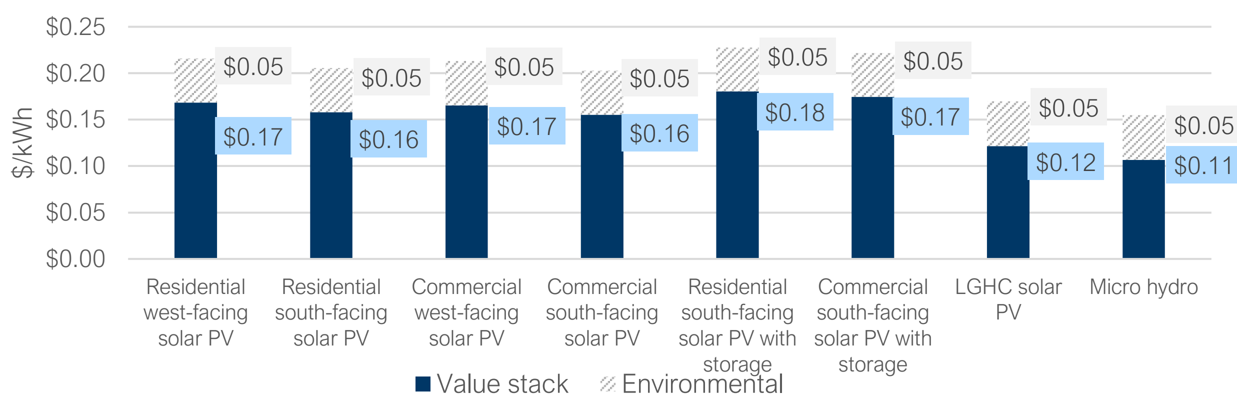
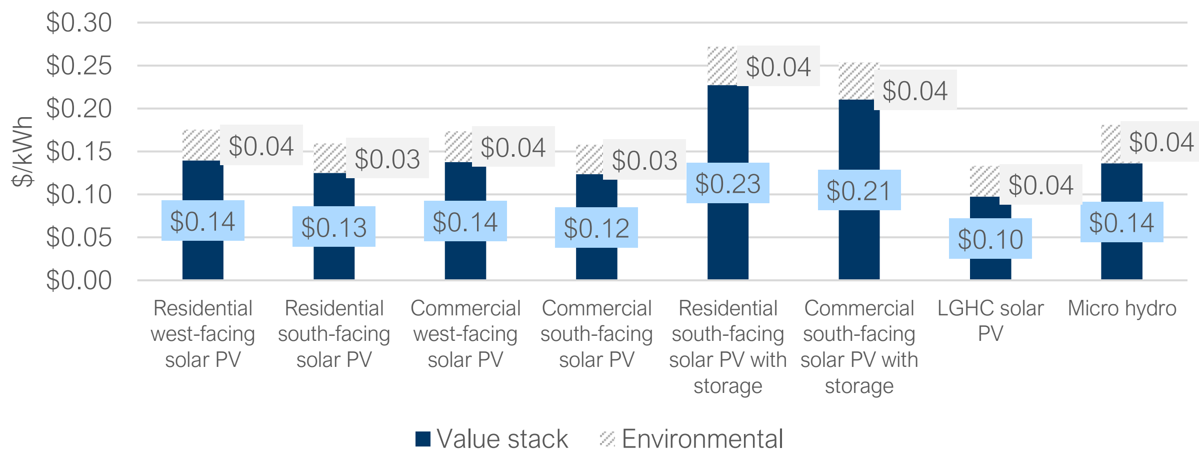


Figure 2. Average Annual Value Stack with Environmental Externalities Sensitivity by DG System Type, 2035 (2021$)



The total avoided cost value stack *decreases* over the study period for solar-only systems, primarily as a result of decreasing energy avoided costs. Net-metered DER value *increases* over time for solar paired with storage and for micro hydro as a result of the ability of those systems to realize greater Transmission and Distribution (T&D) avoided costs, which are assumed to increase over the study period. If the full social cost of environmental externalities (CO2, NOx) is considered, the value of net-metered DERs increases by 20%-45%, varying by year and by DG system type.

Although west-facing solar PV systems provide 5-10% greater avoided cost value by generating electricity later in the day (at times of peak demand), customer-generators in New Hampshire are currently incentivized to maximize solar production by installing south-facing systems, as these systems produce a greater volume of electricity overall.

Avoided cost values may change as a result of increasing system loads or should DERs participate in the regional wholesale energy or capacity markets. The impacts of these factors were assessed through the high load growth scenario (HLGS) and the market resource value scenario (MRVS), respectively. The change in avoided cost value from the baseline value stack for those scenarios is shown for 2021 in Figure 3 and for 2035 in Figure 4 below.

Figure 3. Average Annual Change from Baseline Value Stack Under the HLGS and MRVS, 2021 (2021$)

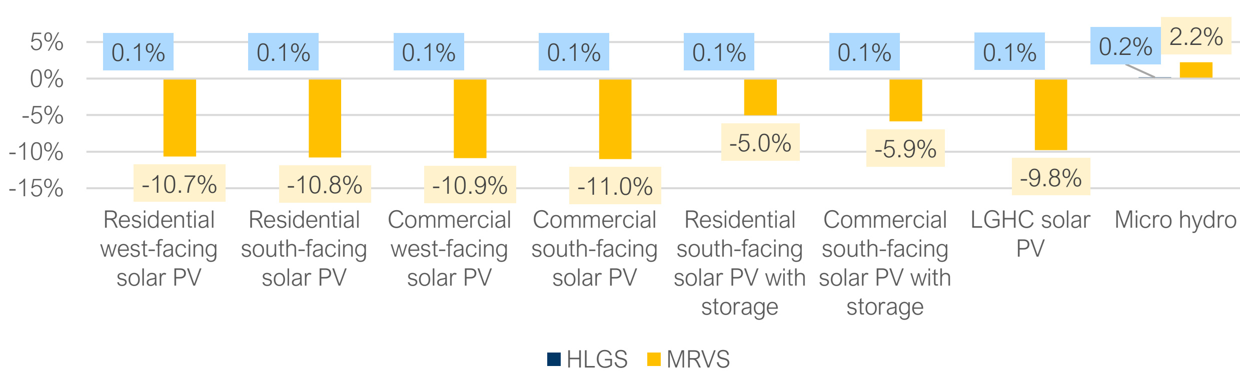
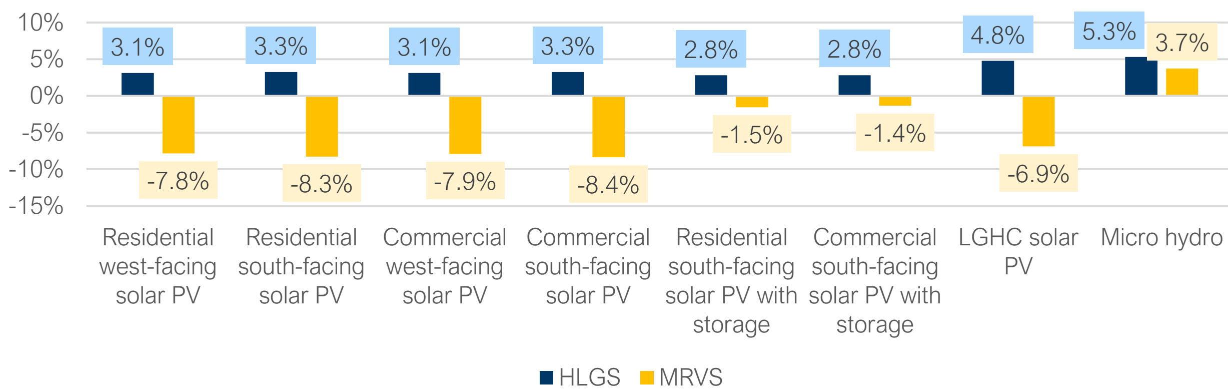


Figure 4. Average Annual Change from Baseline Value Stack Under the HLGS and MRVS, 2035 (2021$)



Increased loads under high load conditions, reflecting increased building and transportation electrification, have minimal impacts on the value of DERs in 2021 (less than 1% difference). In 2035, increased loads drive 2.8% to 5.3% higher values than the baseline value stack, varying by system type. The environmental externalities avoided cost sensitivity is also assumed to change with loads, increasing in value as loads grow due to assumptions that higher-emitting resources will be required to meet the incremental demand.

Net-metered DERs also may participate in the wholesale markets, rather than acting merely as passive resources that generate avoided cost value by reducing customer loads. From a utility system perspective, under current market rules, all systems provide greater value by passively reducing load than by participating as aggregated resources in the wholesales markets, with the exception of micro hydro. Micro hydro plants are able to consistently generate energy during the summer and winter reliability periods, thereby increasing their value in the forward capacity market.

Net-metered DERs are expected to provide value beyond what is shown here, notably for those value stack criteria addressed qualitatively in this study: transmission capacity (for non-pool transmission facilities), transmission and distribution system upgrades, distribution grid support services, and resiliency. Additional research and data collection may support valuation of these criteria in the future.

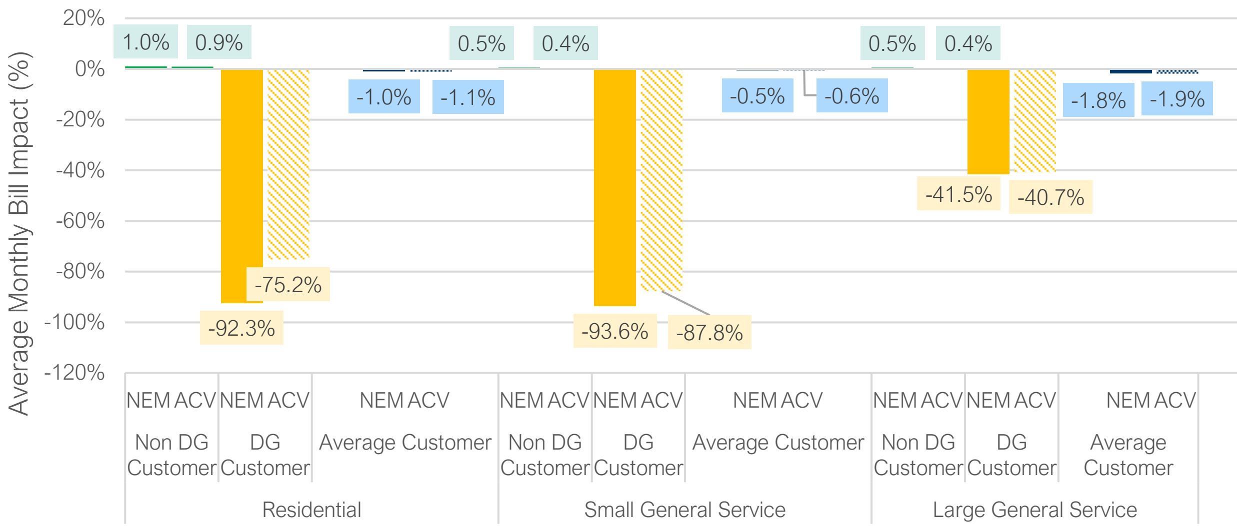
Customer-installed costs are included in this study. In the future, these costs may be used to evaluate how NEM crediting and compensation may affect reasonable opportunities to invest in DG and receive fair compensation, as contemplated by House Bill 1116 (2016).[1]

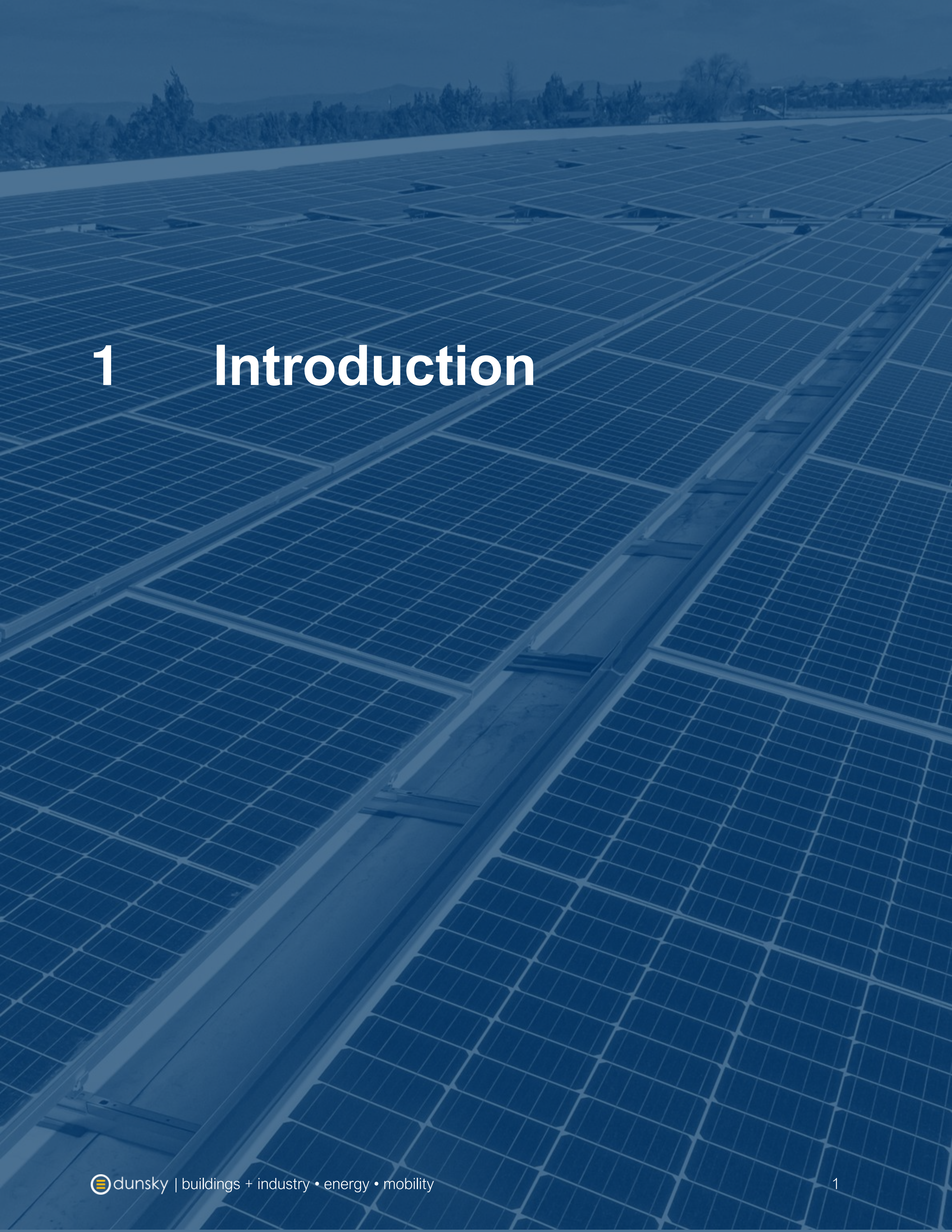
The rate and bill impacts analysis demonstrate that DG will cause rates to increase slightly for all rate classes and across all utilities under the current alternative net metering tariff design. Monthly bills would increase by a small percentage for non-DG customers but would decrease by a larger percentage for DG customers. . The average impact across each customer class, referred to as the “average customer” impact, is expected to be a bill reduction. In the alternative, a compensation model based on the avoided

[1] NH House Bill 1116 (2016). Available online: https://www.gencourt.state.nh.us/bill_status/legacy/bs2016/billText.aspx?sy=2016&id=293&txtFormat=html

cost value stack (i.e., an ACV tariff approach) would slightly reduce rate increases experienced by customers, with virtually the same non-DG customer impacts but slightly lower bill savings for DG customers, which would be reduced to a greater degree – in particular for residential customers (Figure 5).

Figure 5. Bill Impacts Across Rate Classes in Eversource Territory Under ACV and NEM Scenarios (Relative to no-DG scenario)





1 Introduction

Introduction

The New Hampshire Value of Distributed Energy Resources (VDER) study assesses the value of behind-the-meter (BTM) Distributed Energy Resources (DERs) that are owned by customers-generators and that are eligible for compensation through net energy metering (NEM) programs.[2] Statewide value is assessed from the perspective of the utility system and – through a rate and bill impact analysis – from the perspective of New Hampshire's ratepayers.

DG systems can generate energy and thereby decrease utility load, reducing the total demand that must be met by New Hampshire's utilities – and the ISO New England (ISO-NE) wholesale markets. This can reduce utility costs, generating avoided cost values.[3,4] The value that such DERs provide is location- and time-dependent, varying by hour, season, and year. These variations result from changing conditions in the ISO-NE wholesale markets and within New Hampshire's transmission and distribution systems, including resource availability, demand, congestion, and infrastructure. This statewide study *does not* capture variation by specific locations within New Hampshire, which was evaluated in a separate study completed for New Hampshire in 2020.[5] The study *does* capture variation in value by time by quantifying average state-wide hourly avoided cost value stacks from 2021 to 2035. The value that a net-metered DER can generate depends on the coincidence of its energy production/load reduction with the hourly avoided cost value stacks. This study maps hourly load reductions to hourly avoided costs for a sample of DERs that are generally representative of the system types participating in New Hampshire's NEM program.

This report answers the following key questions (with relevant study component indicated in brackets):

- **What are the system-wide avoided cost values of net-metered DERs installed during the 15-year study period to the utility system in New Hampshire?** (base value stack analysis)

- **How does this value change if environmental externalities are considered?** (environmental externalities sensitivity analysis)

- **How does this value change if system-wide loads increase?** (high load growth scenario analysis)

- **How does this value change with direct participation in the ISO-NE wholesale power markets?** (market resource value scenario analysis)

- **How do net-metered DERs impact rates and customer bills, and how do those impacts change under an alternate compensation structure?** (rate and bill impacts analysis)

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[2] In this study, the terms Distributed Energy Resource (DER) and Distributed Generation (DG) are used interchangeably to refer to technologies eligible to participate in New Hampshire's NEM program.
[3] Avoided costs represent reductions in cost as a result of marginal reductions in load.
[4] Alternatively, DERs may also increase utility costs. For example, they may necessitate utility system upgrades.
[5] Guidehouse. (2020). New Hampshire Locational Value of Distributed Generation Study. Available online: https://www.puc.nh.gov/regulatory/Docketbk/2016/16-576/LETTERS-MEMOS-TARIFFS/16-576_2020-08-21_STAFF_LVDG_STUDY_FINAL_RPT.PDF

1.1 – Study Context

The first DER NEM programs were established in New Hampshire many years ago. Today in the state, DER systems up to 1 MW in size (and up to 5 MW in size for "municipal host" facilities) are eligible to net meter, and participants are compensated in accordance with the New Hampshire alternative NEM tariff (NEM 2.0 tariff).[6,7] Since their inception, New Hampshire's NEM programs have experienced considerable year-over-year increases in DG deployment. As of December 2020, there were more than 10,000 systems enrolled in NEM programs with the state's utilities, equivalent to approximately 109 MW of total installed capacity.[8]

New Hampshire has experienced increased DER penetration in recent years, and it is anticipated that trend may continue. As net-metered DER penetration increases, changing impacts – both avoided costs and incurred costs – are expected for both utilities and ratepayers. This value stack assessment quantifies those impacts, considering changes to avoided and incurred costs resulting from future incremental additions of net-metered DERs in the state. For the purposes of this study, these avoided cost/cost categories are referred to as "value stack criteria."

The study was conducted on behalf of the New Hampshire Department of Energy. The New Hampshire alternative NEM tariff (NEM 2.0) was approved in a June 2017 order issued by the Public Utilities Commission (PUC).[9] The same order specified that a VDER study be conducted to assess the value of long-term avoided costs using marginal energy resource values and incorporating test criteria from standard energy efficiency benefit-cost analysis, a directive which shaped the VDER study methodology. The results of this study are expected to inform future NEM tariff development proceedings before the PUC.

1.2 – Study Scope

The study scope is defined by the following:

- **Study Period:** 2021-2035.
- **Geography:** The study is statewide, covering the three regulated electric utility service territories in New Hampshire: Public Service Company of New Hampshire d/b/a Eversource Energy

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[6] An outline of New Hampshire's current alternative "NEM 2.0" tariff, including how it is contrasted with the standard "NEM 1.0" tariff, is available online: https://www.puc.nh.gov/sustainable%20energy/Group%20Net%20Metering/PUC-SE-NEM-Tariff-2020.pdf.
[7] Systems installed prior to September 1, 2017 are compensated under the standard (or interim) net metering tariff (NEM 1.0) and are grandfathered until December 31, 2040.
[8] ISO-NE Distributed Generation Forecast Working Group. (2020). New Hampshire Update on State Distributed Generation Policy Drivers. Available online: https://www.iso-ne.com/static-assets/documents/2020/12/dgfwg_nh2020.pdf
[9] Order No. 26,029, issued in Docket DE 16-576 on June 23, 2017. Systems on the alternative NEM tariff are grandfathered until 2040 if a new rate goes into effect in the future.

(Eversource), Unitil Energy Systems, Inc. (Unitil), and Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty (Liberty).

- **Distributed Generation System Types:** The DERs included in this study are limited to distributed generation (DG) technologies that are eligible for NEM in New Hampshire, specifically solar, solar paired with battery storage, and small hydro. The study includes distributed generation archetypes that are representative of average installations in the residential and commercial sectors. This study does not extend to other types of DERs.

- **Value Perspectives:** The study assesses the value of new net-metered DERs from the perspective of the utility system, participating customer-generators, non-participating utility customers, and average utility customers. Existing DER impacts are assumed to be accounted for in the market.

- **Value Proposition**: The study primarily focuses on the ability of net-metered DERs to generate value through load reductions, however direct participation in the ISO-NE markets is also considered as a sensitivity in the market resource value scenario. The study also includes levelized net present value customer installed costs; in the future, those costs could be used to evaluate how NEM crediting and compensation may impact reasonable opportunities to invest in DG and receive fair compensation for net electricity exports to the grid.

- **Data Sources**: The study aims to maintain consistency with energy efficiency cost-effectiveness evaluation practices, to the extent possible, by using standard benefit-cost criteria, tools and methodologies from the regional Avoided Energy Supply Costs (AESC) 2021 study.[10] Utility data requests and interviews, as well as other relevant sources, were used to assess value stack criteria that fell outside of the AESC study scope.

- **Sensitivities:** The study also assesses sensitivities to determine:

    a. The value of environmental externalities (while mitigating the potential for double-counting by excluding certain price-embedded environmental costs);

    b. Impacts of future high load growth on value stack criteria; and

    c. The value that net-metered DERs can achieve by participating directly as market resources rather than merely as passive load-reducing resources.

- **Model:** The study includes an accompanying interactive model, allowing users to assess the full suite of avoided cost value stack and sensitivity results.

[10] Synapse Energy Economics. (October 2021). Avoided Energy Supply Components in New England: 2021 Report – Non-embedded environmental compliance section. Available online: https://www.synapse-energy.com/project/aesc-2021-materials

1.3 – Study Limitations

The reader should keep in mind the following study limitations:

- In this study, net-metered DERs are treated as price takers, where the magnitude of their adoption has little or no impact on wholesale market prices. The Demand Reduction Induced Price Effect (DRIPE) is intended to evaluate the price-depressive effects on energy and capacity, however the potential price impacts of DERs on the value of other avoided cost components, such as Regional Network Service (RNS) and Local Network Service (LNS) transmission charges, Renewable Portfolio Standard (RPS), and environmental externalities, and others, have not been evaluated.
- The avoided cost values calculated in the VDER study are assumed to apply statewide. Actual avoided costs, however, are expected to vary within the state and may be subject to local grid and market conditions.
- Distribution capacity avoided costs include only avoided small-scale system-wide investments. Locational distribution capacity avoided costs are not considered in this study, but may be significant; potential avoided costs are locational as well as time-varying.11
- For some value stack criteria, such as distribution system operating expenses, avoided cost values were determined using historic investment relative to historic load growth, with the assumption that historic trends will be indicative of future costs. That may not be the case if the utility system experiences unprecedented DER growth or higher load growth in future years.
- In the high load growth scenarios, the equation to calculate marginal emissions for the environmental externalities sensitivity analysis was developed through a regression analysis between New Hampshire's hourly demand and the associated CO_2 and NOx emissions, and as a result the emissions factor is assumed to increase with increased demand. The equation does not capture changes in resource mix and market conditions that could result in lower emissions rates.
- Avoided costs are assessed from the perspective of in-state cost impacts, consistent with the approach used to assess benefits from energy efficiency activities in the state.
- As market conditions evolve, avoided cost values may change. If market conditions change significantly from those forecasted at the time of this study, the avoided cost values may be affected. The accompanying model can be used to assess how changes to avoided cost values would affect the estimated value of various DERs.

[11] Guidehouse. (2020). New Hampshire Locational Value of Distributed Generation Study. Available online: https://www.puc.nh.gov/regulatory/Docketbk/2016/16-576/LETTERS-MEMOS-TARIFFS/16-576_2020-08-21_STAFF_LVDG_STUDY_FINAL_RPT.PDF

2 Methodology

Methodology Summary

2.1 – Methodology Overview

The VDER study methodology framework can be summarized by five high-level steps, outlined below:

1. Establish **Technology Neutral Value Stack** → 2. Develop **DER Production Profiles** → 3. Assess **DER Avoided Cost Value** → 4. Test **Avoided Cost Sensitivities** → 5. Assess **Rate and Bill Impacts**

First, technology-neutral avoided cost values are established (step 1). Next, DER production curves are developed for each resource type (step 2) and mapped against the technology-neutral avoided costs to calculate the avoided cost value of DERs by system type (step 3). Avoided cost values are also calculated under sensitivity cases, including consideration of environmental externalities, high load growth scenarios, and a market resource value scenario (step 4). Finally, the rate and bill impacts are assessed, determining how DER deployment and compensation will affect New Hampshire rates and customer bills (step 5).

The methodologies for each of these steps are described at a high-level in the sections that follow. Additional methodological detail is provided in the appendices.

2.2 – Technology Neutral Value Stack

2.2.1 – Base Value Stack Criteria

In keeping with the study goals of maintaining consistency with energy efficiency cost-effectiveness evaluation, avoided cost values from the AESC study (2021 edition) are used wherever possible.[12] For avoided cost criteria that are not included in the AESC study, relevant inputs were gathered through a combination of New Hampshire utility data requests, utility interviews, and literature reviews. Each value stack criterion falls into one of the following three groupings, categorized according to data availability and the evaluation methodology used:

- Evaluated using **AESC data, methods, and results**
- Evaluated using **quantitative methods unrelated to AESC**
- Evaluated using **qualitative review**

[12] AESC 2021 includes four counterfactual scenarios that estimate avoided costs under scenarios that include or exclude various demand-side resources. The purpose of these counterfactual scenarios is to calculate avoided cost values while either accounting for or excluding demand-side resources in a systematic fashion to understand the associated implications for avoided costs. For this study, AESC counterfactual 2 was selected, which does not include building electrification impacts. Building electrification impacts are included in the high load growth sensitivity, however.

The sections below describe each of the criteria at a high level, providing rationale as to why the criterion has value. Detailed methodologies and sources are included in Appendix C: Detailed Base Value Stack Methodologies.

Across all criteria, prices are adjusted to real 2021 dollars and $/kWh values are calculated for each hour of the study (8,760 hours per year, years 2021-2035).

2.2.1.1 – Energy

Evaluated using **AESC data, methods, and results**

Energy produced by net-metered DG reduces the amount of energy that New Hampshire utilities and load-serving entities must procure through the ISO-NE wholesale energy market, thereby reducing costs. Hourly Locational Marginal Prices (LMPs) specific to the New Hampshire zone reflect the displaced variable generation costs associated with the marginal resource(s) in the system and are thus considered to be an appropriate measure of the value of avoided energy in the state.

2.2.1.2 – Capacity

Evaluated using **AESC data, methods, and results**

Production by net-metered DERs that is coincident with the annual ISO-NE system peak reduces the amount that utilities and load-serving entities pay for capacity procurement in the ISO-NE market, thereby reducing in-state costs for New Hampshire utilities and Load Serving Entities (LSEs).[13] The avoided cost of capacity is determined by the ISO-NE Forward Capacity Market (FCM) and adjusted to reflect the variation between the Forward Capacity Auction (FCA) clearing price, which is established three years in advance of the time that capacity is procured, and the actual cost of capacity procured in the market.

2.2.1.3 – Ancillary Services and Load Obligation Charges

Evaluated using **AESC data, methods, and results**

Two assumptions underpin the valuation of this criteria element:

1. Any reduction in wholesale load would reduce ancillary service and load obligation charges that are assessed to New Hampshire utilities and LSEs;[14] and
2. Given challenges in accurately determining a price forecast and cost projections for these criteria, they can be proportionally pegged to wholesale energy prices for the purpose of this analysis.[15]

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[13] ISO-NE calculates capacity payment obligations for New Hampshire's distribution utilities (and all other load-serving entities in the ISO-NE market area), based on their relative contributions to the ISO-NE annual system peak load hour during the preceding year. If net-metered DG systems reduce utility load during the ISO-NE system peak hour, the capacity payment obligations assigned to New Hampshire's utilities and LSEs are reduced, resulting in in-state avoided costs.

[14] This approach is similar to how such charges are currently calculated for purposes of surplus net-metered generation payments in New Hampshire.

[15] Although ancillary services and load obligation charges are *not* always proportional to wholesale energy costs, there is a rationale for linking these for the purpose of this analysis. In ISO-NE, natural gas combustion turbines are typically the marginal energy resources and also typically provide ancillary services. It therefore follows that the price of ancillary services using those resources would be proportional to the price of providing energy using such resources.

As such, it is assumed that a reduction in wholesale load due to net-metered DER production will reduce the ancillary services and load obligation charges that are assessed to New Hampshire's utilities and LSEs, resulting in in-state avoided costs.

2.2.1.4 – RPS Compliance

Evaluated using **AESC data, methods, and results**

Energy produced by behind-the-meter DERs reduces the utility's retail energy sales. Because RPS obligations are proportional to energy supplied (i.e., retail sales), increased DER output results in decreased RPS compliance costs.[16] This avoided cost value is only applied to the portion of energy that is generated by DERs and consumed behind-the-meter; it excludes the portion of energy output that is exported back to the grid.

2.2.1.5 – Transmission Charges

Evaluated using **quantitative methods unrelated to AESC**

ISO-NE collects Regional Network Service (RNS) and Local Network Service (LNS) charges to cover the costs of upgrading and maintaining regional bulk transmission system infrastructure and certain lower voltage local facilities. Utility RNS and LNS charges are assessed monthly based on the coincidence of utility system monthly peaks with the monthly ISO-NE system peak. Production by net-metered DG resources that is coincident with the monthly ISO-NE system peak reduces the amount that utilities pay in RNS and LNS transmission charges, thereby reducing in-state costs.

2.2.1.6 – Transmission Capacity

Evaluated using **qualitative review**

There may be some transmission capacity upgrades that are not deemed to be either Pool Transmission Facilities (PTF) covered by RNS charges, or more local transmission facilities covered by LNS charges, as described in the 'Transmission Charges' criteria summarized above. It is expected that those other upgrades would be driven by demand during system peak periods. Net-metered DERs that reduce load during those peak windows may be able to avoid or defer such upgrades. Because this criterion is assessed using a qualitative review, it is not quantified as part of the value stack; instead, qualitative insights are included in the results section.

[16] The RPS requires electricity providers to serve a minimum percentage of their retail load using renewable energy. Across ISO-NE, the requirements vary by state. In New Hampshire, the total percentage of renewables required increases each year until 2025 according to a pre-defined schedule. The New Hampshire RPS statute includes minimum requirements by four renewable energy classes (with one specific additional carveout): new renewable energy (class I), useful thermal energy (class I thermal), new solar (class II), existing biomass/methane (class III), and existing small hydroelectric (class IV). If electricity providers are not able to meet the RPS requirements by acquiring renewable energy certificates, they must pay alternative compliance payments ($/MWh) into the state renewable energy fund.

2.2.1.7 – Distribution Capacity

Evaluated using **quantitative methods unrelated to AESC**

Energy produced by net-metered DG has the potential to avoid or defer distribution capacity upgrade costs if it reduces load at hours associated with reliability concerns (i.e., during peak hours that would otherwise drive investments in distribution system upgrades). In connection with the Locational Value of Distributed Generation (LVDG) study,[17] New Hampshire's utilities estimated the capital investments that would be required at various substations or circuits as a result of capacity deficiencies based on relevant planning criteria. Beyond those upgrades required to address capacity deficiencies, some investments are also expected to be required to address non-capacity upgrades (e.g., those related to reliability or performance issues), which the LVDG study did not address. Because the capacity-related deficiencies and the related potential avoided costs, reviewed in the LVDG study are highly locational, those costs are not considered in this study, which reviews system-wide avoided costs only.

2.2.1.8 – Distribution System Operating Expenses

Evaluated using **quantitative methods unrelated to AESC**

Net-metered DG has the potential to increase or decrease distribution-level system operating costs incurred by the utilities. For the purpose of the study, this criterion is considered to be an avoided cost, with any incremental costs associated with distribution system operating expenses covered under the 'T&D system upgrades' criterion. As such, this criterion represents reductions or deferrals of distribution system operating expenses, as a result of equipment life extension, lower maintenance costs, lower labor costs, and other such expense reductions or deferrals.

2.2.1.9 – Transmission Line Losses

Evaluated using **AESC data, methods, and results**

Energy produced by net-metered DG resources reduces the energy that would otherwise move through the transmission network. Any surplus energy that is exported by such resources to the distribution system is assumed to be contained within the distribution network; no transmission backflow associated with such surplus energy is assumed to occur. As such, the avoided transmission line losses apply to the *total* energy produced by the DG resource. It should be noted that this avoided cost criterion is calculated as a *cumulative* value, incorporating line loss values from the energy, capacity, and DRIPE avoided cost criteria. Any value from avoiding transmission line losses that is typically attributed to those other criteria has been removed to avoid double-counting and is included in this criterion instead.

[17] Guidehouse Inc. (2020). New Hampshire Locational Value of Distributed Generation Study. Accessible online at: https://www.puc.nh.gov/Regulatory/Docketbk/2016/16-576/LETTERS-MEMOS-TARIFFS/16-576_2020-08-21_STAFF_LVDG_STUDY_FINAL_RPT.PDF#:~:text=The%20New%20Hampshire%20Public%20Utilities%20Commission%20%28the%20Commission%29,metering%20docket.%20In%20its%20February%202019%20order%2C%201

2.2.1.10 – Distribution System Line Losses

Evaluated using **AESC data, methods, and results**

Energy produced by net-metered DG reduces the energy that would otherwise move through the utility distribution system. Any surplus energy that is exported by such resources to the distribution grid is assumed to stay within the distribution system. As such, avoided distribution line losses apply *only* to the portion of the energy produced by the DG resource that is consumed behind-the-meter. As with the transmission line losses criterion, this avoided cost is calculated as a *cumulative* value, incorporating line loss values from all relevant energy, capacity, RPS compliance, and DRIPE avoided cost criteria. Any value from avoiding distribution line losses that is typically attributed to those other criteria has been removed to avoid double-counting and is included in this criterion instead.

2.2.1.11 – Wholesale Market Price Suppression

Evaluated using **AESC data, methods, and results**

Electricity generated by DG at customers' sites reduces the overall energy and capacity procured through the wholesale market. The reduced demand results in lower market clearing prices, and this price suppression benefit - DRIPE - ultimately may be passed on to market participants and their customers. For this analysis, we considered the direct price suppression benefits that result from reduced energy (Energy DRIPE), reduced capacity (Capacity DRIPE), and the indirect price suppression benefits that result from reduced electricity demand on gas prices, which in turn reduces electricity prices (Electric-to-Gas-to-Electric cross-DRIPE).

2.2.1.12 – Hedging/Wholesale Risk Premium

Evaluated using **AESC data, methods, and results**

Retail avoided costs include a risk premium which increases the price of retail electricity beyond the price of wholesale electricity. This premium accounts for the risk inherent in establishing contract prices in advance of supply delivery; there is uncertainty in the final market prices that will be charged to the supplier, and there is uncertainty in the final electricity demand of buyers. Load reductions from net-metered DERs reduce wholesale energy and capacity obligations, and therefore load-serving entities' (such as the suppliers of default service energy to New Hampshire electric utilities) costs to mitigate those market risks.

2.2.1.13 – Distribution Utility Administrative Costs

Evaluated using **quantitative methods unrelated to AESC**

An increase in installed DG resources may increase associated utility administrative costs. Examples include those costs associated with NEM program administration, metering, billing, collections, evaluations, and any unreimbursed interconnection assessments. The utilities' related administration costs, including labor, materials, and outside services that are in excess of the administration costs for a typical non-DG customer, and are not covered by the customers themselves, are included in this criterion.

2.2.1.14 – Transmission and Distribution System Upgrades

This criterion is an incurred cost category rather than an avoided cost category. It encompasses all costs related to transmission and distribution system upgrades that are driven by the addition of net-metered DG to the grid. Because this criterion was assessed using a qualitative review, it is not quantified as part of the value stack; instead, qualitative insights are included in the results section.

Evaluated using **qualitative review**

2.2.1.15 – Distribution Grid Support Services

This criterion may be an incurred cost or an avoided cost, reflecting an increase or decrease in costs for distribution system support services required as net-metered DG penetration increases. Because this criterion was assessed using a qualitative review, it is not quantified as part of the value stack; instead, qualitative insights are included in the results section.

Evaluated using **qualitative review**

2.2.1.16 – Resilience Services

In this study, resilience services are defined as the ability of DERs to provide back-up power to a site in the event that it loses utility electricity service.[18] Resiliency has the potential to generate significant value, although this value is expected to be highly context-specific. Because this criterion was assessed using a qualitative review, it is not quantified as part of the value stack; instead, qualitative insights are included in the results section.

Evaluated using **qualitative review**

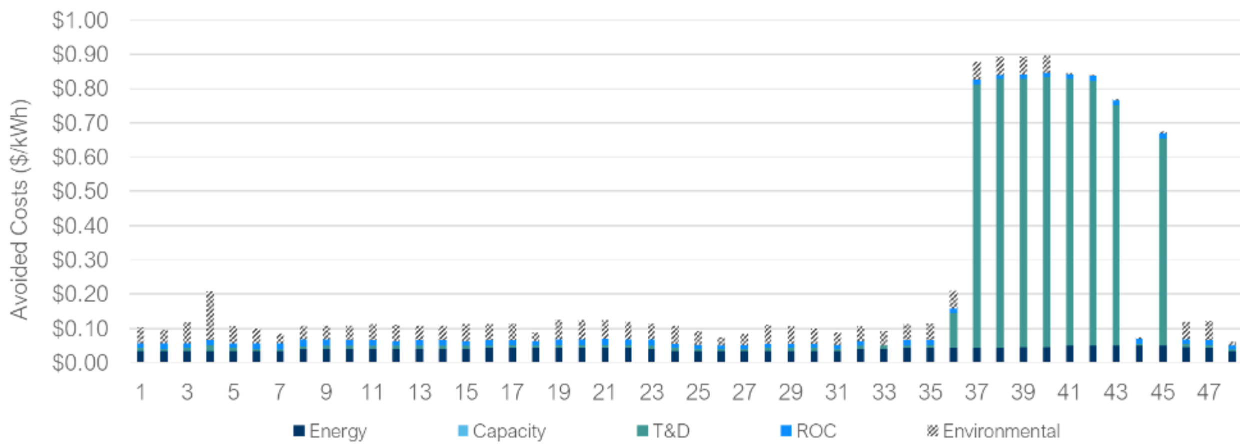
2.2.2 – Example Value Stack

The avoided cost value criteria are combined to develop a technology-neutral value stack which quantifies avoided cost values during each hour of the study period. Figure 6 below illustrates this value stack for a hypothetical 48-hour period. These days include a number of estimated peak demand hours on the New Hampshire distribution grid, demonstrating how avoided cost values vary according to system conditions. For ease of presentation, the avoided cost criteria are grouped into four categories: energy, capacity, transmission and distribution (T&D), and rest of criteria (ROC).[19] The environmental externalities sensitivity is also shown.

[18] This definition was sourced from the US DOE Office of Energy Efficiency and Renewable Energy, available online: https://www.energy.gov/eere/femp/distributed-energy-resources-resilience

[19] Here, T&D includes the following quantified avoided cost criteria: transmission charges, distribution capacity, distribution operating expense, transmission line losses, and distribution line losses. ROC includes all quantified baseline criteria with the exception of energy, capacity, and those criteria included in the T&D category.

Figure 6. Technology-Neutral Value Stack (2021$)



A subset of hours starting at hour 36 includes high avoided cost values in the T&D category, which coincide with periods of high system demand. The hourly avoided costs for these criteria are assumed to be driven by system peaks, and therefore increase in value when demand is high and decrease when demand is low.

2.2.3 – Customer Installed Costs

Customer installed costs are calculated separately from the value stack. Costs are calculated on a net present value basis for each system type, considering upfront and operational costs as well as available incentives. The costs are levelized by total energy production over the system's lifetime. In the future, those estimated costs could be used to assess the cost-effectiveness of DER systems from the perspective of customer-generators with net-metered DG systems. Customer installed costs are described in more detail in Section 3.3 below.

2.3 – DER Production Profiles

To assess the value of DERs, illustrative net-metered DG production curves are required. The study characterizes eight archetypal DG resources for the assessment, aiming to represent the diversity of systems that participate in statewide NEM programs:

- **Residential south-facing solar** (7.8 kW DC, 6.5 kW AC): The system size represents the average residential solar PV system currently installed in Eversource's territory. The normalized solar production profile published by ISO-NE informed the production profile shape. [20]

- **Residential west-facing solar** (7.8 kW DC, 6.5 kW AC): The system size represents the average residential solar PV system installed in Eversource's territory. To date, customer-generators in New Hampshire have been incentivized to maximize volumetric energy credits by installing south-facing systems. Given limited New Hampshire-specific data for west-facing

[20] ISO New England. (2022). Load Forecast. Available online: https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/?document-type=Hourly%20Behind-the-Meter%20Photovoltaic%20Data

production profiles, the normalized solar production profile from PV Watts informed the production profile shape for the west-facing system. [20]

- **Commercial south-facing solar** (36 kW DC, 30 kW AC): The system size represents the average commercial solar PV system installed in Eversource's territory. The normalized solar production profile published by ISO-NE informed the production profile shape.[20]

- **Commercial west-facing solar** (36 kW DC, 30 kW AC): The system size represents the average commercial solar PV system installed in Eversource's territory. To date, customer-generators in New Hampshire have been incentivized to maximize volumetric energy credits by installing south-facing systems. Given limited New Hampshire-specific data for west-facing production profiles, the normalized solar production profile from PV Watts informed the production profile shape for the west-facing system.[21]

- **Residential south-facing solar paired with storage** (7.8 kW DC, 6.5 kW AC solar PV system, 4-hour duration 10 kWh/2.5kW storage system): The system size represents the average residential solar PV system installed in Eversource's territory. The normalized solar production profile published by ISO-NE informed the production profile shape.[20] The storage system size and duration represent a typical residential storage system. The storage system charging hours were selected to occur during high solar production and relatively lower avoided cost values (HE11 to HE14) while discharging hours were selected to occur during periods of higher avoided cost value (HE18 to HE21). The charging and discharging windows remained fixed throughout the study period; a dynamic optimization schedule for charging and discharging was out-of-scope for this study.

- **Commercial south-facing solar paired with storage** (36 kW DC, 30 kW AC solar PV system, 4-hour duration 40 kWh/10kW storage system): The system size represents the average commercial solar PV system installed in Eversource's territory. The normalized solar production profile published by ISO-NE informed the production profile shape.[20] The storage system size and duration represent a typical small commercial storage system. The storage system charging hours were selected to occur during high solar production and relatively lower avoided cost values (HE11 to HE14) while discharging hours were selected to occur during periods of higher avoided cost value (HE18 to HE21). The charging and discharging windows remained fixed throughout the study period; a dynamic optimization schedule for charging and discharging was out-of-scope for this study.

- **Large Group Host Commercial Solar** (195 kW DC, 162 kW AC single-axis tracking): The system size represents the average large general commercial solar PV system installed in Eversource's territory. The normalized solar production profile published by ISO-NE informed the production profile shape. [22]

- **Micro hydro** (3 MW): Using internal tools, Dunsky developed an 8,760 hourly load profile for a small hydro facility that considered the month-to-month variation in generation for a small run-

[21] NREL. (2022). PVWatts Calculator. Available online: https://pvwatts.nrel.gov/
[22] ISO New England. (2022). Load Forecast. Available online: https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/?document-type=Hourly%20Behind-the-Meter%20Photovoltaic%20Data

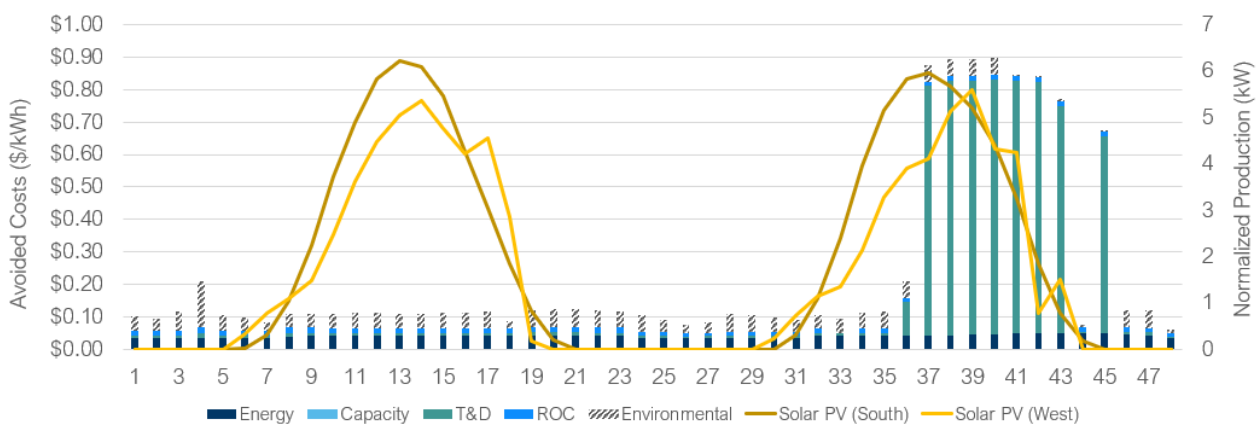
of-river hydro facility located in New Hampshire. The month-to-month variation in hydro generation was developed using New Hampshire-specific hydro data from the U.S. DOE EIA.[23] Because hydro facilities vary in size and capacity factors, for modelling purposes, we assumed a small hydro facility of 3 MW.

To minimize day to day variations, the production profile was averaged by hour for each month for all solar systems. Annual 8,760 production profiles for each system type are included in Appendix Section A: DER Production Profiles.

2.4 – DER Avoided Cost Value

Figure 7 below shows how production of two residential systems, one south-facing and one west-facing, varies across the same hypothetical 48-hour period, and how that production maps to the illustrative hourly avoided cost stack presented in section 2.2.2 Example Value Stack.

Figure 7. Technology-Neutral Value Stack and Sample Solar Production Profile (2021$)



To assess DER value, the production curves for each DG type (in kW) are combined with the technology-neutral value stack for each hour (in $/kW) to assess technology-specific hourly avoided costs (in $/kWh). To assess average annual avoided cost values, the technology-specific avoided costs are summed across all hours in each year and then divided by the total annual DG production to calculate an average annual avoided cost value. A similar process is used to determine average seasonal avoided cost values – the total avoided costs are summed across all months in a season, then divided by total production during that season.

2.5 – Avoided Cost Sensitivities

Sensitivities are included in the study to test how the avoided cost value associated with DERs may be expected to change according to the degree to which externalities are considered (Environmental Externalities Sensitivity), should future load growth be higher-than-projected (High Load Growth

[23] EIA. (2022). New Hampshire Electricity Dashboard. Available online: https://www.eia.gov/beta/states/states/nh/data/dashboard/electricity

Scenarios), or should aggregated DERs participate in the ISO-NE market (Market Resource Value Scenario). The methodologies used to assess these sensitivities are briefly described in the following sections.

2.5.1 – Environmental Externalities Sensitivity

Fossil fuel combustion generates greenhouse gas (GHG) emissions and other air pollutants, including carbon dioxide (CO_2) emissions, sulfur dioxide (SO_2) emissions, nitrogen oxide (NO_x) emissions, and particulate matter. Methane emissions are also released during natural gas production, transportation, and use. A portion of the environmental costs associated with CO_2 emissions are already embedded in wholesale electric energy prices. However, there are additional societal costs associated with CO_2 and other emissions that are not embedded in energy prices. Where possible, the environmental externalities sensitivity assesses the avoided cost value of each air pollutant type considering only non-embedded costs. The approach taken for each air pollutant type is described below:

- **CO_2 emissions:** The AESC wholesale energy price forecasts include the costs of compliance with the Regional Greenhouse Gas Initiative (RGGI). For this analysis, the full social cost of CO_2 emissions (net of RGGI compliance costs to avoid double-counting) is included in the environmental externalities value.[24]

- **SO_2 emissions:** The AESC assumes that all coal-fired generation – the primary source of SO_2 emissions from electricity generation – is taken offline by 2025. For this analysis, the value of SO_2 emissions is assumed to be minimal, and therefore is not included in the environmental externalities value.

- **NO_x emissions:** The AESC wholesale energy forecasts do not include any costs associated with NO_x emissions. For this analysis, the full social cost of NO_x emissions (AESC 2021) is included in the environmental externalities value.[25]

- **Particulate matter:** The AESC wholesale energy price forecasts do not include any costs associated with particulate matter. When considering energy generation, particulate matter is primarily produced by coal and biomass combustion. Because coal-fired generation is assumed to be taken offline by 2025, the impacts of particulate matter from coal combustion are not included in the environmental externalities value. Although biomass remains a generation source throughout the study period, it provides baseload power rather than marginal generation. Because biomass facilities do not generate electricity on the margin, reductions in biomass-related particulate matter emissions are not expected as a result of net-metered DER load reductions. The impacts of particulate matter are therefore also excluded from the environmental externalities value.

[24] Synapse Energy Economics. (2021). AESC 2021 Supplemental Study: Update to Social Cost of Carbon Recommendation. Available online: https://www.synapse-energy.com/sites/default/files/AESC_2021_Supplemental_Study-Update_to_Social%20Cost_of_Carbon_Recommendation.pdf

[25] Synapse Energy Economics. (2021). Avoided Energy Supply Components in New England: 2021 Report – Non-embedded environmental compliance. Available online: https://www.synapse-energy.com/project/aesc-2021-materials

- **Methane:** Although the societal costs of methane are considerable on a per ton basis, methane emissions are challenging to quantify and forecast as they primarily occur upstream from power generation during the production, processing, storage, transmission, and distribution of natural gas and oil, and have not been thoroughly monitored or studied. In addition, the U.S. government is taking steps to substantially reduce upstream methane emissions through a proposed rule applicable to new and existing facilities, which targets a 74% reduction in methane emissions from oil and gas production from 2005 levels by 2030.[26] Given the challenges inherent in developing methane emissions forecasts for ISO-NE, and in view of federal government proposals to reduce methane emissions during the study period, methane is not included in the environmental externalities value.

Environmental externalities represent benefits/costs that are external to utility system valuation and therefore are not currently included in NEM tariff design. There is value in estimating actual non-embedded environmental externality benefits associated with net-metered DG production, however, and as such those benefits are included in the study as a sensitivity.

2.5.2 – High Load Growth Scenarios

The value that net-metered DG resources bring to customers, utilities, and the grid will vary to some degree depending on the magnitude and characteristics of future load growth. Future electricity load growth will depend, in large part, on the extent of heating electrification in buildings and transportation electrification, each of which will exert an influence on the timing and extent of seasonal electric system peaks. The inherent uncertainty around the adoption of these technologies translates into uncertainty around load growth on the system. The high load growth scenarios (HLGS) analysis considers several scenarios for increased load growth – each varying with respect to building or transportation electrification adoption – to investigate the impact of loads on the value of net-metered DERs. The detailed HLGS methodology is included in Appendix Section D: High Load Growth Scenarios Methodology.

2.5.3 – Market Resource Value Scenario

Apart from the avoided cost benefits achieved through passive load reduction, aggregated DG resources may generate monetizable value by participating directly in wholesale power markets. The market resource value scenario (MRVS) sensitivity quantifies the value of net-metered DG resources participating directly in relevant wholesale power markets for those criteria where there is a readily discernible market value or a value different from those established in the load reduction estimate, notably capacity. DG resources could theoretically also provide ancillary services to the market; however, provision of those services typically requires that resources do not participate in the energy market, so DER provision of ancillary services is expected to be uneconomic.[27] Accordingly, ancillary services market values are not

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[26] US EPA. (2021). News Release: U.S. to Sharply Cut Methane Pollution that Threatens the Climate and Public Health. Available online: https://www.epa.gov/newsreleases/us-sharply-cut-methane-pollution-threatens-climate-and-public-health

[27] As one example, for a solar resource to provide operating reserves, it requires "headroom," which would allow it to increase output in response to a generator activation instruction by ISO-NE. To provide such headroom, the generator would need to be dispatched down, resulting in an opportunity cost for the operator.

quantified as part of the MRVS. The detailed MRVS methodology is included in Appendix E: Market Resource Value Scenario Methodology.

2.6 – Rate and Bill Impacts

The Rate and Bill Impact Assessment provides high-level insight into the impact of DG deployment in New Hampshire on ratepayers, considering the benefits received and the costs incurred by the utilities as a result of incremental DG additions (which, for the purpose of this analysis, are limited to solar PV systems), and considering how those values are passed on to ratepayers.

The assessment aims to provide a future-looking estimate of the direction and magnitude of the rate and bill impacts of DG deployment and to identify any potential cost-shifting between customers with and without DG. It is not intended to represent an exact projection of future electricity rates and utility cost recovery. Instead, it serves as a future-looking approximation of the impacts on ratepayers attributable to DG deployment in New Hampshire.

The rate and bill impacts methodology can be summarized by four high-level steps, outlined below:

1. Define DG system archetypes → 2. Develop DG and no-DG Load Forecasts → 3. Assess changes to rates → 4. Assess changes to bills

2.6.1 – Define DG System Archetypes

For this analysis, solar PV system archetypes are defined for each utility (Eversource, Unitil, and Liberty) and for representative rate classes (residential, small commercial, and large commercial). System archetypes are defined by the PV system size as well as the percentage of energy produced that is consumed behind-the-meter based on the load patterns of a typical customer in that rate class.

The assumptions used for each are calculated using *utility-specific* interconnection data, resulting in average system size assumptions that vary by utility. The archetypes used for this analysis are summarized in Table 1 below.

Table 1. Rate and Bill Impacts Analysis Solar PV Archetype by Rate Class and Utility

Rate Class	Eversource	Unitil	Liberty	% Self-Consumed
Residential	7.6	12.2	10.1	72% (Monthly Netting)
Small Commercial	24.5	43.0	41.3	65% (Monthly Netting)
Large Commercial	329.2	47.2	209.6	99% (Hourly Netting)

2.6.2 – Develop DG and no-DG Load Forecasts

To assess the impacts of DG, a 'no-DG' scenario is required to serve as a baseline. The 'no-DG' scenario is a hypothetical illustration of the system outlook in the absence of projected *new* DG capacity additions and is used as a comparison to evaluate the impact attributable to future incremental DG deployment. The no-DG load forecast is developed by multiplying the forecast of customer counts for each rate class by the expected electricity sales.

The DG scenario reflects the impacts associated with future DG deployment forecasted by ISO-NE, which assumes that 140 MW of additional DG (predominantly solar PV) will be deployed in New Hampshire between 2021 and 2030; that amount is above and beyond the existing 120 MW already deployed today. Using insights from historical utility interconnection data, we estimated the expected distribution of future DG deployment among the three utilities and three rate classes.

Using the forecasted level of DG uptake, our team then estimated the corresponding hourly energy production and used that to estimate the expected impacts of DG deployment on annual energy consumption (GWh) and peak load (MW) for each utility and rate class. The impacts were calculated at the customer meter/distribution system, transmission system, and bulk system, using assumptions on system losses as well as the peak coincidence factor between the different levels.

Beyond the utility/rate class level load forecast, our team computed the average monthly electricity consumption (i.e., kWh consumed per month), as well as the annual non-coincident peak demand (i.e., kW peak demand used for the purpose of demand charges), for each of the three archetype rate classes across the three utilities for three representative customer types:

- **Typical DG customer:** a customer assumed to install the defined archetype DG system and experiencing a corresponding reduction in the customer's energy consumption and peak demand.
- **Typical non-DG Customer:** assumed to have the same consumption profile as the average utility customer in the no-DG scenario.[28]
- **Average utility customer:** computed as the total consumption divided by the number of customers across each rate class and utility.

[28] The consumption profile of all three customer types is assumed to be the same in the hypothetical no-DG scenario, equivalent to the energy consumption and peak demand of the average customer in that rate class.

2.6.3 – Assess Changes to Rates

The future deployment of DG is expected to create upward pressure on rates (due to lost utility revenues and program cost recovery) and downward pressure on rates (due to avoided utility costs).[29, 30] Additionally, rates are also impacted by reduced system throughput. The figure below highlights the theoretical framework that was used to assess the rate impacts of DG.[31]

Figure 8. Theoretical Framework Used to Assess the Rate Impacts of DG

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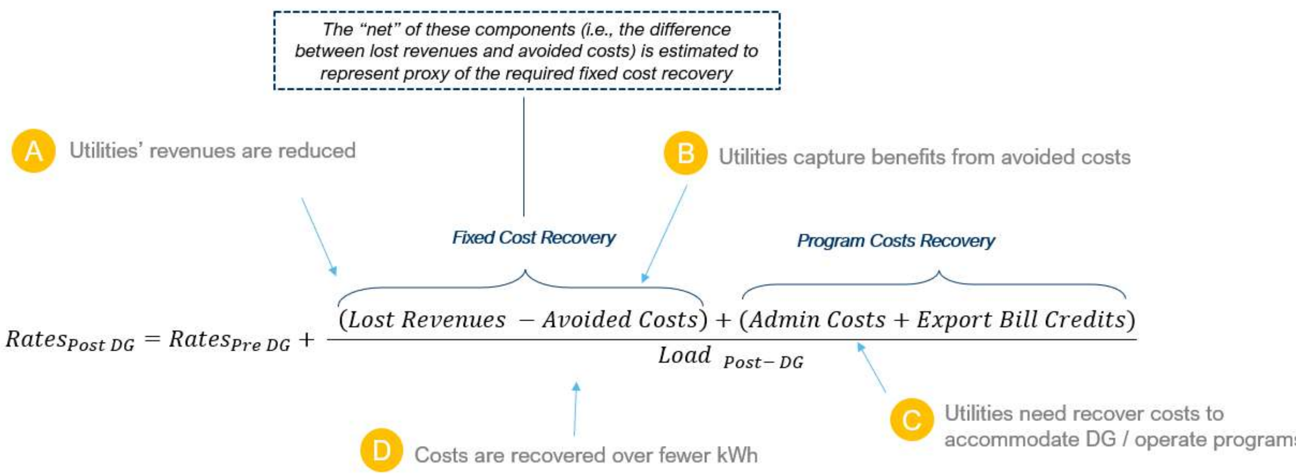

Specifically, the framework captures several key impacts of DG deployment on rates[32]:

A. Lost utility revenues due to reductions in electricity consumption.

B. Avoided costs, as indicated and quantified by the Value Stack assessment.

C. Program administration[33] and system costs, including compensation for net DG exports, incurred by utilities to accommodate DG.

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[29] Utility revenues are reduced because of reduced retail sales. These retail sales reductions are equivalent to the energy production by DG systems that is consumed behind-the-meter. Reduced retail sales create upward pressure on rates by increasing the share of utility fixed costs that must be covered by each unit of energy that is sold. Program costs refer to the costs required to administer DG-specific programs and compensate for exports. Utilities must recover the costs of running programs through rates. Again, as retail sales volumes are reduced, the share of program costs that must be covered by each unit of energy sold must be increased.

[30] Utilities also realize value as retail sales are reduced, avoiding the costs that would have been required to serve loads if they were not being served by behind-the-meter DG.

[31] This approach is largely in-line with that applied to evaluate the Rate and Bill Impacts of Energy Efficiency Programs in New Hampshire.

[32] The results of the rate impact assessment are based on the relative changes in the volumetric portion of the rates post-DG. The fixed charges and non-bypassable charges are assumed to be unchanged in the post-DG scenario.

[33] The assumed program administration costs include the costs for FTE (Labor), Engineering, Management, IT Support, Metering, and Installation. The administration cost projections were based on the forecasted number of installations across the three rate classes for each utility.

D. System costs that are recovered over lower energy sales.

The rate at which exported DG electricity output is compensated impacts rates for all utility customers. To illustrate the impacts of different potential DG program designs on ratepayers, changes to rates were assessed under two scenarios for DG compensation:

1. **NEM Tariff Scenario:** Assumes DG exports are compensated at a rate that is in alignment with current NEM compensation rates in the state.[34]
2. **Avoided Cost Value Stack (ACV) Tariff Scenario**: Assumes that DG exports are compensated at an avoided cost rate that is in alignment with the calculated value stack assessment.[35]

DG compensation impacts rates by changing the 'export bill credits' portion of the program cost recovery value (item C above). All other factors remain constant between the two scenarios.

2.6.4 – Assess Changes to Bills

Simply considering rates does not tell the whole story. Analysis of effects on customer bills, which are calculated using volumetric rates ($/kWh and $/kW) and consumption (kWh and kW peak), as well as fixed charges, provides a better indication of the overall impact on customers.

Representative monthly bills were computed for each of the utility/rate class permutations under the no-DG scenarios. Bills were then recalculated for each of the three representative customer groups described above (i.e., typical DG, typical non-DG customer, and average utility customer) under the assumed level of future DG deployment. Evaluating changes in bills of customers with DG and those without DG provides insights into the degree of cost-shifting between customer groups (i.e., the degree to which non-DG customers will see bill increases as a result of rate impacts from DG installations). Additionally, the estimated impacts on monthly bill for the average utility customer pre- and post-DG highlight the extent to which utility customers on average are better or worse off as a result of future DG uptake.

Changes to bills are assessed under two scenarios: the NEM scenario and the ACV scenario described above. The results are largely focused on presenting the average per cent increase/decrease in customers' monthly bills attributable to DG over the period 2021 to 2035 for each of the typical customer archetypes to indicate the long-term impacts of DG on utility customers.

[34] The current alternative NEM tariff structure compensates systems under 100 kW at 100% of the generation and transmission rate components and 25% of the distribution rate component through monetary bill credits for monthly net exports. For systems over 100 kW, the export bill credit is equivalent to 100% of the generation rate component based on hourly net exports over the billing month.

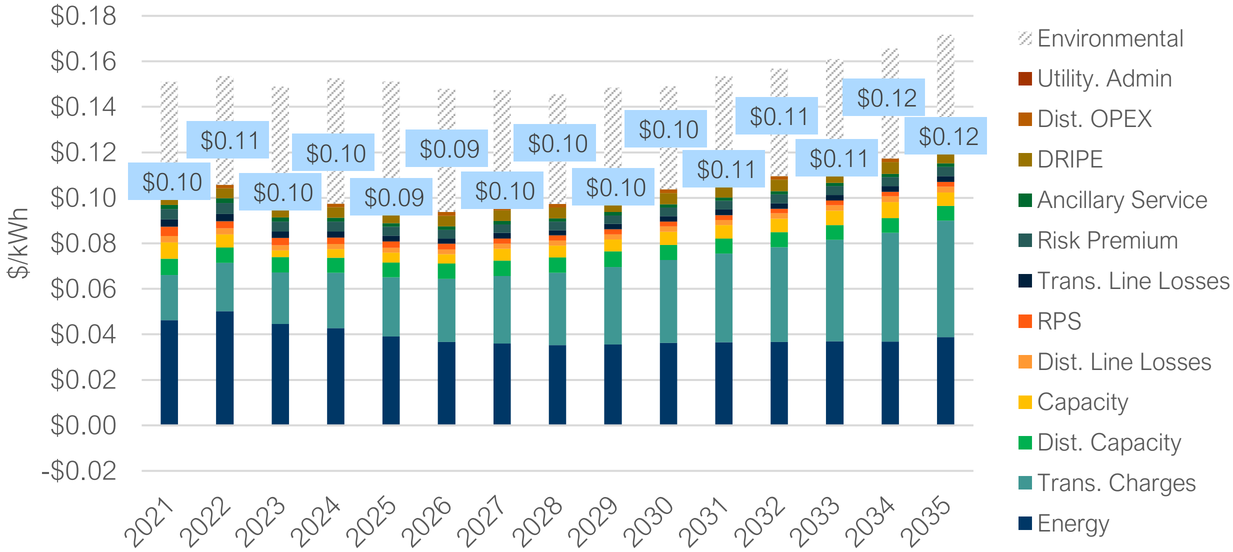
[35] The analysis **does not** consider the impact that the transition to an Avoided Cost Value Stack compensation model would have on DG economics and deployment trends in New Hampshire (i.e., the same level of future DG deployment is assumed to occur under both scenarios).

3 Results

3.1 – Technology-Neutral Value Stack

The technology-neutral value stack quantifies the total avoided cost value during each hour of the study period. These hourly values can be averaged across each study year to generate average annual avoided costs, as shown in Figure 9 below.

Figure 9. Average Annual Technology-Neutral Value Stack (2021$)[a]



a. Totals shown are net values and exclude the value of environmental externalities

On an average annual basis, the technology-neutral avoided cost value stack ranges from $0.09/kWh to $0.12/kWh, excluding environmental externalities. Energy and transmission charges are the largest two value stack criteria in each study year, collectively representing between 65% and 74% of the total value. Initially, energy represents a larger share of the value stack. However, the avoided cost value of energy generally decreases over the study period as a result of 1) study-specific assumptions, and 2) AESC forecast trends:

1) In the first five years of the study, the energy avoided costs included in this study are higher than the AESC avoided cost forecast to account for increases in natural gas prices since the AESC was published.[36]
2) The value of energy declines over time in the AESC forecast as lower-cost resources increasingly participate in the market, such as offshore wind and solar.

Meanwhile, transmission charges avoided costs are forecasted to increase over time. For the initial study years, the transmission charge forecast trend was sourced from near-term (2021-2024) projections. Given limited insight into how these projections may vary post-2024, this near-term trend

[36] Energy prices have continued to increase following the analysis phase of the study. The study represents a snapshot in time, and there is a high degree of uncertainty around how prices can be expected to move in the future.

was extrapolated over the study period. Additional insights into this calculation are included in Appendix Section C.5: Transmission Charges.
Each of the remaining value stack criteria individually represents, at most, 7% of the value in any given year. Utility administration is the only value stack criteria with an average negative value. This represents the additional utility administrative costs of connecting and maintaining customer-generator DG installations over-and-above standard customer administrative costs.

Environmental externalities, which account for the social cost of carbon (net of carbon costs already embedded in wholesale energy prices) and the social cost of nitrogen oxide, would increase the value stack by between 41% and 59%, varying by year. Changes in the value of environmental externalities decline over time as the generating resource mix on the ISO-NE system is projected to increasingly include lower-emitting resources. Specifically, the AESC assumes that all coal-fired generating resources in ISO-NE are retired by 2025, and that some gas and oil generating units also are retired during the study period.

Annual averages are provided above for each of the criteria, however the values can vary considerably from hour to hour within a given year. Table 2 below includes the average annual values alongside the minimum and maximum hourly values for each of the criteria in 2021 and in 2035. These values are also provided for years 2025 and 2030 in Appendix Section B: Results Tables.

Table 2. Average Annual, Minimum Hourly, and Maximum Hourly Technology-Neutral Value Stack for 2021 and 2035 (2021$)

Criteria	2021			2035		
	Average Annual Value ($/kWh)	Minimum Hourly Value ($/kWh)	Maximum Hourly Value ($/kWh)	Average Annual Value ($/kWh)	Minimum Hourly Value ($/kWh)	Maximum Hourly Value ($/kWh)
Energy	$0.046	$0.030	$0.082	$0.039	($0.008)	$0.159
Transmission Charges	$0.020	$0.000	$14.945	$0.051	$0.000	$38.407
Distribution Capacity	$0.007	$0.000	$0.667	$0.006	$0.000	$0.602
Capacity	$0.007	$0.000	$63.000	$0.006	$0.000	$52.000
Distribution Line Losses	$0.003	$0.000	$7.674	$0.002	($0.000)	$5.873
RPS	$0.004	$0.004	$0.004	$0.002	$0.002	$0.002
Transmission Line Losses	$0.003	$0.000	$4.474	$0.003	($0.000)	$3.424
Risk Premium	$0.005	$0.001	$1.151	$0.004	($0.001)	$0.726
Ancillary Service	$0.002	$0.001	$0.005	$0.002	($0.001)	$0.009
DRIPE	$0.004	$0.001	$4.954	$0.005	($0.001)	$8.541
Distribution OPEX	$0.002	$0.000	$0.149	$0.002	$0.000	$0.149
Utility Admin	($0.000)	($0.002)	$0.000	($0.000)	($0.002)	$0.000

For some criteria, the average annual value is considerably different from the maximum value in a given hour. In the most extreme case – the capacity criteria – value is only assigned to a single hour of the year, the annual ISO-NE system peak hour. The capacity payment obligations assigned to New Hampshire's utilities and load-serving entities are calculated according to the contribution of their customers to peak load during that single hour; production at any other hour will not affect capacity payment obligations, and therefore has zero capacity value. This results in a large difference between the average annual capacity value and the maximum hourly value. As other examples, the distribution capacity, transmission line loss, and distribution line loss criteria avoided costs are assumed to be driven by load reductions during peak hours on New Hampshire distribution systems. The annual value of each of those components is spread out over the top 100 peak distribution system hours, while the remaining 8,660 hours in each year have zero value, again driving considerable differences between the average annual value and the maximum hourly value.

The average annual value achieved by a particular DER (on a $/kWh basis) may be higher or lower than the average annual technology-neutral value stack value, depending on the specific DER production characteristics. DER-specific avoided cost values are influenced by the degree to which its electricity production coincides with hours of high avoided cost value and not with hours with zero avoided cost value. The avoided cost value achieved by a number of illustrative DER systems is presented in the sections that follow.

3.2 – Value Generated by DERs

The avoided cost value that net-metered DERs provide to the electricity system is assessed by considering DER production profiles in combination with the hourly value stack, as described in the DER Avoided Cost Value section above. The VDER model that accompanies this report allows users to produce the value stack that can be achieved by common DER technologies in New Hampshire. This tool is used to analyze the DER system types described in the "DER Production Profiles" section of this report, calculating the benefits that each provides to the electric system and – if reflected in rates – to customer-generators over the 2021 to 2035 period. The results show the degree to which load reductions from DERs can generate avoided cost value for the electric system, and how that value can be expected to vary over time as a result of changing system conditions.[37]

This study does not address all DERs, but rather focuses on a subset of those resources that are eligible for NEM in New Hampshire. The following sections illustrate key trends for sample DER system types that are generally representative of the most commonly-installed configurations: residential and commercial solar PV, residential and commercial solar PV paired with storage, large group host commercial solar PV, and micro hydro generation.

The results provided in this section are illustrative. Because the values presented below are calculated using specific sample system types, they should not be applied to other system types. The model that accompanies this report allows users to generate results specific to other system types using a custom production profile.

[37] Although avoided costs also vary by location, the scope of this study only considers statewide averages. A separate Locational Value of Distributed Generation Study was conducted and the results of that study are available online: https://www.puc.nh.gov/Regulatory/Docketbk/2016/16-576/LETTERS-MEMOS-TARIFFS/16-576_2020-08-21_STAFF_LVDG_STUDY_FINAL_RPT.PDF.

3.2.1 – Residential and Commercial Solar PV

Avoided cost values are modeled for south- and west-facing solar PV arrays for the residential and commercial sectors. Figure 10 and Figure 11 below show the calculated value of the south- and west-facing residential systems for several years during the study period. Detailed results tables showing the average annual value of each of the criteria in each study year are included in Appendix Section B: Results Tables. The results shown are for systems installed in 2021, and all values are in real 2021 dollars.

Figure 10. Average Annual Avoided Cost Value for Residential South-Facing Solar PV Array Installed in 2021 (2021$)[a]

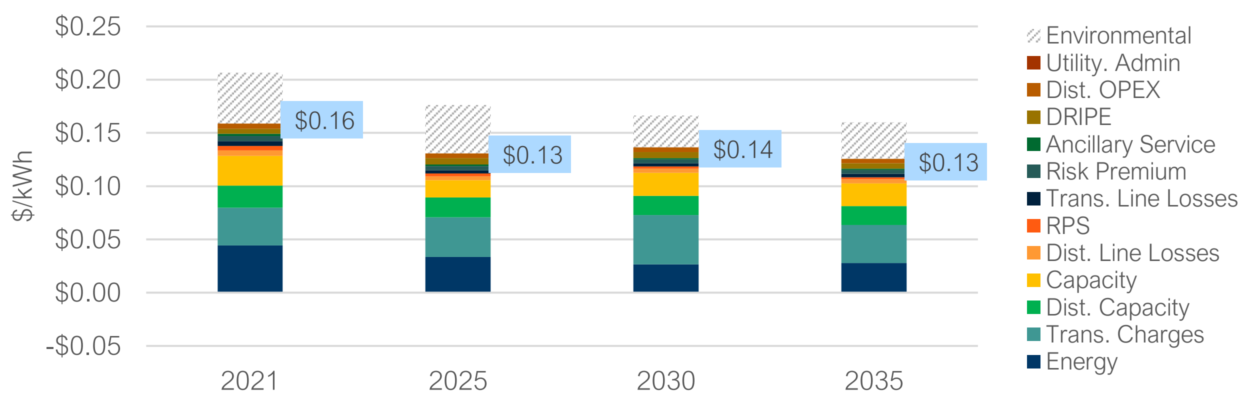
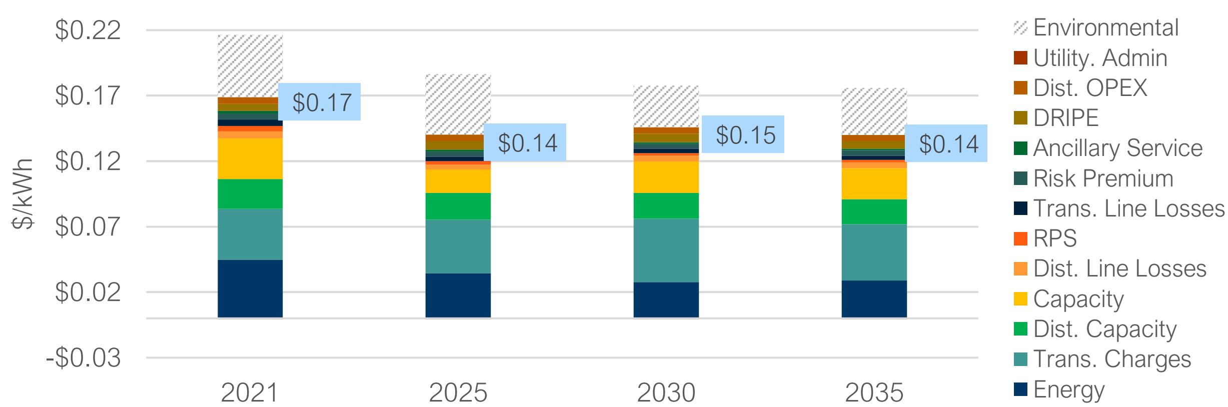


Figure 11. Average Annual Avoided Cost Value for Residential West-Facing Solar PV Array Installed in 2021 (2021$) [a]



a. Totals shown are net values and exclude the value of environmental externalities

Throughout the study period, residential west-facing solar PV generates 5%-10% more avoided cost value than residential south-facing solar PV.[38] Although south-facing systems have greater production overall, west-facing systems generate energy later in the day, increasing the portion of generated energy that is coincident with ISO-NE and New Hampshire-specific peak hours. This allows west-facing systems to generate greater value for those avoided cost categories that are driven by peak demand. Customer-

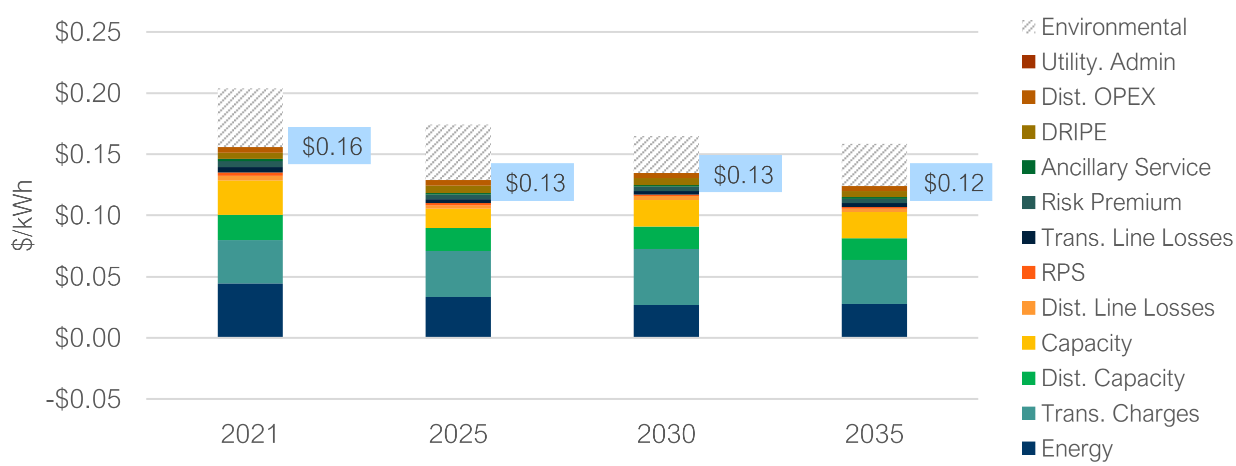
[38] When considering all study years, not only those highlighted in the graphs above, and excluding environmental externalities.

generators in New Hampshire are currently incentivized to maximize solar production by installing south-facing systems, given that those systems produce a greater volume of electricity overall.

Energy is the largest avoided cost criterion for both system types in 2021, representing 28% of the base avoided cost value stack for south-facing systems and 27% for west-facing systems.[39] The value of energy is assumed to decline over time, however, as lower marginal cost resources increasingly participate in the market. By 2035, transmission charges – which are assumed to increase over the course of the study period, based on trends seen in short-term forecasts – become the largest avoided cost criteria for both system types, representing 29% of the base value stack for south-facing systems and 31% for west-facing systems. Accounting for the non-embedded social costs of carbon and nitrogen oxide as environmental externalities increases the value of each system by $0.03-$0.05/kWh (representing 22%-36% of total value for a south-facing system and 22%-34% of total value for a west-facing system).

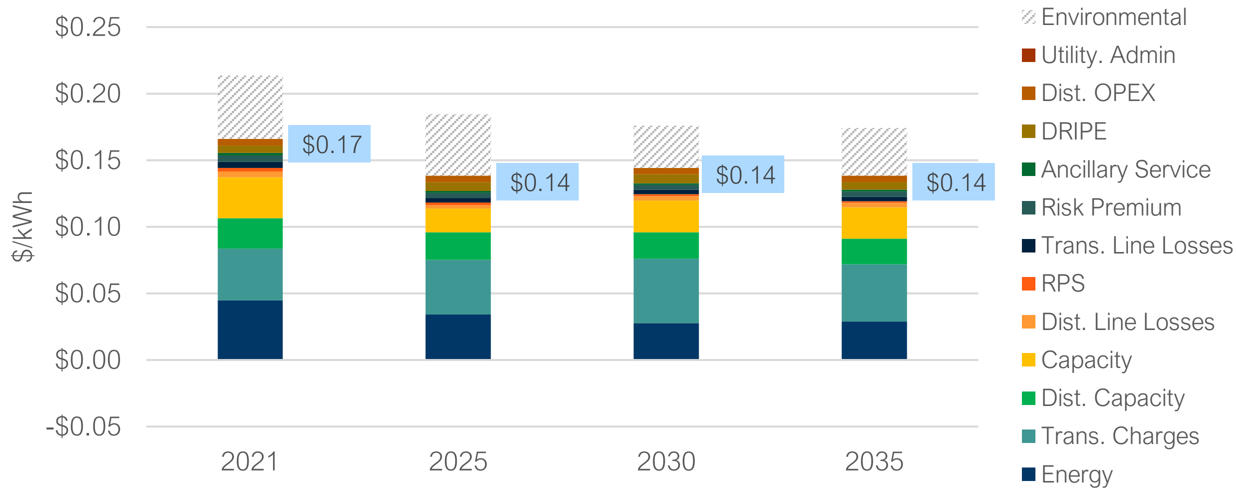
Figure 12 and Figure 13 below show the average annual avoided cost value of commercial south-facing and west-facing systems, respectively, for several years during the study period. The results shown are for systems installed in 2021, and all values are in real 2021 dollars.

Figure 12. Average Annual Avoided Cost Value for Commercial South-Facing Solar PV Array Installed in 2021 (2021$)[a]



[39] The base avoided cost value stack refers to the value stack excluding environmental externalities.

Figure 13. Average Annual Avoided Cost Value for Commercial West-Facing Solar PV Array Installed in 2021 (2021$) [a]



a. Totals shown are net values and exclude the value of environmental externalities

West-facing commercial solar PV systems produce 6%-10% more value than south-facing commercial solar PV systems, again due to their production having greater coincidence with evening system peaks. Commercial solar PV systems with the same orientation as residential systems have the same avoided costs for all criteria with the exception of RPS compliance and distribution line losses. Both the RPS compliance and distribution line loss criteria have sector-specific elements that lead to variations in avoided costs between the sectors.[40] As a result, commercial systems offer slightly less value (1%-2% lower across the study period) than residential systems. Because commercial customer-generators are assumed to consume a smaller portion of the energy produced by solar PV systems behind-the-meter, the reduction in retail sales is less for commercial PV systems, which results in reduced RPS and line loss avoided costs. Moreover, the commercial sector has lower assumed line loss factors than residential systems, again reducing line loss avoided cost value.

The previous graphs illustrate the year-over-year variations in avoided cost values. However, there is also considerable variation throughout a given year due to differences in DER production profiles as well as seasonal changes in demand, congestion, generating resources, and other factors that influence grid conditions. Figure 14 below illustrates how avoided cost value ($/kWh) changes over an average 24-hour period in each season in the year 2021 for a south-facing residential system.[41,42] For ease of presentation,

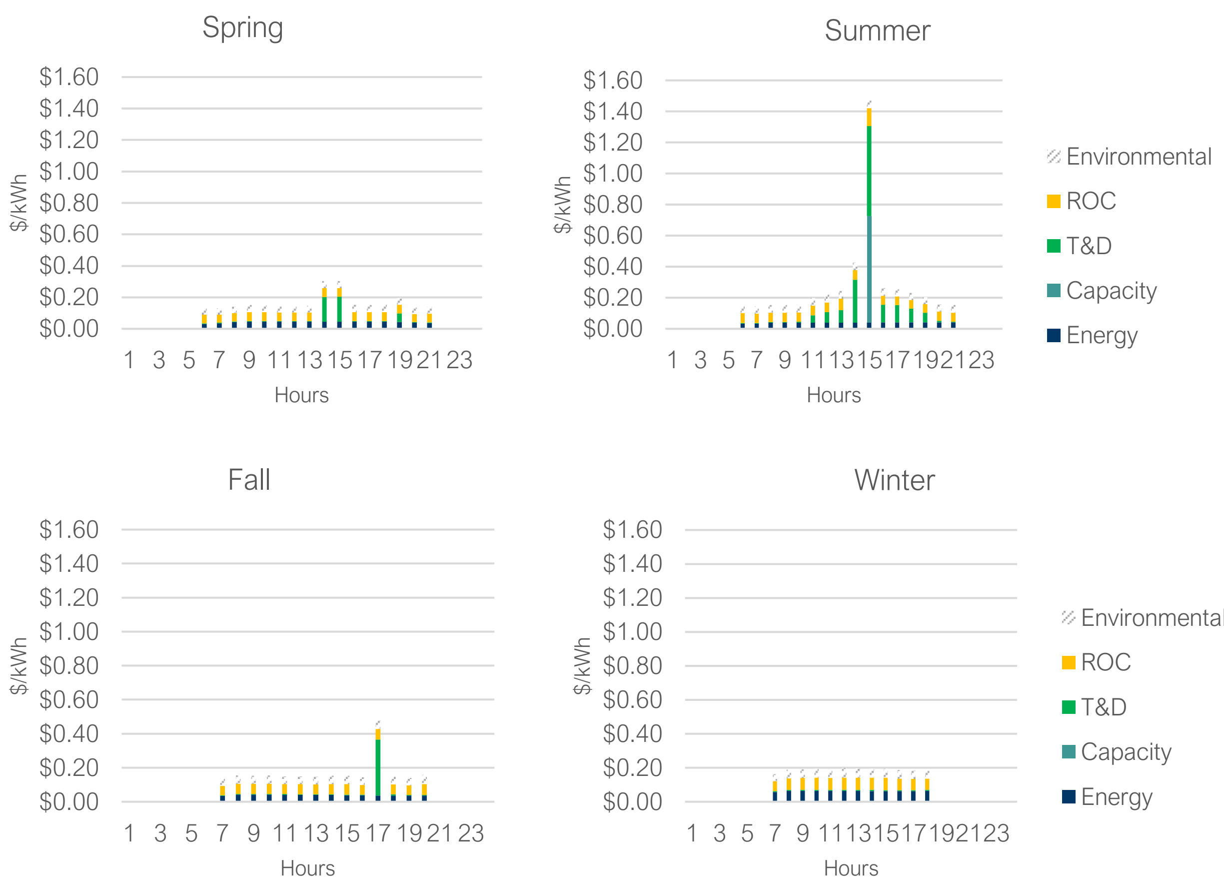
[40] RPS compliance is calculated using sector-specific assumptions for the portion of DG energy output generated that is consumed behind-the-meter. Line losses account for sector-specific behind-the-meter consumption and sector-specific line loss factors. The sector-specific assumptions used to calculate these values are described in Appendix C.

[41] For brevity, we do not include parallel graphs for a residential west-facing system or commercial systems as the high-level seasonal trends are similar among various solar PV system types. These results can be generated using the accompanying VDER model.

[42] The seasonal avoided cost values for years 2025, 2030, and 2035 are included in Appendix Section B: Results Tables.

the avoided cost criteria are presented as energy, capacity, T&D, Rest of Criteria (ROC), and environmental externalities.

Figure 14. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Installed in 2021, Year 2021 Shown (2021$)



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

Avoided cost values may also be impacted by the total system load, or if resources participate in the market. Avoided cost values were assessed under those conditions through the high load growth scenarios (HLGS) and the market resource value scenario (MRVS), respectively. These sensitivity scenarios are described below, and the results are presented in the figure that follows.

High Load Growth Scenarios (HLGS): To a degree, avoided cost values will be affected by total system loads. The study considers how avoided costs could change under higher load conditions, reflecting increased adoption of transportation and building electrification. Generally, it is assumed that increased loads will lead to higher avoided cost values, increasing the value of load reductions from DERs. The figure that follows features the highest load growth scenario assessed, which includes building electrification and transportation electrification assumptions that exceed those included in the AESC.[43] In addition to the baseline value stack, the figure also shows how the avoided costs for environmental externalities are expected to rise with increased overall system load due to an assumption that higher-emitting generating resources will be needed to meet that higher load.[44]

Market Resource Value Scenario (MRVS): Rather than acting as passive resources that generate value merely by reducing loads on the system, net-metered DERs may participate directly in the ISO-NE markets as aggregated resources that provide wholesale market services. For this analysis, DERs are assumed to have the ability to provide energy, capacity, or ancillary services. The energy value that DERs can achieve is assumed to be equal to the avoided cost of energy, and so is unchanged from the value stack assessment. For practical purposes, DERs are assumed to *not* participate in the ancillary services market, even through they do have the ability to provide those services; additional information regarding DER provision of ancillary services is included in the Qualitative Market Resource Value Scenario Insights section of this report. However, the capacity value that DERs can achieve in the wholesale market is different from the avoided cost of capacity as a result of two factors:

1. MW Value: Reducing demand requirements through load reductions, as considered in the value stack assessment, has the benefit of reducing capacity requirements *and* reducing the reserves associated with those capacity requirements. By instead acting as a supply resource, as considered in the MRVS assessment, DERs do not realize the benefits associated with reserve avoidance, generating less total value. In general terms, the value of each MW reduced by a DER through behind-the-meter consumption is of greater value than that of each MW bid into the wholesale market as capacity.

2. Timing of Value: Avoided capacity value attributable to load reduction is assessed according to production during a single hour of the year: the ISO-NE annual system peak hour. In contrast, market capacity value is assessed according to average production during summer and winter reliability hours.[45] Whether a DER provides greater value by reducing load or by participating in the

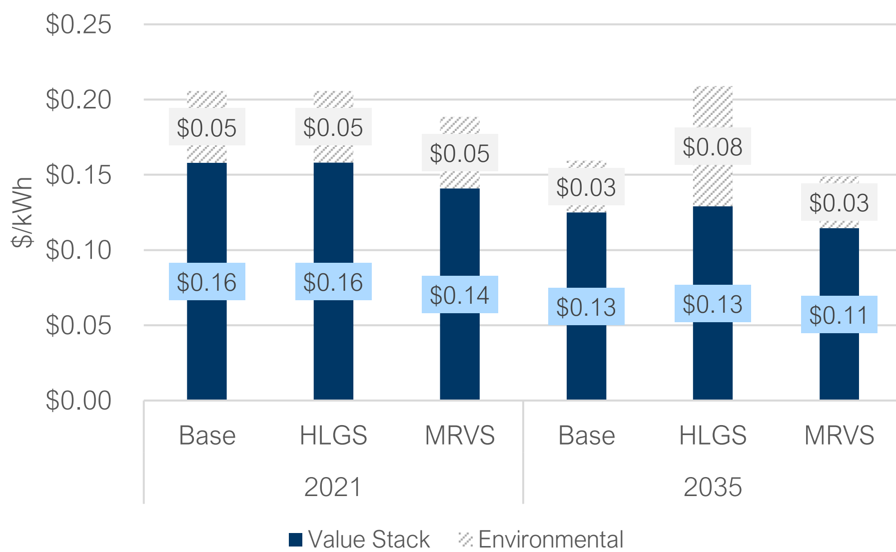
[43] The HLGS analysis includes three load growth scenarios which vary with respect to assumed levels of transportation and building electrification. Scenario 3 – the results of which are highlighted above – assumes higher-than-AESC transportation and building electrification. These scenarios are described in greater detail in Appendix Section D: High Load Growth Scenarios Methodology and can also be explored in the accompanying VDER model.
[44] In the high load growth scenarios, the equation to calculate marginal emissions was developed through a regression analysis between New Hampshire's hourly demand and the associated CO_2 and NOx emissions. The equation does not capture changes in resource mix and market conditions that could result in lower emissions rates.
[45] Additional information regarding reliability hours is included in Appendix Section E: Market Resource Value Scenario Methodology.

capacity market depends on the peak or reliability hours in a given year and the DER's production during those hours.

Mirroring the baseline value stack, the value of the MRVS declines over time. This is primarily a result of declining energy price avoided costs. Market participation may result in changes to avoided cost criteria values beyond energy and capacity (for example, RPS compliance or line losses); however, for the purposes of this analysis, the remaining value stack criteria are assumed be to the same as the baseline value stack.

Figure 15 illustrates the avoided cost value for the baseline avoided cost value stack alongside the HLGS and MRVS for a south-facing residential solar PV array.

Figure 15. Average Annual Avoided Cost Value for Residential South-Facing Solar PV Array Installed in 2021 Under the Baseline Value Stack (Base), High Load Growth Scenario (HLGS), and Market Resource Value Scenario (MRVS), for Years 2021 and 2035 (2021$)



The HLGS generates approximately the same value as the base value stack in 2021 but has 3% higher value than the base value stack in 2035 excluding environmental externalities (a difference too small to show in the data label). In the early years of the study, the variation in load between the baseline and HLGS is minimal. However, in later years, the cumulative impact of electrification under the HLGS drives increased avoided cost values over the baseline. Under the HLGS, the environmental externalities value is essentially the same as the base value stack in 2021 but increases to 132% of the base value stack in 2035 due to the assumption that higher-emitting resources are required to meet additional load.

Under current wholesale market rules, south-facing residential solar PV systems provide more value to the utility system by passively reducing load than by participating in the energy and capacity markets. That result is mirrored for the west-facing residential system and the south- and west-facing commercial systems. For the south-facing residential system featured in Figure 15 above, the MRVS results in 11% less value than the baseline in 2021 and 8% less value in 2035.

3.2.2 – Residential and Commercial Solar PV Paired with Storage

Avoided cost values are modeled for south-facing solar PV arrays paired with storage for the residential and commercial sectors.[46] Figure 16 and Figure 17 below show the value of these systems for several years during the study period. Detailed results tables showing the average annual value of each of the avoided cost criteria in each study year are included in Appendix Section B: Results Tables. The results shown are for systems installed in 2021, and all values are in real 2021 dollars.

Figure 16. Average Annual Avoided Cost Value for Residential South-Facing Solar PV Array Paired with Storage Installed in 2021 (2021$)a

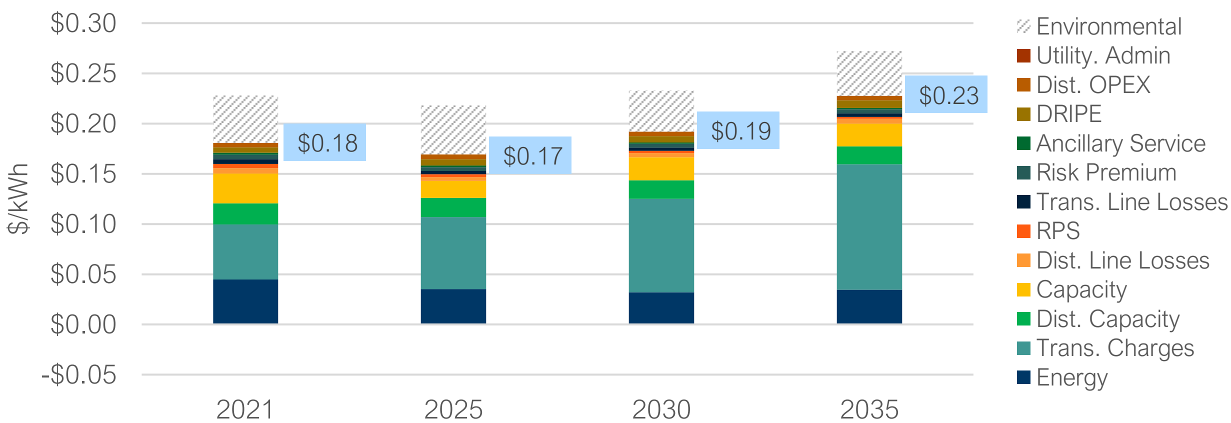
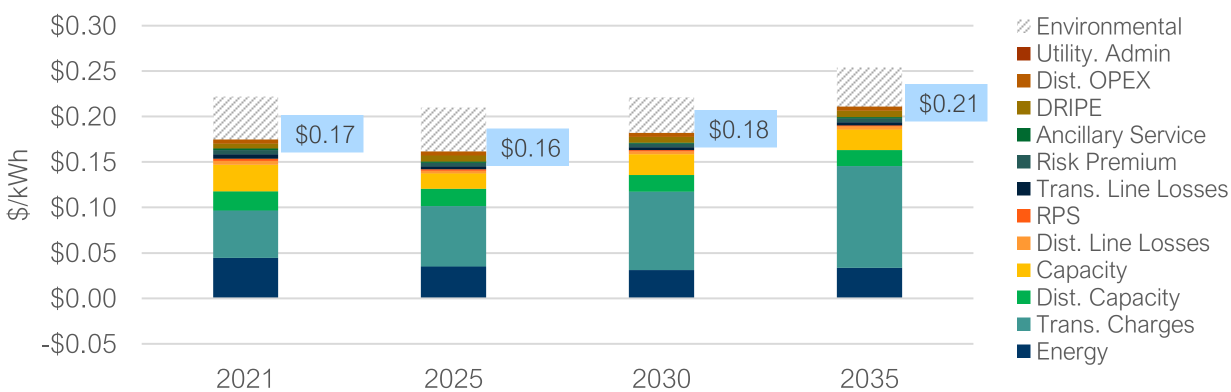


Figure 17. Average Annual Avoided Cost Value for Commercial South-Facing Solar PV Array Paired with Storage Installed in 2021 (2021$)[a]



a. Totals shown are net values and exclude the value of environmental externalities

[46] Although west-facing solar PV arrays paired with storage are not modeled, the accompanying VDER model allows users to input custom resource profiles to generate value stacks for other solar paired with storage configurations using the tool.

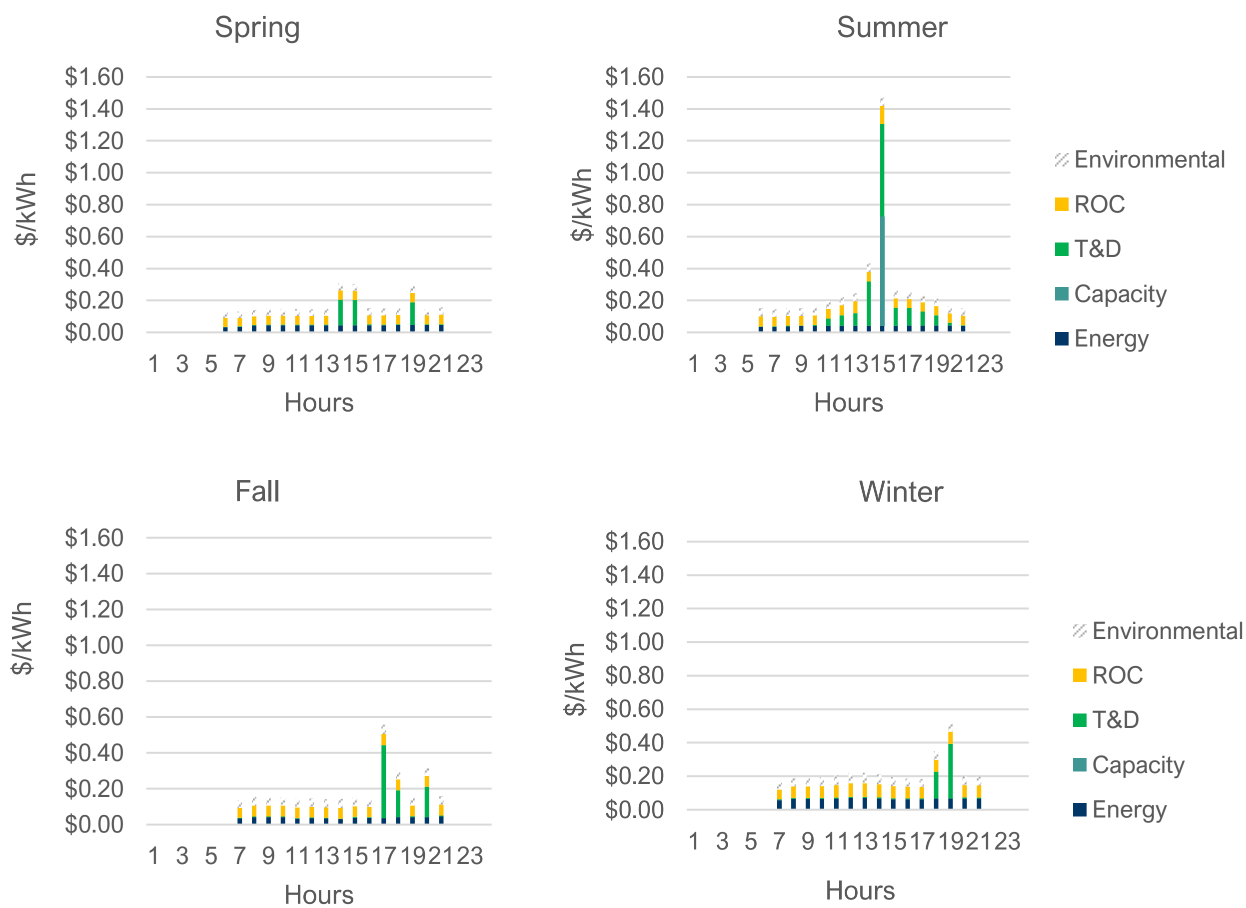
In any given year, residential solar PV systems paired with storage generate between 14% and 82% greater base avoided cost value than solar-only systems; commercial solar PV systems paired with storage generate 12% to 70% greater base avoided cost value.[47] The battery storage system is assumed to be charged with energy generated by the solar array during off-peak times when avoided costs are low and solar generation is high (i.e., HE11 to HE14). The storage system is assumed to discharge during peak periods in the early evening (HE18 to HE21 in Winter and HE17 to HE20 in Summer) when solar production is lower and avoided cost values are higher. This timing of battery charging, and discharging provides considerable additional benefits for many avoided cost categories, including transmission charges, energy, line losses, and DRIPE.

Unlike solar-only systems, the total avoided cost value for solar paired with storage systems increases over time. These increases are primarily a result of transmission charge avoided costs, which are assumed to increase in value over the study period. In 2021, transmission charges are the largest avoided cost value for both system types (30% of the base value stack). By 2035 the value of transmission charges is projected to make up 55% of base avoided cost values for residential systems and 53% for commercial systems while other avoided costs, including energy, decline over time.[48] Environmental externalities increase the value of residential systems by 20%-29% and of commercial systems by 20%-30%.

As with solar-only systems, there is considerable variation within each year as a result of seasonal production patterns and distribution system condition changes. Figure 18 below illustrates how avoided cost values change over an average 24-hour period in each season for a residential solar paired with storage system. For ease of presentation, the avoided cost criteria are presented as energy, capacity, T&D, Rest of Criteria (ROC), and environmental externalities.[49]

[47] The base avoided cost value stack refers to the value stack excluding environmental externalities. These comparisons consider all study years, not just those shown above.
[48] The base avoided cost value stack refers to the value stack excluding environmental externalities.
[49] Here, T&D includes the following quantified avoided cost criteria: transmission charges, distribution capacity, distribution operating expense, transmission line losses, and distribution line losses. ROC includes all quantified baseline criteria with the exception of energy, capacity, and those criteria included in the T&D category.

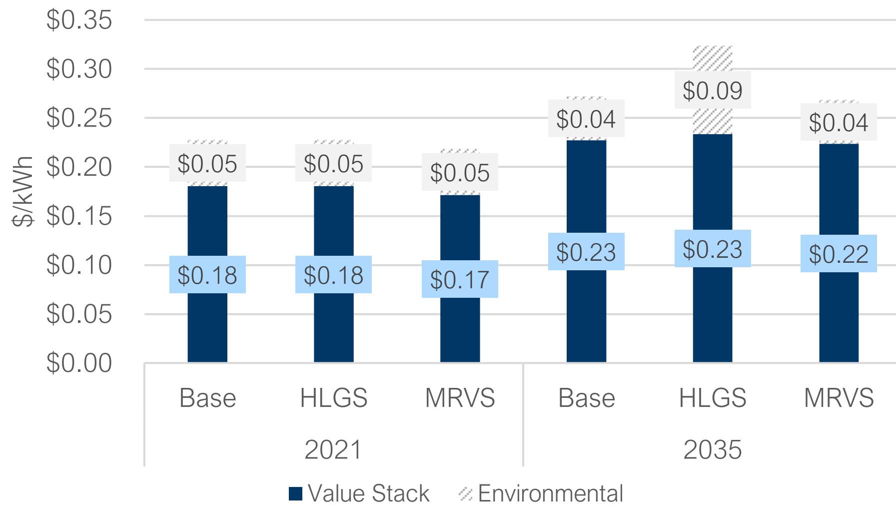
Figure 18. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Paired with Storage Installed in 2021, Year 2021 Shown (2021$)



The addition of storage allows these systems to realize greater value than solar-only systems across all seasons. This is particularly the case for T&D costs – solar and storage systems offer load reductions during ISO-NE and New Hampshire peak times during all seasons, achieving greater value.

The avoided cost load reduction values of solar paired with storage systems are also assessed under the HLGS and MRVS. These values are contrasted with the baseline avoided cost value stack for a south-facing residential solar paired with storage system in Figure 19. Because both system types have the same orientation, the commercial system results mirror the residential system results; only residential system results are shown here.

Figure 19. Average Annual Avoided Cost Value for Residential South-Facing Solar PV Array Paired with Storage Installed in 2021 Under the Baseline Value Stack (Base), High Load Growth Scenario (HLGS), and Market Resource Value Scenario, for Years 2021 and 2035 (MRVS) (2021$)

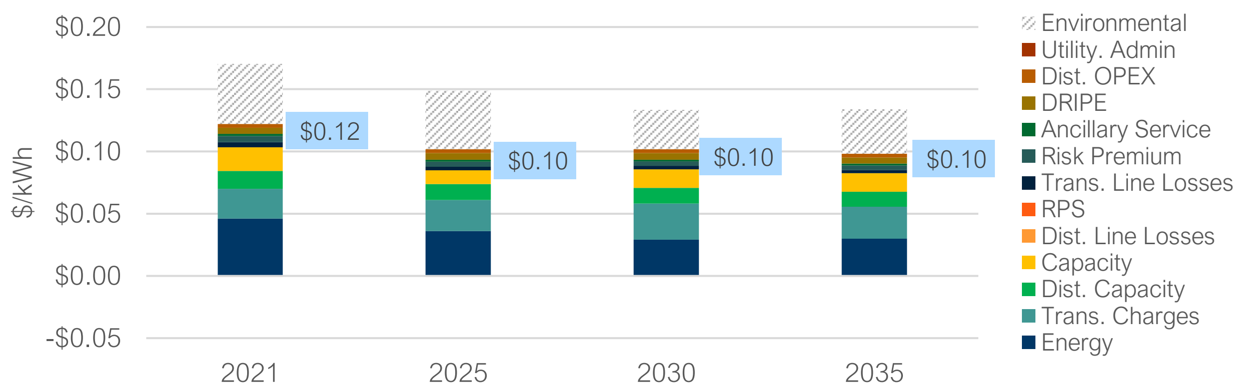


In 2021, the HLGS has approximately the same value (less than 1% difference) as the base value stack, excluding environmental externalities. This increases to nearly 3% higher value by 2035 - again, excluding environmental externalities – as increased transportation and building electrification load impacts increase the per unit costs of meeting system needs. It should be noted that the change is too slight to be captured as an increase in the labels shown above. The HLGS environmental externalities are the same as baseline values in 2021 but 102% higher in 2035. This reflects the assumption that increased electric energy demand will increase the emissions intensity of generating resources on the margin. Considering the market participation impacts modeled under the MRVS, the system realizes 5% less value through direct market participation as compared to passive load reduction in 2021 and 2% less value in 2035.

3.2.3 – Large Group Host Commercial Solar PV

Avoided cost values are modeled for a single-axis tracking large group host commercial (LGHC) solar PV array. Figure 20 shows the value of such a system for several years during the study period. A detailed results table showing the average annual value of each of the avoided cost criteria in each study year is included in Appendix Section B: Results Tables. The results shown are for a system installed in 2021, and all values are in real 2021 dollars.

Figure 20. Average Annual Avoided Cost Value for Large Group Host Commercial Solar PV Array Installed in 2021 (2021$)a



a. Totals shown are net values and exclude the value of environmental externalities

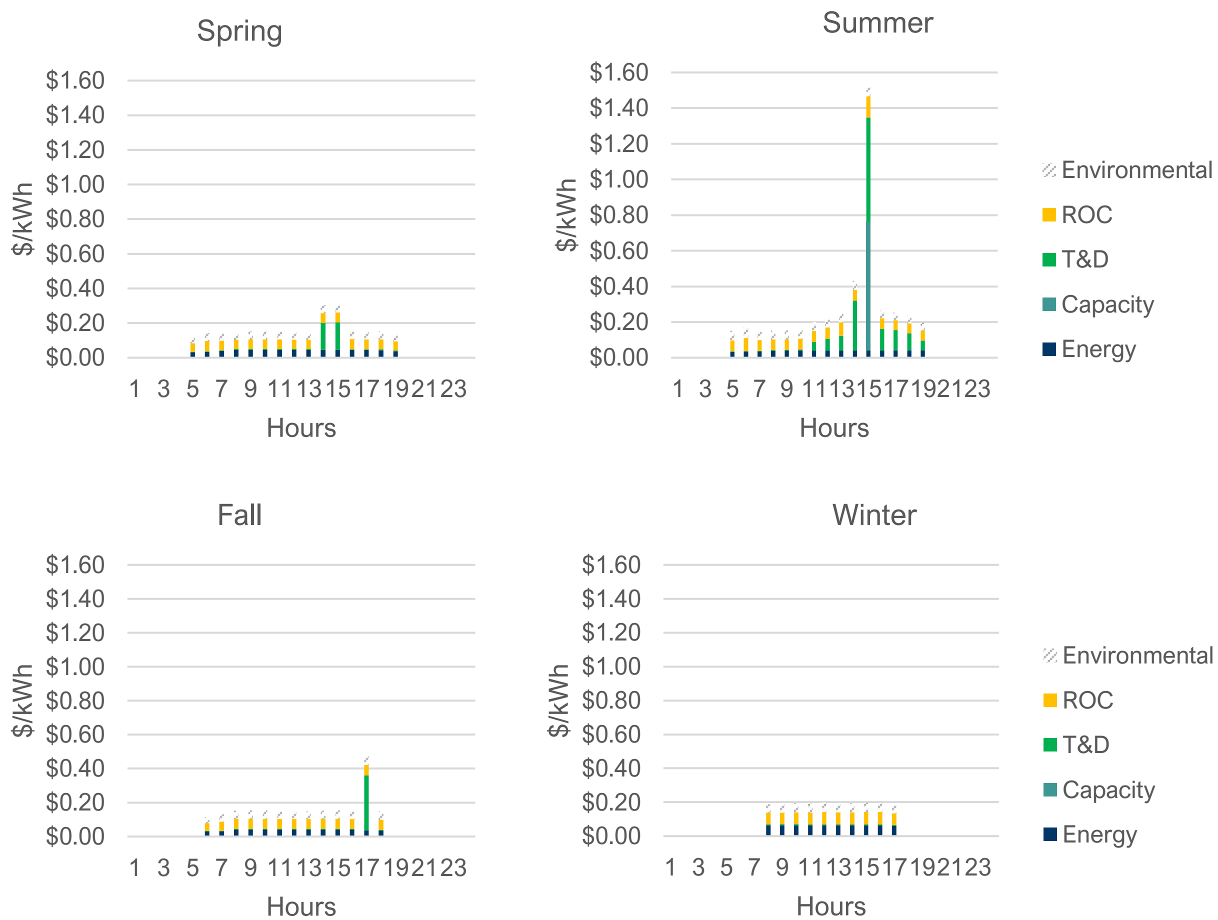
The LGHC solar avoided cost value trends mirror the residential and commercial solar-only system results, declining across the study period largely due to declining energy avoided costs. In a given year, LGHC avoided cost values are lower than residential or commercial systems. Because there is assumed to be minimal load associated with the LGHC system, there is no significant opportunity to reduce retail sales through electricity production to generate RPS compliance avoided cost values. Distribution line loss values are also less as a result of lower assumed line loss values for these systems.

Energy is the largest avoided cost component in all study years, representing 38% of the base avoided cost value stack value in 2021 and 31% by 2035.[50] Environmental externalities increase the total avoided cost value stack value by $0.03-$0.05 per kWh (31%-48% of the total value), varying by year due to changing system emissions intensity.

As with the residential and commercial systems with behind-the-meter load, the LGHC system shows variation by season as a result of shifting production profiles and system conditions. Seasonal 24-hour period averages are shown in Figure 21. For ease of presentation, the avoided cost criteria are presented as energy, capacity, T&D, Rest of Criteria (ROC), and environmental externalities.[51]

[50] The base avoided cost value stack refers to the value stack excluding environmental externalities.
[51] Here, T&D includes the following quantified avoided cost criteria: transmission charges, distribution capacity, distribution operating expense, transmission line losses, and distribution line losses. ROC includes all quantified baseline criteria with the exception of energy, capacity, and those criteria included in the T&D category.

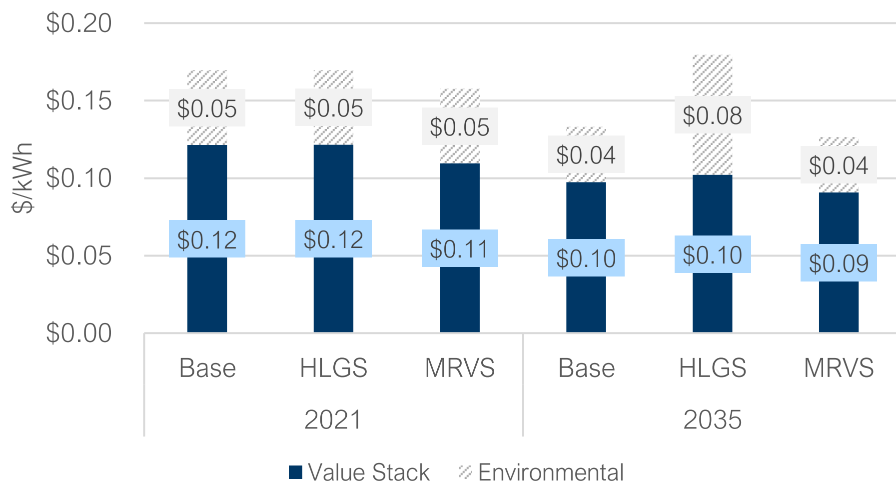
Figure 21. Average Hourly Seasonal Avoided Cost Values for Large Group Host Commercial Solar PV Array Installed in 2021, Year 2021 Shown (2021$)



Mirroring the smaller solar-only systems, the LGHC system avoided cost values show a spike in spring and summer late afternoon hours due to avoidance of transmission charges. Capacity values also increase avoided costs during summer afternoons due to coincidence with annual ISO-NE peaks.

As with other system types, LGHC system avoided cost values will vary with total system loads. Furthermore, the value of LGHC systems would change if they directly participated in the wholesale markets. Figure 22 illustrates the avoided cost value for the baseline avoided cost value stack, as well as for the HLGS and the MRVS.

Figure 22. Average Annual Avoided Cost Value for Large Group Host Commercial Solar PV Array Installed in 2021 Under the Baseline Value Stack (Base), High Load Growth Scenario (HLGS), and Market Resource Value Scenario (MRVS), for Years 2021 and 2035 (2021$)



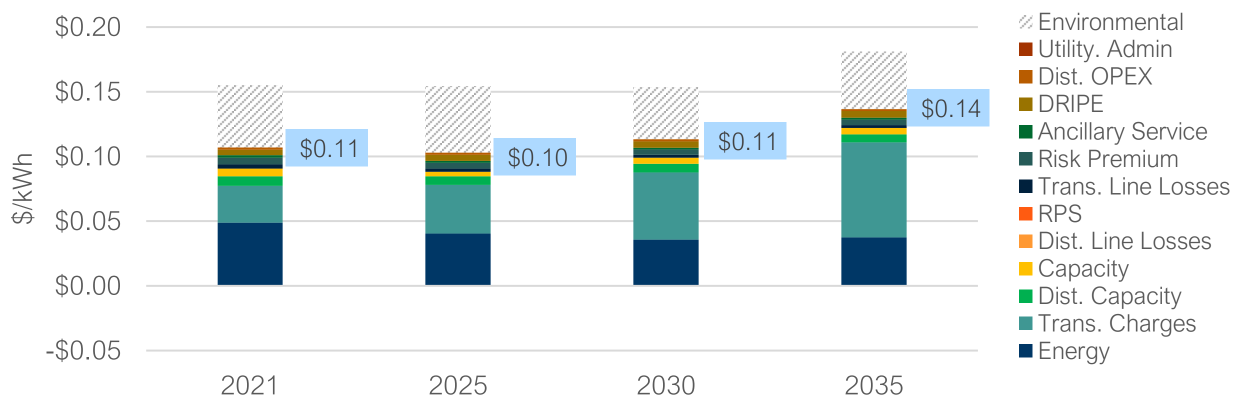
In 2021, the high load growth scenario has approximately the same value (less than 1% difference) as the base avoided cost value stack. In 2035, the high load growth scenario results in 5% higher value excluding environmental externalities. The value increases under the high load growth scenario as increased transportation and building electrification load impacts increase the per unit costs of meeting system needs. High load growth scenario environmental externalities are the same as base values in 2021 but 117% higher in 2035. This reflects the assumption that higher demand will increase the emissions intensity of generating resources on the margin. The system realizes 10% less value through direct market participation as compared to passive load reduction in 2021 and 7% less in 2035, excluding environmental externalities.

3.2.4 – Micro Hydro

Avoided cost values are modeled for a small run-of-river hydroelectric facility. Figure 23 shows the value of such a facility for several years during the study period. A detailed results table showing the average annual value of each of the criteria in each study year is included in Appendix Section B: Results Tables. The results shown are for an existing hydroelectric project.[52] All values are in real 2021 dollars.

[52] The facility is assumed to apply run-of-river operation strategies, where the flow rate into the reservoir behind an existing dam is equal to the flow rate out of the facility.

Figure 23. Average Annual Avoided Cost Value for Micro Hydro Facility (2021$) [a]



a. Totals shown are net values and exclude the value of environmental externalities

Similar to LGHC solar, micro hydro avoided cost value is limited compared to behind-the-meter systems. Because there are assumed to be minimal loads directly attached to the hydro facility, there is no significant opportunity to reduce retail sales through generation, eliminating RPS compliance avoided cost values. Distribution line loss values are also eliminated as hydro systems are expected to export virtually their entire production into the distribution network, and therefore they cannot avoid distribution line loses. Similar to solar paired with storage systems, and in contrast to solar-only systems, the avoided cost value of micro hydro increases from the study start to the study end. Consistent generation allows the hydro facility to achieve significant transmission charge benefits, which are assumed to increase in value over the study period. A slight decline is noted from the early study years to the mid-point in the study period as the value of energy – high in the first years of the study as a result of high natural gas prices – starts to decline.

In 2021, energy is the largest avoided cost criterion, representing 46% of the base avoided cost value stack.[53] By 2035, transmission charges are the largest criterion, representing 54% of the total base avoided cost value. Environmental externalities increase the total avoided cost value stack value by $0.05 in 2021 and by $0.04 in 2035 (45% and 33% of the total value, respectively).

Figure 24 illustrates how avoided cost value changes over an average 24-hour period in each season in the year 2021 for the micro hydro facility. For ease of presentation, the avoided cost criteria are presented as energy, capacity, T&D, Rest of Criteria (ROC), and environmental externalities.[54]

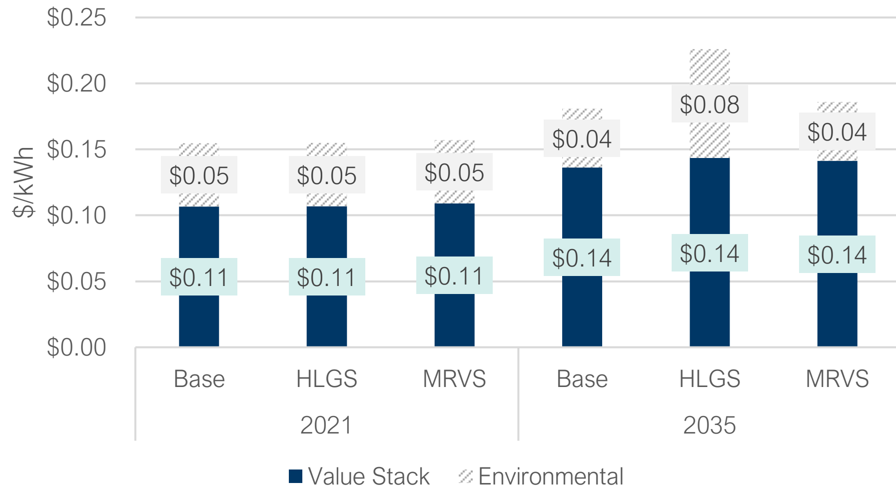
[53] The base avoided cost value stack refers to the value stack excluding environmental externalities.
[54] Here, T&D includes the following quantified avoided cost criteria: transmission charges, distribution capacity, distribution operating expense, transmission line losses, and distribution line losses. ROC includes all quantified baseline criteria with the exception of energy, capacity, and those criteria included in the T&D category.

Figure 24. Average Hourly Seasonal Avoided Cost Values for Micro Hydro Facility, Year 2021 Shown (2021$)

Although micro hydro facilities also experience seasonality effects, their production realizes avoided cost value at all hours of the day and across all seasons. Micro hydro power plants have higher avoided cost values during many hours in the winter season as a result of increased production. In all seasons, production is coincident with monthly ISO-NE system peaks and generates avoided transmission charge benefits. Coincidence with the annual ISO-NE peak also provides capacity benefits during the summer season.

As with other system types, micro hydro facility avoided costs values will vary with total system loads. Also, the value of micro hydro facilities would change should they directly participate in the market. Figure 25 illustrates the avoided cost value for the baseline avoided cost value stack, as well as for the HLGS and the MRVS.

Figure 25. Average Annual Avoided Cost Value for Micro Hydro Facility Under the Baseline Value Stack (Base), High Load Growth Scenario (HLGS), and Market Resource Value Scenario (MRVS), for Years 2021 and 2035 (2021$)



In 2021, the HLGS has approximately the same value (less than 1% difference) as the base avoided cost value, but it grows to 5% by 2035, excluding environmental externalities. Environmental externalities between the base value stack and the HLGS are approximately the same in 2021 but increase to be 85% higher than the base value stack in 2035. Unlike all other system types, micro hydro facilities generate greater value to the system by directly participating in the wholesale energy and capacity markets rather than by just passively reducing load. Unlike the avoided capacity cost value, which is limited to a single annual peak hour, the capacity market value for direct market participants is distributed across a number of hours during ISO-NE's summer and winter reliability periods. The consistent generation of hydro plants realizes greater value during these periods than other system types, resulting in higher values. In 2021, direct market participation generates 2% higher values than the baseline value stack and in 2035 that differential increases to 4%.

3.2.5 – Qualitative Value Stack Criteria

Four value stack criteria were assessed qualitatively; there was not enough data at this time to develop values, or it was determined that they likely had relatively minimal value that did not warrant extensive quantitative analysis. The qualitatively assessed criteria are described below:

Transmission capacity: The AESC outlines a general approach for assessing the value of non-Pool Transmission Facilities (PTF) avoided transmission capacity costs – i.e., those costs related to transmission upgrades that are not covered by RNS or LNS transmission charges - by considering planned expenditures resulting from planned load increases. The New Hampshire utilities that were interviewed, however, did not identify any non-PTF transmission-related expenditures which could be avoided or deferred due to load reductions to support this assessment. The utilities noted that transmission capacity value is primarily covered under the Transmission Charges criteria. The AESC includes a summary of the T&D avoided cost criteria considered by each utility in ISO-NE when screening demand-side management (DSM) measures and programs. Eversource in Connecticut was the only utility included in that review which considers non-PTF avoided costs in addition to PTF avoided costs when evaluating or screening DSM. The non-PTF value is estimated to be 1.1% of the PTF value, supporting the assertion that the Transmission Charge criteria accounts for the vast majority of the transmission system avoided costs that can be realized from reduced loads.

Transmission and Distribution System Upgrades: This criterion is an incurred cost category rather than an avoided cost category. Although individual customers who have installed DG systems are responsible for most if not all of the incremental investment required to support their systems, future DG deployment is expected to have a cumulative impact on the system not attributable to any single customer which may require utility investment. Through interviews, the utilities acknowledged that this would likely be the case in the future as DER penetration on the system increases, but they were not able to quantify the values as, to date, all upgrades associated with DER installations have been funded by the customer-generators.

Distribution Grid Support Services: This criterion may be an incurred cost or an avoided cost, reflecting an increase or decrease in costs for distribution system support services required as DER penetration increases. For example, costs may be incurred to correct for voltage issues caused by DERs. On the other hand, some DER resources can provide support services such as power factor correction or power quality support, potentially resulting in avoided costs to the utilities. Beyond converting direct current energy to alternating current energy, advanced solar PV inverters are increasingly designed to serve additional functions related to grid integration and monitoring. During the interviews, the utilities noted that they have not required additional grid support services as a result of DER installation to-date, nor have they tested the full functionality of advanced inverters. They also indicated that support service functionality offered by advanced inverters may simply be used to correct issues caused by the associated DER systems; therefore, it is unclear whether there would be a net benefit from a system perspective. At least one of the utilities is planning a pilot to test advanced inverter support functionality as part of its grid modernization plan, so data to support the valuation of this criterion may become available in the future.

Resiliency: A formal definition of resiliency has not been developed in New Hampshire regulation or for the purpose of energy efficiency programs and policies. In this study, "resilience services" are defined as the ability of DERs to provide back-up power to a site in the event that it loses utility electricity service.[55] In order to provide such resilience services, DERs must be configured as microgrids, or a group of interconnected loads and DERs within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and can operate in both grid-connected and island-mode.[56] To use DERs in a microgrid context, additional equipment is required beyond that associated with typical systems used in net-metering applications. Requirements vary according to need; for example, manually establishing a grid-islanded load will require less investment than advanced applications that can centrally control load shedding and generator output.[56] The costs and benefits of microgrid installations will vary from site-to-site, as each installation requires site-specific analysis, engineering, and equipment. Planning solar PV systems to be microgrid-ready can be a low- or no-cost way to facilitate installation of equipment

[55] This definition was sourced from the U.S. DOE Office of Energy Efficiency and Renewable Energy, available online: https://www.energy.gov/eere/femp/distributed-energy-resources-resilience.
[56] U.S. DOE. (2019). Energy Exchange Pre-Conference Workshop: Distributed Energy Technologies for Resilience and Cost Savings. Available online: https://www.nrel.gov/docs/fy19osti/74625.pdf.

required for microgrid applications at a later date.[57] This may include selecting inverters that are able to interact with the grid or operate in microgrid modes, inverters that are responsive to microgrid controllers, or simply ensuring there is space onsite near the DER installation for additional components in the future.

A report from the National Association of Regulatory Utility Commissioners (NARUC) found previous regulatory proceedings that have attempted to value resiliency but were unsuccessful at arriving at a quantified value of resilience services.[58] The report noted that resilience value has been quantified in non-regulatory proceedings, but these have been highly context specific.

Regulatory bodies in New Hampshire have not yet explored a definition for resiliency in the state nor considered the metrics that might be used to measure resiliency. There may be an opportunity to consider additional ways to value resiliency should these definitions or metrics be developed in the future. Opportunities for DER microgrids are being actively investigated by researchers and utilities across the country. Those initiatives may also provide insights about the value of resiliency from DERs in New Hampshire moving forward.

3.2.6 – Qualitative Market Resource Value Scenario Insights

Ancillary services are wholesale market functions that ensure the reliability of the bulk power system through the dispatch of low-cost and fast-responding resources. Traditional dispatchable resources, such as natural gas combustion turbines, provide ancillary services such as regulation, 10-minute spinning, 10-minute non-spinning, and 30-minute operating reserves. However, in the future, such services potentially could be provided by aggregated DERs such as solar PV, energy storage, or micro hydro facilities.

Micro hydro facilities are traditionally run-of-river systems, where the flow rate into the reservoir matches the flow rate out of the facility. Since such a facility’s output flexibility is constrained, it would be technically challenging for such facilities to provide ancillary and balancing services. On the other hand, solar PV has the technical capability to provide regulation and balancing services through precise output control. Solar would traditionally reduce its output and make itself available to provide up or down regulation services either by increasing the generation (to the technical max) or reducing its output. It is often required that resources providing ancillary services do not participate in the energy market, however. Because wholesale energy is currently a significant value driver, it is considered unlikely that such generation systems would sacrifice energy values for ancillary services values.

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[57] NREL. (2017). Microgrid-Ready Solar PV – Planning for Resilience. Available online: https://www.nrel.gov/docs/fy18osti/70122.pdf.
[58] NARUC. (2019). The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices. Available online: https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198.

3.3 – Levelized Customer Installed Costs

This section addresses levelized customer installed costs for the systems modeled for the study. The costs[59] in each year represent the net present value of total lifetime capital and operational costs for a system installed *in that year* levelized by the system's total lifetime energy production: the levelized costs in 2021 represent the lifetime costs of a system installed in 2021, while the levelized costs in 2035 represent the lifetime costs of a system installed in 2035.[60]

The costs account for available incentives, notably the Federal Solar Tax Credit, but do not account for benefits from net-energy metering participation. These costs could be compared to levelized net-metered customer-generator tariff compensation to assess cost-effectiveness and in future proceedings to evaluate potential tariff impacts on reasonable opportunities to invest in and receive fair compensation for net metering systems, per House Bill 1116 (2016), from the customer-generator perspective.[61]

Table 3. Levelized Customer Installed Costs by System Type

System Type	Lifetime $/kWh Cost			
	2021	2025	2030	2035
Residential solar, south-facing	$0.07	$0.06	$0.04	$0.04
Residential solar, west-facing	$0.09	$0.08	$0.05	$0.05
Commercial solar, south-facing	$0.04	$0.04	$0.03	$0.03
Commercial solar, west-facing	$0.06	$0.06	$0.04	$0.04
Residential solar, south-facing, paired with storage	$0.10	$0.10	$0.06	$0.06
Commercial solar, south-facing, paired with storage	$0.07	$0.06	$0.05	$0.04
Large Group Host Commercial Solar	$0.05	$0.06	$0.04	$0.04
Micro hydro	$0.06	$0.06	$0.06	$0.06

Generally, solar costs are assumed to decline over time, with the exception of a short-term increase in costs as the Federal Solar Tax Credit expires (assumed for this study to expire in 2024).[62] The lower energy production of west-facing systems increases their costs over south-facing systems on a levelized basis, while the larger size of commercial systems – in particular LGHC systems – allows them to benefit from economies of scale, resulting in lower levelized costs.

[59] Costs were informed by the NREL Annual Technology Baseline, available online: https://atb.nrel.gov/
[60] Costs include all administrative and project management costs associated with project development and operation, inverter costs at year 15 (for solar systems), and general maintenance costs.
[61] A levelized net-metered tariff is not included in this study.
[62] Additional information about the source for the projected technology cost declines is included in Appendix Section C.18: Customer Installed Costs.

South-facing residential solar with storage systems are assumed to have 50% to 66% higher levelized lifetime costs than south-facing residential solar-only systems, varying by year. Commercial south-facing solar and storage systems are assumed to have 51% to 56% greater levelized lifetime costs than commercial south-facing solar-only systems.

It is expected that few if any new hydro dams and reservoirs will be constructed in New Hampshire during the study period. As a result of recent amendments to New Hampshire's net energy metering program eligibility, micro-hydro systems between 1 and 5 MW in size that are operating as municipal group hosts can now participate in net-energy metering programs. Given this change, it is possible that existing dams and reservoirs will be energized in order to participate. As such, the customer levelized installed costs include the upfront capital and ongoing operations and maintenance costs associated with energizing an existing dam and reservoir. Only considering operation and maintenance expenses – in order to assess costs for existing energized systems – is expected to decrease levelized micro hydro facility levelized costs by approximately 60%. No changes to costs due to technology improvements are forecasted over the study period.

3.4 – Rate and Bill Impacts

The Rate and Bill Impacts analysis provides high-level insights into the impact of future DG deployment in New Hampshire on ratepayers. The goal of the assessment is to provide a future-looking estimate of the direction and magnitude of the impacts of DG deployment on all ratepayers and to identify any potential cost-shifting between customers with and without DG. The Rate and Bill Impacts assessment is not intended to be a projection of future electricity rates and cost recovery, but it serves as a future-looking approximation of the impacts of future DG adoption on retail electricity rates for New Hampshire customers.

The reported results[63] in this study analysis are predominantly focused on two key metrics:

- **Rate impacts** are presented as the average annual percentage increase/decrease in rates relative to a no-DG scenario over the period 2021 to 2035 for each rate class and each utility.[64]
- **Bill impacts** are presented as the average annual percentage increase/decrease in customers' bills relative to a no-DG scenario over the period 2021 to 2035 for each rate class, each utility, and each customer type – those with DG and those without DG.

To illustrate the impacts of different potential DG program designs on ratepayers, the analysis is conducted under two different scenarios for DG compensation: a **NEM Tariff Scenario**, which assumes that DG exports are compensated under the current NEM tariff structure, and an **Avoided Cost Value Stack (ACV) Tariff scenario,** which assumes that DG exports are compensated at rates equal to the calculated avoided cost value stack.[65] The ACV scenario illustrates the impacts on rates and bills of a net-metering export tariff that is aligned with the avoided cost value stack, and therefore representative of actual values achieved from the perspective of the utility system.

[63] The results do not assume inflationary effects and consider only real impacts.
[64] The no-DG scenario is defined as a scenario that assumes no incremental future deployment of DG in New Hampshire post-2021.
[65] NEM 2.0 Tariff adopted September 2017

3.4.1 – NEM Scenario

This scenario reflects the net-metering program that is currently in effect in New Hampshire (effective as of September 2017).[66] The export credit rate is based on the alternative net metering tariff, under which monthly net exports from residential and small general service customer DG (i.e., those with DG facilities up to 100 kW) are compensated at 25% of the distribution rate component and 100% of the generation and transmission rate components. For exports from customers with DG greater than 100 kW, hourly net exports are compensated at 100% of the generation rate component only.

3.4.1.1 – Rate Impacts

Under the current NEM Tariff scenario, forecasted DG adoption is expected to result in slight rate increases relative to a no-DG scenario over the study period (2021-2035), as seen in Figure 26. Across the three utilities, residential customers experience the highest increase in rates among the rate classes, followed by small and then large general service customers.

This variation in retail rate increases across the rate classes is a by-product of sector-specific retail rate designs (rates and tariff structures) and NEM program administration costs, as well as the assumed proportion of solar exports relative to the overall customer load. Customers with net DG exports are compensated through monetary credits at the rates applicable under the current alternative net metering tariff. Rate classes that exhibit a higher proportion of net exports receive greater compensation through export bill credits. This will increase the utility's program costs which in turn will be recovered from the retail customer class. Additionally, the proportion of DG production that is self-consumed will reduce the consumption that is registered behind the meter and result in lost revenues for the utilities. Both the export bill credits and the lost revenues increase the utility costs that need to be recovered, increasing rates. Statewide, average monthly rate increases across the study period are found to be 1.3% for residential customers, and 0.5% for small and large general service customers. Variation is also observed among utilities as a result of differences in system archetype definitions, DG forecast assumptions, and individual utility rate designs.[67,68]

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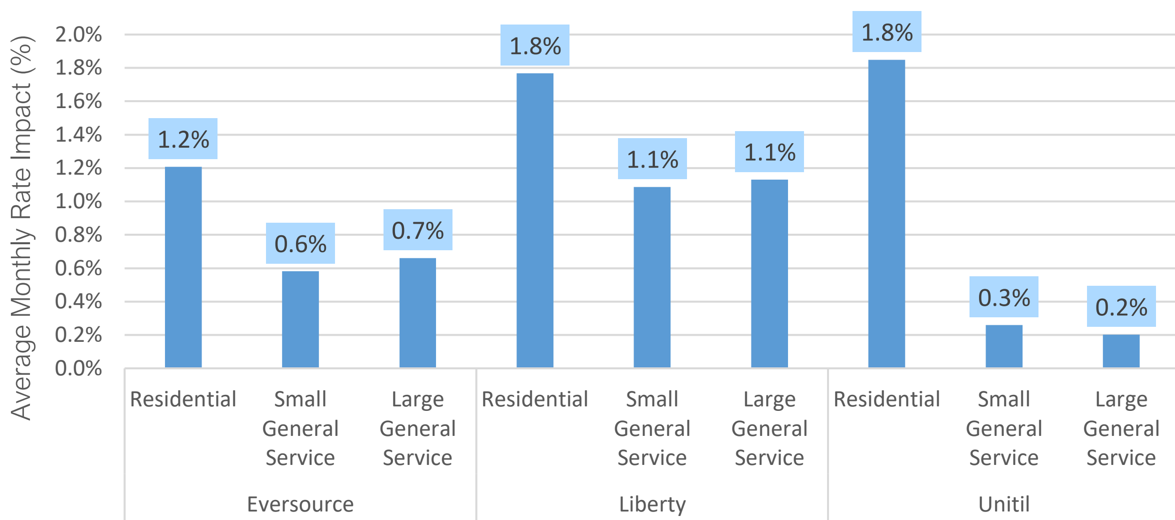
[66] New Hampshire Department of Energy. Net Energy Metering Tariff. Available online: https://www.energy.nh.gov/sites/g/files/ehbemt551/files/inline-documents/sonh/net-metering-tariff-2020-overview.pdf

[67] System archetype definitions are described in methodology section 2.6.1 – Define DG System Archetypes section

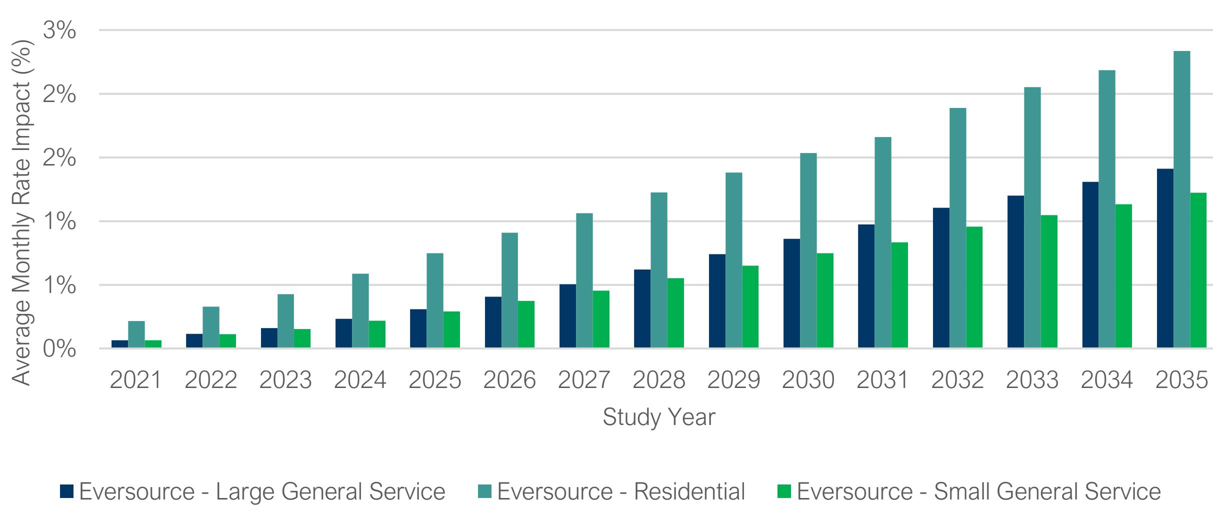
[68] DG forecast assumptions are described in methodology section 2.6.2 – Develop DG and no-DG Load Forecasts

Figure 26. Average Monthly Rate Impact for Average Utility Customer (2021-2035) under NEM Compensation Scenario (Relative to no-DG Scenario)



As seen in Figure 27, the average monthly rate impact for utility customers in Eversource's service territory increases gradually over the study period, with residential customers experiencing the greatest increase followed by small and then large general service customers.

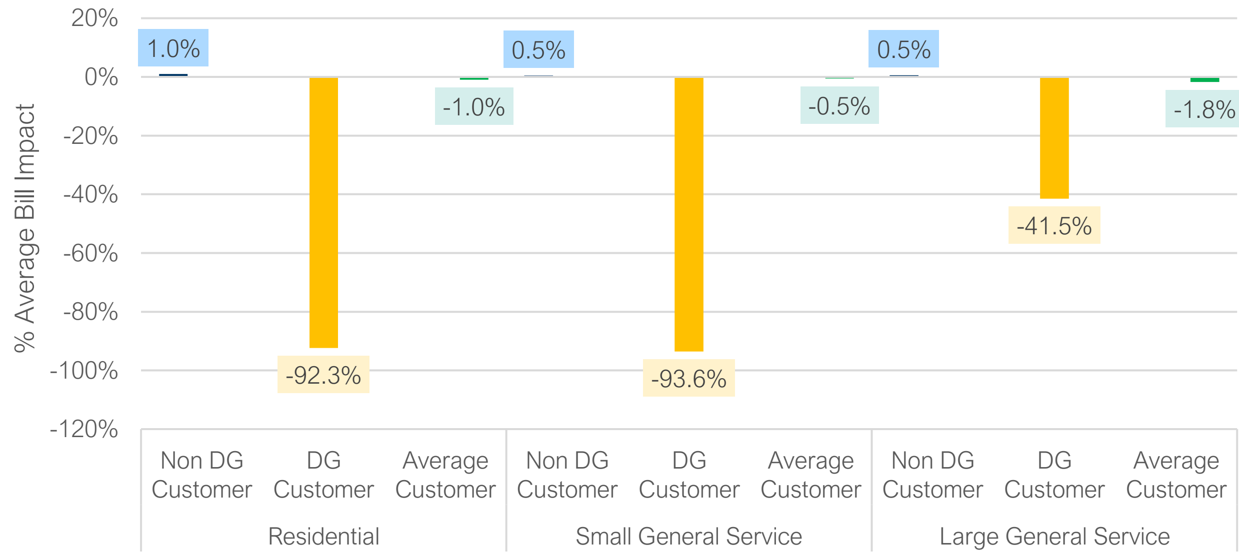
Figure 27. Average Monthly Rate Impact for Utility Customers in Eversource Territory Under NEM Scenario (Relative to no-DG scenario)



3.4.1.2 – Bill Impacts

Among customers with DG, customers without DG, and the average utility customer, DG customers will experience the largest reduction in monthly bills. Figure 28 below illustrates the findings for customers in Eversource's service territory as an example.[69]

Figure 28. Average Monthly Bill Impacts Across Rate Classes in Eversource Territory Under NEM Scenario (Relative to no-DG Scenario)[70]



In the example above, for the system archetypes defined for this analysis, residential and small general service DG customers who adopt behind-the-meter solar see an average reduction of 92% in monthly bills. Large general service DG customers see an average reduction of 42% in monthly bills. Customers who do not adopt DG see a slight increase in monthly bills (~1% for residential and 0.5% for small and large general service customers). Overall, however, the average impact across each rate class, referred to as the "average utility customer" impact is a reduction in monthly bills from 0.5% to 1%.

The following sections present the bill impacts for each customer archetype – DG customer or non-DG customer – as well as the overall average customer impact across the residential and general service customer classes in each utility service territory.

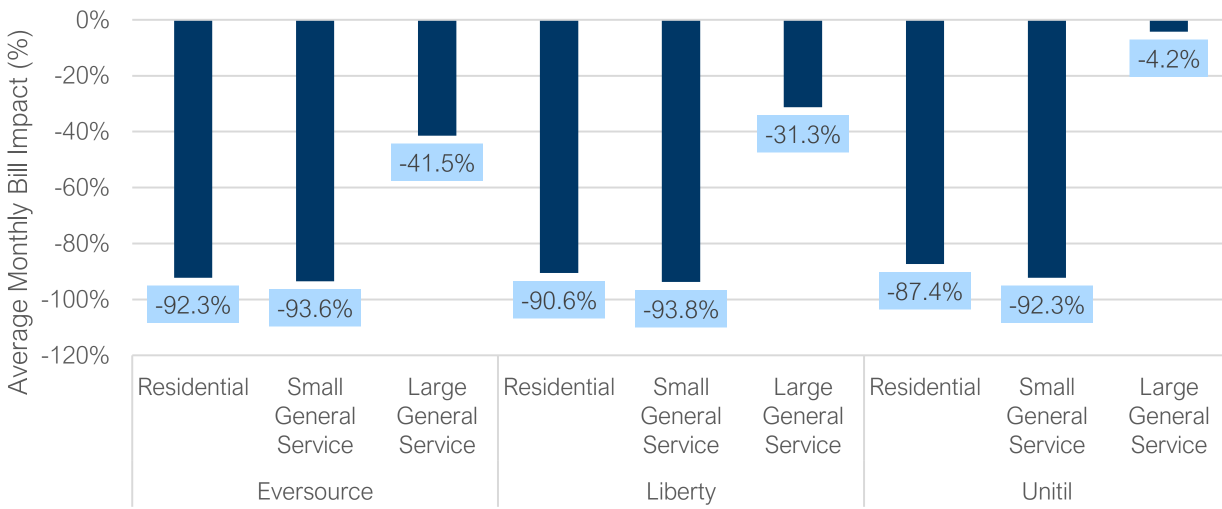
DG Customers

As seen in Figure 29, DG customers across all utilities will observe a significant reduction in monthly bills. Over the study period, residential customers who adopt DG will have 87% to 92% in average monthly bill reductions. Similarly, small general service customers will have approximately 93% in average monthly bill reductions. Large variation is seen in average monthly bill reductions for large general service customers across the three utilities, ranging from 4% to 40%. This is primarily due to

[69] This reflects monthly bills and does not include the costs of installation and ownership of solar PV systems.
[70] Averaged across the study period

the significant variation in the utility-specific average PV system sizes when compared to the overall customer load.

Figure 29. Average Monthly Bill Impact for DG Utility Customer Under NEM Scenario (2021-2035) (Relative to no-DG Scenario)[71]

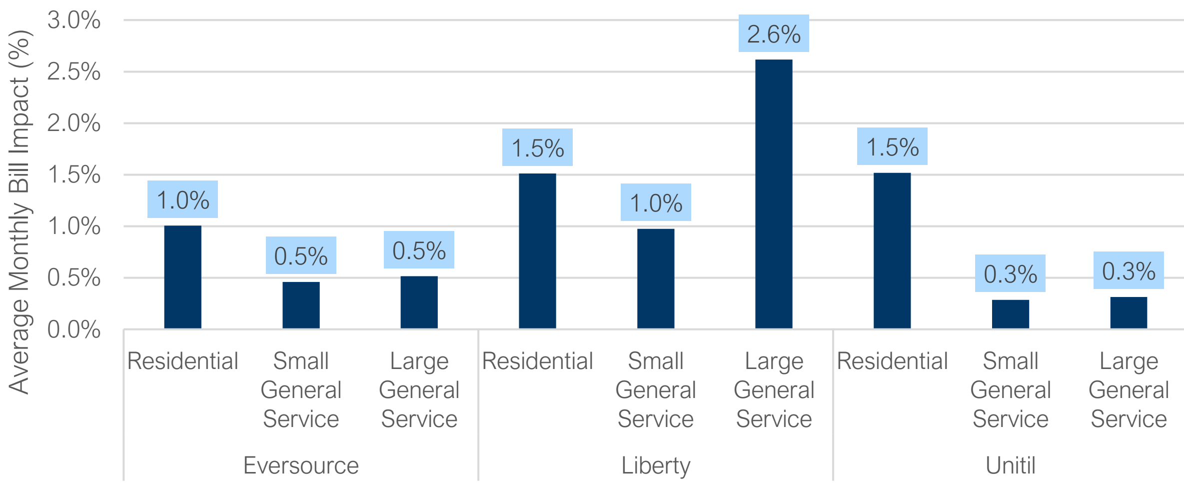


Non-DG Customers

As seen in Figure 30, utility customers that do not adopt DG experience a slight increase in bills across all utilities and rate classes. Residential customers see on average a 1.0 to 1.5% increase in average monthly bills, while small and large general service customers see on average a 0.3% to 2.6% increase in average monthly bills. The largest increase in customer bills is observed for large general service customers in Liberty's service territory. This is a result of Liberty's large generation service rate design, which is more demand-based than the other utilities, and also a result of Liberty having the highest expected proportion of large general service DG customers among the three utilities by 2032.

[71] Averaged across the study period

Figure 30. Average Monthly Bill Impact for Non-DG Utility Customer Under NEM Scenario (2021-2035)(Relative to no-DG Scenario)[72]

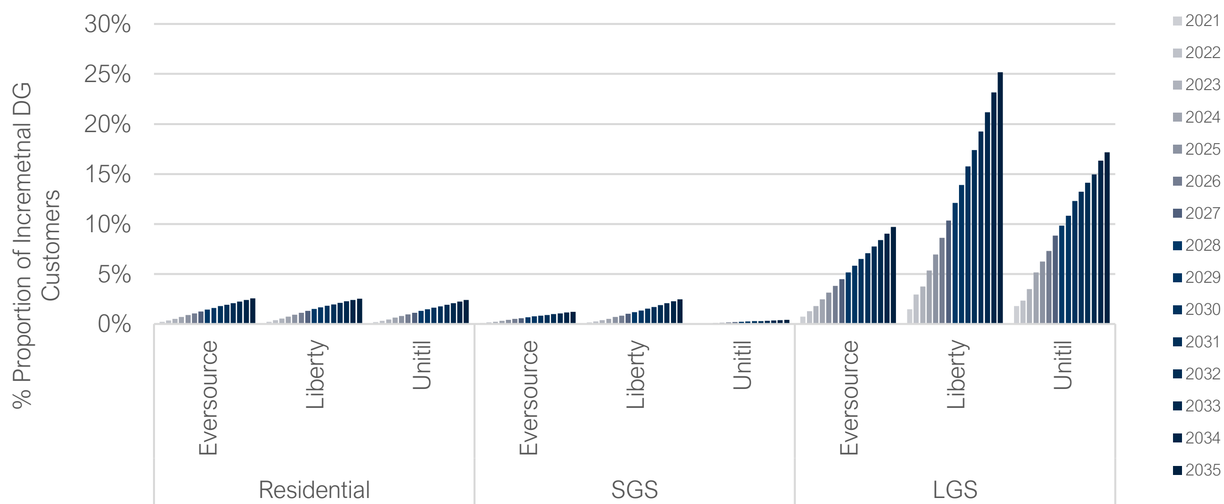


Average Customers

The adoption of distributed solar PV would enable DG customers to experience significant reductions in bills, while resulting in a slight increase in bills for customers who do not adopt DG. Average impacts across all customer types can be assessed by considering DG customer bill impacts, non-DG customer bill impacts, and the proportion of customers that fall into each category. The proportion of DG customers to non-DG customers varies over time for each utility and within each rate class, as illustrated below.

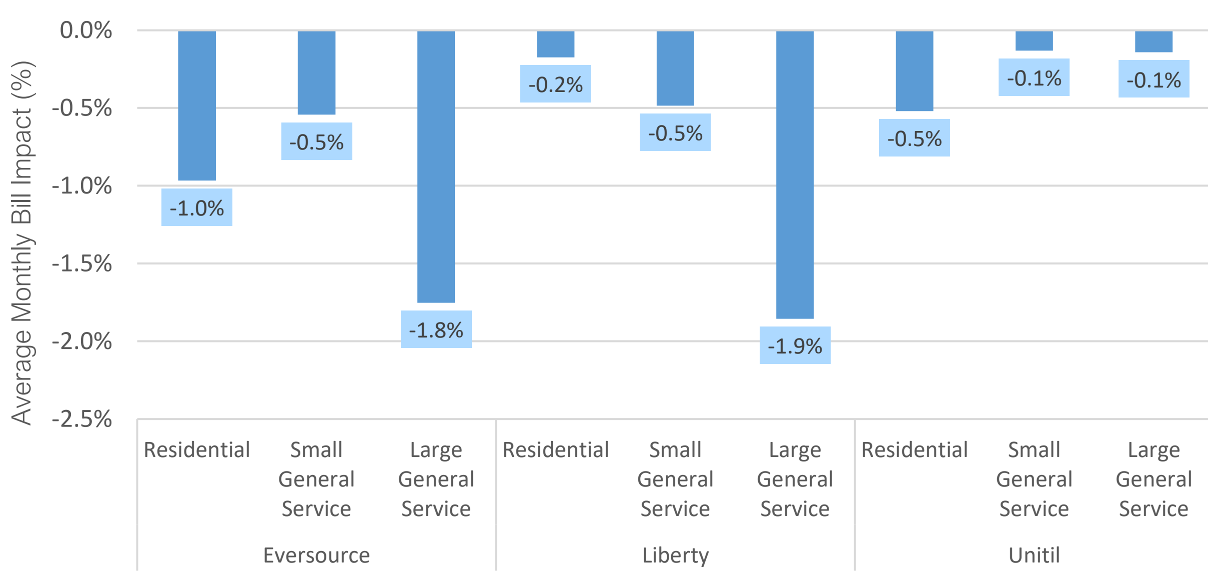
[72] Averaged across the study period

Figure 31. Proportion of Incremental DG Customers Across Rate Classes in Each Utility Service Territory[73] (Relative to no-DG Scenario)



Despite the forecasted electricity rate increases, average monthly bills across all utilities and rate classes are expected to decline over the study period. This is because the average reduction in consumption compensates for the rate increases, resulting in bill decreases overall.

Figure 32. Average Monthly Bill Impact for Average Utility Customer Under NEM Scenario (2021-2035)(Relative to no-DG Scenario)[74]



[73] The proportion of DG customers informed by the utility interconnection data and the CELT forecasts for New Hampshire.
[74] Averaged across the study period

3.4.2 – Avoided Cost Value (ACV) Tariff Scenario

The Avoided Cost Value (ACV) Tariff scenario represents a hypothetical scenario under which net exports from DG are compensated at the avoided cost value, as quantified by the base avoided cost value stack assessment. The treatment of net export compensation is the key differentiator between the two tariff scenarios. Under the NEM Tariff scenario, exports are compensated at a rate that represents a proportion of the underlying retail rates, whereas under the ACV Tariff scenario, net exports are compensated based on the value of the avoided costs calculated in this study (excluding environmental externalities). Because net export bill credits are determined based on the avoided cost values under the ACV Tariff, which is effectively less than the current export compensation rate, the program costs that are recovered by the utilities are lower. Consequently, the ACV has a slightly lower impact on retail rates.

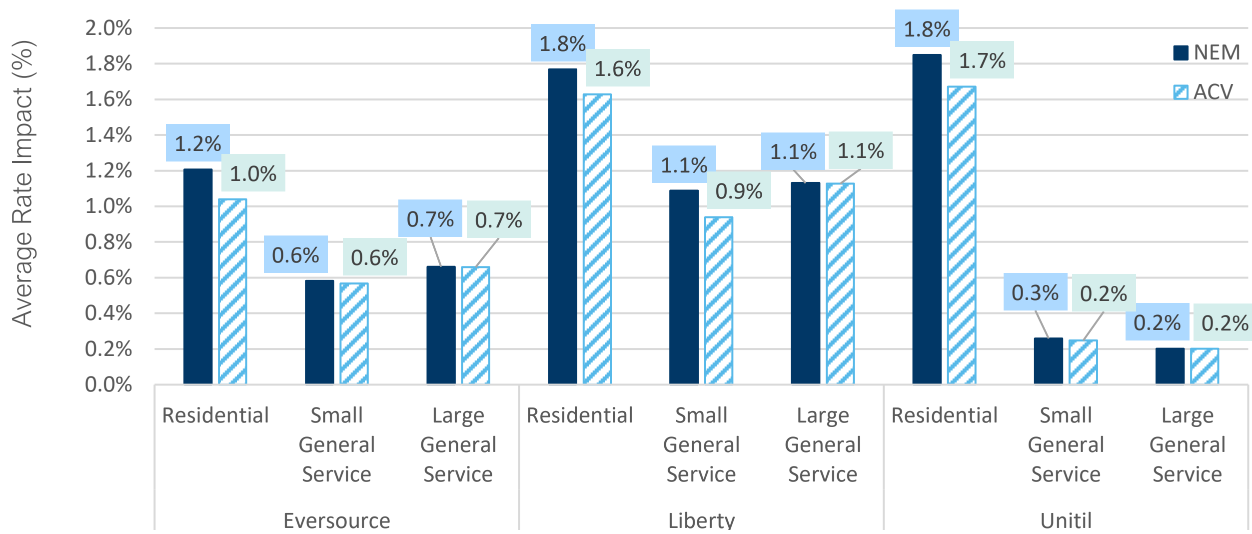
It is important to note that the analysis does not consider any impacts that the transition to an ACV Tariff compensation model may have on DG economics and deployment trends in New Hampshire (i.e., the same level of future DG deployment is assumed under both scenarios).

3.4.2.1 – Rate Impacts

Comparing the rate impacts (relative to a no-DG scenario) for the ACV Tariff scenario with the current NEM Tariff scenario highlights that both scenarios result in slight increases in rates. As seen in Figure 33, both the NEM and ACV scenarios show a comparable increase in rates across most customer classes; however, slightly lower rate impacts for some customer classes are observed under the ACV Tariff scenario.

As discussed above, the effective compensation of net exports is the primary driver for the rate impacts observed. Therefore, differences in rate impacts are primarily observed in rate classes where a significant portion of the electricity produced is exported to the grid. For example, residential customers across all three utilities experience slightly lower rate increase impacts under the ACV Tariff when compared against the current NEM scenario. The rate impacts experienced for small and large general service customers are similar between the NEM and ACV Tariff scenarios, due to the high proportion of energy production that offsets on-site consumption (i.e., assumption of little to no net exports).

Figure 33. Average Rate Impact by Utility and Rate Class (2021-2035) (Relative to no-DG Scenario)[75]



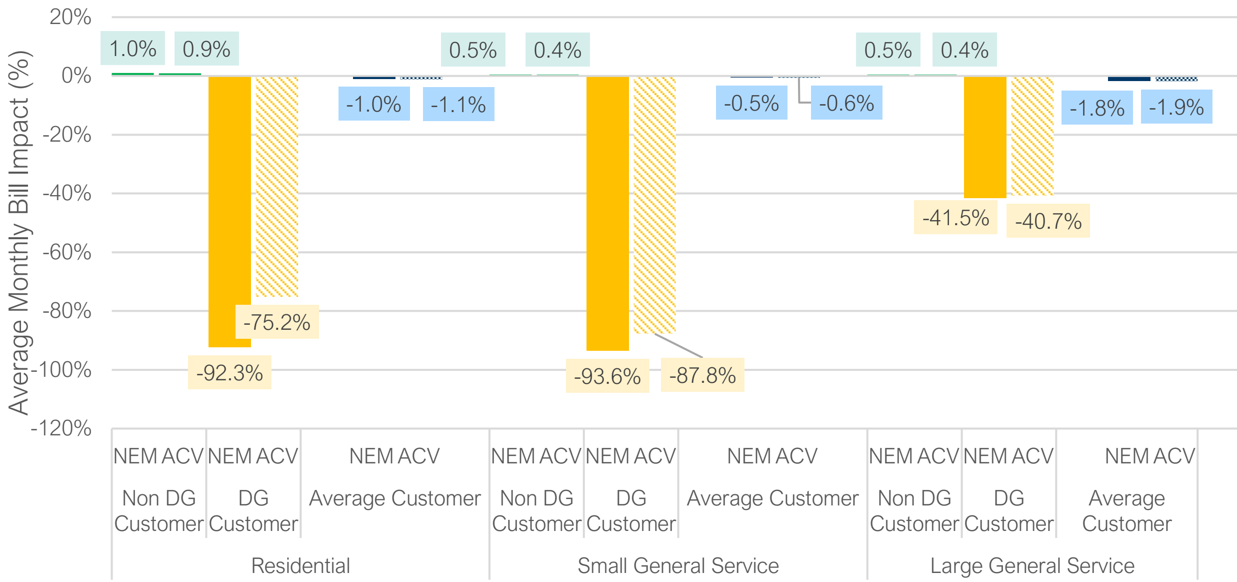
3.4.2.2 – Bill Impacts

A similar trend is observed for bills under the NEM Tariff scenario and the ACV Tariff scenario, where bill impacts do not change significantly for most customers under the two alternative scenarios. Figure 34 below illustrates the findings for customers in Eversource's service territory as an example.[76]

Overall, non-DG customers experience slightly lower bill impacts due to the lower rate impacts under the ACV Tariff scenario, DG customers observe lower bill savings due to the reduced benefits from lower net export credits, while utility customers on average observe slightly higher bill reductions. The following subsections describe the impacts for each of the three representative customer types.

[75] Averaged across the study period
[76] This reflects monthly bills and does not include the costs of installation and ownership solar PV systems.

Figure 34. Bill Impacts Across Rate Classes in Eversource Territory Under ACV and NEM Scenarios (Relative to no-DG Scenario)[77]

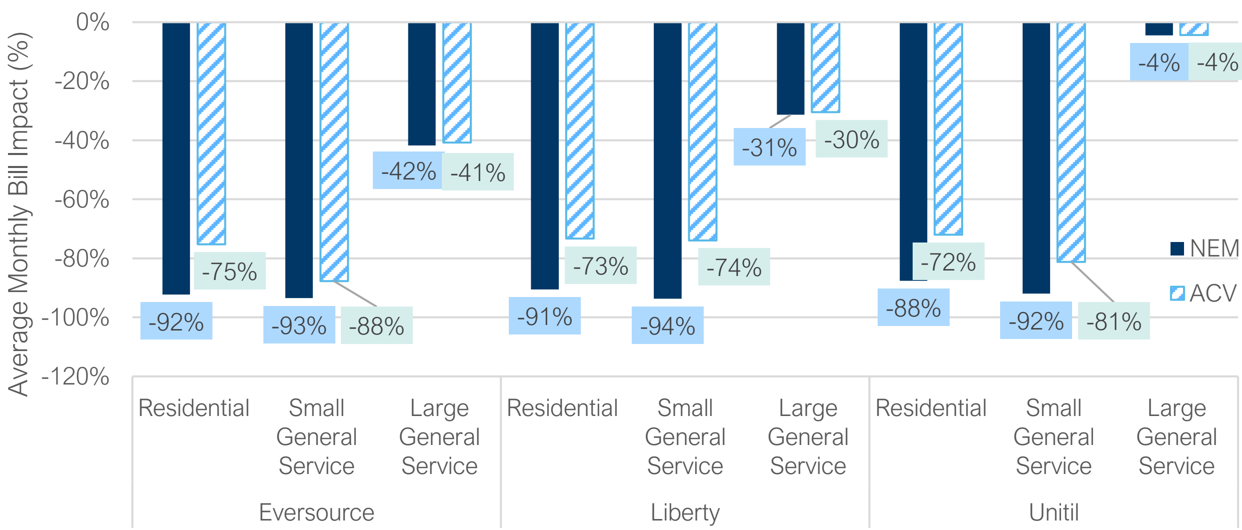


DG Customers

Under the ACV Tariff scenario, most DG customers will experience a reduction in bill savings relative to NEM as a result of the reduced value of net export credits. The impacts will be most prominent in rate classes with high levels of grid exports which makes them more sensitive to changes to net export credits. Specifically, residential customers would experience 72-75% bill savings under ACV as compared to 88-92% bill savings under NEM, an 18% difference in bill savings. Similarly, small general service customers would experience reductions of up to 20% in their average monthly bill savings as compared to their savings under the NEM Tariff scenario. Conversely, large general service customers would experience minimal impacts in their average monthly bills, because of the large share of DG self-consumption assumed for those customers.

[77] Averaged across the study period

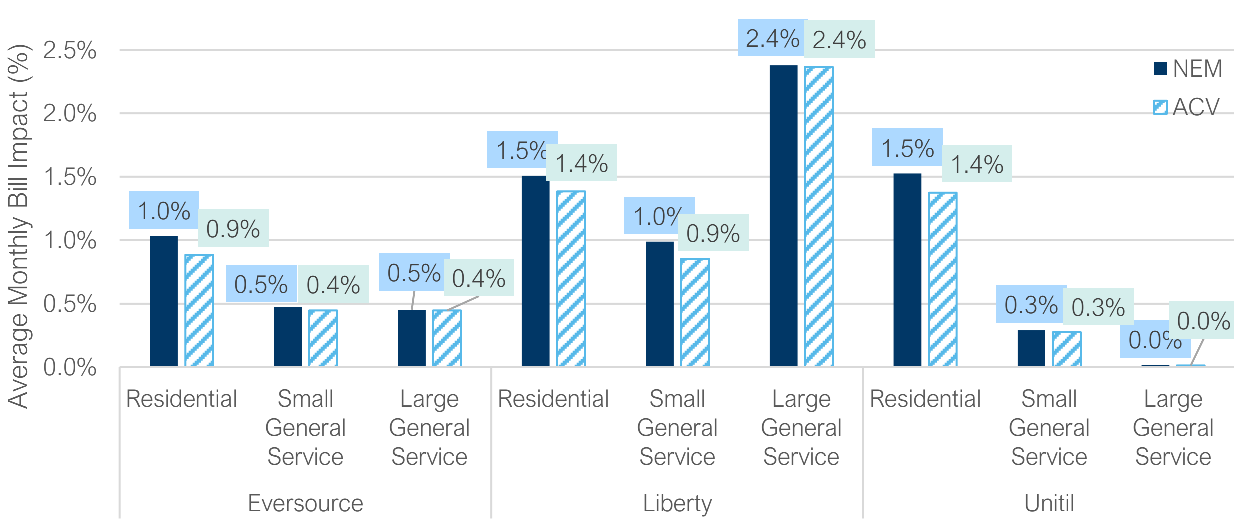
Figure 35. Average Monthly Bill Impact for DG Customer Under NEM and ACV Scenarios (2021-2035)(Relative to no-DG Scenario)[78]



Non-DG Customers

Differences in monthly bills for non-DG customers are insignificant under the ACV Tariff scenario relative to the NEM Tariff scenario. As described above, the differences are primarily observed in residential rate classes that tend to have a higher proportion of net exports, where non-DG customers would benefit from lower rate impacts under the ACV tariff as compared to the NEM scenario, thereby leading to a corresponding reduction in bill impacts.

Figure 36. Average Monthly Bill Impact for Non-DG Customer (2021-2035)(Relative to no-DG Scenario)[79]

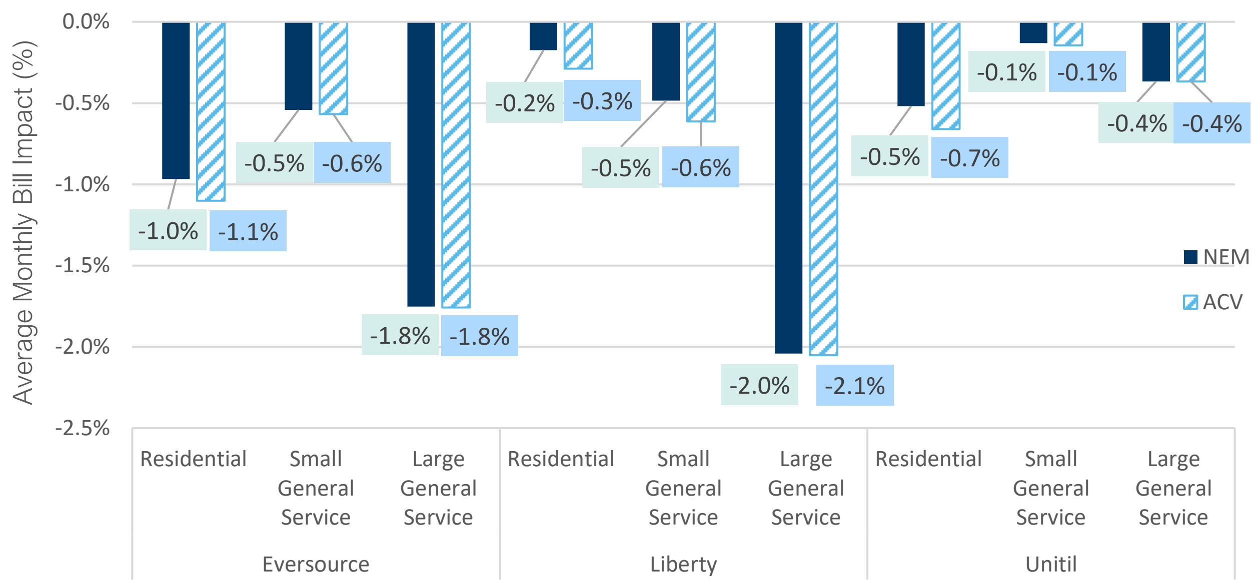


[78] Averaged across the study period
[79] ibid

Average Customers

In assessing the bill impacts for an average utility customer under the ACV Tariff scenario relative to the NEM Tariff scenario, we observe insignificant differences in monthly bills for customers across most utilities and rate classes, with slight bill reductions observed for residential and small commercial classes. The impacts and corresponding magnitude of the differences are largely driven by the magnitude of the net exports within a customer class.

Figure 37. Average Monthly Bill Impact for Average Utility Customer (2021-2035)(Relative to no-DG Scenario)[80]



80 Averaged across the study period

4 Key Findings

Key Findings

In New Hampshire, DERs are forecasted to provide a total net avoided cost value of **$0.11 to $0.18 per kWh energy produced in 2021** (Figure 38) and **$0.10 to $0.23 per kWh produced in 2035** (Figure 39), varying by DER system type.

The total avoided cost value stack value decreases over the study period for solar-only systems, primarily as a result of decreasing energy avoided costs. West-facing PV systems provide 5-10% greater avoided cost value overall, although currently in New Hampshire south-facing systems are most commonly installed because of production incentives embedded in the current NEM Tariff structure.

Net-metered DER value *increases* over time for solar paired with storage and for micro hydro, as a result of the ability of those systems to generate greater T&D avoided costs, which are assumed to increase over the study period. If the full social cost of environmental externalities (CO_2, NO_x) is considered, the value of net-metered DERs increases by 20%-45%**,** varying by year and by DG system type.

Figure 38. Average Annual Value Stack with Environmental Externalities Sensitivity by DG System Type, 2021 (2021$)

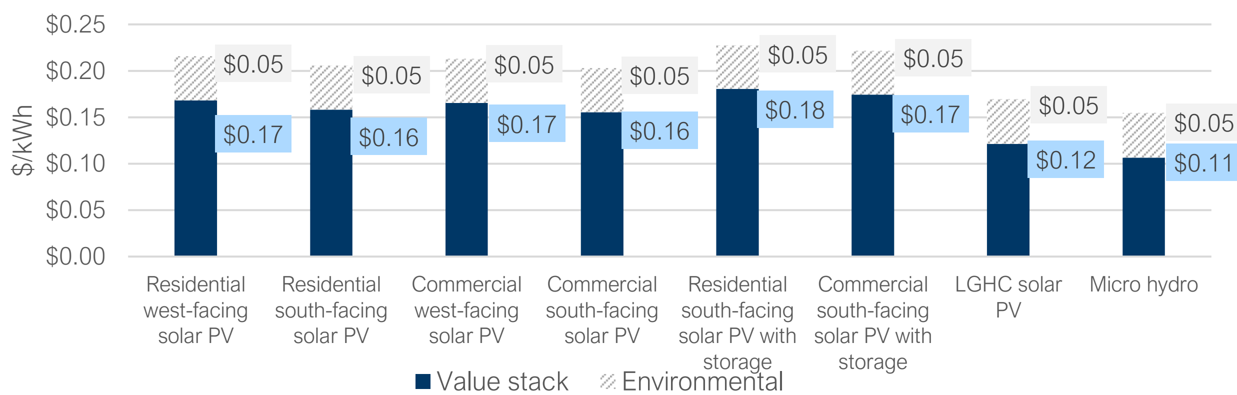
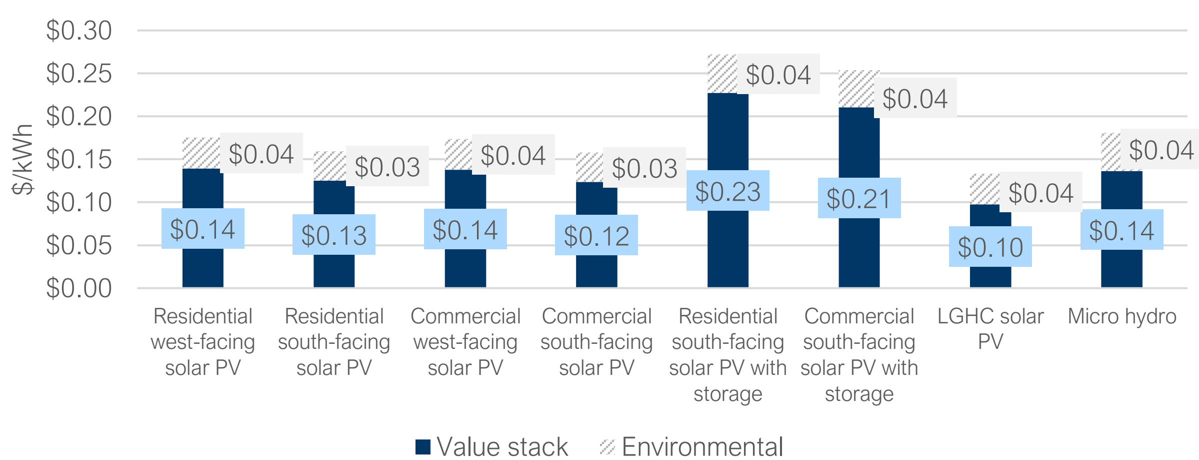


Figure 39. Average Annual Value Stack with Environmental Externalities Sensitivity by DG System, 2035 (2021$)



Avoided cost values may change as a result of increasing system loads and would be different were

DERs to participate in the regional wholesale energy or capacity markets. The impacts of those factors were assessed through the high load growth scenarios (HLGS) and the market resource value scenario (MRVS), respectively. The changes in avoided cost values from the baseline value stack for those scenarios are shown for 2021 in Figure 40 and for 2035 in Figure 41 below.

Increased loads under high load conditions, reflecting increased building and transportation electrification, have minimal impacts on the value of DERs in 2021 (less than 1% difference). In 2035, increased loads drive 2.8% to 5.3% higher values than the baseline value stack, varying by DG system type. The environmental externalities avoided cost sensitivity is also expected to change with loads, increasing in value as loads grow due to changes in the regional generating resource mix.

Net-metered DERs also may participate in the wholesale power markets through aggregations, rather than acting merely as passive resources that generate avoided cost value solely by reducing customer loads. From a utility system perspective, under current ISO-NE market rules, all systems provide greater value by passively reducing load than by participating as aggregated resources in the markets, with the single exception of micro hydro facilities. Micro hydro plants are able to consistently generate energy during the summer and winter peak reliability periods, thereby increasing their value in the capacity market.

Figure 40. Average Annual Change from Baseline Value Stack Under the HLGS and MRVS, 2021 (2021$)

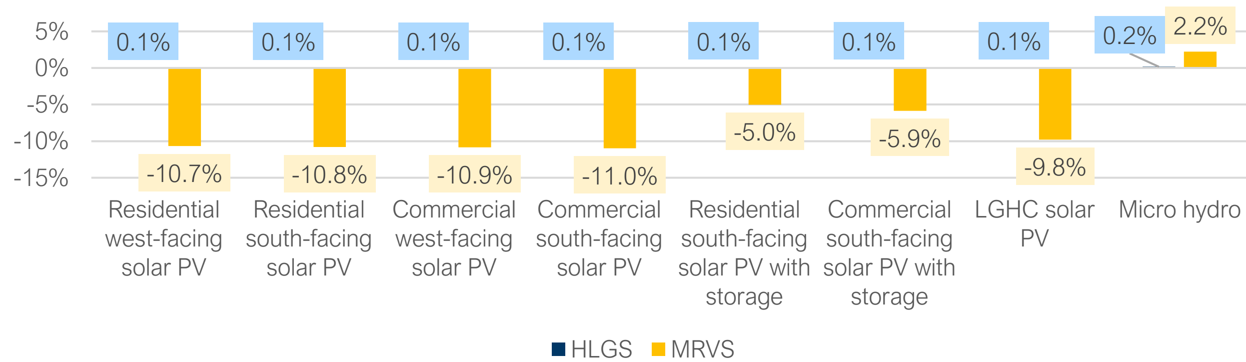
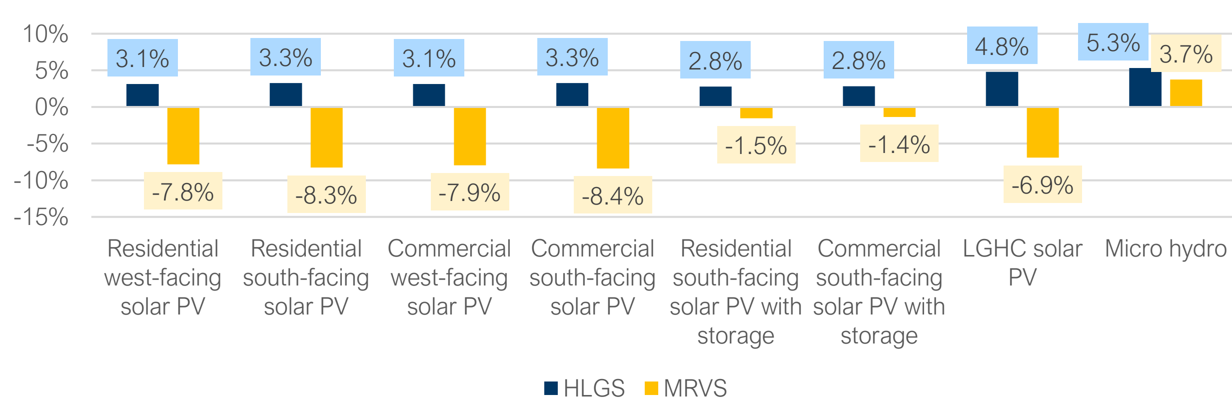


Figure 41. Average Annual Change from Baseline Value Stack Under the HLGS and MRVS, 2035 (2021$)

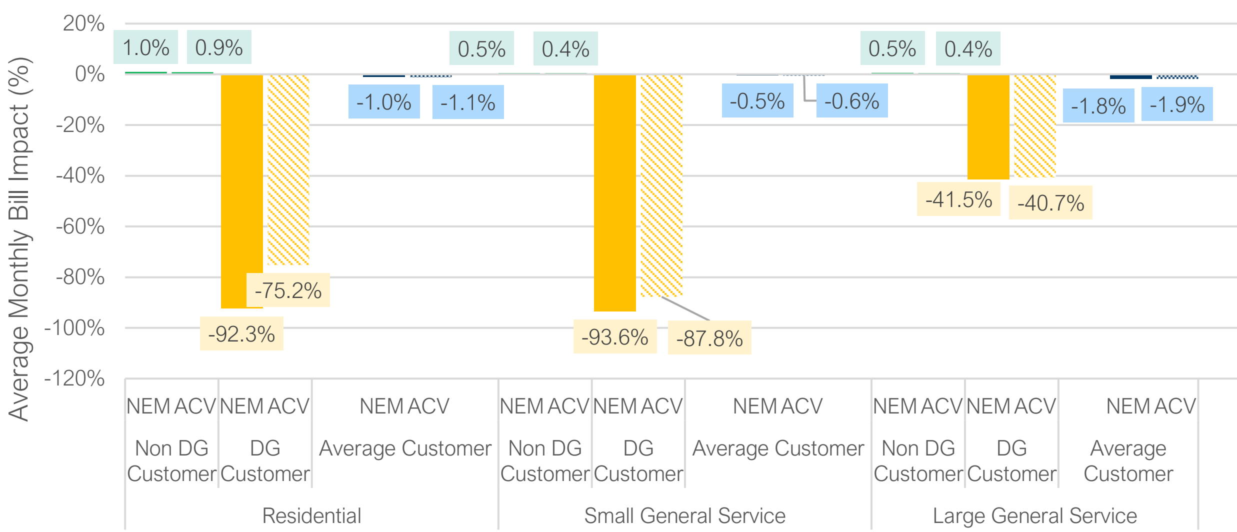


Net-metered DERs are expected to provide additional value beyond what is shown here, notably for those value stack criteria addressed qualitatively in this study: transmission capacity (for non-pool transmission facilities), transmission and distribution system upgrades, distribution grid support services, and resiliency. Additional research and data collection may support quantitative valuation of these criteria in the future.

Customer installed costs are included in this study. In the future, these costs may be used to evaluate how NEM crediting and compensation may affect reasonable opportunities to invest in DG and receive fair compensation, as contemplated by House Bill 1116 (2016).[81]

The rate and bill impacts analysis demonstrates that DG will cause rates to increase slightly for all rate classes and across all utilities under the current alternative net metering tariff design. Monthly bills would increase by a small percentage for non-DG customers (1% to 1.5% for residential, 0.3% to 2.6% for commercial), but would decrease by a large percentage for DG customers. The average impact across each customer class, referred to as "average customer" impact, is expected to be a bill reduction. In the alternative, a compensation model based on the avoided cost value stack (i.e., an ACV tariff approach) would slightly reduce rate increases experienced by customers, with virtually the same non-DG customer impacts, but slightly lower bill savings for DG customers, which would be reduced to a greater degree – in particular for residential customers (Figure 42).

Figure 42. Bill Impacts Across Rate Classes in Eversource Territory Under NEM and ACV Scenarios (Relative to no-DG scenario)



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[81] NH House Bill 1116. Available online: https://www.gencourt.state.nh.us/bill_status/legacy/bs2016/billText.aspx?sy=2016&id=293&txtFormat=html

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