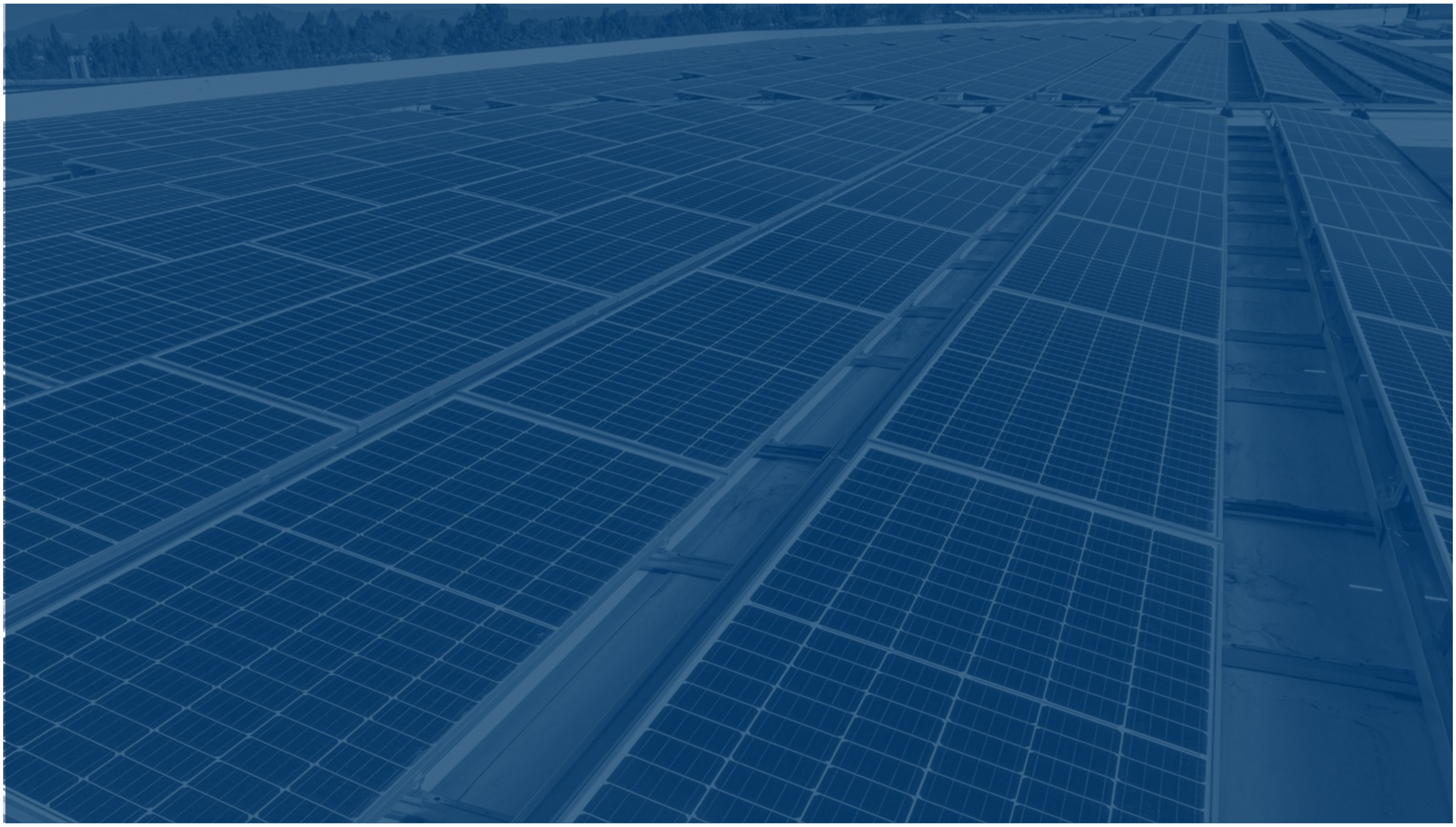


New Hampshire Value of Distributed Energy Resources

Final Report

Submitted to:

New Hampshire
Department of Energy

New Hampshire Department of Energy

www.energy.nh.gov

Prepared by:

dunsky
Energy + Climate

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

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

With support from Power Advisory

About Dunsky

Founded in 2004, Dunsky supports leading governments, utilities, corporations and non-profits across North America in their efforts to **accelerate the clean energy transition**, effectively and responsibly.

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).

Dunsky is proudly Canadian, with offices and staff in Montreal, Toronto, Vancouver, Ottawa and Halifax.

Table of Contents

List of Figures

List of Tables

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:

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$)

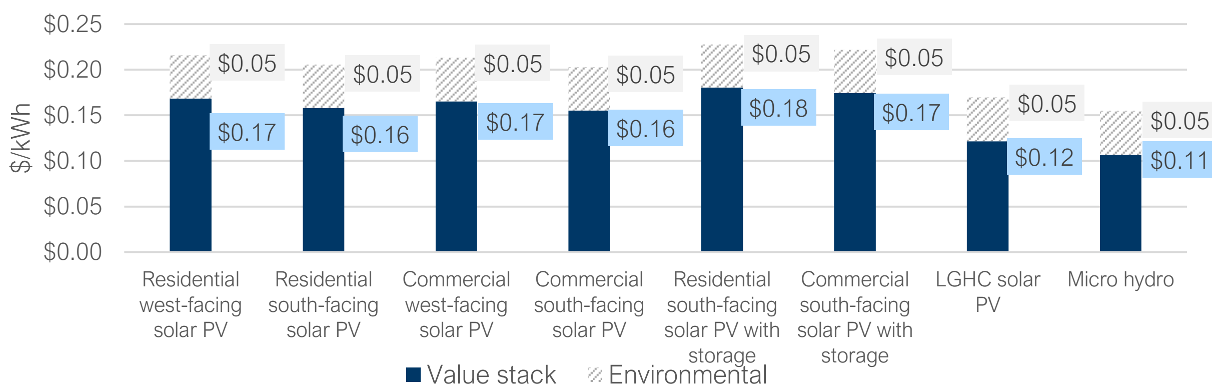
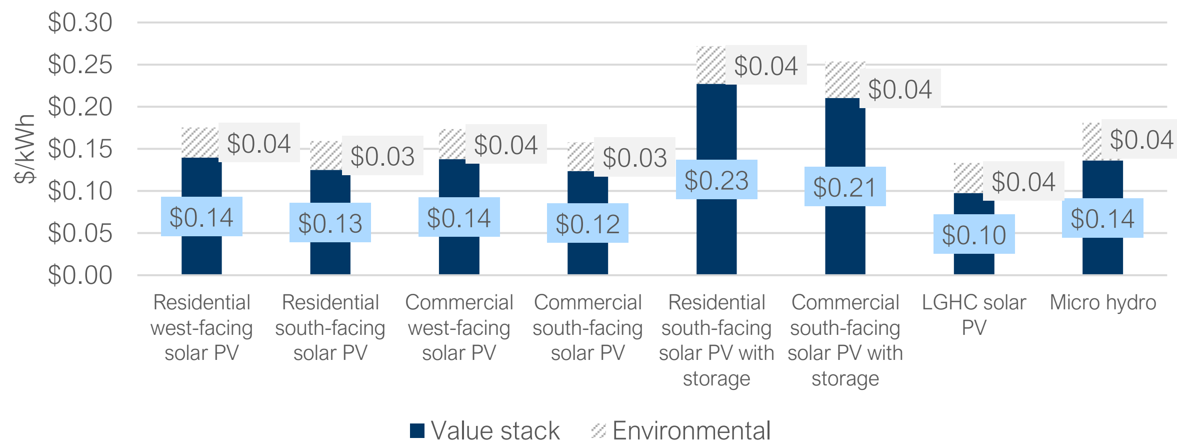


Figure 2. Average Annual Value Stack with Environmental Externalities Sensitivity by DG System Type, 2035 (2021$)



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$)

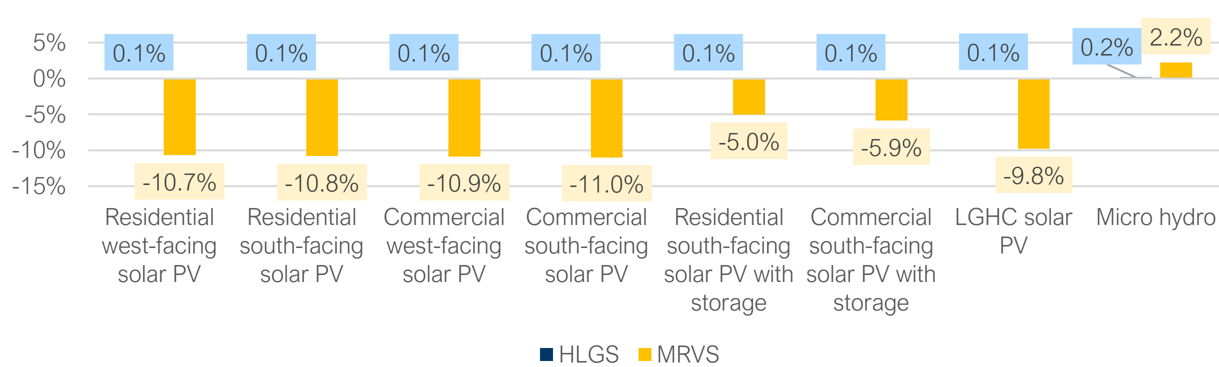
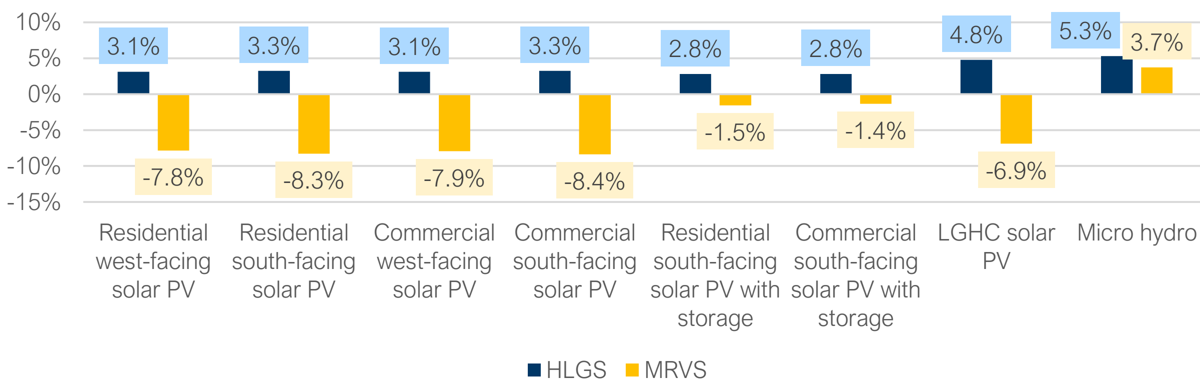


Figure 4. Average Annual Change from Baseline Value Stack Under the HLGS and MRVS, 2035 (2021$)



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.

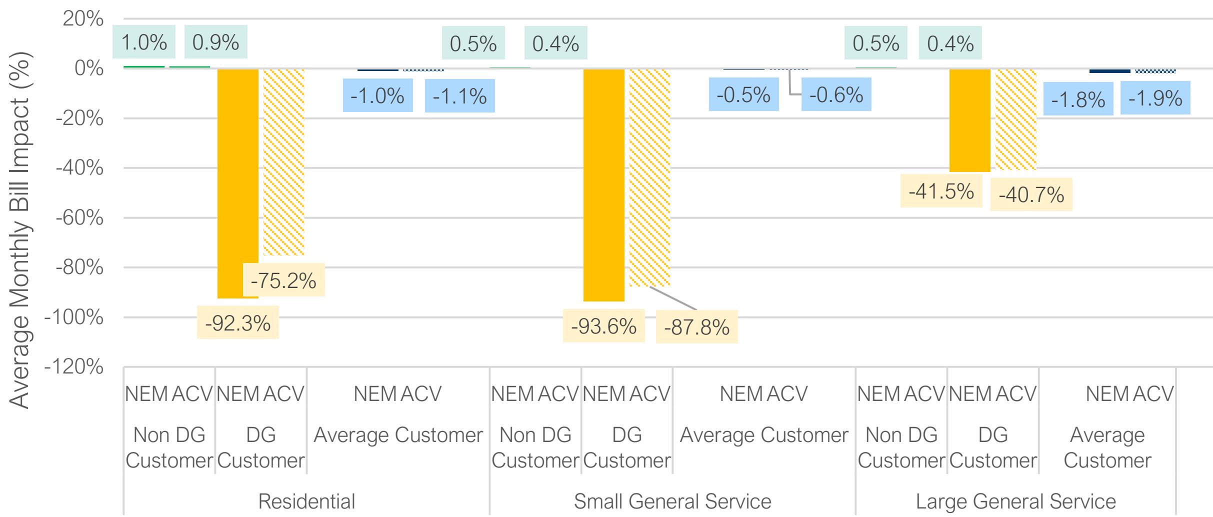
Customer-installed costs are included in this study. In the future, these costs may be used to evaluate how NEM crediting and compensation may affect reasonable opportunities to invest in DG and receive fair compensation, as contemplated by House Bill 1116 (2016).[1]

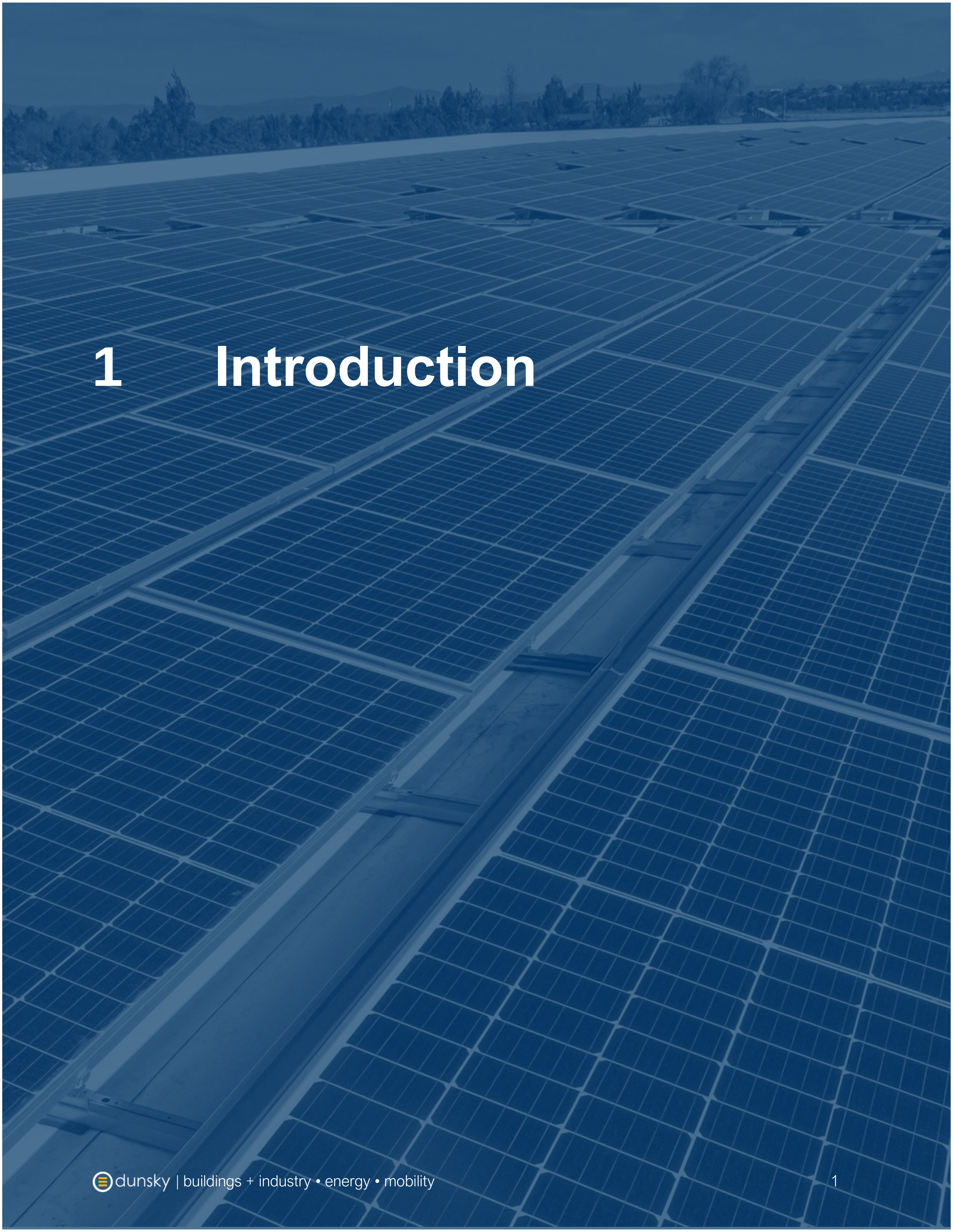
The rate and bill impacts analysis demonstrate that DG will cause rates to increase slightly for all rate classes and across all utilities under the current alternative net metering tariff design. Monthly bills would increase by a small percentage for non-DG customers but would decrease by a larger percentage 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)

---

[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

[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.

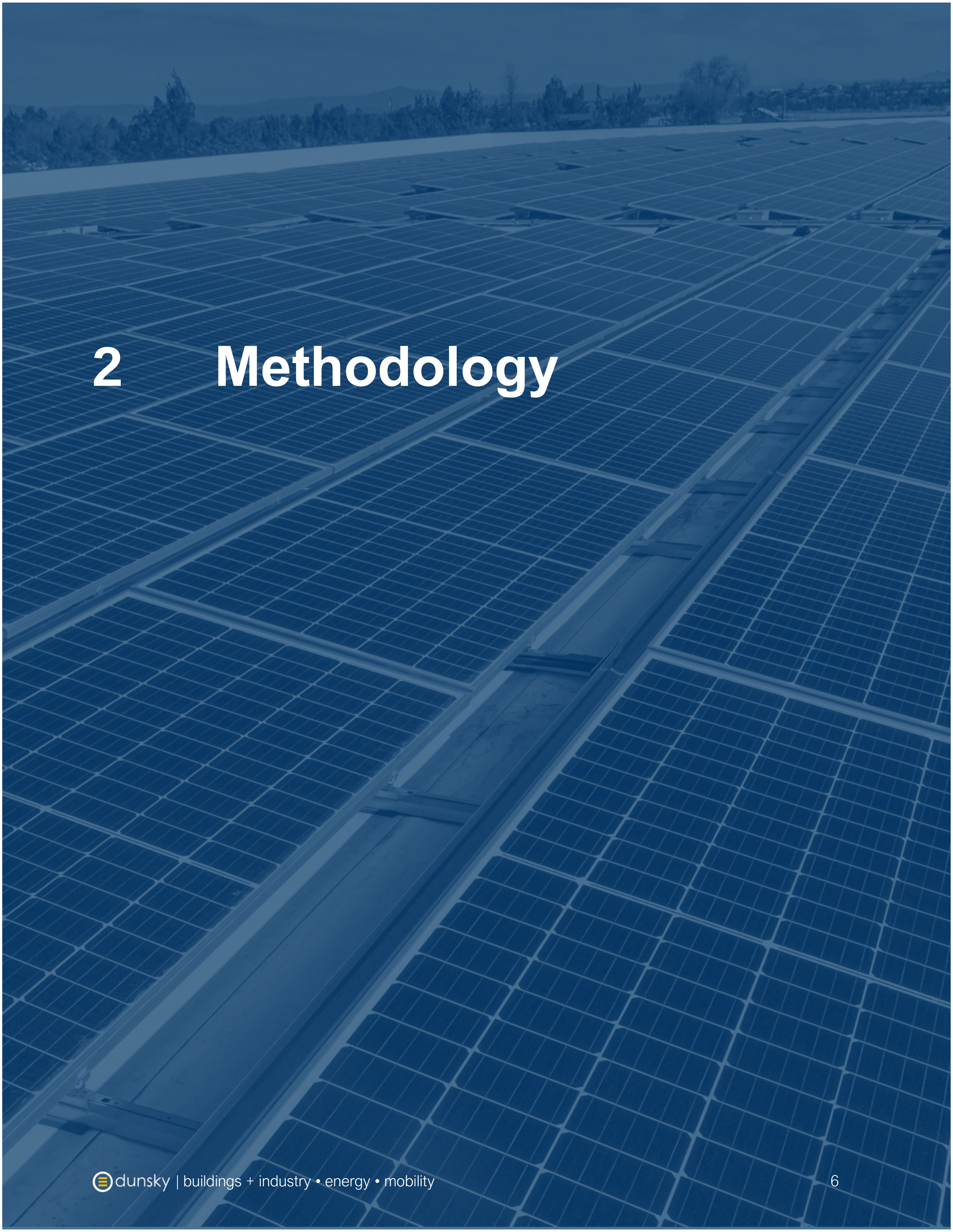
[10] Synapse Energy Economics. (October 2021). Avoided Energy Supply Components in New England: 2021 Report – Non-embedded environmental compliance section. Available online: https://www.synapse-energy.com/project/aesc-2021-materials

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:

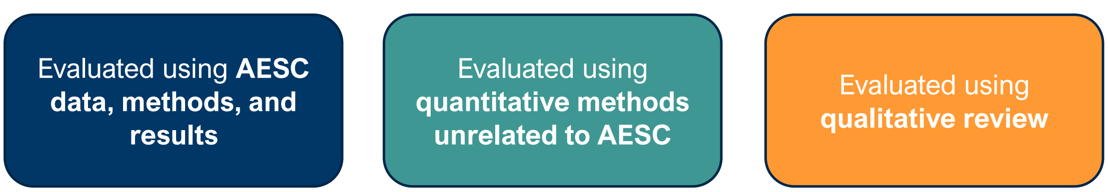
First, technology-neutral avoided cost values are established (step 1). Next, DER production curves are developed for each resource type (step 2) and mapped against the technology-neutral avoided costs to calculate the avoided cost value of DERs by system type (step 3). Avoided cost values are also calculated 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:



[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]

[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.

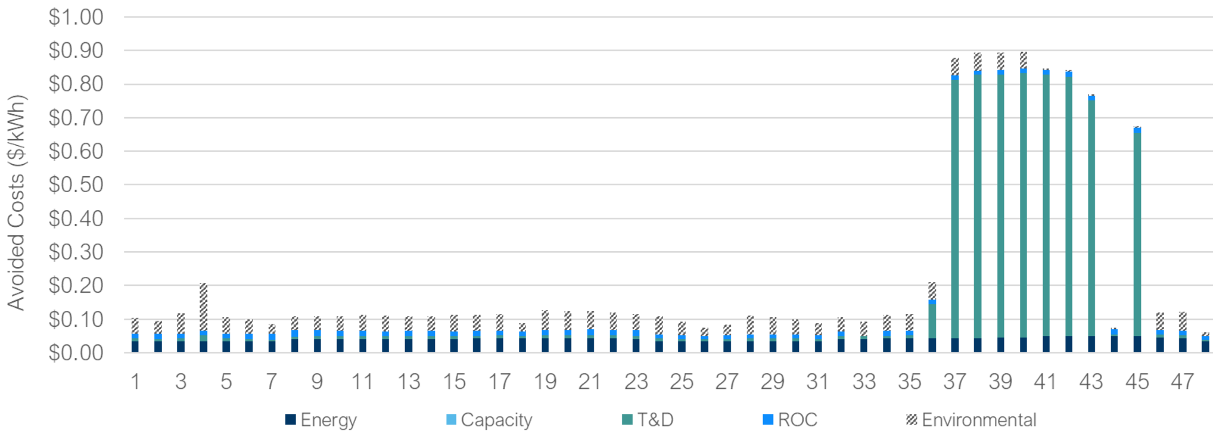
Evaluated using **qualitative review**

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

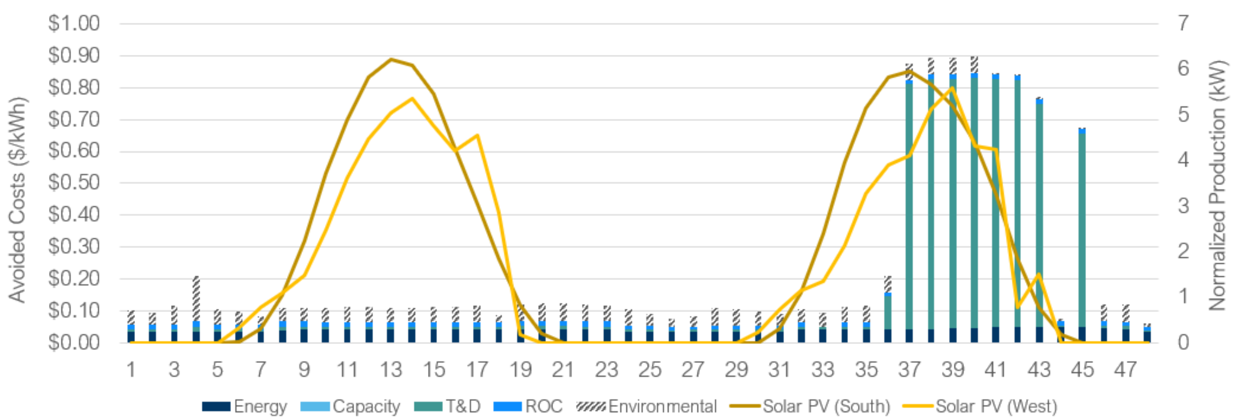
of-river hydro facility located in New Hampshire. The month-to-month variation in hydro generation was developed using New Hampshire-specific hydro data from the U.S. DOE EIA.[23] Because hydro facilities vary in size and capacity factors, for modelling purposes, we assumed a small hydro facility of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

[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 <u>not</u> 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.

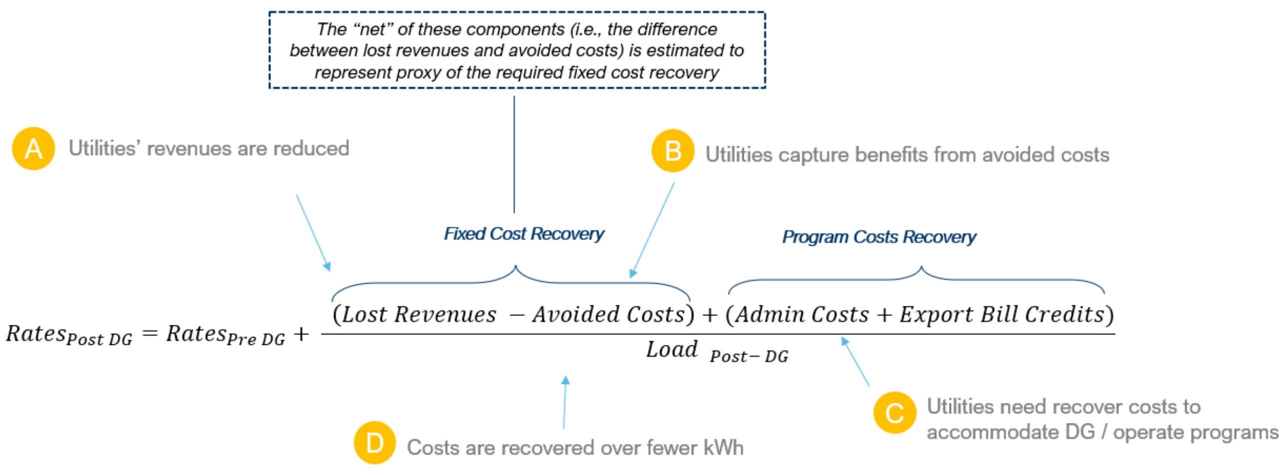
[28] The consumption profile of all three customer types is assumed to be the same in the hypothetical no-DG scenario, equivalent to the energy consumption and peak demand of the average customer in that rate class.

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

.



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.

[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.

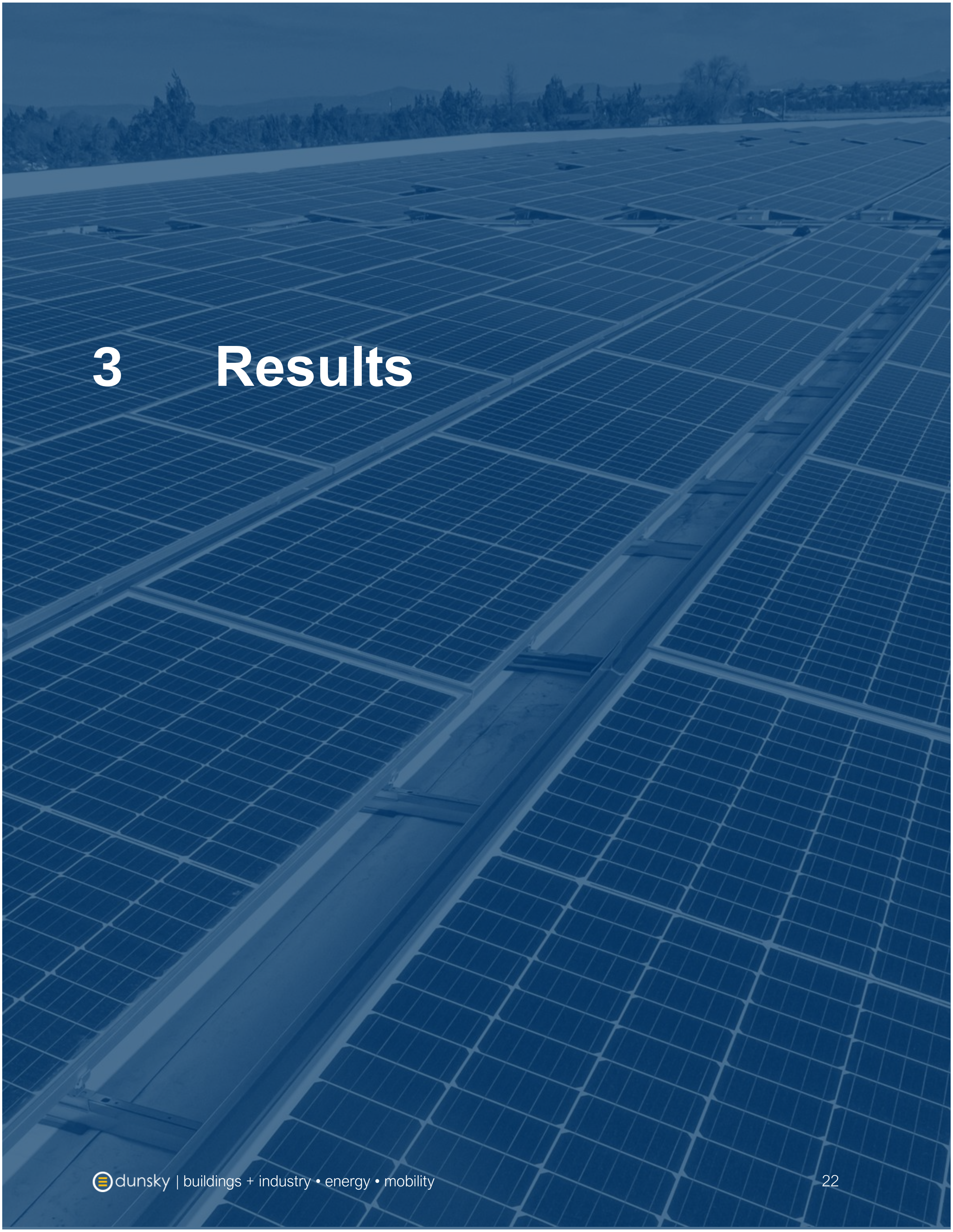
2.6.4 – Assess Changes to Bills

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).



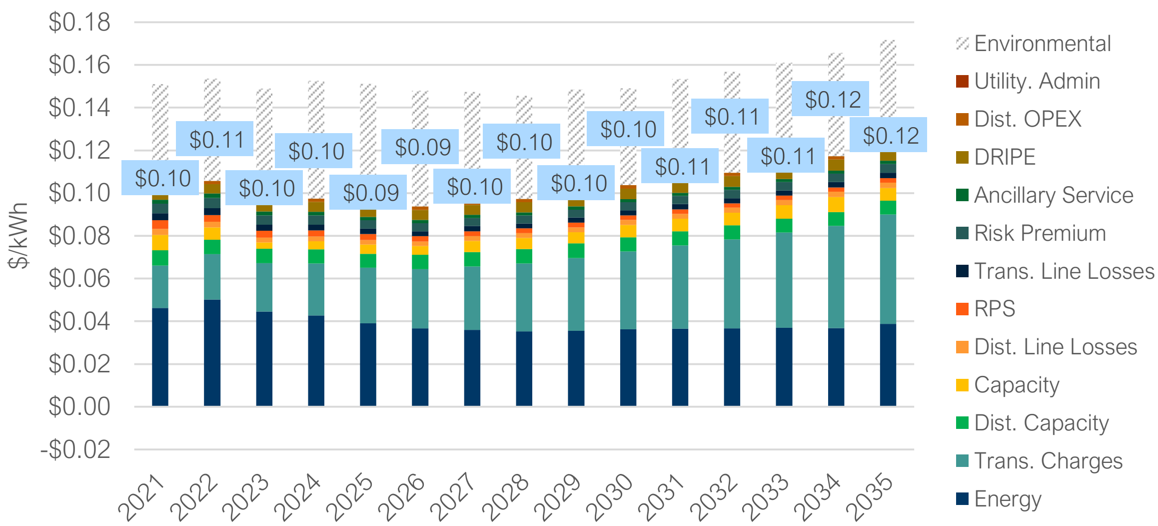
3 Results

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]

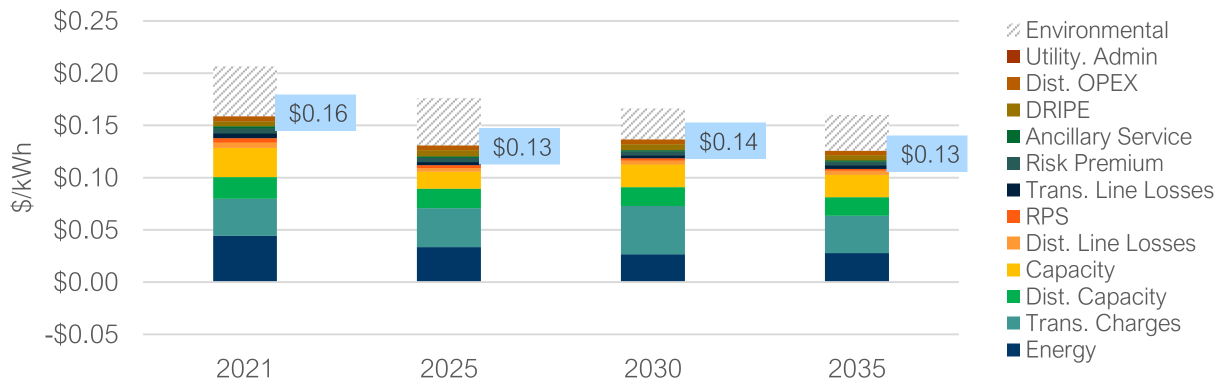
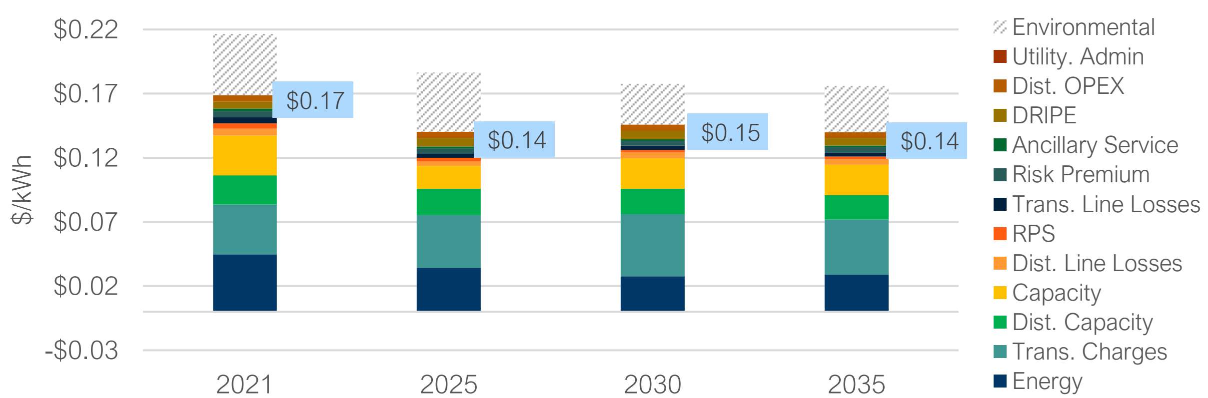


Figure 11. Average Annual Avoided Cost Value for Residential West-Facing Solar PV Array Installed in 2021 (2021$)[a]



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-

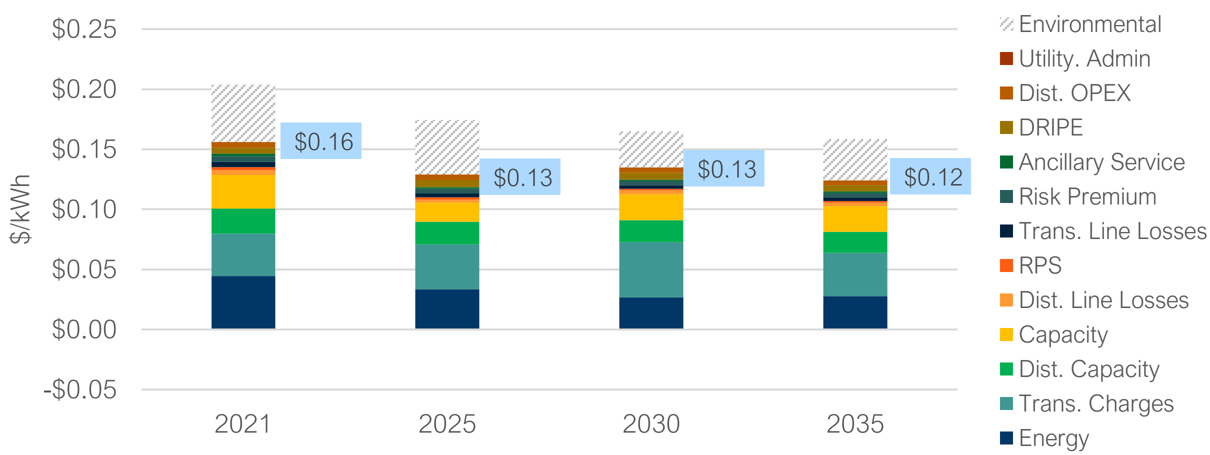
[38] When considering all study years, not only those highlighted in the graphs above, and excluding environmental externalities.

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).

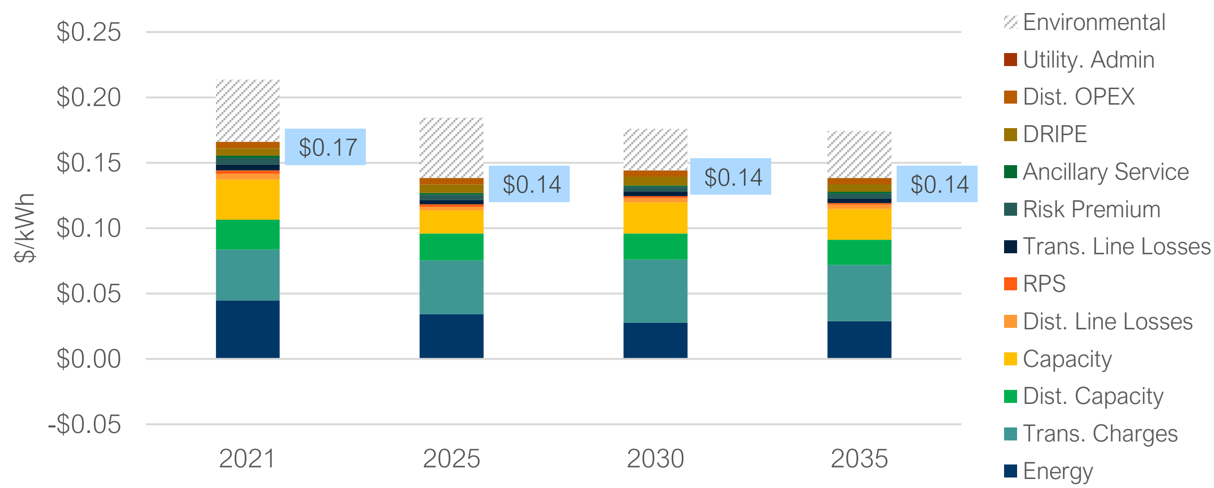
Figure 12 and Figure 13 below show the average annual avoided cost value of commercial south-facing and west-facing systems, respectively, for several years during the study period. The results shown are for systems installed in 2021, and all values are in real 2021 dollars.

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

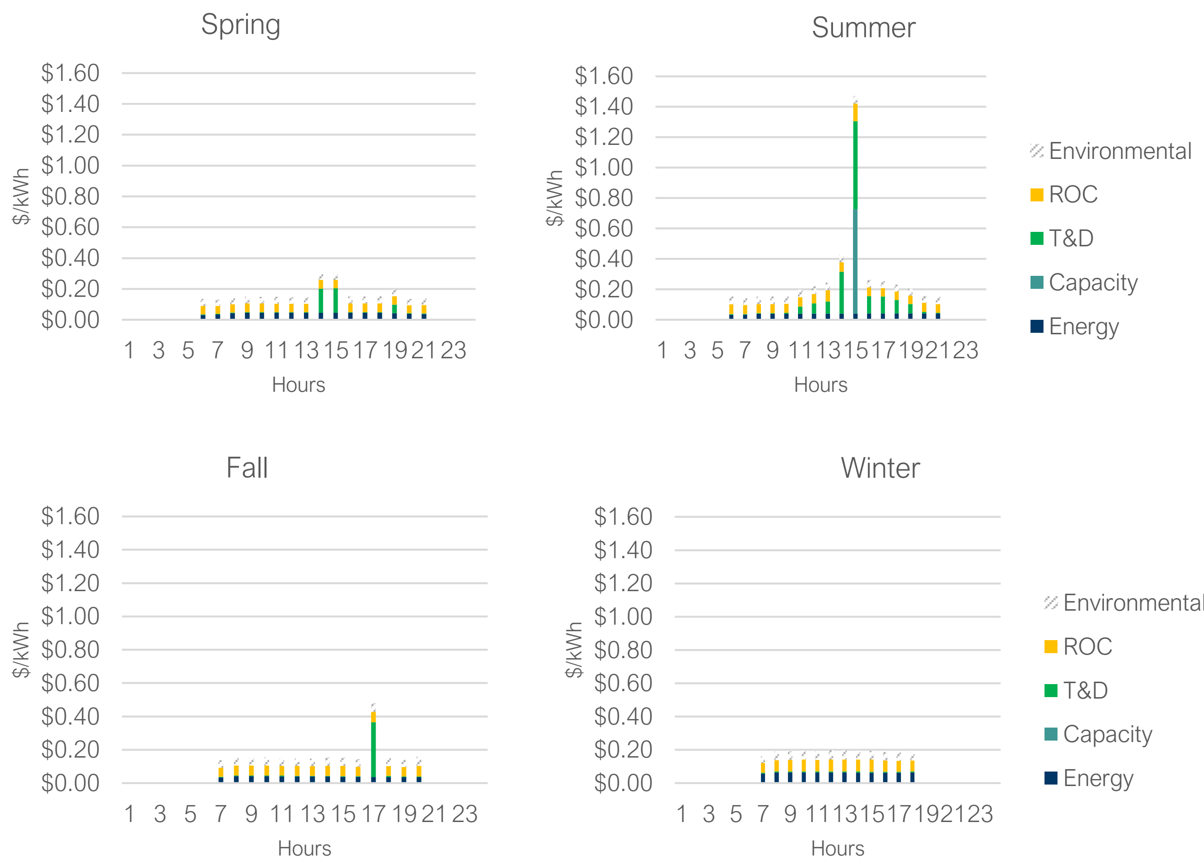
West-facing commercial solar PV systems produce 6%-10% more value than south-facing commercial solar PV systems, again due to their production having greater coincidence with evening system peaks. Commercial solar PV systems with the same orientation as residential systems have the same avoided costs 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

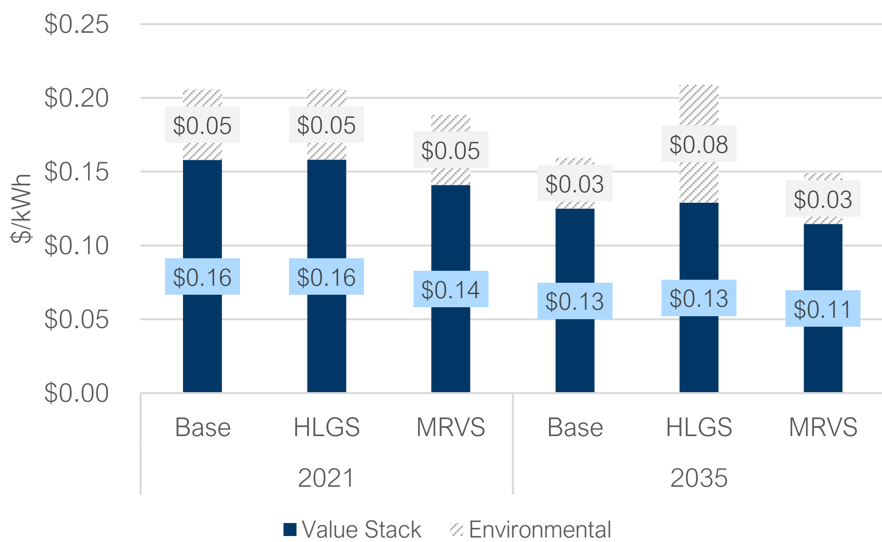
[43] The HLGS analysis includes three load growth scenarios which vary with respect to assumed levels of transportation and building electrification. Scenario 3 – the results of which are highlighted above – assumes higher-than-AESC transportation and building electrification. These scenarios are described 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

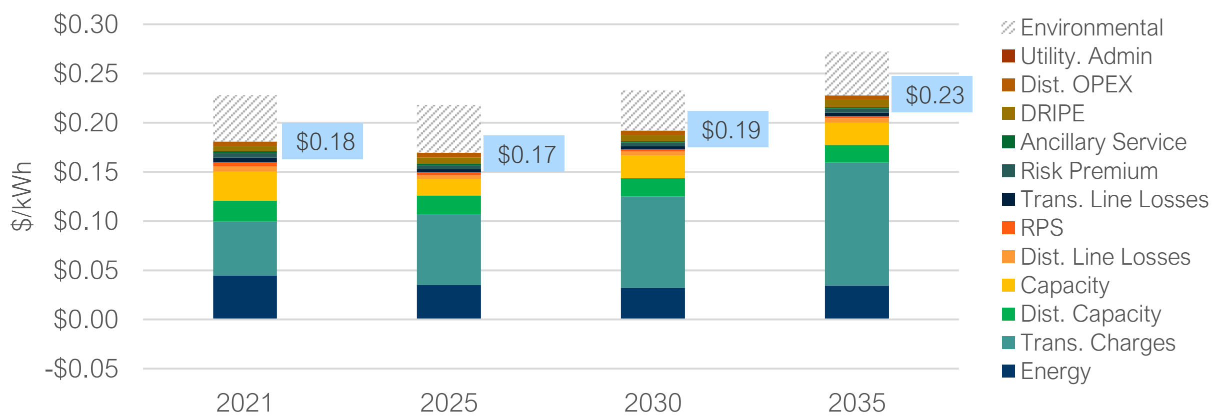
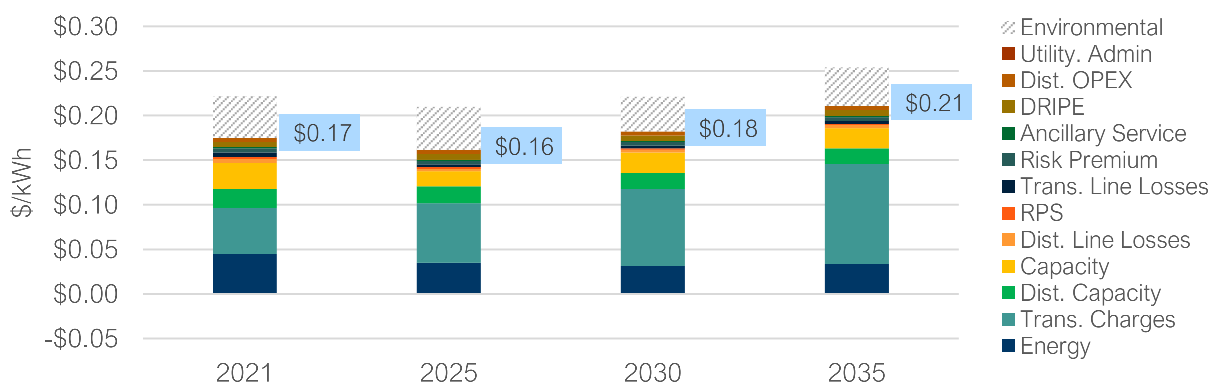


Figure 17. Average Annual Avoided Cost Value for Commercial South-Facing Solar PV Array Paired with Storage Installed in 2021 (2021$)[a]



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.

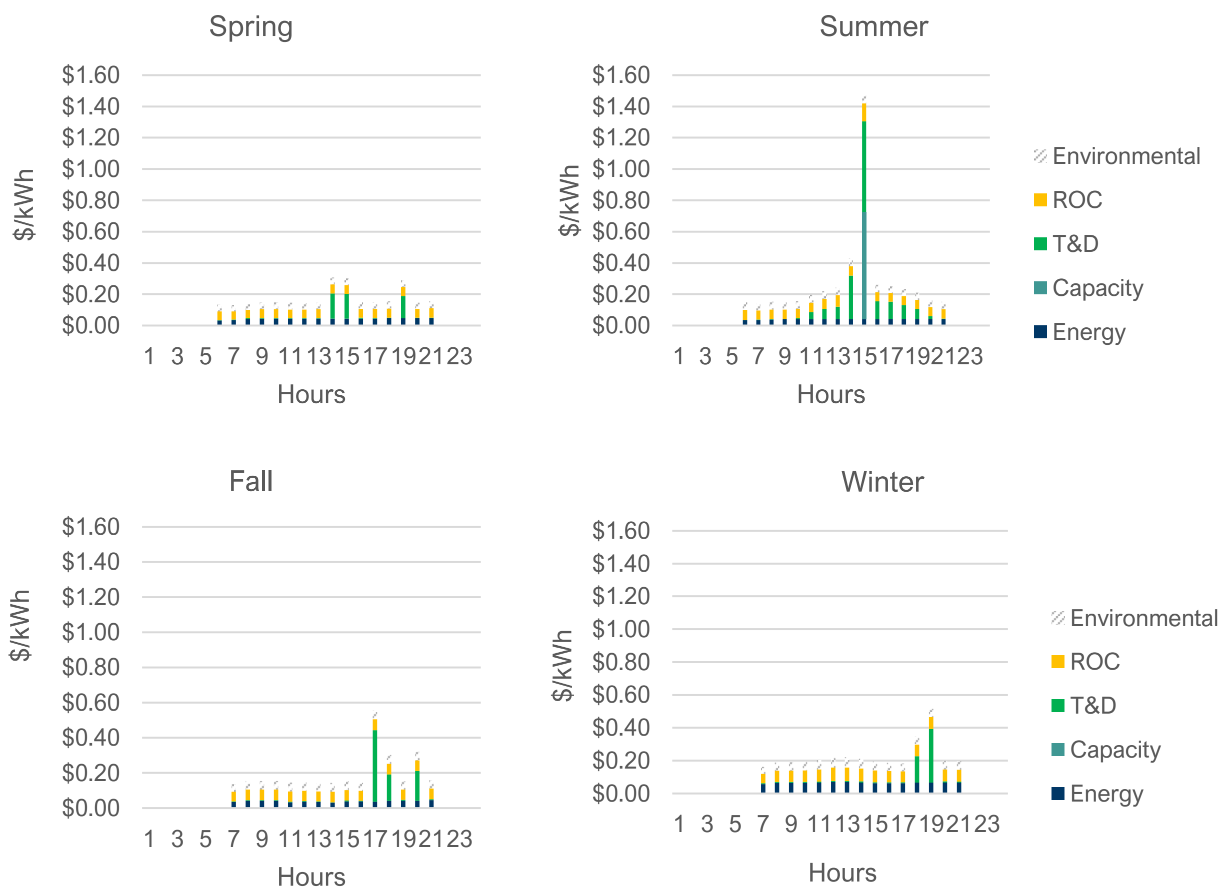
In any given year, residential solar PV systems paired with storage generate between 14% and 82% greater base avoided cost value than solar-only systems; commercial solar PV systems paired with storage generate 12% to 70% greater base avoided cost value.[47] The battery storage system is assumed to be 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.

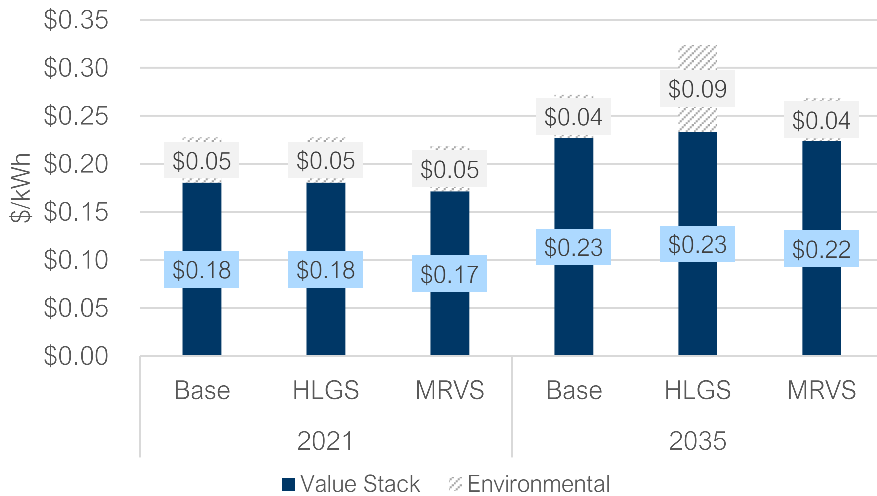
Figure 18. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Paired with Storage Installed in 2021, Year 2021 Shown (2021$)



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$)

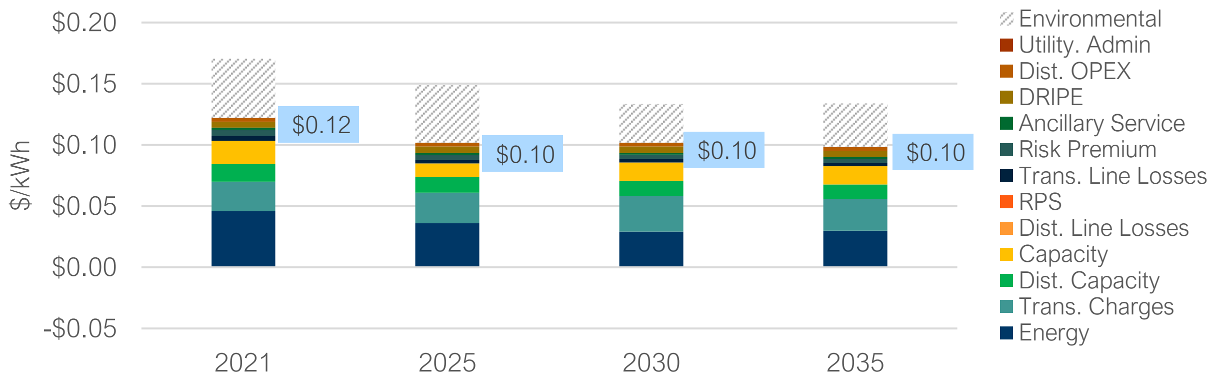


In 2021, the HLGS has approximately the same value (less than 1% difference) as the base value stack, excluding environmental externalities. This increases to nearly 3% higher value by 2035 - again, excluding environmental externalities – as increased transportation and building electrification load 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

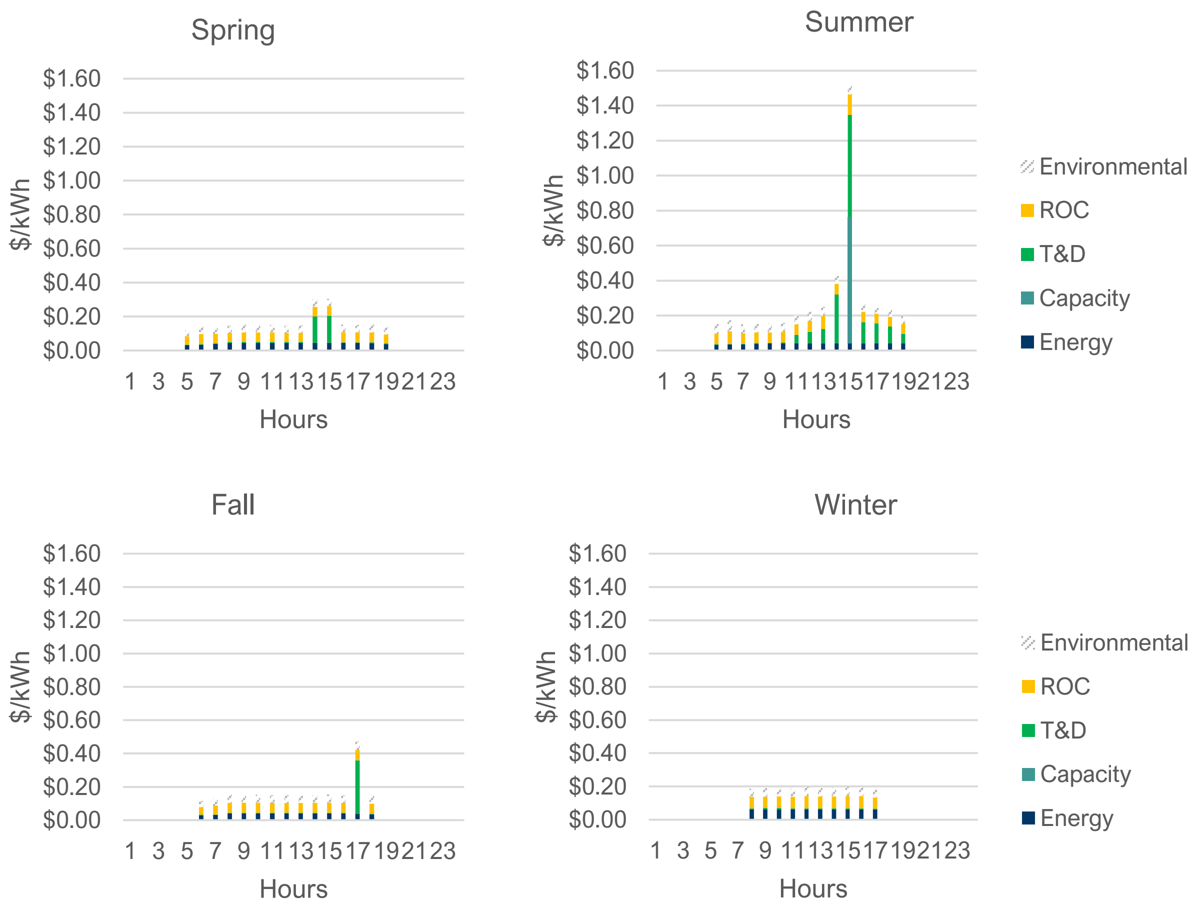
The LGHC solar avoided cost value trends mirror the residential and commercial solar-only system results, declining across the study period largely due to declining energy avoided costs. In a given year, LGHC avoided cost values are lower than residential or commercial systems. Because there is assumed 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.

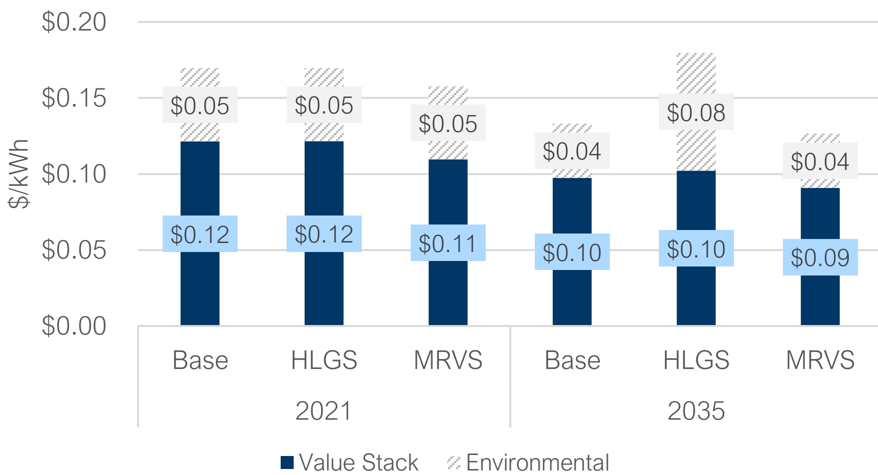
Figure 21. Average Hourly Seasonal Avoided Cost Values for Large Group Host Commercial Solar PV Array Installed in 2021, Year 2021 Shown (2021$)



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$)



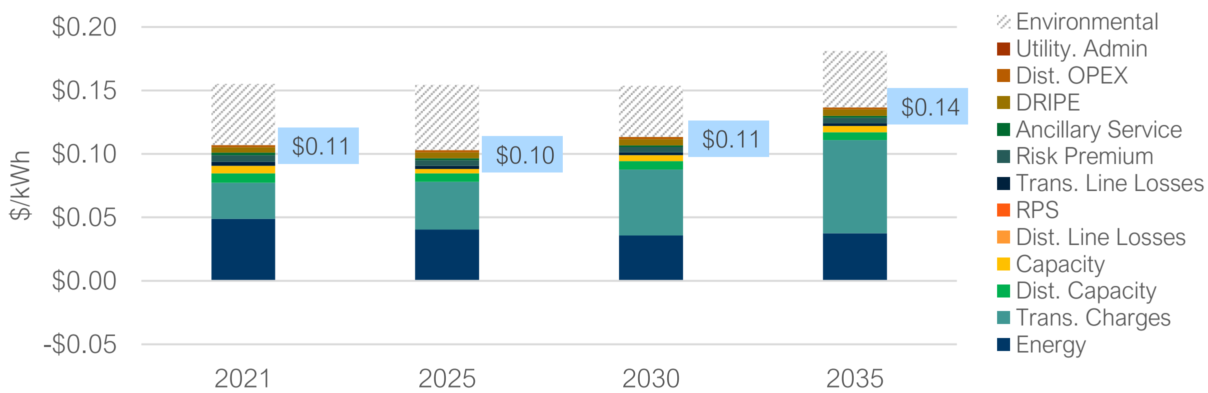
In 2021, the high load growth scenario has approximately the same value (less than 1% difference) as the base avoided cost value stack. In 2035, the high load growth scenario results in 5% higher value excluding environmental externalities. The value increases under the high load growth scenario as increased 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]

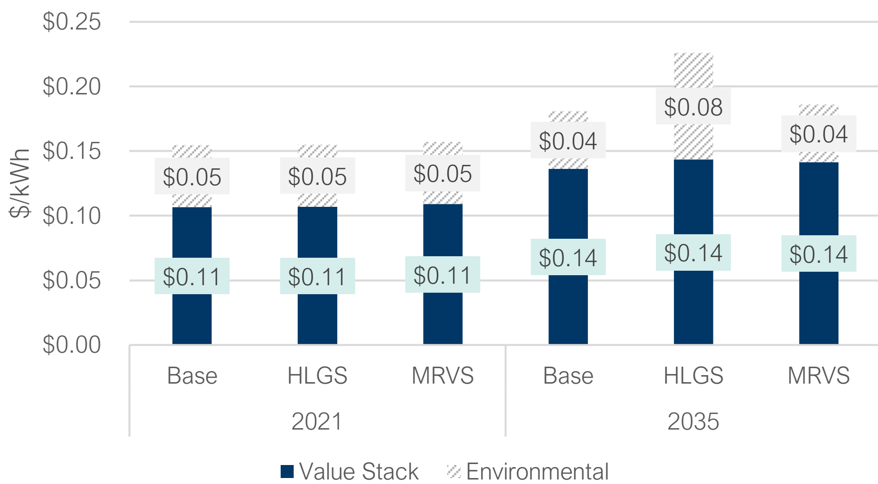
[53] The base avoided cost value stack refers to the value stack excluding environmental externalities.
[54] Here, T&D includes the following quantified avoided cost criteria: transmission charges, distribution capacity, distribution operating expense, transmission line losses, and distribution line 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.

---

[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.

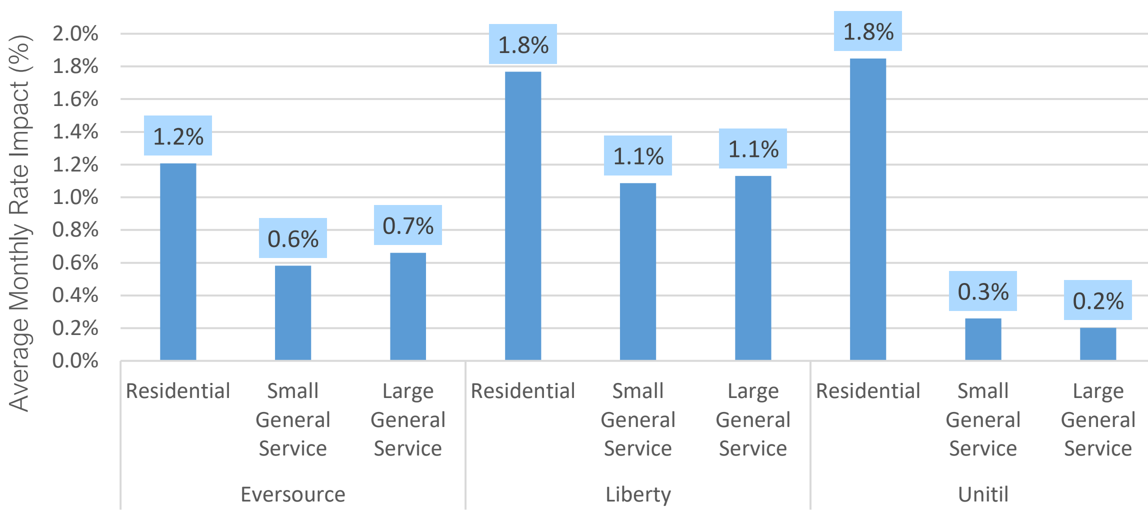
3.4.1.1 – Rate Impacts

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]

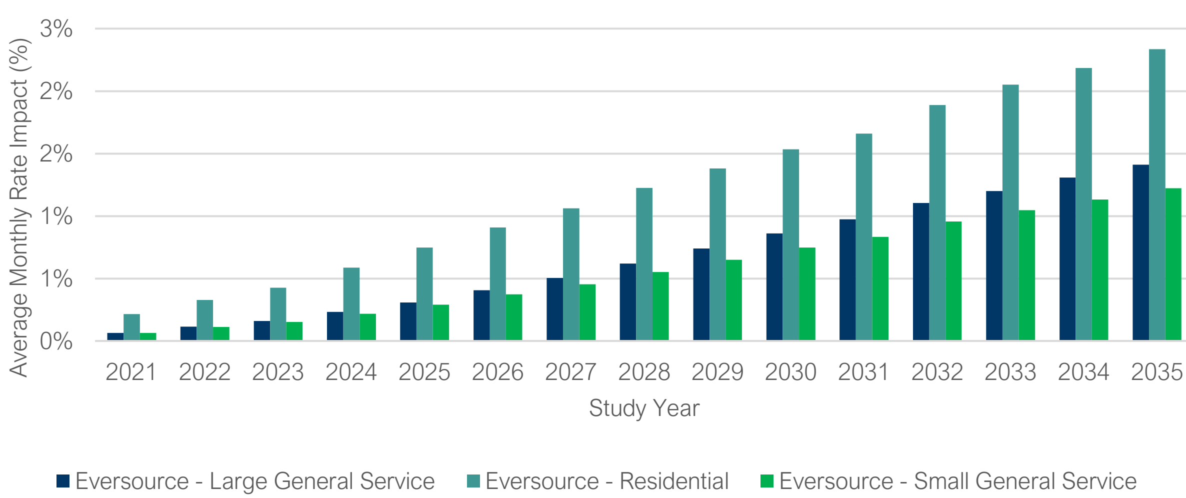
[66] New Hampshire Department of Energy. Net Energy Metering Tariff. Available online: https://www.energy.nh.gov/sites/g/files/ehbemt551/files/inline-documents/sonh/net-metering-tariff-2020-overview.pdf
[67] System archetype definitions are described in methodology section 2.6.1 – Define DG System Archetypes 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.

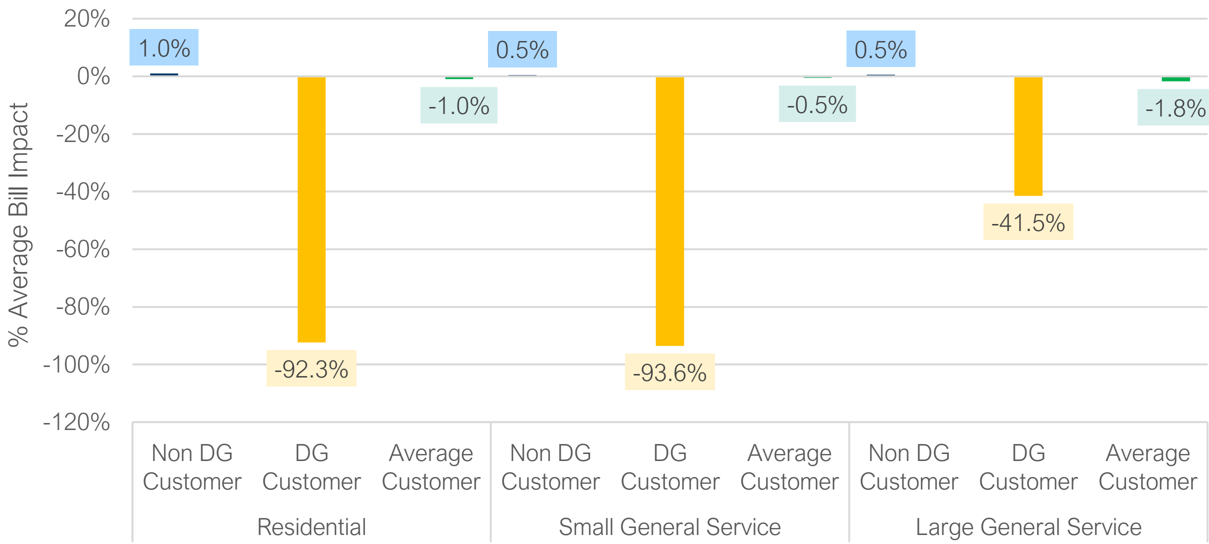
Figure 27. Average Monthly Rate Impact for Utility Customers in Eversource Territory Under NEM Scenario (Relative to no-DG scenario)



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.

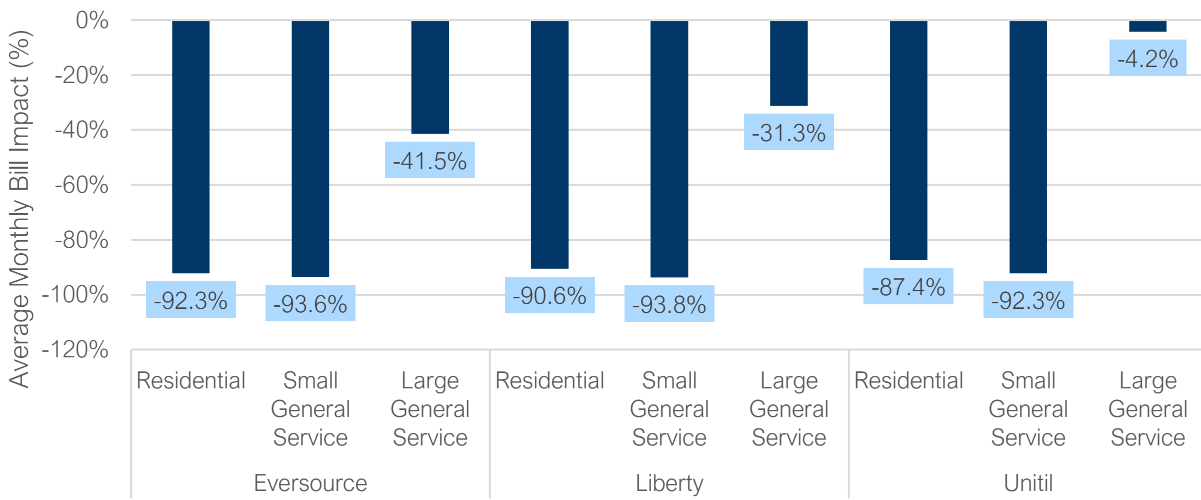
DG Customers

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]

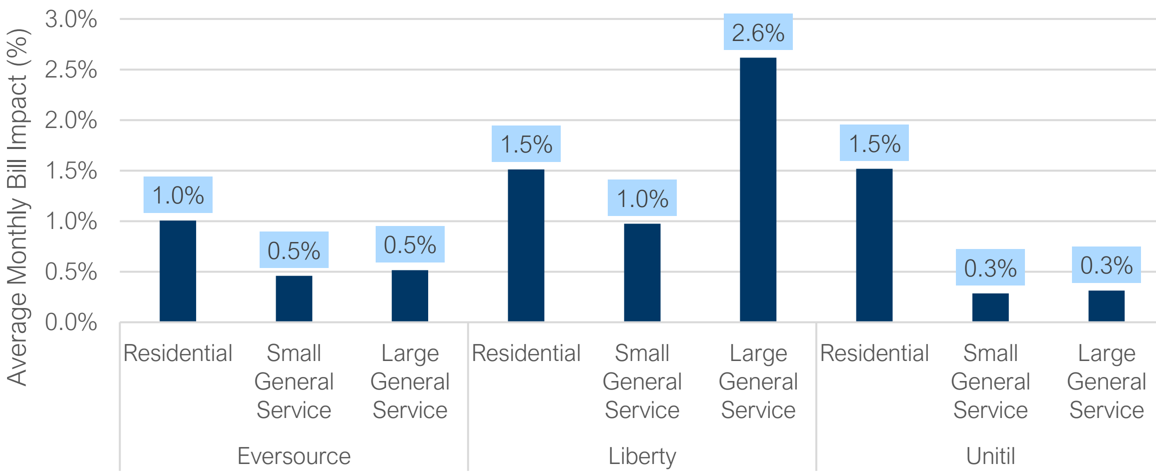


Non-DG Customers

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]

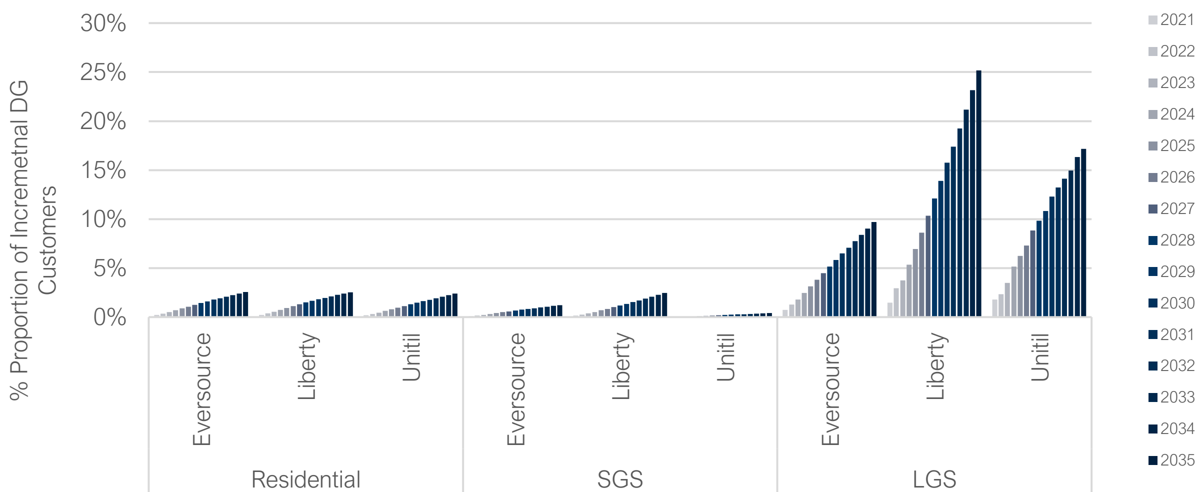


Average Customers

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.

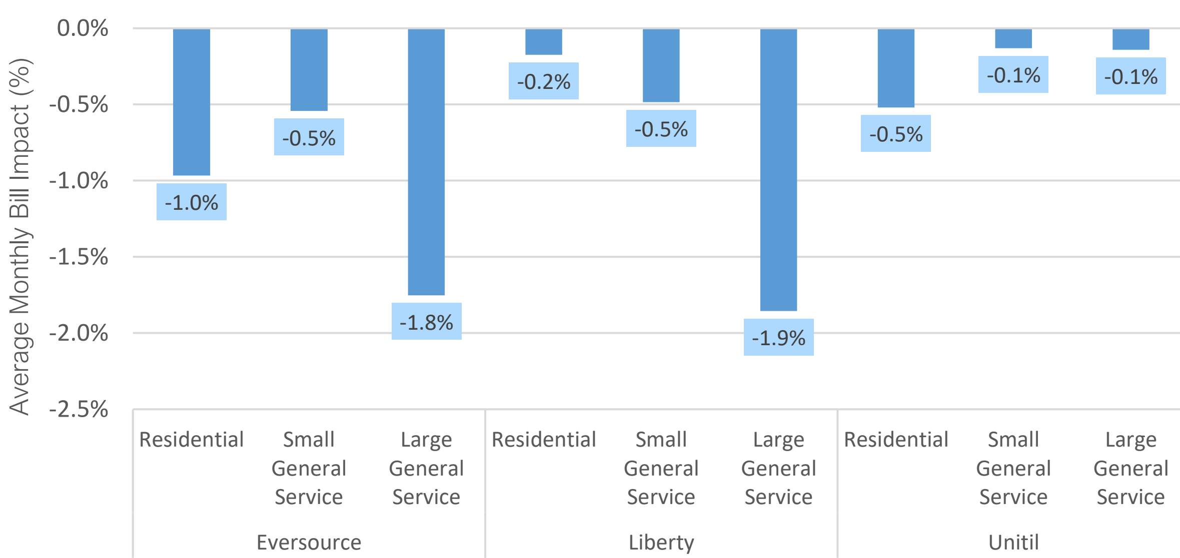
[72] Averaged across the study period

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.

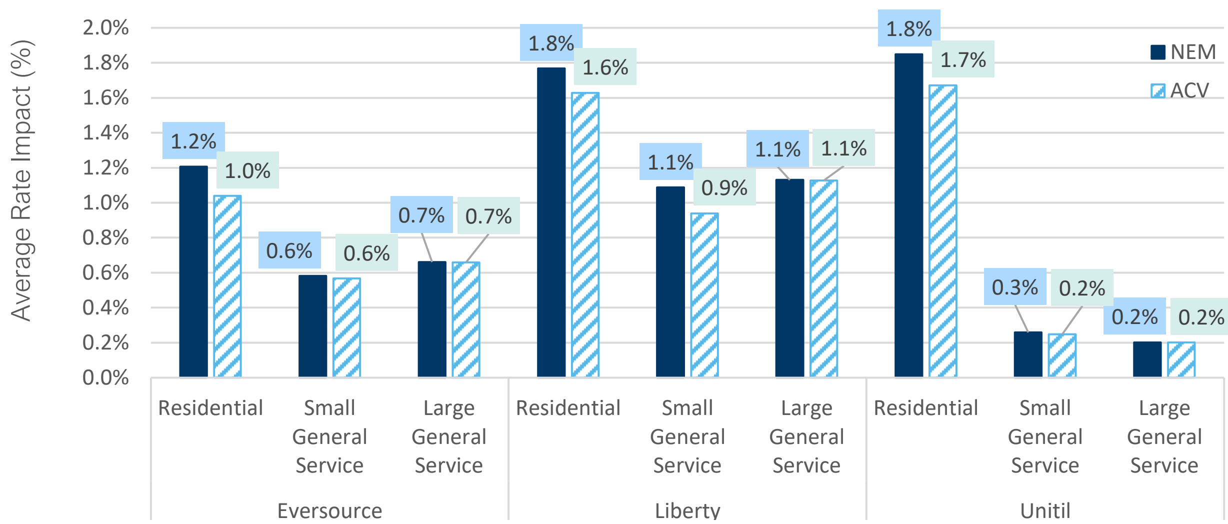
It is important to note that the analysis <u>does not</u> consider any impacts that the transition to an ACV Tariff compensation model may have on DG economics and deployment trends in New Hampshire (i.e., the same level of future DG deployment is assumed under both scenarios).

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]



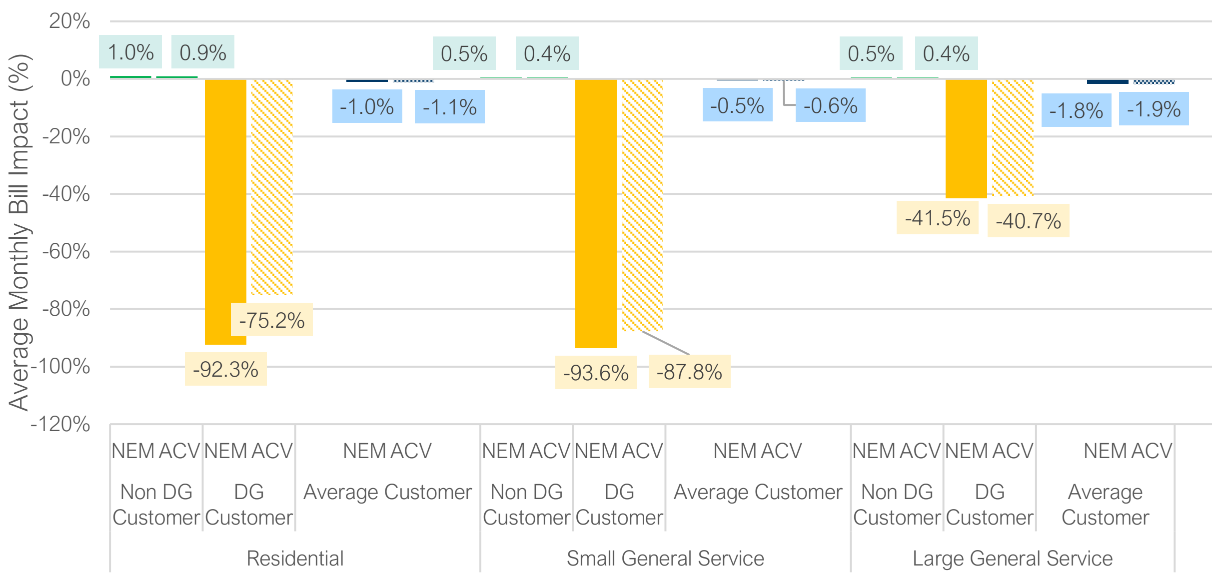
3.4.2.2 – Bill Impacts

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]

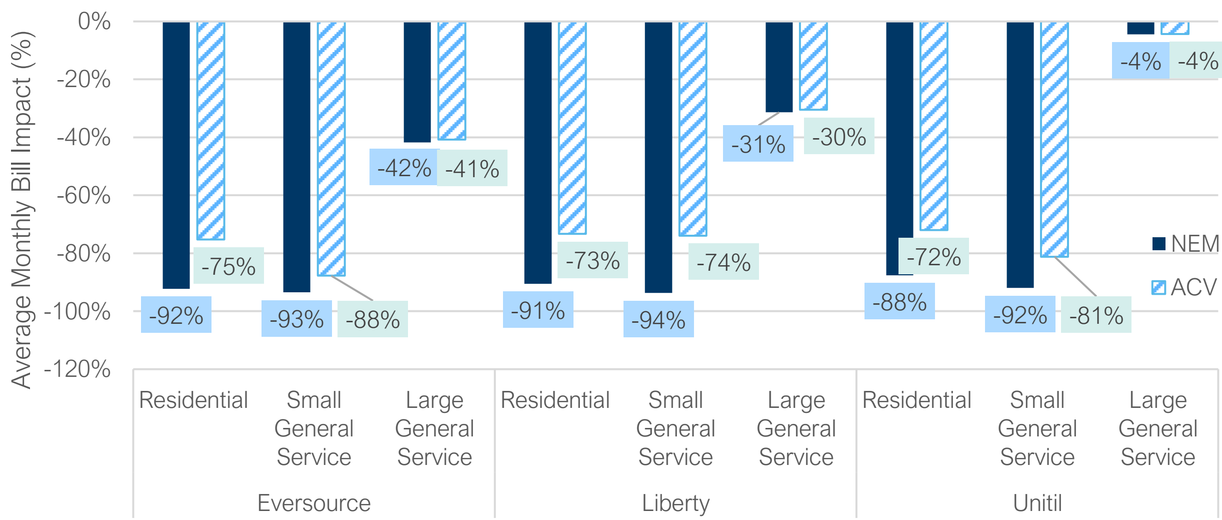


DG Customers

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

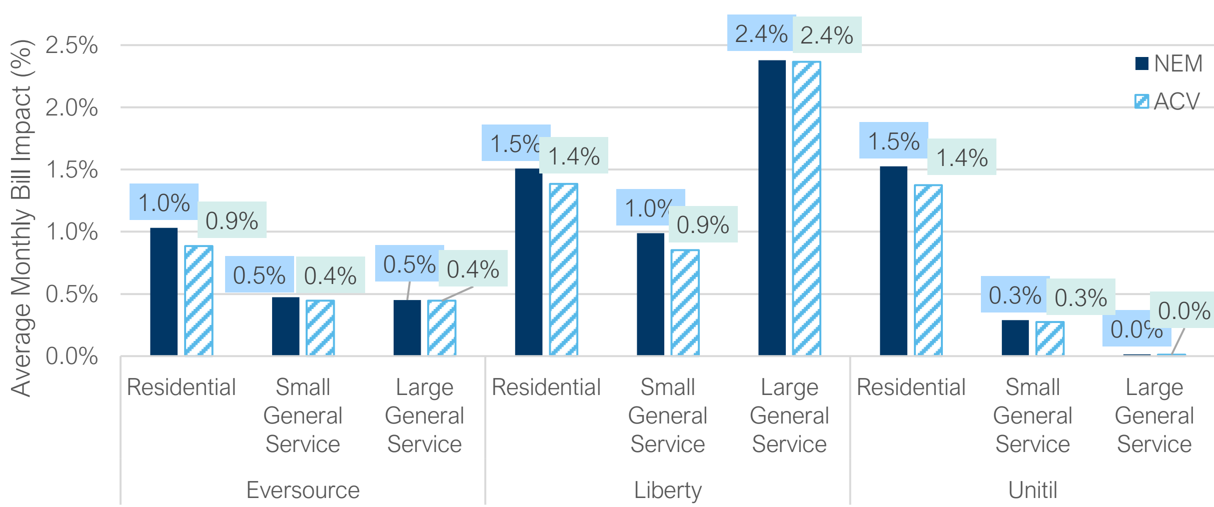
Figure 35. Average Monthly Bill Impact for DG Customer Under NEM and ACV Scenarios (2021-2035)(Relative to no-DG Scenario)[78]



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]

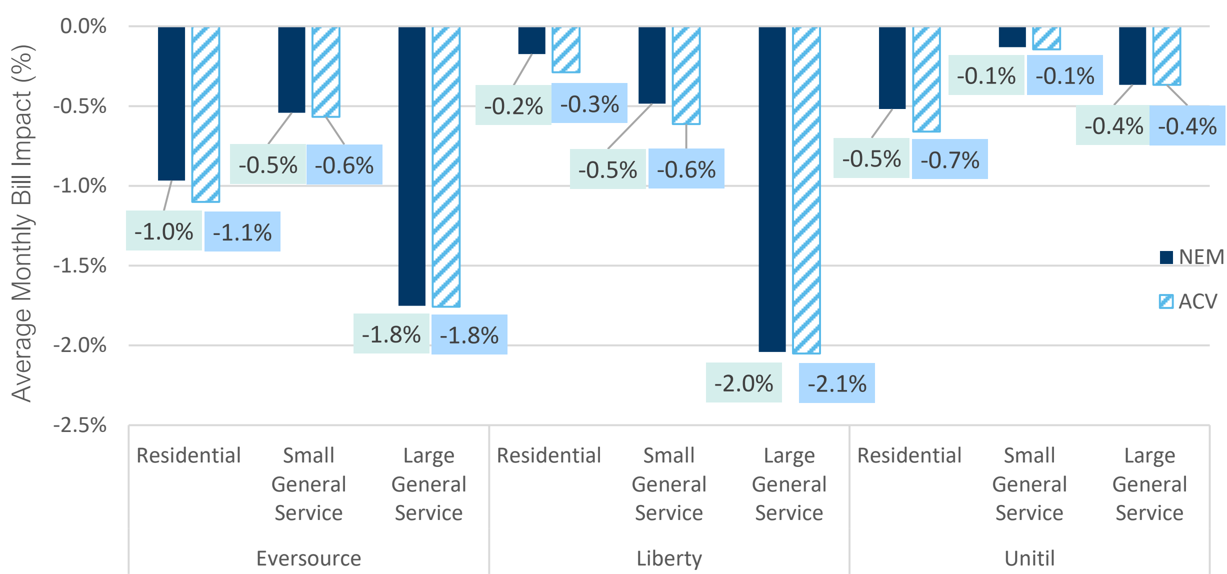


[78] Averaged across the study period
[79] ibid

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$)

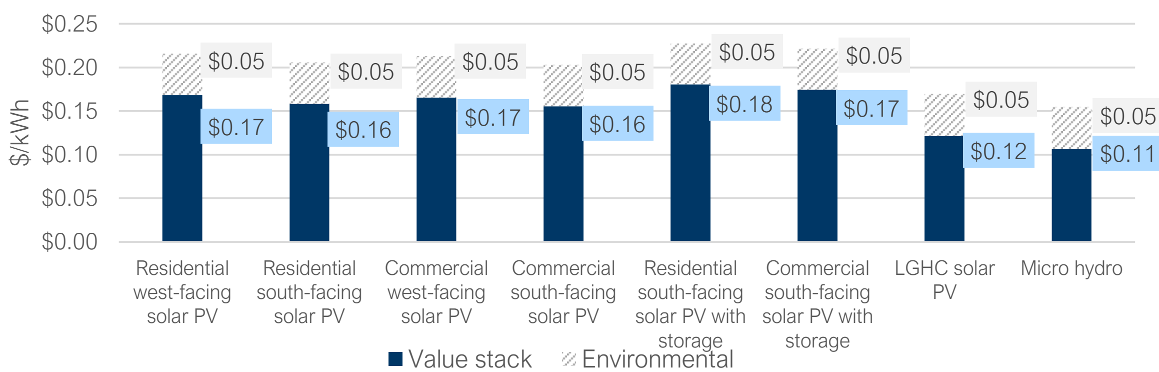
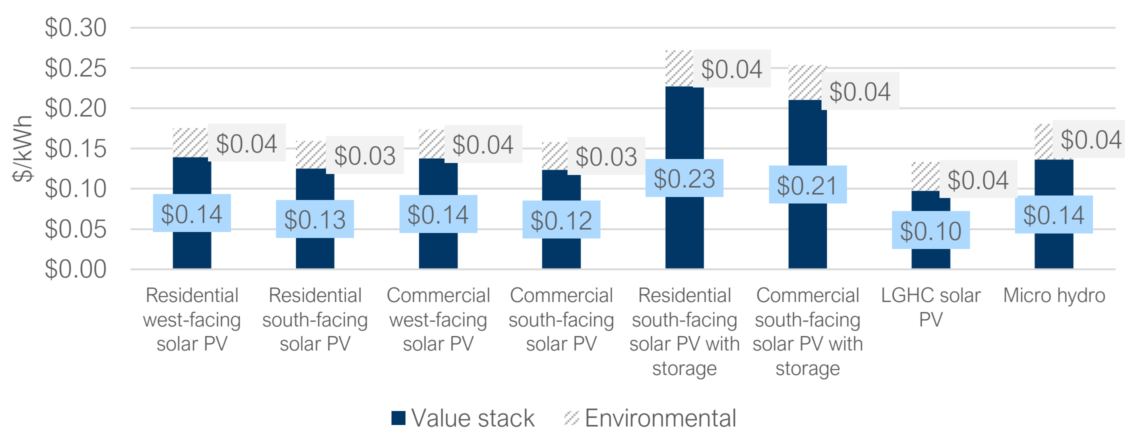


Figure 39. Average Annual Value Stack with Environmental Externalities Sensitivity by DG System, 2035 (2021$)



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$)

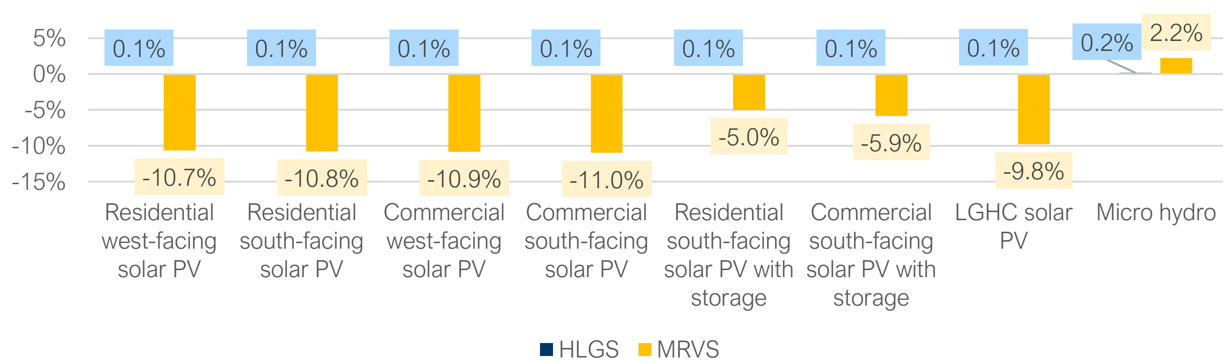
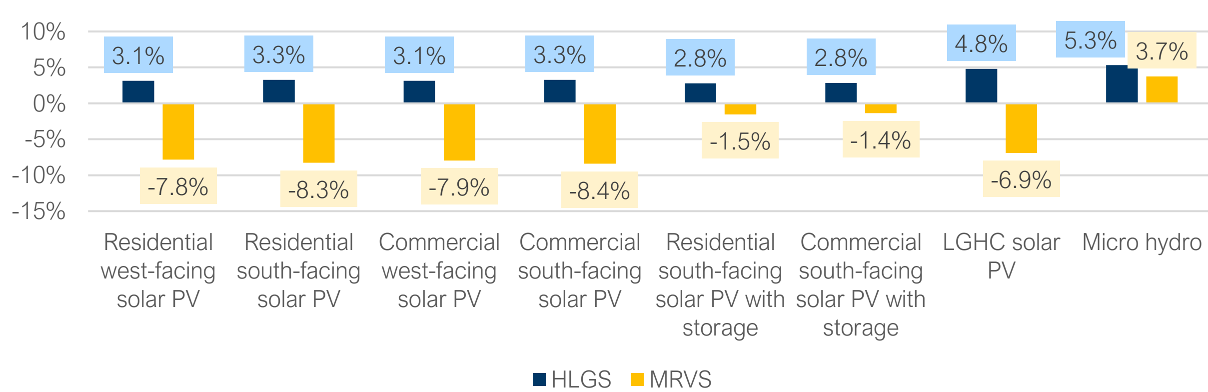


Figure 41. Average Annual Change from Baseline Value Stack Under the HLGS and MRVS, 2035 (2021$)

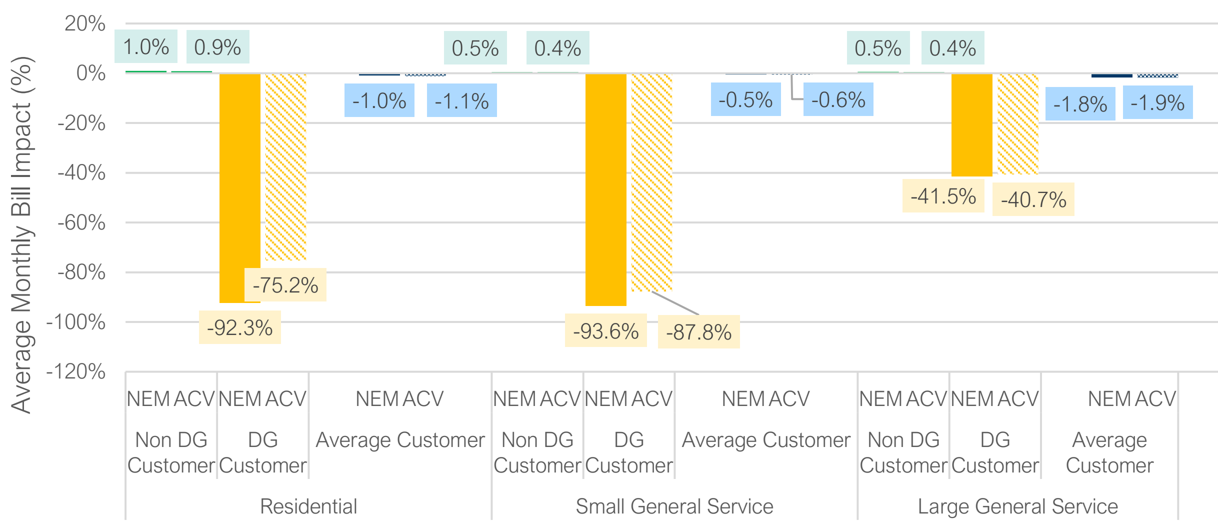


Net-metered DERs are expected to provide additional value beyond what is shown here, notably for those value stack criteria addressed qualitatively in this study: transmission capacity (for non-pool transmission facilities), transmission and distribution system upgrades, distribution grid support services,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

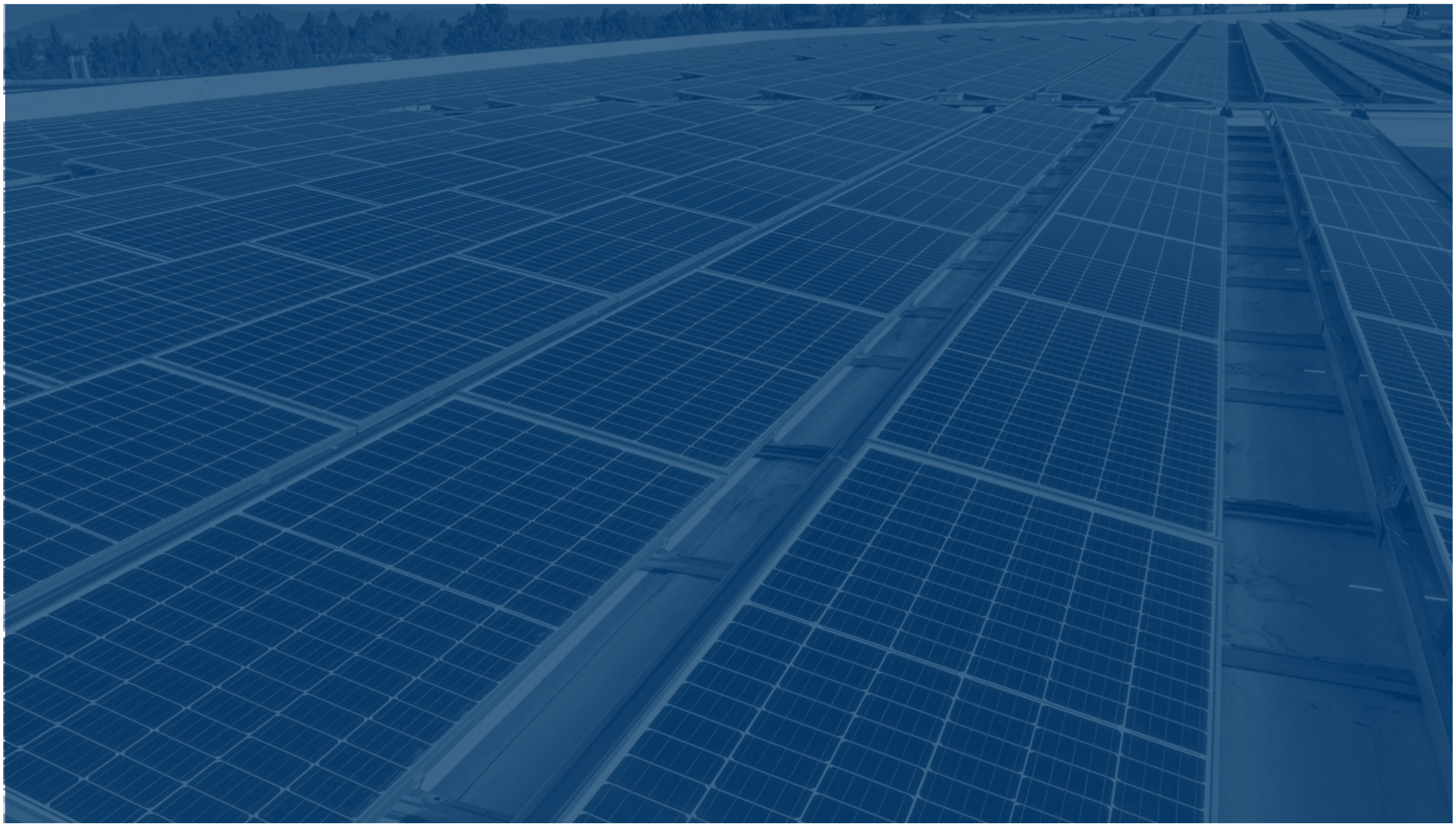
Customer installed costs are included in this study. In the future, these costs may be used to evaluate how NEM crediting and compensation may affect reasonable opportunities to invest in DG and receive fair compensation, as contemplated by House Bill 1116 (2016).[81]

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)



[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



New Hampshire Value of Distributed Energy Resources

Appendices

Submitted to:

New Hampshire Department of Energy

www.energy.nh.gov

Prepared by:

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

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

With support from Power Advisory

About Dunsky

Founded in 2004, Dunsky supports leading governments, utilities, corporations and non-profits across North America in their efforts to **accelerate the clean energy transition**, effectively and responsibly.

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).

Dunsky is proudly Canadian, with offices and staff in Montreal, Toronto, Vancouver, Ottawa and Halifax.

Table of Contents

A. DER Production Profiles

Figure 1. 8,760 Profile for Residential South-Facing Solar PV Array,7.8 kW DC (6.5 kW AC), Azimuth 180, tilt 37.86, assumed location: Concord, New Hampshire

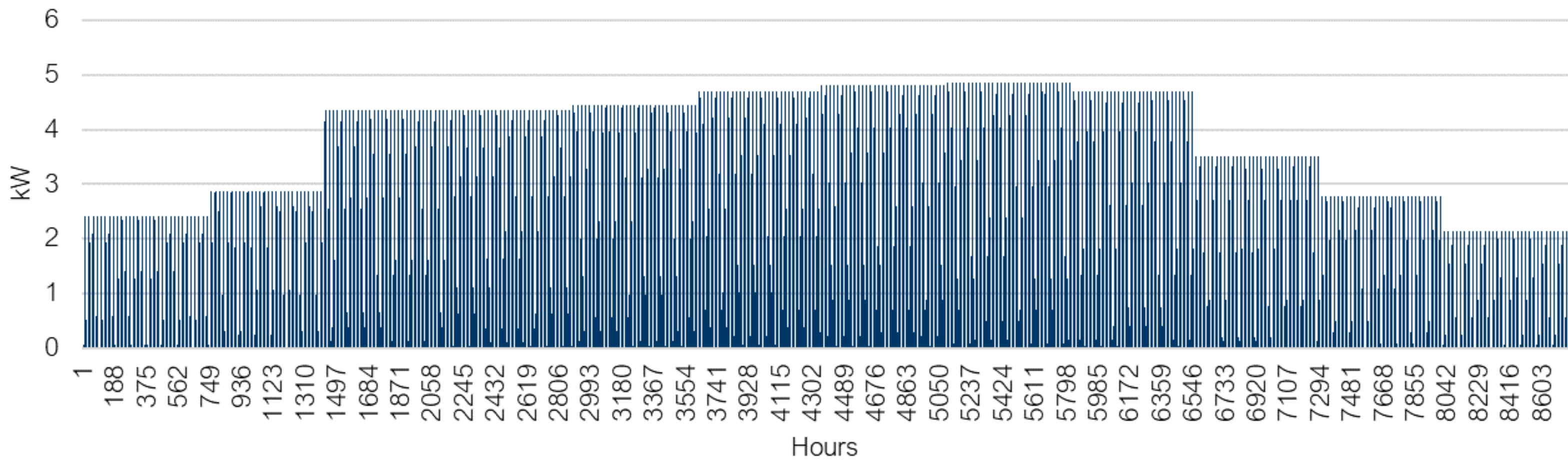


Figure 2. 8,760 Profile for Residential West-Facing Solar PV Array, 7.8 kW DC (6.5 kW AC), Azimuth 270, tilt 37.86, assumed location: Concord, New Hampshire

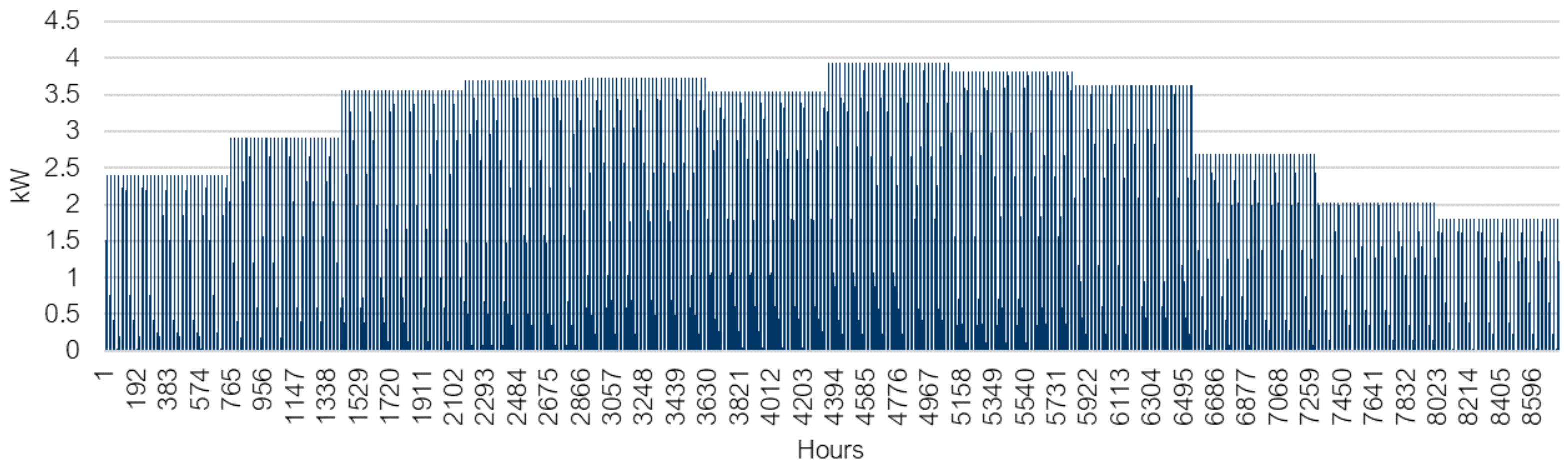


Figure 3. 8,760 Profile for Commercial South-Facing Solar PV Array, 36 kW DC (30 kW AC), Azimuth 180, tilt 37.86, assumed location: Concord, New Hampshire

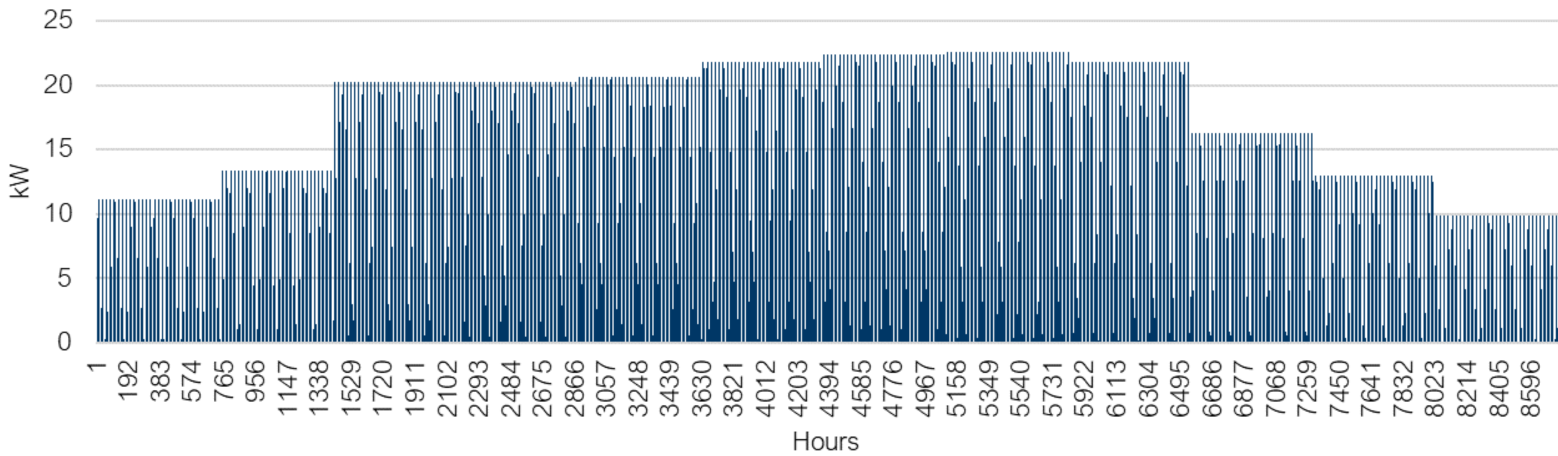


Figure 4. 8,760 Profile for Commercial West-facing Solar PV Array, 36 kW DC (30 kW AC), Azimuth 270, tilt 37.86, assumed location: Concord, New Hampshire

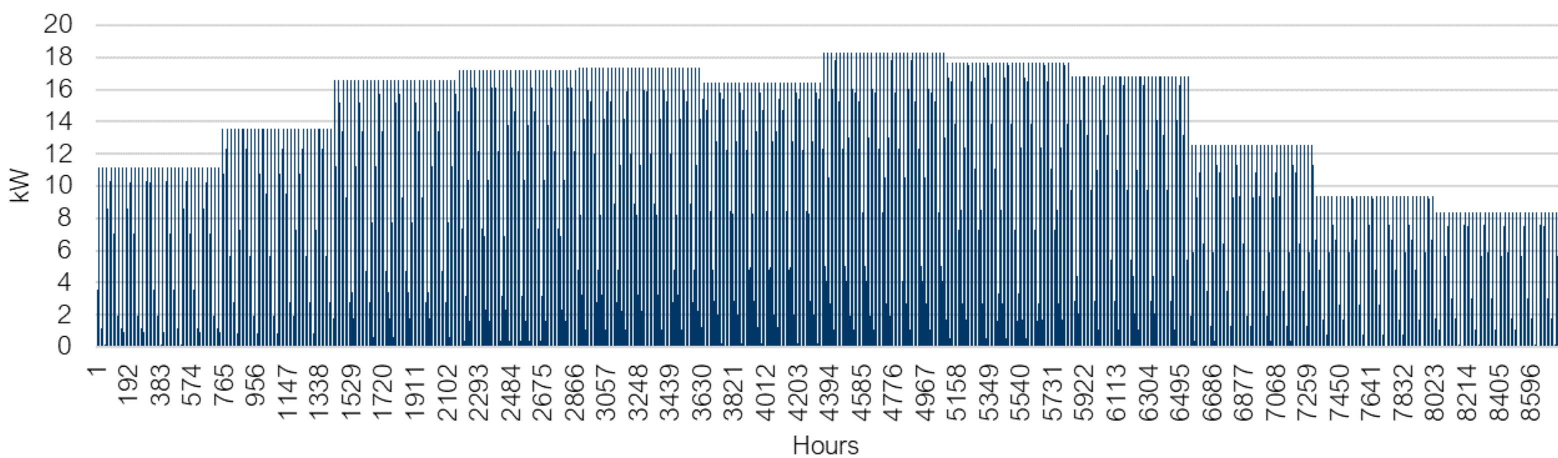


Figure 5. 8,760 Profile for Residential South-Facing Solar PV Array Paired with Storage, 7.8 kW DC (6.5 kW AC), 4-hour duration 10 kWh/2.5kW storage system, Azimuth 180, tilt 37.86, assumed location: Concord, New Hampshire

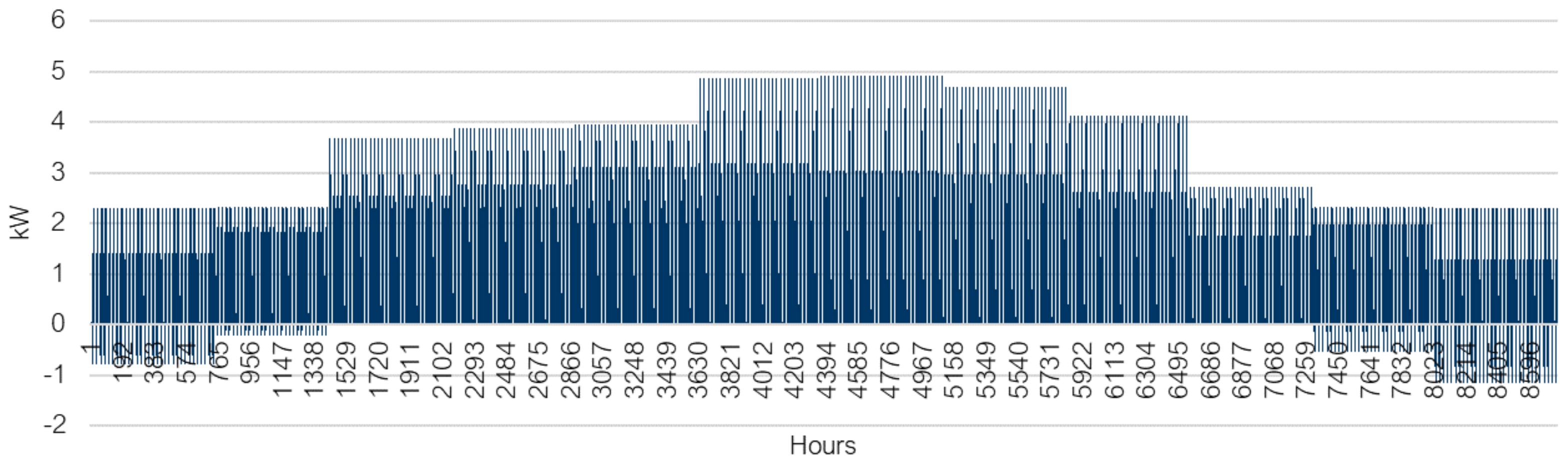


Figure 6. 8,760 Profile for Commercial South-facing Solar Paired with Storage, 36 kW DC Solar (30 kW AC), 4-hour duration 40 kWh/10kW storage system, Azimuth 180, tilt 37.86, assumed location: Concord, New Hampshire

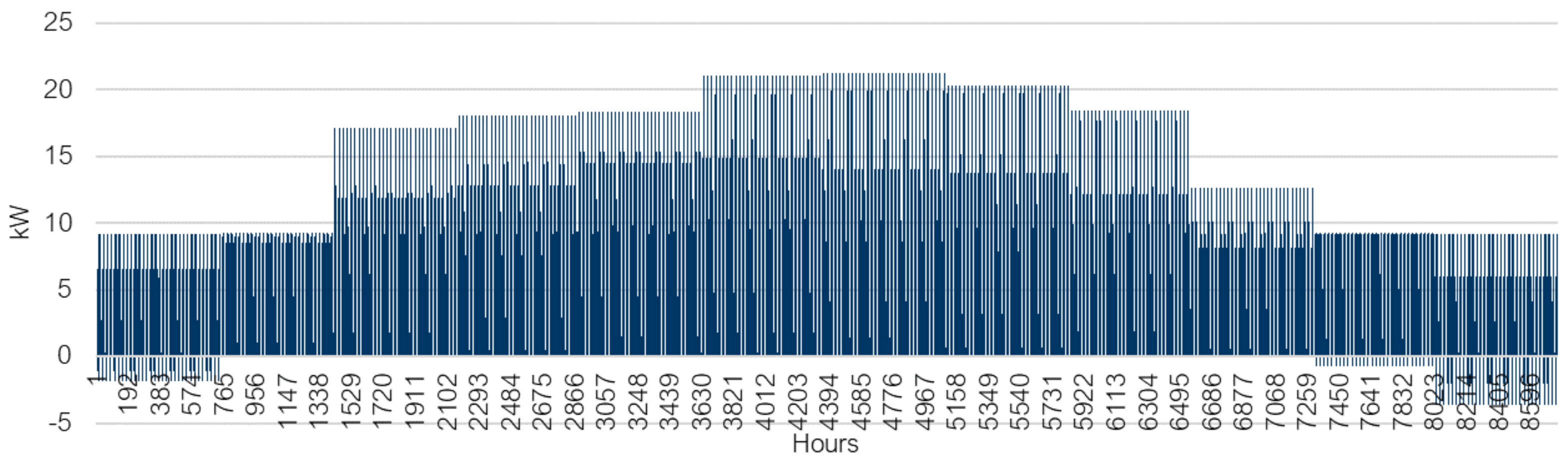


Figure 7. 8,760 Profile for Large Group Host Commercial Solar, 195 kW DC (162 kW AC), Azimuth 180, tilt 37.86, assumed location: Concord, New Hampshire

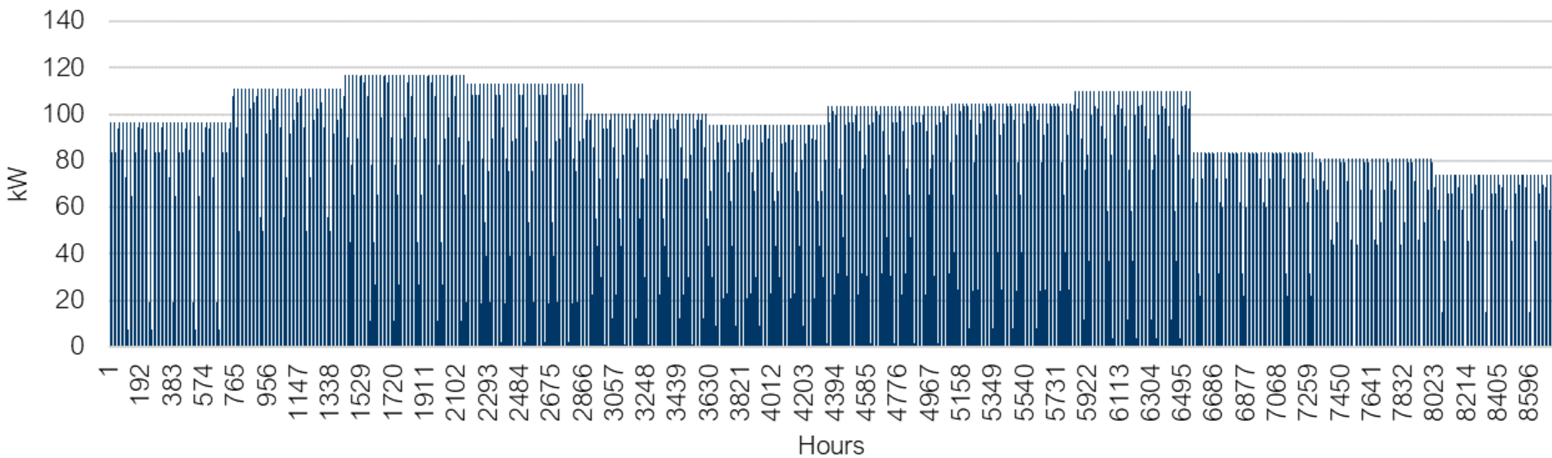
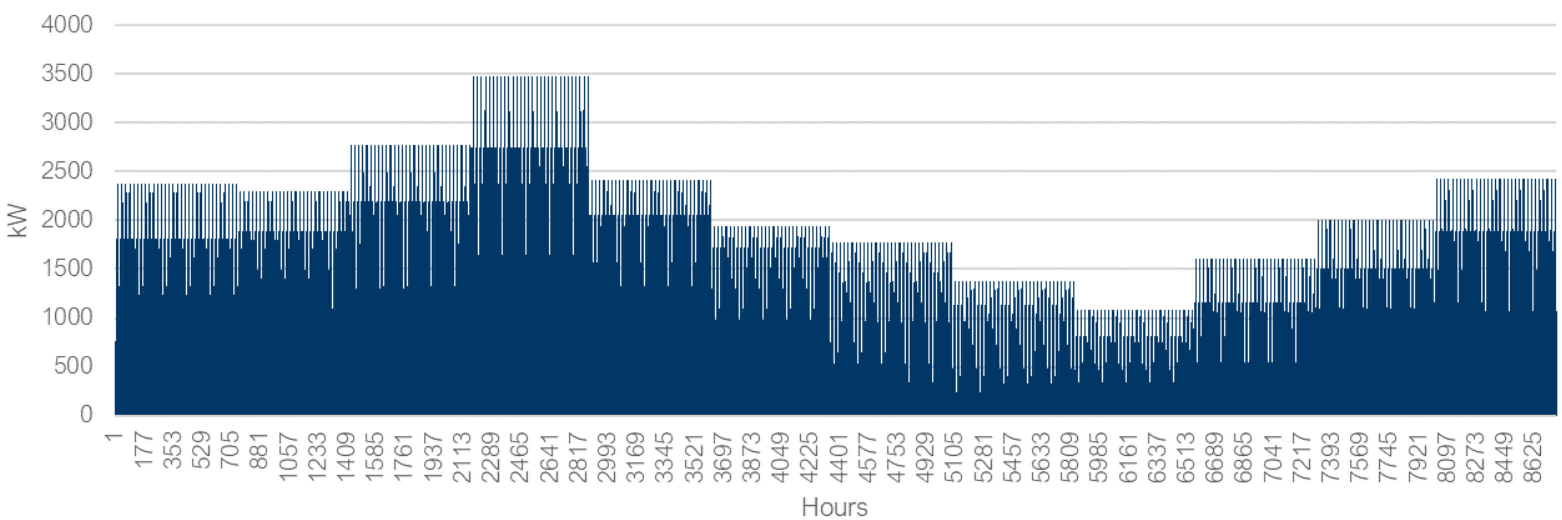


Figure 8. 8,760 Profile for Micro Hydro, 3 MW



B. Results Tables

B.1 Technology-Neutral Value Stack

Table 1. Average Annual Technology-Neutral Value Stack ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.046	0.050	0.045	0.043	0.039	0.037	0.036	0.035	0.036	0.036	0.037	0.037	0.037	0.037	0.039
Transmission Charges	0.020	0.021	0.023	0.024	0.026	0.028	0.030	0.032	0.034	0.036	0.039	0.042	0.045	0.048	0.051
Distribution Capacity	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.006	0.006
Capacity	0.007	0.006	0.003	0.004	0.004	0.004	0.005	0.005	0.005	0.006	0.006	0.006	0.006	0.007	0.006
Distribution Line Losses	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.003	0.002
RPS	0.004	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Transmission Line Losses	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.003	0.003
Risk Premium	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.002
DRIPE	0.004	0.004	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Distribution OPEX	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Utility Admin	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Environmental Externality	0.049	0.048	0.051	0.055	0.056	0.054	0.051	0.048	0.048	0.045	0.047	0.047	0.048	0.048	0.050
Total – Excluding Environmental	0.102	0.105	0.097	0.097	0.095	0.093	0.096	0.097	0.100	0.103	0.106	0.109	0.113	0.117	0.122
Total – Including Environmental	0.151	0.153	0.149	0.152	0.151	0.148	0.147	0.145	0.148	0.149	0.153	0.157	0.161	0.165	0.171

Table 2. Average Annual Technology-Neutral Value, Minimum Hourly Value, and Maximum Hourly Value ($/kWh) (2021$)

	2021			2025			2030			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)	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	0.009	0.077	0.036	-0.008	0.144	0.039	-0.008	0.159
Transmission Charges	0.020	0.000	14.945	0.026	0.000	19.453	0.036	0.000	27.334	0.051	0.000	38.407

Distribution Capacity	0.007	0.000	0.667	0.007	0.000	0.614	0.007	0.000	0.613	0.006	0.000	0.602
Capacity	0.007	0.000	63.000	0.004	0.000	37.000	0.006	0.000	51.000	0.006	0.000	52.000
Distribution Line Losses	0.003	0.000	7.674	0.002	0.000	4.982	0.002	0.000	5.760	0.002	0.000	5.873
RPS	0.004	0.004	0.004	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002
Transmission Line Losses	0.003	0.000	4.474	0.003	0.000	2.905	0.002	0.000	3.358	0.003	0.000	3.424
Risk Premium	0.005	0.001	1.151	0.004	0.000	1.009	0.004	-0.001	0.644	0.004	-0.001	0.726
Ancillary Services	0.002	0.001	0.005	0.002	0.000	0.005	0.001	-0.001	0.006	0.002	-0.001	0.009
DRIPE	0.004	0.001	4.954	0.005	0.000	7.116	0.005	-0.001	8.037	0.005	-0.001	8.541
Distribution OPEX	0.002	0.000	0.149	0.002	0.000	0.149	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	0.000	-0.002	0.000	0.000	-0.002	0.000
Environmental Externality	0.049	-0.069	0.350	0.056	-0.008	0.160	0.045	0.000	0.119	0.050	0.000	0.112

B.2 Residential and Commercial Solar PV

Table 3. Average Annual Avoided Cost Value for Residential South-Facing Solar PV Array Installed in 2021 ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.044	0.046	0.040	0.038	0.033	0.030	0.029	0.027	0.027	0.027	0.026	0.026	0.026	0.026	0.028
Transmission Charges	0.035	0.038	0.040	0.036	0.037	0.040	0.038	0.041	0.043	0.046	0.049	0.041	0.035	0.037	0.036
Distribution Capacity	0.021	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.018	0.018	0.018	0.018	0.018	0.018
Capacity	0.028	0.022	0.011	0.015	0.016	0.016	0.019	0.019	0.020	0.022	0.022	0.022	0.023	0.025	0.021
Distribution Line Losses	0.005	0.005	0.003	0.004	0.004	0.003	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
RPS	0.004	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Transmission Line Losses	0.005	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Risk Premium	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.003	0.003	0.004	0.004	0.004	0.004	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.005	0.005	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.005	0.005	0.005	0.005	0.005
Distribution OPEX	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Utility Admin	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)
Environmental Externality	0.048	0.046	0.047	0.048	0.045	0.040	0.037	0.033	0.032	0.030	0.030	0.030	0.031	0.032	0.034

Total – Excluding Environmental	0.158	0.153	0.136	0.132	0.130	0.127	0.129	0.129	0.131	0.136	0.138	0.129	0.124	0.129	0.125
Total – Including Environmental	0.206	0.200	0.183	0.180	0.176	0.167	0.166	0.162	0.164	0.166	0.168	0.159	0.155	0.161	0.159

Table 4. Average Annual Avoided Cost Value for Residential West-Facing Solar PV Array Installed in 2021 ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.045	0.047	0.041	0.039	0.034	0.031	0.030	0.028	0.028	0.028	0.028	0.027	0.027	0.027	0.029
Transmission Charges	0.039	0.041	0.044	0.039	0.041	0.044	0.040	0.043	0.045	0.048	0.051	0.042	0.039	0.041	0.043
Distribution Capacity	0.023	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.020	0.020	0.020	0.019	0.019	0.019
Capacity	0.031	0.025	0.013	0.016	0.018	0.017	0.021	0.021	0.022	0.024	0.024	0.024	0.025	0.028	0.024
Distribution Line Losses	0.006	0.005	0.003	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.005	0.004
RPS	0.004	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Transmission Line Losses	0.005	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.004	0.003
Risk Premium	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.005	0.006	0.006	0.006	0.006	0.006	0.007	0.007	0.007	0.007	0.006	0.006	0.006	0.006	0.006
Distribution OPEX	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Utility Admin	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)
Environmental Externality	0.048	0.047	0.047	0.048	0.046	0.041	0.039	0.035	0.034	0.032	0.032	0.032	0.033	0.034	0.036
Total – Excluding Environmental	0.168	0.164	0.145	0.141	0.140	0.138	0.137	0.138	0.141	0.145	0.147	0.137	0.135	0.140	0.139
Total – Including Environmental	0.216	0.210	0.192	0.189	0.186	0.179	0.176	0.173	0.175	0.177	0.179	0.170	0.168	0.174	0.175

Table 35. Average Annual Avoided Cost Value for Commercial South-Facing Solar PV Array Installed in 2021 ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.044	0.046	0.040	0.038	0.033	0.030	0.029	0.027	0.027	0.027	0.026	0.026	0.026	0.026	0.028
Transmission Charges	0.035	0.038	0.040	0.036	0.037	0.040	0.038	0.041	0.043	0.046	0.049	0.041	0.035	0.037	0.036
Distribution Capacity	0.021	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.018	0.018	0.018	0.018	0.018	0.018

Capacity	0.028	0.022	0.011	0.015	0.016	0.016	0.019	0.019	0.020	0.022	0.022	0.022	0.023	0.025	0.021
Distribution Line Losses	0.004	0.003	0.002	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
RPS	0.003	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Transmission Line Losses	0.005	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Risk Premium	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.003	0.003	0.004	0.004	0.003	0.003	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.005	0.005	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.005	0.005	0.005	0.005	0.005
Distribution OPEX	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Utility Admin	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)
Environmental Externality	0.048	0.046	0.047	0.048	0.045	0.040	0.037	0.033	0.032	0.030	0.030	0.030	0.031	0.032	0.034
Total – No Environmental	0.155	0.151	0.134	0.130	0.128	0.126	0.127	0.127	0.130	0.134	0.136	0.127	0.122	0.127	0.123
Total – Including Environmental	0.203	0.198	0.181	0.178	0.174	0.166	0.164	0.160	0.162	0.164	0.166	0.157	0.154	0.159	0.158

Table 46. Average Annual Avoided Cost Value for Commercial West-Facing Solar PV Array Installed in 2021 ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.045	0.047	0.041	0.039	0.034	0.031	0.030	0.028	0.028	0.028	0.028	0.027	0.027	0.027	0.029
Transmission Charges	0.039	0.041	0.044	0.039	0.041	0.044	0.040	0.043	0.045	0.048	0.051	0.042	0.039	0.041	0.043
Distribution Capacity	0.023	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.020	0.020	0.020	0.019	0.019	0.019
Capacity	0.031	0.025	0.013	0.016	0.018	0.017	0.021	0.021	0.022	0.024	0.024	0.024	0.025	0.028	0.024
Distribution Line Losses	0.004	0.004	0.002	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.004	0.003
RPS	0.003	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Transmission Line Losses	0.005	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.004	0.003
Risk Premium	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.005	0.006	0.006	0.006	0.006	0.006	0.007	0.007	0.007	0.007	0.006	0.006	0.006	0.006	0.006
Distribution OPEX	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Utility Admin	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)

Environmental Externality	0.048	0.047	0.047	0.048	0.046	0.041	0.039	0.035	0.034	0.032	0.032	0.032	0.033	0.034	0.036
Total – No Environmental	0.165	0.161	0.143	0.139	0.138	0.136	0.135	0.136	0.139	0.144	0.146	0.136	0.133	0.139	0.138
Total – Including Environmental	0.213	0.208	0.190	0.187	0.184	0.177	0.174	0.171	0.173	0.175	0.178	0.168	0.167	0.173	0.174

Table 7. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Installed in 2021 ($/kWh) (2021$)

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Spring	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.032	-	0.003	0.055	0.044	0.024	-	0.003	0.089	0.080
	7	0.034	-	0.004	0.052	0.041	0.028	-	0.003	0.095	0.086
	8	0.042	-	0.004	0.053	0.041	0.031	-	0.003	0.101	0.091
	9	0.044	-	0.004	0.057	0.045	0.030	-	0.003	0.103	0.094
	10	0.045	-	0.004	0.056	0.044	0.024	-	0.003	0.104	0.096
	11	0.045	-	0.004	0.055	0.044	0.021	-	0.002	0.104	0.096
	12	0.045	-	0.004	0.054	0.042	0.022	-	0.003	0.104	0.096
	13	0.045	-	0.004	0.054	0.043	0.022	-	0.003	0.104	0.095
	14	0.045	-	0.157	0.057	0.045	0.022	-	0.003	0.104	0.095
	15	0.045	-	0.158	0.056	0.044	0.023	-	0.003	0.105	0.095
	16	0.045	-	0.004	0.058	0.045	0.029	-	0.003	0.107	0.095
	17	0.045	-	0.004	0.057	0.044	0.040	-	0.004	0.110	0.096
	18	0.044	-	0.004	0.058	0.045	0.046	-	0.004	0.113	0.099
	19	0.042	-	0.055	0.055	0.043	0.049	-	0.005	0.116	0.102
	20	0.038	-	0.004	0.053	0.041	0.046	-	0.004	0.116	0.102
	21	0.037	-	0.004	0.056	0.044	0.046	-	1.532	0.119	0.105
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Summer	1	-	-	-	-	-	-	-	-	-	-

	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.034	-	0.003	0.063	0.053	0.030	-	0.003	0.090	0.081
	7	0.034	-	0.003	0.059	0.049	0.036	-	0.003	0.096	0.086
	8	0.039	-	0.004	0.060	0.049	0.040	-	0.004	0.103	0.093
	9	0.039	-	0.004	0.060	0.049	0.040	-	0.004	0.110	0.100
	10	0.040	-	0.006	0.060	0.049	0.037	-	0.007	0.118	0.108
	11	0.040	-	0.047	0.061	0.050	0.036	-	0.056	0.125	0.115
	12	0.040	-	0.067	0.063	0.052	0.037	-	0.080	0.130	0.120
	13	0.040	-	0.079	0.074	0.050	0.038	-	0.095	0.142	0.123
	14	0.040	-	0.275	0.062	0.051	0.039	-	0.689	0.138	0.127
	15	0.041	0.685	0.580	0.115	0.050	0.040	0.746	0.283	0.149	0.127
	16	0.041	-	0.114	0.059	0.048	0.043	-	0.137	0.140	0.127
	17	0.041	-	0.111	0.056	0.044	0.052	-	1.239	0.260	0.129
	18	0.042	-	0.088	0.057	0.044	0.059	-	0.107	0.145	0.129
	19	0.042	-	0.061	0.057	0.045	0.066	-	0.076	0.144	0.128
	20	0.041	-	0.011	0.058	0.047	0.062	-	0.014	0.140	0.124
	21	0.041	-	0.004	0.059	0.048	0.056	-	0.005	0.135	0.121
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Fall	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	0.034	-	0.003	0.055	0.044	0.042	-	0.004	0.095	0.083
	8	0.042	-	0.004	0.060	0.048	0.049	-	0.005	0.103	0.089
	9	0.042	-	0.004	0.060	0.048	0.048	-	0.005	0.106	0.092
	10	0.041	-	0.004	0.061	0.049	0.042	-	0.004	0.106	0.093
	11	0.041	-	0.004	0.058	0.047	0.041	-	0.004	0.107	0.094
	12	0.040	-	0.004	0.059	0.047	0.042	-	0.004	0.106	0.094
	13	0.040	-	0.004	0.058	0.046	0.043	-	0.004	0.106	0.093
	14	0.040	-	0.004	0.060	0.048	0.044	-	0.004	0.107	0.094

	15	0.039	-	0.004	0.061	0.049	0.043	-	0.004	0.108	0.094
	16	0.038	-	0.004	0.057	0.045	0.046	-	0.004	0.108	0.094
	17	0.037	-	0.328	0.063	0.051	0.049	-	0.005	0.109	0.096
	18	0.036	-	0.006	0.060	0.048	0.049	-	0.005	0.111	0.097
	19	0.036	-	0.004	0.056	0.045	0.049	-	0.005	0.112	0.099
	20	0.036	-	0.004	0.065	0.054	0.048	-	1.694	0.116	0.104
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Winter	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	0.057	-	0.005	0.058	0.041	0.076	-	0.007	0.114	0.094
	8	0.064	-	0.006	0.068	0.051	0.084	-	0.008	0.123	0.101
	9	0.064	-	0.006	0.069	0.051	0.086	-	0.008	0.128	0.106
	10	0.064	-	0.006	0.071	0.054	0.071	-	0.007	0.128	0.108
	11	0.064	-	0.006	0.070	0.053	0.067	-	0.006	0.127	0.107
	12	0.064	-	0.006	0.073	0.055	0.066	-	0.006	0.126	0.106
	13	0.064	-	0.006	0.072	0.055	0.066	-	0.006	0.124	0.104
	14	0.063	-	0.006	0.071	0.053	0.067	-	0.006	0.125	0.103
	15	0.063	-	0.006	0.072	0.054	0.068	-	0.006	0.126	0.102
	16	0.062	-	0.006	0.069	0.050	0.078	-	0.007	0.129	0.103
	17	0.062	-	0.006	0.067	0.048	0.094	-	0.008	0.135	0.109
	18	0.064	-	0.006	0.067	0.050	0.098	-	0.009	0.151	0.126
	19	-	-	-	-	-	-	-	-	-	-
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

B.3 Residential and Commercial Solar PV Paired with Storage

Table 8. Average Annual Avoided Cost Value for Residential South-Facing Solar PV Array Paired with Storage Installed in 2021 ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.045	0.046	0.041	0.039	0.035	0.033	0.032	0.031	0.032	0.032	0.032	0.032	0.032	0.033	0.034
Transmission Charges	0.055	0.058	0.062	0.063	0.072	0.076	0.077	0.082	0.087	0.093	0.099	0.100	0.106	0.113	0.125
Distribution Capacity	0.021	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.018	0.018	0.018	0.018	0.018	0.018
Capacity	0.030	0.024	0.012	0.016	0.017	0.017	0.021	0.020	0.021	0.023	0.023	0.023	0.024	0.027	0.023
Distribution Line Losses	0.005	0.005	0.003	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.005	0.005	0.005
RPS	0.004	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Transmission Line Losses	0.005	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.004	0.004	0.004	0.004	0.004
Risk Premium	0.004	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.005	0.006	0.006	0.006	0.007	0.006	0.006	0.006	0.006	0.006	0.007	0.007	0.008	0.008	0.008
Distribution OPEX	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Utility Admin	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)
Environmental Externality	0.047	0.046	0.041	0.047	0.049	0.048	0.045	0.044	0.044	0.041	0.042	0.042	0.042	0.044	0.045
Total – Excluding Environmental	0.181	0.177	0.160	0.163	0.169	0.169	0.173	0.178	0.184	0.192	0.200	0.201	0.207	0.218	0.227
Total – Including Environmental	0.228	0.223	0.202	0.209	0.218	0.217	0.218	0.221	0.228	0.232	0.241	0.243	0.250	0.261	0.272

Table 9. Average Annual Avoided Cost Value for Commercial South-Facing Solar PV Array Paired with Storage Installed in 2021 ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.045	0.046	0.041	0.039	0.035	0.032	0.031	0.031	0.031	0.031	0.032	0.031	0.032	0.032	0.033
Transmission Charges	0.052	0.055	0.059	0.059	0.067	0.071	0.071	0.076	0.081	0.086	0.092	0.092	0.095	0.101	0.112
Distribution Capacity	0.021	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.018	0.018	0.018	0.018	0.018	0.018
Capacity	0.029	0.024	0.012	0.016	0.017	0.016	0.020	0.020	0.021	0.023	0.023	0.023	0.024	0.027	0.023
Distribution Line Losses	0.004	0.004	0.002	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.004	0.004	0.003

RPS	0.003	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Transmission Line Losses	0.005	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.004	0.004	0.004
Risk Premium	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.005	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.007	0.007	0.007	0.007	0.007
Distribution OPEX	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Utility Admin	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)
Environmental Externality	0.047	0.046	0.042	0.047	0.048	0.047	0.044	0.042	0.042	0.039	0.040	0.041	0.041	0.042	0.043
Total – Excluding Environmental	0.174	0.171	0.154	0.156	0.161	0.161	0.165	0.169	0.174	0.182	0.189	0.188	0.193	0.203	0.210
Total – Including Environmental	0.222	0.217	0.197	0.203	0.210	0.208	0.209	0.211	0.217	0.221	0.229	0.229	0.234	0.245	0.254

Table 10. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Paired with Storage Installed in 2021 ($/kWh) (2021$)

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Spring	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.032	-	0.003	0.055	0.044	0.024	-	0.003	0.089	0.080
	7	0.034	-	0.004	0.052	0.041	0.028	-	0.003	0.095	0.086
	8	0.042	-	0.004	0.053	0.041	0.031	-	0.003	0.101	0.091
	9	0.044	-	0.004	0.057	0.045	0.030	-	0.003	0.103	0.094
	10	0.045	-	0.004	0.056	0.044	0.024	-	0.003	0.104	0.096
	11	0.044	-	0.004	0.055	0.044	0.021	-	0.002	0.104	0.096
	12	0.045	-	0.004	0.054	0.042	0.022	-	0.003	0.104	0.096
	13	0.045	-	0.004	0.054	0.043	0.022	-	0.003	0.104	0.095
	14	0.045	-	0.160	0.057	0.045	0.022	-	0.003	0.104	0.095
	15	0.045	-	0.158	0.056	0.044	0.023	-	0.003	0.105	0.095
	16	0.045	-	0.004	0.058	0.045	0.029	-	0.003	0.107	0.095
	17	0.045	-	0.004	0.057	0.044	0.040	-	0.004	0.110	0.096
	18	0.046	-	0.004	0.059	0.046	0.048	-	0.005	0.114	0.099
	19	0.046	-	0.142	0.058	0.045	0.054	-	0.005	0.121	0.105
	20	0.046	-	0.004	0.055	0.041	0.055	-	0.508	0.124	0.108

	21	0.046	-	0.004	0.060	0.046	0.055	-	1.034	0.122	0.107
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Summer	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.034	-	0.003	0.063	0.053	0.030	-	0.003	0.090	0.081
	7	0.034	-	0.003	0.059	0.049	0.036	-	0.003	0.096	0.086
	8	0.039	-	0.004	0.060	0.049	0.040	-	0.004	0.103	0.093
	9	0.039	-	0.004	0.060	0.049	0.040	-	0.004	0.110	0.100
	10	0.040	-	0.006	0.060	0.049	0.037	-	0.007	0.118	0.108
	11	0.040	-	0.047	0.061	0.050	0.036	-	0.056	0.125	0.115
	12	0.040	-	0.067	0.063	0.052	0.037	-	0.080	0.130	0.120
	13	0.040	-	0.080	0.074	0.050	0.038	-	0.097	0.142	0.123
	14	0.040	-	0.278	0.062	0.051	0.039	-	0.696	0.138	0.127
	15	0.041	0.685	0.580	0.115	0.050	0.040	0.746	0.283	0.149	0.127
	16	0.041	-	0.114	0.059	0.048	0.043	-	0.137	0.140	0.127
	17	0.041	-	0.112	0.056	0.044	0.052	-	1.249	0.264	0.129
	18	0.042	-	0.090	0.057	0.045	0.060	-	0.109	0.146	0.129
	19	0.042	-	0.066	0.057	0.045	0.067	-	0.081	0.146	0.129
	20	0.041	-	0.019	0.059	0.047	0.065	-	0.024	0.144	0.128
	21	0.041	-	0.004	0.059	0.048	0.056	-	0.005	0.135	0.121
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Fall	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	0.034	-	0.003	0.055	0.044	0.042	-	0.004	0.095	0.083

	8	0.042	-	0.004	0.060	0.048	0.049	-	0.005	0.103	0.089
	9	0.042	-	0.004	0.060	0.048	0.048	-	0.005	0.106	0.092
	10	0.041	-	0.004	0.061	0.049	0.042	-	0.004	0.106	0.093
	11	0.032	-	0.003	0.059	0.050	0.027	-	0.003	0.098	0.092
	12	0.036	-	0.004	0.059	0.048	0.034	-	0.003	0.103	0.093
	13	0.035	-	0.004	0.056	0.046	0.035	-	0.003	0.103	0.093
	14	0.030	-	0.003	0.059	0.050	0.029	-	0.003	0.101	0.093
	15	0.039	-	0.004	0.061	0.049	0.043	-	0.004	0.108	0.094
	16	0.038	-	0.004	0.057	0.045	0.046	-	0.004	0.108	0.094
	17	0.036	-	0.407	0.062	0.051	0.048	-	0.004	0.109	0.096
	18	0.042	-	0.149	0.062	0.049	0.057	-	0.005	0.120	0.103
	19	0.042	-	0.004	0.059	0.046	0.059	-	0.550	0.125	0.108
	20	0.042	-	0.168	0.062	0.048	0.059	-	1.119	0.128	0.110
	21	0.045	-	0.005	0.062	0.047	0.063	-	0.006	0.127	0.107
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Winter	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	0.057	-	0.005	0.058	0.041	0.076	-	0.007	0.114	0.094
	8	0.064	-	0.006	0.068	0.051	0.084	-	0.008	0.123	0.101
	9	0.064	-	0.006	0.069	0.051	0.086	-	0.008	0.128	0.106
	10	0.064	-	0.006	0.071	0.054	0.071	-	0.007	0.128	0.108
	11	0.066	-	0.006	0.075	0.057	0.075	-	0.007	0.129	0.107
	12	0.070	-	0.007	0.082	0.063	0.085	-	0.008	0.130	0.106
	13	0.070	-	0.007	0.082	0.063	0.086	-	0.008	0.129	0.104
	14	0.067	-	0.006	0.079	0.060	0.080	-	0.007	0.128	0.103
	15	0.063	-	0.006	0.072	0.054	0.068	-	0.006	0.126	0.102
	16	0.062	-	0.006	0.069	0.050	0.078	-	0.007	0.129	0.103
	17	0.062	-	0.006	0.067	0.048	0.094	-	0.008	0.135	0.109
	18	0.067	-	0.160	0.071	0.051	0.108	-	0.009	0.172	0.142
	19	0.067	-	0.327	0.071	0.051	0.110	-	1.625	0.188	0.158

	20	0.067	-	0.006	0.073	0.053	0.109	-	0.009	0.187	0.157
	21	0.066	-	0.006	0.072	0.052	0.108	-	0.009	0.170	0.141
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

B.4 Large Group Host Commercial Solar PV

Table 11. Average Annual Avoided Cost Value for Large Group Host Commercial Solar PV Array Installed in 2021 ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.046	0.049	0.043	0.041	0.036	0.033	0.031	0.029	0.029	0.029	0.029	0.028	0.028	0.028	0.030
Transmission Charges	0.024	0.025	0.027	0.024	0.025	0.026	0.024	0.026	0.027	0.029	0.031	0.026	0.023	0.024	0.026
Distribution Capacity	0.014	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.012	0.012	0.012	0.012	0.012
Capacity	0.019	0.015	0.008	0.010	0.011	0.011	0.013	0.013	0.013	0.015	0.015	0.015	0.016	0.017	0.015
Distribution Line Losses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RPS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission Line Losses	0.004	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Risk Premium	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.003	0.003	0.004	0.003	0.003	0.003	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Distribution OPEX	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Utility Admin	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)
Environmental Externality	0.048	0.047	0.048	0.050	0.047	0.042	0.039	0.035	0.034	0.032	0.032	0.032	0.033	0.034	0.036
Total – Excluding Environmental	0.121	0.122	0.108	0.105	0.101	0.099	0.097	0.097	0.098	0.101	0.102	0.096	0.094	0.097	0.097
Total – Including Environmental	0.170	0.169	0.156	0.155	0.148	0.140	0.136	0.132	0.133	0.133	0.134	0.128	0.127	0.131	0.133

Table 12. Average Hourly Seasonal Avoided Cost Values for Large Group Host Commercial Solar PV Array Installed in 2021 ($/kWh) (2021$)

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.

Spring	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	0.032	-	0.003	0.049	0.038	0.024	-	0.003	0.086	0.076
	6	0.034	-	0.004	0.058	0.047	0.023	-	0.003	0.089	0.079
	7	0.039	-	0.004	0.055	0.043	0.031	-	0.003	0.096	0.086
	8	0.046	-	0.004	0.054	0.042	0.033	-	0.003	0.101	0.091
	9	0.045	-	0.004	0.057	0.045	0.031	-	0.003	0.104	0.094
	10	0.045	-	0.004	0.056	0.044	0.024	-	0.003	0.104	0.096
	11	0.046	-	0.004	0.056	0.044	0.021	-	0.002	0.104	0.096
	12	0.046	-	0.004	0.054	0.042	0.022	-	0.003	0.104	0.096
	13	0.046	-	0.004	0.055	0.043	0.022	-	0.003	0.104	0.095
	14	0.045	-	0.155	0.057	0.045	0.023	-	0.003	0.105	0.095
	15	0.045	-	0.159	0.056	0.044	0.023	-	0.003	0.105	0.095
	16	0.045	-	0.004	0.058	0.045	0.029	-	0.003	0.107	0.095
	17	0.045	-	0.004	0.057	0.044	0.040	-	0.004	0.110	0.096
	18	0.044	-	0.004	0.058	0.045	0.046	-	0.004	0.113	0.099
	19	0.038	-	0.004	0.053	0.041	0.045	-	0.004	0.114	0.100
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Summer	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	0.034	-	0.003	0.062	0.052	0.028	-	0.003	0.086	0.078
	6	0.034	-	0.003	0.073	0.063	0.036	-	0.003	0.092	0.082
	7	0.034	-	0.003	0.061	0.050	0.038	-	0.004	0.097	0.087
	8	0.039	-	0.004	0.061	0.049	0.041	-	0.004	0.104	0.093
	9	0.039	-	0.004	0.060	0.049	0.041	-	0.004	0.111	0.100
	10	0.040	-	0.007	0.061	0.050	0.038	-	0.007	0.119	0.108
	11	0.040	-	0.049	0.061	0.050	0.036	-	0.058	0.125	0.115
	12	0.040	-	0.067	0.063	0.052	0.037	-	0.081	0.130	0.120
	13	0.040	-	0.083	0.075	0.050	0.038	-	0.099	0.143	0.123

	14	0.040	-	0.279	0.062	0.051	0.040	-	0.697	0.138	0.128
	15	0.041	0.723	0.584	0.118	0.050	0.040	0.787	0.297	0.151	0.128
	16	0.041	-	0.121	0.059	0.048	0.044	-	0.146	0.142	0.128
	17	0.041	-	0.113	0.056	0.044	0.052	-	1.252	0.268	0.129
	18	0.042	-	0.094	0.056	0.044	0.061	-	0.115	0.147	0.130
	19	0.041	-	0.055	0.056	0.044	0.064	-	0.068	0.142	0.126
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Fall	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.030	-	0.003	0.046	0.036	0.034	-	0.003	0.085	0.075
	7	0.031	-	0.003	0.054	0.043	0.039	-	0.004	0.094	0.083
	8	0.040	-	0.004	0.060	0.048	0.048	-	0.005	0.102	0.088
	9	0.041	-	0.004	0.060	0.048	0.047	-	0.005	0.105	0.092
	10	0.041	-	0.004	0.061	0.049	0.041	-	0.004	0.106	0.093
	11	0.041	-	0.004	0.059	0.046	0.042	-	0.004	0.107	0.094
	12	0.041	-	0.004	0.059	0.047	0.042	-	0.004	0.107	0.094
	13	0.041	-	0.004	0.058	0.046	0.044	-	0.004	0.107	0.094
	14	0.041	-	0.004	0.060	0.048	0.045	-	0.004	0.108	0.094
	15	0.040	-	0.004	0.061	0.049	0.045	-	0.004	0.108	0.094
	16	0.040	-	0.004	0.058	0.046	0.050	-	0.005	0.110	0.094
	17	0.036	-	0.323	0.063	0.051	0.048	-	0.005	0.109	0.095
	18	0.036	-	0.004	0.060	0.049	0.048	-	0.004	0.110	0.098
	19	-	-	-	-	-	-	-	-	-	-
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Winter	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	-	-	-	-	-	-	-	-	-	-
	8	0.063	-	0.006	0.068	0.050	0.085	-	0.008	0.123	0.101
	9	0.064	-	0.006	0.069	0.051	0.086	-	0.008	0.129	0.106
	10	0.064	-	0.006	0.071	0.053	0.071	-	0.007	0.128	0.108
	11	0.063	-	0.006	0.070	0.052	0.066	-	0.006	0.127	0.107
	12	0.063	-	0.006	0.072	0.055	0.066	-	0.006	0.126	0.106
	13	0.063	-	0.006	0.072	0.054	0.066	-	0.006	0.124	0.104
	14	0.063	-	0.006	0.071	0.053	0.067	-	0.006	0.125	0.104
	15	0.063	-	0.006	0.073	0.055	0.071	-	0.007	0.127	0.103
	16	0.063	-	0.006	0.072	0.053	0.083	-	0.008	0.131	0.104
	17	0.062	-	0.006	0.066	0.048	0.094	-	0.008	0.135	0.108
	18	-	-	-	-	-	-	-	-	-	-
	19	-	-	-	-	-	-	-	-	-	-
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

B.5 Micro Hydro

Table 13. Average Annual Avoided Cost Value for Micro Hydro System ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.049	0.053	0.047	0.044	0.040	0.038	0.036	0.035	0.036	0.036	0.036	0.036	0.036	0.036	0.037
Transmission Charges	0.028	0.030	0.032	0.035	0.038	0.040	0.043	0.046	0.049	0.052	0.055	0.060	0.065	0.069	0.074
Distribution Capacity	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.006	0.006	0.006	0.006	0.006	0.006
Capacity	0.006	0.005	0.003	0.003	0.004	0.003	0.004	0.004	0.004	0.005	0.005	0.005	0.005	0.006	0.005

Distribution Line Losses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RPS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission Line Losses	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Risk Premium	0.005	0.005	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.004	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Distribution OPEX	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Utility Admin	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)
Environmental Externality	0.048	0.046	0.046	0.050	0.051	0.051	0.046	0.044	0.045	0.041	0.042	0.043	0.042	0.044	0.045
Total – Excluding Environmental	0.107	0.112	0.104	0.105	0.103	0.102	0.104	0.106	0.110	0.113	0.117	0.122	0.126	0.131	0.136
Total – Including Environmental	0.155	0.158	0.150	0.155	0.154	0.152	0.150	0.150	0.155	0.153	0.159	0.165	0.168	0.174	0.181

Table 14. Average Hourly Seasonal Avoided Cost Values for Micro Hydro System ($/kWh) (2021$)

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Spring	1	0.039	-	0.002	0.056	0.048	0.031	-	0.002	0.090	0.083
	2	0.038	-	0.002	0.058	0.050	0.030	-	0.002	0.087	0.079
	3	0.039	-	0.002	0.052	0.045	0.028	-	0.002	0.084	0.077
	4	0.039	-	0.002	0.052	0.044	0.027	-	0.002	0.083	0.076
	5	0.039	-	0.002	0.049	0.041	0.026	-	0.002	0.084	0.077
	6	0.040	-	0.002	0.055	0.047	0.027	-	0.002	0.088	0.080
	7	0.041	-	0.002	0.052	0.044	0.032	-	0.002	0.094	0.086
	8	0.046	-	0.003	0.050	0.041	0.033	-	0.002	0.098	0.091
	9	0.045	-	0.003	0.053	0.045	0.030	-	0.002	0.100	0.094
	10	0.045	-	0.003	0.052	0.044	0.024	-	0.001	0.101	0.096
	11	0.045	-	0.003	0.051	0.043	0.021	-	0.001	0.101	0.096
	12	0.045	-	0.003	0.049	0.041	0.022	-	0.001	0.101	0.096
	13	0.045	-	0.003	0.050	0.042	0.022	-	0.001	0.100	0.095
	14	0.045	-	0.154	0.053	0.045	0.022	-	0.001	0.101	0.095
	15	0.045	-	0.177	0.052	0.044	0.023	-	0.001	0.102	0.095
	16	0.045	-	0.003	0.053	0.045	0.028	-	0.002	0.104	0.095
	17	0.045	-	0.003	0.053	0.044	0.040	-	0.002	0.107	0.096
	18	0.046	-	0.003	0.055	0.046	0.048	-	0.003	0.111	0.099

	19	0.047	-	0.156	0.054	0.045	0.055	-	0.003	0.118	0.106
	20	0.047	-	0.003	0.051	0.041	0.055	-	0.498	0.121	0.108
	21	0.046	-	0.003	0.056	0.047	0.055	-	1.069	0.119	0.106
	22	0.046	-	0.003	0.052	0.043	0.052	-	0.003	0.111	0.099
	23	0.045	-	0.003	0.051	0.043	0.047	-	0.002	0.102	0.092
	24	0.040	-	0.002	0.052	0.045	0.040	-	0.002	0.096	0.087

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Summer	1	0.034	-	0.002	0.050	0.045	0.036	-	0.002	0.092	0.086
	2	0.034	-	0.002	0.055	0.049	0.035	-	0.002	0.088	0.082
	3	0.034	-	0.002	0.058	0.052	0.033	-	0.002	0.085	0.079
	4	0.034	-	0.002	0.058	0.052	0.033	-	0.002	0.084	0.078
	5	0.034	-	0.002	0.061	0.055	0.033	-	0.002	0.085	0.079
	6	0.034	-	0.002	0.061	0.055	0.031	-	0.002	0.087	0.081
	7	0.034	-	0.002	0.055	0.048	0.035	-	0.002	0.093	0.086
	8	0.039	-	0.002	0.055	0.049	0.038	-	0.002	0.100	0.093
	9	0.039	-	0.002	0.055	0.048	0.038	-	0.002	0.107	0.100
	10	0.039	-	0.004	0.055	0.049	0.036	-	0.005	0.114	0.107
	11	0.040	-	0.040	0.056	0.050	0.034	-	0.047	0.120	0.114
	12	0.040	-	0.055	0.058	0.052	0.036	-	0.066	0.125	0.119
	13	0.040	-	0.067	0.112	0.050	0.037	-	0.080	0.178	0.121
	14	0.040	-	0.273	0.057	0.050	0.038	-	0.700	0.133	0.125
	15	0.040	0.528	0.469	0.098	0.050	0.039	0.575	0.178	0.142	0.126
	16	0.041	-	0.107	0.055	0.048	0.043	-	0.129	0.136	0.126
	17	0.041	-	0.105	0.052	0.044	0.051	-	1.189	0.237	0.128
	18	0.042	-	0.083	0.052	0.044	0.059	-	0.101	0.142	0.128
	19	0.041	-	0.058	0.053	0.045	0.066	-	0.071	0.141	0.127
	20	0.041	-	0.014	0.055	0.047	0.063	-	0.017	0.139	0.126
	21	0.041	-	0.022	0.056	0.048	0.060	-	0.027	0.138	0.126
	22	0.041	-	0.011	0.056	0.049	0.056	-	0.013	0.126	0.115
	23	0.040	-	0.002	0.056	0.050	0.049	-	0.003	0.108	0.100
	24	0.034	-	0.002	0.053	0.047	0.040	-	0.002	0.097	0.091

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Fall	1	0.041	-	0.002	0.047	0.038	0.053	-	0.003	0.097	0.083
	2	0.040	-	0.002	0.055	0.046	0.052	-	0.003	0.093	0.079
	3	0.041	-	0.002	0.055	0.046	0.052	-	0.003	0.091	0.077
	4	0.040	-	0.002	0.052	0.043	0.051	-	0.003	0.089	0.076
	5	0.040	-	0.002	0.051	0.043	0.050	-	0.003	0.089	0.076

	6	0.039	-	0.002	0.049	0.041	0.049	-	0.003	0.092	0.079
	7	0.039	-	0.002	0.052	0.044	0.050	-	0.003	0.098	0.085
	8	0.044	-	0.003	0.057	0.048	0.054	-	0.003	0.103	0.090
	9	0.044	-	0.003	0.057	0.048	0.052	-	0.003	0.105	0.093
	10	0.044	-	0.003	0.057	0.048	0.047	-	0.002	0.106	0.094
	11	0.044	-	0.003	0.055	0.046	0.046	-	0.002	0.107	0.094
	12	0.043	-	0.003	0.054	0.046	0.046	-	0.002	0.106	0.094
	13	0.043	-	0.003	0.055	0.046	0.048	-	0.003	0.106	0.094
	14	0.043	-	0.003	0.056	0.047	0.050	-	0.003	0.107	0.094
	15	0.043	-	0.003	0.058	0.048	0.050	-	0.003	0.108	0.094
	16	0.043	-	0.003	0.055	0.046	0.054	-	0.003	0.109	0.094
	17	0.043	-	0.126	0.059	0.050	0.058	-	0.003	0.113	0.098
	18	0.044	-	0.213	0.059	0.050	0.061	-	0.003	0.121	0.106
	19	0.044	-	0.003	0.056	0.046	0.062	-	0.717	0.126	0.110
	20	0.044	-	0.169	0.057	0.048	0.061	-	0.967	0.128	0.112
	21	0.045	-	0.003	0.057	0.047	0.061	-	0.003	0.123	0.107
	22	0.046	-	0.003	0.058	0.048	0.062	-	0.003	0.115	0.099
	23	0.046	-	0.003	0.057	0.047	0.061	-	0.003	0.108	0.092
	24	0.041	-	0.002	0.048	0.038	0.055	-	0.003	0.102	0.088

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Winter	1	0.058	-	0.003	0.063	0.050	0.079	-	0.004	0.109	0.090
	2	0.057	-	0.003	0.059	0.045	0.075	-	0.004	0.106	0.087
	3	0.057	-	0.003	0.058	0.045	0.072	-	0.004	0.103	0.085
	4	0.057	-	0.003	0.058	0.045	0.071	-	0.004	0.102	0.084
	5	0.057	-	0.003	0.057	0.044	0.070	-	0.004	0.104	0.085
	6	0.058	-	0.003	0.069	0.055	0.074	-	0.004	0.108	0.088
	7	0.059	-	0.003	0.079	0.065	0.083	-	0.004	0.115	0.094
	8	0.065	-	0.004	0.068	0.053	0.089	-	0.004	0.123	0.102
	9	0.065	-	0.004	0.066	0.052	0.088	-	0.004	0.126	0.106
	10	0.065	-	0.004	0.068	0.054	0.073	-	0.004	0.125	0.108
	11	0.065	-	0.004	0.067	0.054	0.068	-	0.003	0.124	0.107
	12	0.065	-	0.004	0.070	0.056	0.069	-	0.003	0.123	0.106
	13	0.065	-	0.004	0.070	0.056	0.068	-	0.003	0.121	0.104
	14	0.065	-	0.004	0.069	0.056	0.071	-	0.004	0.123	0.103
	15	0.065	-	0.004	0.071	0.057	0.073	-	0.004	0.124	0.102
	16	0.065	-	0.004	0.070	0.055	0.085	-	0.004	0.128	0.104
	17	0.066	-	0.004	0.067	0.052	0.100	-	0.005	0.142	0.116

	18	0.067	-	0.156	0.066	0.051	0.108	-	0.005	0.169	0.142
	19	0.067	-	0.323	0.067	0.051	0.110	-	1.620	0.185	0.158
	20	0.067	-	0.004	0.068	0.053	0.109	-	0.005	0.184	0.157
	21	0.066	-	0.004	0.067	0.052	0.108	-	0.005	0.167	0.141
	22	0.066	-	0.004	0.070	0.055	0.105	-	0.005	0.144	0.119
	23	0.065	-	0.004	0.073	0.058	0.100	-	0.005	0.127	0.102
	24	0.059	-	0.003	0.087	0.073	0.090	-	0.004	0.116	0.094

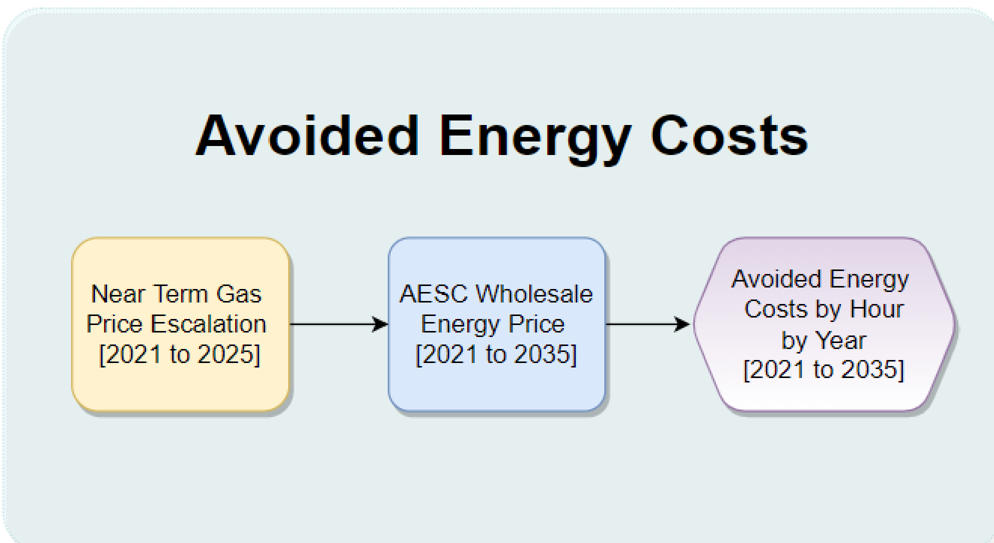
C. Detailed Base Value Stack Methodologies

C.1 Energy

C.1.1 Rationale

This avoided cost criteria represents the cost of energy that would otherwise be generated and procured through the ISO-NE wholesale energy market in the absence of load reductions attributed to distributed generation resources. Hourly LMPs in the New Hampshire zone reflect the displaced variable generation costs associated with the marginal resource(s) in the system and are thus an appropriate measure of the value of avoided energy in the state. The AESC 2021[1] study's hourly wholesale energy avoided cost forecasts are based on detailed modelling, which New England stakeholders vetted, and using this approach is consistent with EE methodology.

C.1.2 Model Map



C.1.3 Avoided Cost Methodology

Step 1: Forecasted Avoided Energy Prices

- Start with the avoided wholesale energy price forecast from the AESC 2021 study, which includes 8760 hourly energy prices for New Hampshire for 2021-2035.[2]

[1] The VDER study uses the latest data from the AESC October 2021 Release (AESC 2021 public files | Powered by Box)
[2] Values from the AESC Counterfactual #2 scenario (and workbook) are used here and throughout the study, as it is deemed the most appropriate of the four counterfactual scenarios included in the AESC 2021 study. The AESC Counterfactual

- Adjust the forecast during the near-term (2021 to 2025) to reflect current and anticipated increases in natural gas prices.[3]

C.1.4 Inputs, Assumptions, and Notes

Inputs

Inputs	Sources
Historic Energy Prices	ISO-NE Day-Ahead Pricing Reports by zone
Forecasted Energy Prices	AESC 2021 study (Counterfactual #2)[4]
Updated Natural Gas Prices	NYMEX Futures for Henry Hub

Assumptions and Notes

- Embedded environmental compliance costs – RGGI cap and trade and SO_2– are included in avoided energy costs.
- Transmission line losses (beyond losses embedded in LMPs), distribution line losses, and the wholesale risk premium are considered separate avoided cost criteria and are thus not accounted for in the avoided energy methodology.

Scenario #2 includes impacts of energy efficiency, active demand response, transportation electrification, and distributed generation but excludes the impact from building electrification.

[3] The AESC uses NYMEX futures prices for the Henry Hub and historical basis differential between Henry Hub and New England trading hubs to establish its short-term natural gas commodity price forecast. Natural gas prices have increased since the AESC 2021 study was finalized, so we updated the short-term natural gas prices based on more recent Henry Hub futures prices. Specifically, we calculated the market heat rate and multiplied this by the higher natural gas prices to derive the new wholesale energy prices. Data was accessed as of February 2022.

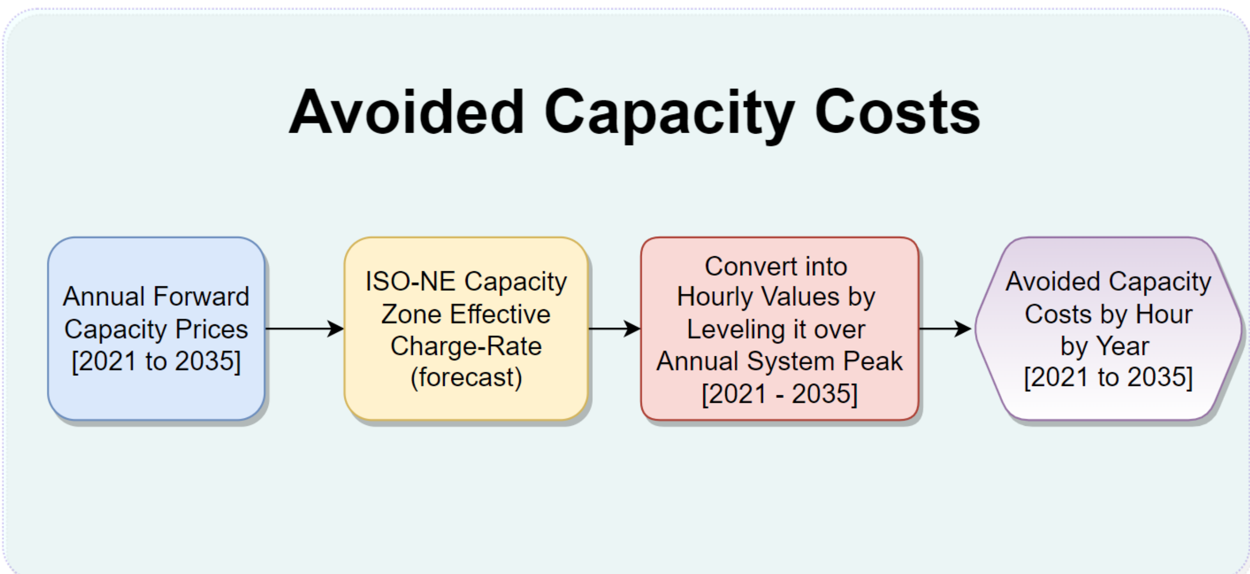
[4] For the NH VDER Study, the ideal avoided cost values would be estimated under a counterfactual scenario that includes region-wide EE, ADR, BE, and transportation electrification impacts along with non-New Hampshire distributed generation impacts. This scenario, unfortunately, is not readily available. However, in lieu of such a scenario, the most appropriate set of AESC avoided costs to utilize for the NH VDER Study is the ones emanating from Counterfactual #2 as this scenario is likely to be most representative of a scenario that includes all demand-side resource impacts sans New Hampshire DG impacts. This is because Counterfactual #2 only excludes the impacts of BE, which is expected to have the smallest influence on avoided costs of importance to the NH VDER study relative to EE and ADR.

C.2 Capacity

C.2.1 Rationale

The VDER Study is primarily focused on estimating the avoided cost impacts from distributed energy resources on New Hampshire regulated load-serving entities. The avoided capacity cost criterion represents the cost of generation capacity that would otherwise be procured through the ISO-NE Forward Capacity Market (FCM). Since individual behind-the-meter distributed generation resources do not qualify for or participate in the FCM[5], these resources provide indirect benefits by reducing ISO-NE peak demand – to the extent that DG production is coincident with system peak – and thus the amount of generation capacity that is procured through the market. From the utility perspective, if customer-sited distributed energy resources reduce utility load during the annual coincident peak hour, the capacity prices assessed on New Hampshire's utilities are reduced, resulting in an in-state avoided cost. In other words, avoidance or reduction of capacity market charges is the basis for the avoided cost calculations, to the extent that DG reduces utilities' peak hourly load in a given year.

C.2.2 Model Map



C.2.3 Avoided Cost Methodology

Step 1: Establish Annual Effective Cleared Capacity Prices (2021-2035)

- We start with the cleared capacity price forecast (2021 to 2035) from the AESC 2021 study and multiply the forecast prices by 1 + the reserve margin (%0.[6] To account for the actual capacity

[5] FERC Order No. 2222 will remove the barriers for aggregated DERs from competing on a level playing field in the organized capacity, energy and ancillary services markets run by regional grid operators.

[6] When establishing market-wide capacity needs, ISO-NE includes a planning reserve margin. This margin provides a buffer, ensuring that there will be adequate capacity should system peak demand be greater than forecasted need. AESC estimates the planning reserve margin to be 14.2% based on actual results from recent auctions. The forecast FCA prices are

charges assessed on utilities, the cleared capacity prices are adjusted using the most recent differential between the FCM Regional Net Clearing Price and the Effective Charge-Rate short-term forecast.[7] The result is the effective cleared capacity prices from 2021 to 2035.

Step 2: Distribute Annual Avoided Capacity Values by Hour

- Identify the ISO-NE's system peak hour by year and forecast any expected shift (due to renewables and increases in beneficial electrification) from 2021 to 2035. Each system year's effective cleared capacity market costs are then distributed over the ISO-NE's annual system peak hour to generate hourly avoided cost values.

C.2.4 Inputs, Assumptions, and Notes

Inputs

Inputs	Sources
Historic Capacity Prices	ISO-NE FCM annual auction results by zone
Forecasted Capacity Prices	AESC 2021 study
Reserve Margin	AESC 2021 study (14.2%)
EffectiveCharge-Rate (by zone)	ISO-NE FCM Net Regional Clearing Price and Effective Charge-Rate Forecast.

Assumptions and Notes: Transmission and distribution line losses and the wholesale risk premium are considered separate avoided cost criteria and are thus not accounted for in the avoided capacity methodology.

multiplied by 1 + the planning reserve margin (114.2%) because each MW that is reduced using DERs *also* reduces the planning reserve margin requirement. So, for example, a 1 MW reduction from DERs results in a 1.142 MW reduction in capacity that must be met through the FCA. The avoided costs are increased to represent the value of each MW reduction, accounting for the planning reserve impacts.

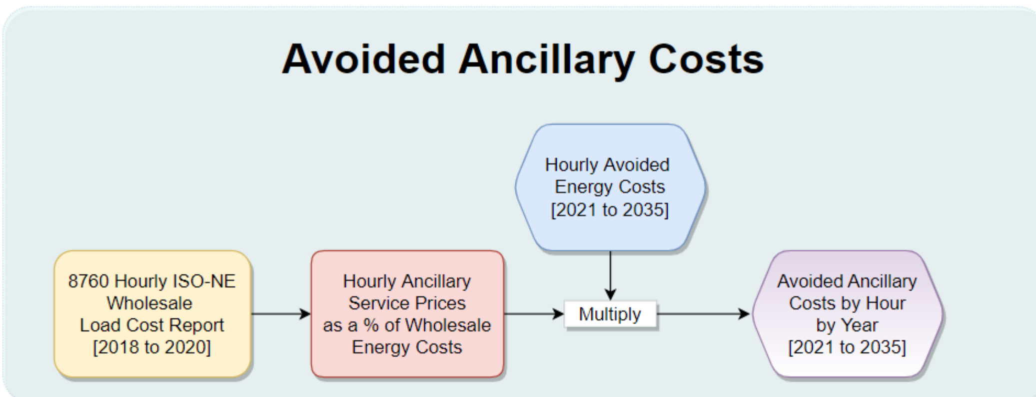
[7] Because Forward Capacity Auctions are held three years in advance, the actual cost of capacity procured on the market at the time that it is needed can vary from the FCA clearing price. The effective charge rate is a factor that is forecasted by ISO-NE which represents the difference between the future-looking auction prices and the actual prices at which resources are procured. Effective charge forecasts are only available on a short-term basis, however. To calculate expected actual capacity prices over the study period, the study team assessed the near-term relationship between the effective charge forecast and the FCA. The team then applied this relationship to the remaining FCA forecast years, considering the planning reserve margin, to estimate actual capacity prices over the study period.

C.3 Ancillary Services and Load Obligation Charges

C.3.1 Rationale

This study is focused on the avoided cost impacts on New Hampshire-regulated electric distribution utilities and the load-serving entities providing electric supply to the utilities' customers. The AESC does not calculate avoided costs for ancillary services and hence was not used as the basis for this methodology. From the utility perspective, if customer-sited distributed energy resources reduce utility load, then ancillary service charges and other load obligation charges assessed on New Hampshire's utilities and LSEs are reduced, resulting in an in-state avoided cost.

C.3.2 Model Map



C.3.3 Avoided Cost Methodology

Step 1: Calculate Historic Hourly Ancillary Service Prices (2018-2020)

- Calculate ancillary service and wholesale load obligation costs[8] as a percentage of hourly energy costs by service or charge.[9]
- For each historic year (2018 to 2020), calculate an hourly ancillary service and load obligation cost as a percentage of wholesale energy cost for each respective hour.
- Average hourly ancillary costs (as a percentage) for each type of ancillary service and load obligation charge across the three historic years to generate an 8760 ancillary avoided cost template.

[8] The ancillary services included are First and Second Contingency, Forward and Real Time Reserves, Regulation, Inadvertent energy, Net Commitment Period Compensation (NCPC), Auction Revenue Rights (ARR) revenues, NEPOOL expenses, etc. – as charged to wholesale load obligations). Ancillary service cost data was obtained from ISO-NE's Wholesale Load Cost reports for the NH zone.
[9] Ancillary service cost data obtained from ISO-NE's Wholesale Load Cost reports for the NH zone.

Step 2: Forecast Hourly Ancillary Service Prices (2021-2035)

- Multiply the 8760 ancillary avoided cost template from Step 1 by the forecasted wholesale energy prices (2021 to 2035) to develop hourly ancillary service price and wholesale load obligation avoided cost projections.

C.3.4 Inputs, Assumptions, and Notes

Inputs

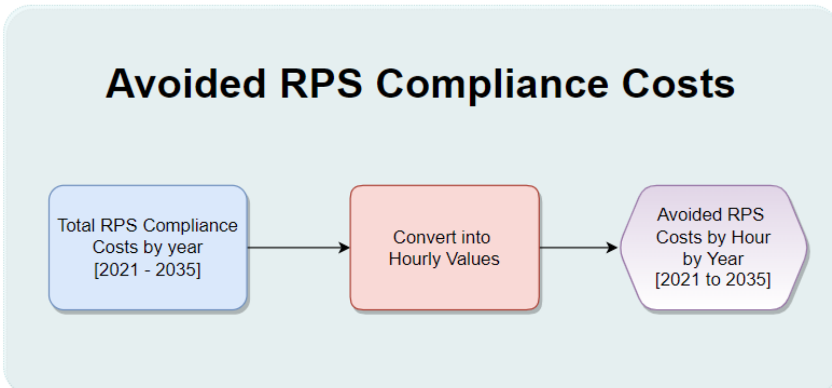
Inputs	Sources
Wholesale Hourly Energy Prices	AESC 2021 study (Counterfactual #2)
Wholesale Ancillary and Load Charges	ISO-NE wholesale monthly reports by zone

C.4 RPS Compliance

C.4.1 Rationale

The AESC Study provides RPS compliance avoided cost forecasts by state, which quantify the avoided costs attributable to reducing the load on which the RPS obligations are assessed. The value of RPS avoided costs is calculated for each sector, accounting for the share of energy produced by DG that is expected to be consumed behind-the-meter and the share expected to be exported back to the grid.[10] Therefore, for this analysis, it is assumed that the avoided RPS compliance costs (per MWh) are equal to the weighted statewide compliance costs across all RPS classes as forecast in the AESC 2021 Study.

C.4.2 Model Map



Overview: The AESC provides RPS compliance avoided cost forecasts by state which summarize the expected cost of meeting RPS obligations

C.4.3 Avoided Cost Methodology

Step 1: Calculate the Total Annual RPS Compliance Costs (2021-2035)

- Sum the RPS compliance costs from the AESC 2021 study for each New Hampshire RPS Class, for each study year (2021 to 2035), under Counterfactual #2.[11] The following RPS classes are included:

RPS Class	Eligibility Notes
Class I	Includes New Non-Thermal
Class I (Thermal)	Thermal Carve out
Class II	New Solar Only
Class III	Existing biomass and methane
Class IV	Existing Small hydro

[10] RPS compliance costs are proportional to retail sales. Reductions in retail sales through behind-the-meter consumption reduces RPS compliance costs, while electricity exported back to the grid does not.
[11] The RPS compliance costs are weighted based on the RPS requirement and expressed as a percentage for each Class.

- Convert to customer sector-specific hourly values by multiplying RPS compliance costs by the behind-the-meter consumption expected for each sector, as outlined in the table below. Apply the avoided cost value to all hours in each respective study year.

Customer-Generator Type	Behind-the-Meter Consumption (% of Total Production) [12]
Residential	38% (hourly netting)
Commercial	24% (hourly netting)
Large Group Host Commercial Solar	0%
Micro Hydro	0%

C.4.4 Inputs, Assumptions, and Notes

Inputs

Inputs	Sources
RPS Compliance Costs (All Classes)	AESC 2021 study (Counterfactual #2)

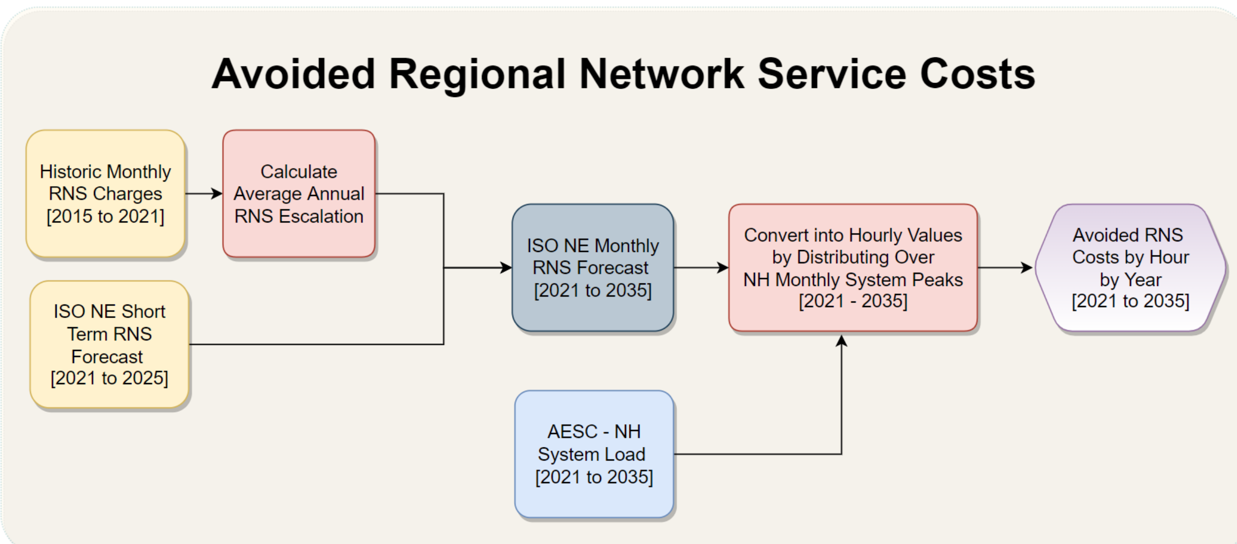
[12] For the purpose of the value stack assessment, we calculated the hourly netting from a south-facing solar PV system then applied this assumption to the west-facing and south-facing solar with storage systems within a given sector. Although the current NEM tariff in New Hampshire uses monthly netting for systems less than 100 kW, hourly netting is an emerging practice used in VDER studies conducted in other jurisdictions given its ability to realize temporal values more granularly.

C.5 Transmission Charges

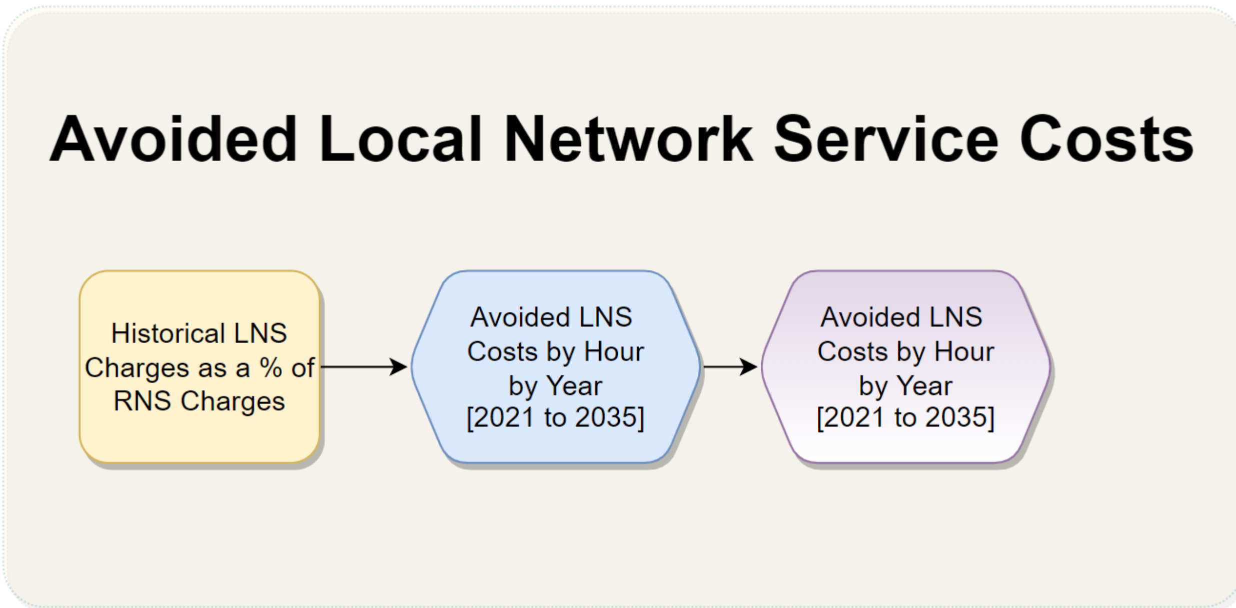
C.5.1 Rationale

RNS and LNS charges are collected to cover the cost of upgrading and maintaining regional bulk transmission infrastructure and localized facilities. Costs are assessed monthly based on a utility's demand that coincides with the peak load hour on the relevant transmission system. Therefore, from a New Hampshire utility perspective, reductions in monthly coincident system peak load attributable to DG resource production will decrease the allocation of RNS and LNS charges assessed to New Hampshire utilities, and thus to ratepayers in the state, representing avoided transmission charges based on DG production. Short-term NEPOOL Reliability Committee/Transmission Committee transmission charge forecasts were found to exceed AESC avoided cost forecasts.[13] Given the discrepancy, these short-term forecasts were used, as described below.

C.5.2 Model Map



[13] The 2021 AESC estimated the PTF avoided cost as $99 per kW-year (2021$). The RNS charge in 2021, as approved by FERC was $140 per kW-year from June 2021 onwards: https://www.iso-ne.com/static-assets/documents/2016/05/rto_bus_prac_sec_2.pdf



Overview: Load cost reports published by ISO-NE used to establish historic monthly RNS and LNS charges in $/kW-month (2016 to 2020).

C.5.3 Avoided Cost Methodology

Step 1: Establish Historic Monthly RNS and LNS Rates (2016-2020)

- Use ISO-NE Load Cost Reports to establish historic monthly RNS and LNS rates for 2016-2020. Use this to calculate historic LNS charges as a portion of historic RNS charges.[14] Include all RNS and LNS cost categories (i.e., infrastructure, reliability, and administrative cost categories) that are allocated based on Monthly Regional Network Load. Adjust rates to $2021 real values for comparison purposes.

Step 2: Establish Projected Monthly RNS and LNS Rates (2021-2035)

- Forecast forward-looking monthly RNS rates using 1) short-term RNS forecasts published by ISO-NE (for near-term study years),[15] 2) the assumption that LNS charges are a fixed percentage of RNS charges, based on historic trends.[16]

[14] The LNS charges vary considerably from month to month so are a challenge to forecast. As a simplifying approach, we reviewed historic monthly LNS charges as a % of RNS charges over the 2016 to 2020 time frame. On average, LNS charges were 22% of RNS charges during this time frame.
[15] NEPOOL Reliability Committee/Transmission Committee. (2020). RNS Rates: 2020-2024 PTF Forecast. Source: https://www.iso-ne.com/static-assets/documents/2020/08/a02_tc_2020_08_19_rns_5_year_forecast.pptx
[16]Here, LNS charges were assumed to remain constant at 22% of RNS charges. In reality, LNS charges are not a fixed percent of RNS charges and in fact fluctuate from month-to-month – this is a simplifying assumption that uses the average LNS charges as a percent of RNS charges from 2016-2020.

Step 3: Distribute Monthly RNS and LNS Charges by Hour

A) Establish Monthly Peak Load Hours

- Determine each utility's historic monthly Regional Network Load (RNL) – i.e., demand on the New Hampshire transmission network coinciding with the system peak load for each month. Then, based on historic RNL data (over the past 5 years), define the peak hour for each month in the year.

B) Convert Monthly into Hourly Values

- Distribute monthly RNS and LNS charges over the monthly peak hours by multiplying the calculated rates by utility peak contributions across the study year to generate hourly avoided cost values.

Step 4: Establish Hourly Avoided Transmission Charge Costs by Year

- Repeat this process for each forecasted monthly RNS and LNS charge to generate hourly avoided transmission charges for each year of the study period.

C.5.4 Inputs, Assumptions, and Notes

Inputs

Inputs	Sources
Historic RNS Charges	ISO-NE Load Cost Reports
Historic LNS Charges	Utility data request; docket filings
Forecasted RNS Rates	NEPOOL Reliability Committee/Transmission Committee RNS Rates: 2020-2024 PTF Forecast[15]
Regional Network Load	ISO-NE RNL Reports[17]

C.6 Transmission Capacity

This criterion was assessed qualitatively. The rationale and the sources used to inform this assessment are included in the body of the report.

C.7 Distribution Capacity

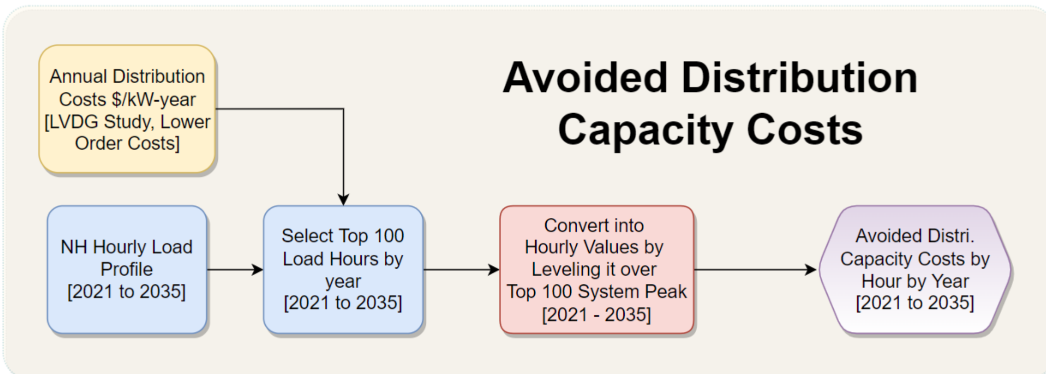
C.7.1 Rationale

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

[17] ISO-NE. (2021). Monthly Regional Network Load Cost Report and Historical Regional Network Load Cost Report. Accessible online at: https://www.iso-ne.com/markets-operations/market-performance/load-costs

of Distributed Generation (LVDG) study,[18] 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.

C.7.2 Model Map



C.7.3 Avoided Cost Methodology

Step 1: Annual Distribution Capacity Costs

- Assess actual and planned distribution-related capital expenditures, by utility, to determine which expenditures are load-related and what components (lower-order and higher-order investments) are included.

- Review utility capital expenditure data and compare it to the LVDG Study results under the base case, which is used to determine which lower-order distribution system investments are not accounted for in that study but could be avoided or deferred as a result of load reductions.

- Use utility data and the LVDG Study to develop an annual per unit ($/kW), system-wide proxy estimate of annual system-wide avoided distribution costs. Use an escalation factor based on inflation to estimate annual distribution capacity costs beyond planned investment needs.[19]

Step 2: Distribute Annual Avoided Distribution Capacity Value by Hour

[18] 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

[19] To the extent possible we used annual avoided cost forecasts from the LVDG study, which are based on a Real Economic Carrying Charge approach. Forecasted lower-order distribution costs were inflation-adjusted.

A) Establish New Hampshire System Load Profiles

- Use New Hampshire zone load profiles in the AESC 2021 study for system load profiles for 2021 through 2035.

B) Establish Distribution of Load During Peak Hours

- Assume distribution system upgrades are driven by reliability concerns associated with the highest distribution peak load hours on the system. Rank the top 100 hours in each year (2021-2035) to select the distribution system peak hours.

- Establish the weighted average of the total sub-set of load during each month/hour pairs. For example, the table below (based on NH 2021 system load) demonstrates that, during the highest load hours, 3.3 percent of load occurs in January from 5-7pm (i.e., hour beginning at 17).

		Month											
		1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
	Number of Days:	*15*	*6*	*0*	*0*	*0*	*5*	*13*	*11*	*2*	*0*	*0*	*11*
Hour Beginning	**0**	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	3	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	7	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	8	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.4%	1.1%	0.0%	0.0%	0.0%	0.0%
	9	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	2.4%	1.6%	0.0%	0.0%	0.0%	0.0%
	10	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%	2.7%	2.1%	0.0%	0.0%	0.0%	0.0%
	11	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	3.0%	2.2%	0.0%	0.0%	0.0%	0.0%
	12	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	3.1%	2.4%	0.2%	0.0%	0.0%	0.0%
	13	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	3.1%	2.4%	0.4%	0.0%	0.0%	0.0%
	14	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	3.1%	2.4%	0.4%	0.0%	0.0%	0.0%
	15	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	3.1%	2.4%	0.4%	0.0%	0.0%	0.0%
	16	0.2%	0.0%	0.0%	0.0%	0.0%	1.1%	3.1%	2.4%	0.4%	0.0%	0.0%	0.4%
	17	3.3%	0.4%	0.0%	0.0%	0.0%	0.7%	3.0%	2.4%	0.4%	0.0%	0.0%	2.4%
	18	3.3%	1.3%	0.0%	0.0%	0.0%	0.7%	2.7%	2.1%	0.4%	0.0%	0.0%	2.4%
	19	2.3%	0.8%	0.0%	0.0%	0.0%	0.7%	2.3%	1.9%	0.4%	0.0%	0.0%	1.7%
	20	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	2.0%	2.1%	0.2%	0.0%	0.0%	0.4%
	21	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	2.0%	1.6%	0.0%	0.0%	0.0%	0.0%
	22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	0.4%	0.0%	0.0%	0.0%	0.0%
	23	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

C) Establish Hourly Avoided Distribution Costs by Year

- Distribute the annual $/kW avoided distribution cost from Step 1 across hours in a given year based on the peak load hour determination performed in Step 2.B.

    - Note: If a DG system's output covered all of the peak hours, it would realize 100% of the avoided distribution cost value.

- Complete this process for each year of the study through 2035.

C.7.4 Inputs, Assumptions, and Notes

Inputs

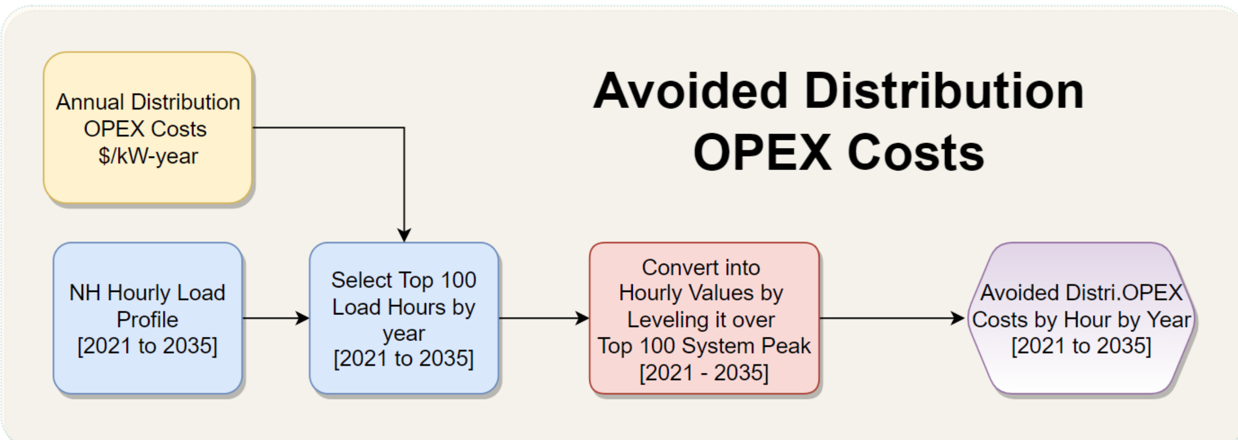
Inputs	Sources
Distribution Capital Expenditure Proxy Value	Utility data and interviews
	LVDG Study
NH System Load Profiles	Utility Data Requests
	AESC 2021 study forecasts

C.8 Distribution System Operating Expenses

C.8.1 Rationale

Utilities incur costs to maintain the safe and reliable operation of distribution facilities, which includes maintenance of substations, wires, and poles and repairs and replacements of portions of the distribution system over time. These costs are variable and partially a function of the volume of energy transferred through the system. While this criterion may be a cost and/or avoided cost stream – reflecting an increase or decrease in costs associated with infrastructure and services as a result of DG deployment – for this assessment, we assume that it is a positive avoided cost value and that any costs incurred rather than avoided are achieved under the T&D System Upgrades criterion.

C.8.2 Model Map



C.8.3 Avoided Cost Methodology

Step 1: Annual Distribution OPEX Costs

Ask the utilities to identify distribution system operating expense budget items that could be offset through reduced load. Normalize these costs by expected load increases during the same time period.

Step 2: Distribute Annual Avoided Distribution OPEX Value by Hour

- Assume distribution system operational costs are largely driven by the highest load hours on the system. Rank the top 100 hours in each year (2021-2035) to select the distribution system peak hours.
- Distribute the annual $/kW avoided distribution cost across hours in a given year based on the peak load hour determination performed for the Distribution Capacitycriterion.

C.8.4 Inputs, Assumptions, and Notes

Inputs

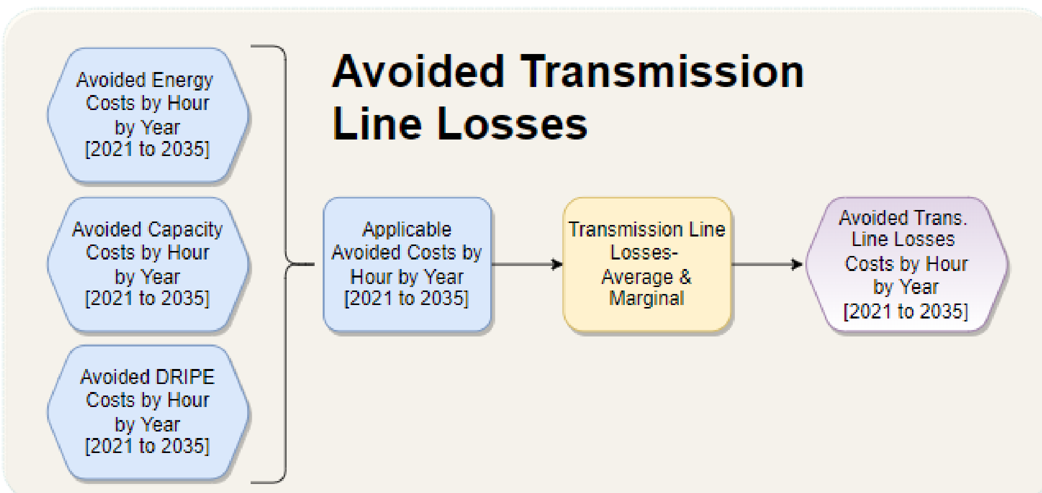
Inputs	Sources
Distribution OPEX Expenditure Proxy Value	Utility data and interviews
	FERC Form 1 Filings
NH System Load Profiles	Utility Data Requests
	AESC 2021 study forecasts

C.9 Transmission Line Losses

C.9.1 Rationale

The electricity generated by customer-sited DG resources reduces the amount of energy that would otherwise be distributed through the transmission network. Any surplus energy exported to the system from the DG resources is assumed to be contained within the distribution network, and therefore no transmission backflow occurs due to surplus energy. The avoided transmission line losses apply to the total energy produced by the distributed energy resource. To note, this avoided cost criterion is a cumulative value, incorporating line loss values from all relevant avoided cost criteria: energy, capacity, and wholesale market price suppression. In other words, any inherent value from avoiding transmission line losses attributable to those other criteria has been pulled out (to avoid double-counting) and is included here in this stand-alone transmission line loss criterion.

C.9.2 Model Map



C.9.3 Avoided Cost Methodology

Step 1: Establish an Appropriate Line Loss Factor

- Assess transmission line loss factors from NH electric distribution utilities, AESC 2021, and other relevant valuation studies to determine an appropriate system-wide transmission line loss factor.
- Apply marginal line loss factors to the top 100 NH system peak hours in a year, and average line loss values to the remaining hours.[20]

[20] Line losses vary as a function of grid conditions. During peak loading periods losses can be higher as a result of increased current flows. Average transmission line losses were estimated to be 2.5% while marginal line losses were estimated to be 3.75% (1.5 times the average line loss factors). This assumption was established in a previous study from the Regulatory Assistance Project (RAP) available here.

Step 2: Calculate Historic and Forecasted Hourly Avoided Costs

- Multiply the transmission line loss factor for a given hour by the following avoided cost values for that hour to determine the hourly avoided transmission line loss values:[21]
  - Hourly avoided energy costs (See C.1.)
  - Hourly avoided capacity costs (See C.2.)
  - Hourly avoided DRIPE (See C.11.)

C.9.4 Inputs, Assumptions, and Notes

Inputs:

Inputs	Sources
Transmission Line Losses	AESC 2021 study, NH Utility Data Request (primary), RAP Study (secondary)
NH System Load Profiles	AESC 2021 study, NH Utilities

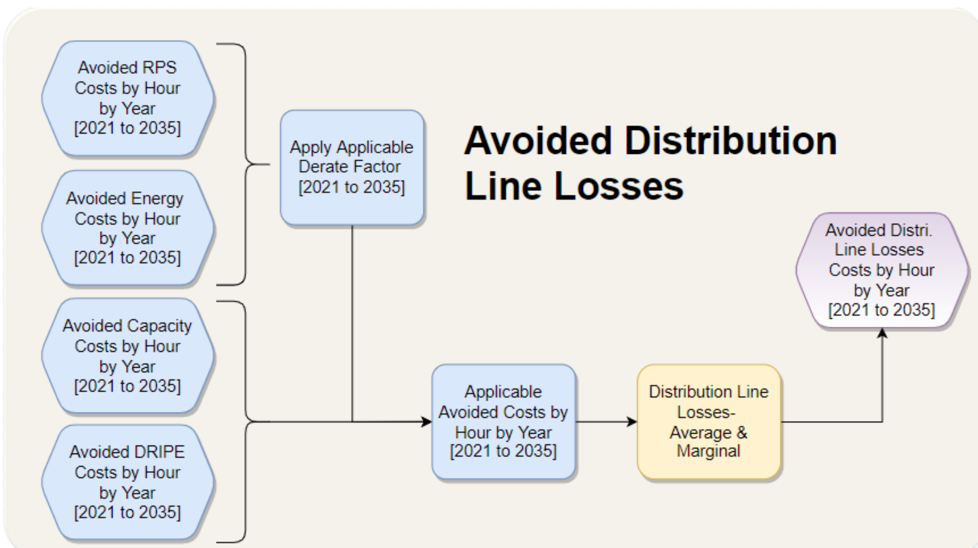
[21] This is consistent with the approach laid out in Table 136 in the AESC.

C.10 Distribution Line Losses

C.10.1 Rationale

The electricity generated by customer-sited DG resources reduces the amount of energy that would otherwise be distributed through the distribution network. Any surplus energy exported back to the grid is assumed to be distributed within the distribution network. Therefore, the avoided distribution line losses apply only to the behind-the-meter or self-consumed portion of the energy produced by the distributed energy resource. To note, this avoided cost criterion is a cumulative value, incorporating line loss value from all relevant avoided cost criteria: energy, capacity, RPS compliance and wholesale market price suppression. In other words, any inherent value from avoiding distribution line losses attributable to those other criteria has been pulled out (to avoid double-counting) and is included here in this stand-alone distribution line loss criterion.

C.10.2 Model Map



C.10.3 Avoided Cost Methodology

Step 1: Establish an Appropriate Line Loss Factor

- Gather sector-specific distribution line loss factors from New Hampshire electric distribution utilities. Apply sector-specific marginal line loss factors to the top 100 NH system peak hours in a year, and sector-specific average line loss factors to the remaining hours.[22]

[22] Line losses vary as a function of grid conditions. During peak loading periods losses can be higher because of increased current flows. Average distribution line losses were estimated to be 7.5% for the residential sector and between 4.4% and 6.4% commercial sector, while marginal line losses were estimated to be 1.5 times the average line loss factors. This assumption was established in a previous study from the Regulatory Assistance Project (RAP) available here.

Step 2: Apply Distribution Line Losses

- Calculate an appropriate derate factor – which is used to reduce the volume of energy produced such that line loss avoided costs only apply to energy that is consumed behind-the-meter – for each customer class and system archetype.
- Calculate line losses for each customer-generator sector and for each hour by multiplying the line loss factor for a given hour by the following avoided cost values in that hour and the derate factor to determine the hourly avoided distribution line loss values:
    - Hourly avoided energy costs (See C.1.)
    - Hourly avoided capacity costs (See C.2.)
    - Hourly avoided RPS costs (See C.4.)
    - Hourly avoided DRIPE (See C.11.)

C.10.4 Inputs, Assumptions, and Notes

Inputs

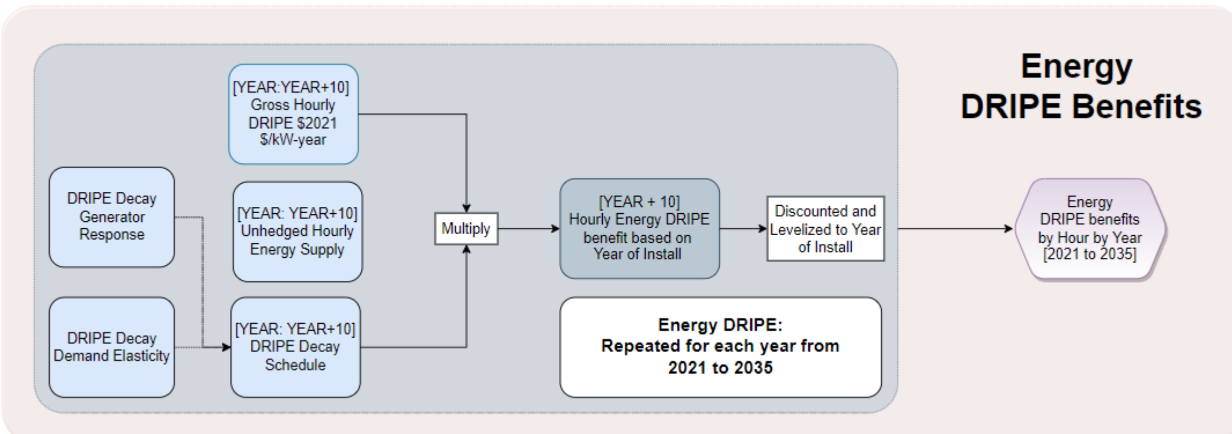
Inputs	Sources
Distribution Line Losses	AESC 2021 study, NH Utility (primary), RAP Study (secondary)
NH System Load Profiles	AESC 2021 study, NH Utilities

C.11 Wholesale Market Price Suppression

C.11.1 Rationale

The electricity produced at the customer-generator's site reduces the overall energy and capacity procured through the wholesale market, resulting in lower market clearing prices. This price suppression effect, also known as Demand Reduction Induced Price Effect, or DRIPE, is ultimately passed on to all market participants. 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 reduce electricity prices (Electric-to-Gas-to-Electric Cross-DRIPE).

C.11.2 Model Map – Energy DRIPE



C.11.3 Avoided Cost Methodology– Energy DRIPE

Step 1: Calculate Energy DRIPE for Each Study Year (2021-2035)

a) Calculate Net Energy DRIPE

- Use gross energy DRIPE wholesale values (based on Counterfactual #2 scenario and intrazonal-only values for New Hampshire) from the AESC 2021 study as the starting point for each study year, The values reflect four periods: summer on-peak, summer off-peak, winter on-peak, and winter off-peak.

- Multiply gross energy DRIPE by the percentage of unhedged energy supply in New Hampshire – i.e., the portion of energy purchased on the spot market.

- Multiply the values by the energy DRIPE benefits decay schedule, which varies based on year of DER installation. The benefits decay schedule reflects a lower DRIPE value in future years as a) existing generating resources respond to lower prices by becoming less efficient, and b) customers respond to lower energy prices by increasing demand. To note, based on the methodology in the AESC 2021 study, energy DRIPE value persists for 11 years, including the year of installation.

b) Levelize to Year of Installation

- Discount the series of four net energy DRIPE values for each study year (e.g., for 2021: 2021 to 2031 summer on-peak; 2021 to 2031 summer off-peak; 2021 to 2031 winter on-peak; and 2021-2031 winter off-peak), then calculate the levelized values for the year of installation to develop four net energy DRIPE values for each study year.

Step 2: Convert to Hourly Values

- Convert the four season/peak period values[23] into 8760 hourly values using the following assumptions:
    - The summer on-peak value is applied to the corresponding ISO-NE summer months and on-peak hours. The summer off-peak value is applied to the corresponding ISO-NE summer months and off-peak hours.
    - The winter on-peak value is applied to the corresponding ISO-NE winter months and on-peak hours, while the winter off-peak value is applied to the winter off-peak hours.
- This conversion to hourly values for each year is repeated for all study years (2021-2035).

C.11.4 Inputs, Assumptions, and Notes– Energy DRIPE

Inputs	Sources
Gross Energy DRIPE Forecast	AESC 2021 study*

**See note 2, below.*

Assumptions and Notes

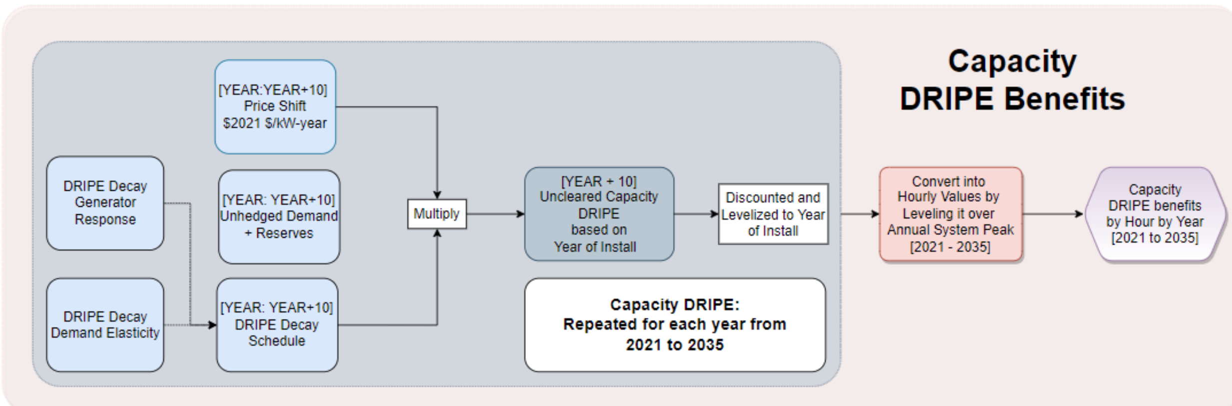
- For systems installed in 2021, the annual energy DRIPE persist through 2031. This is because the AESC assumes that the DRIPE effect decays over time because owners of existing generating resources, in response to lower energy and capacity prices, would allow their assets to become less efficient and reliable, while customers might respond to lower energy prices by using more energy.

[23] These time periods are defined by ISO-NE as follows: Winter on-peak is October through May, weekdays from 7am to 11pm; winter off-peak is October through May, weekdays from 11 p.m. to 7 a.m., plus weekends and holidays; summer on-peak is June through September, weekdays from 7 a.m. to 11 p.m.; and summer off-peak is June through September, weekdays from 11 p.m. to 7 a.m., plus weekends and holidays

- The DRIPE values from 2021 to 2025 are available in the AESC 2021 Counterfactual Workbook #2. However, because the AESC study does not include values beyond 2025, those DRIPE values are modelled outside the workbook by applying the appropriate decay schedule (corrected for customer demand elasticity and generation effects) to the unhedged energy portion and gross DRIPE values.

- The intrazonal DRIPE values are proportional to the percentage of the zonal load with respect to the ISO-NE system load. Therefore, zones with less load will have lower zone-on-zone energy DRIPE values than zones with higher load.

C.11.5 Model Map – Capacity DRIPE



C.11.6 Avoided Cost Methodology – Capacity DRIPE

Step 1: Calculate Capacity DRIPE for Each Study Year (2021-2035)

c) Calculate Uncleared Capacity DRIPE

- For each study year, multiply New Hampshire's zonal unhedged demand (from the AESC 2021 Counterfactual #2 workbook), plus a reserve margin, by a benefit decay schedule based on the useful life of the DER and by the applicable annual price shift (which is expressed as $/MW-year per MW).[24] As with energy DRIPE, capacity DRIPE value is assumed to persist for 11 years, including the year of installation.

d) Levelize to Year of Installation

- Generate a series of uncleared capacity DRIPE values for each study year (e.g., for 2021, values are generated for 2021 through 2031), and then discount those values and calculate the levelized values for the year of installation.

[24] The uncleared capacity DRIPE methodology is used as the DG resources are not capacity market participants and therefore their impact on capacity wholesale market prices is linked to changes in unhedged load. Further, unlike other avoided cost components, this is a market impact (benefit) and not a potentially avoided cost that would be allocated through a market.

Step 2: Convert to Hourly Values

- Convert the annual values into 8760 hourly values by distributing the value over a set of peak hours based on an effective load carrying capability (ELCC) approach.[25] Repeat this conversion to annual hourly values for all study years (2021-2035).

C.11.7 Inputs, Assumptions, and Notes – Capacity DRIPE

Inputs

Inputs	Sources
Uncleared Capacity DRIPE Forecast	AESC 2021 study*
Reserve margin	AESC 2021 study

**See note 2, below.*

Assumptions and Notes

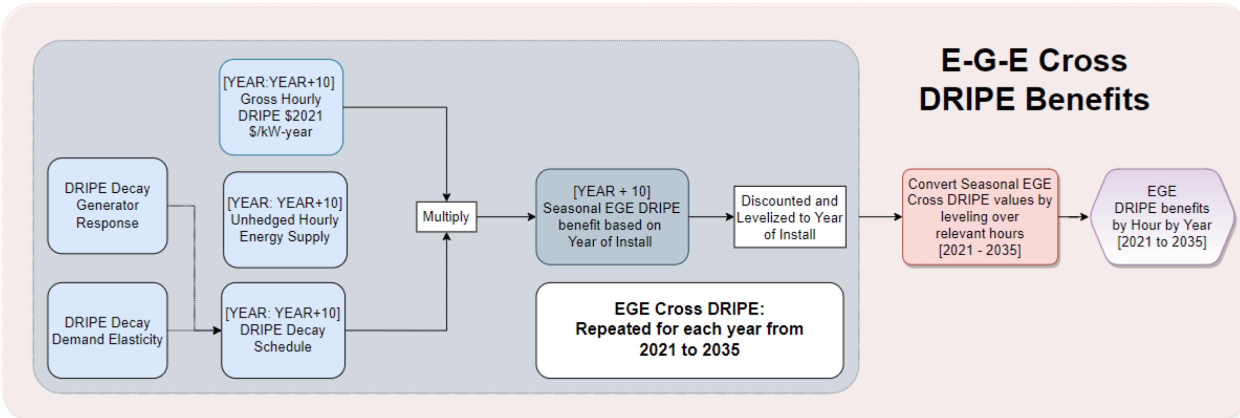
- For systems installed in 2021, the annual capacity DRIPE persist through 2031. This is because the AESC 2021 study assumes that the DRIPE effect decays over time because owners of existing generating resources, in response to lower energy and capacity prices, would allow their assets to become less efficient and reliable, and customers might respond to lower energy prices by using more energy.

- The DRIPE values from 2021 to 2025 are available in the AESC 2021 Counterfactual Workbook #2. However, because the AESC study does not include values beyond 2025, those DRIPE values are modelled outside the workbook by using the appropriate decay schedule (corrected for customer demand elasticity and generation effects).

- The intrazonal DRIPE values are proportional to the percentage of the zonal load with respect to the ISO-NE system load. Therefore, zones with less load will have lower zone-on-zone Capacity DRIPE values than zones with higher load.

[25] ISO-NE has indicated that it will employ an ELCC approach for assessing resource capacity contribution to resource adequacy in the Forward Capacity Market. Because a strict application would require probabilistic modelling, a simplified approach is used here.

C.11.8 Model Map – Electric-to-Gas-to-Electric Cross DRIPE



C.11.9 Avoided Cost Methodology – Electric-to-Gas-to-Electric Cross DRIPE

Step 1: Calculate Electric-Gas-Electric Cross DRIPE for Each Study Year (2021-2035)

e) Calculate Electric-Gas-Electric Cross DRIPE for Summer and Winter

- For each study year, multiply New Hampshire's zonal unhedged energy demand (from the AESC 2021 Counterfactual #2 workbook) by a decay schedule based on the useful life of the DER multiplied by the applicable Electric-Gas-Electric coefficient (which is expressed as $/TWh per MWh/Period Reduced). As with energy DRIPE, Electric-Gas-Electric Cross DRIPE value persists for 11 years, including the year of installation.

f) Levelize to Year of Installation

- Generate Electric-Gas-Electric Cross DRIPE values for each study year (e.g., for 2021, values are generated for 2021 through 2031), and then discount those values and calculate the levelized values for the year of installation.

Step 2: Convert to Hourly Values

- Convert the seasonal $/kWh values (summer/winter) by distributing over the hours corresponding to each season. This conversion to hourly values is repeated for each year of the study period (2021-2035).

C.11.10 Inputs, Assumptions, and Notes – Electric-to-Gas-to-Electric Cross DRIPE

Inputs

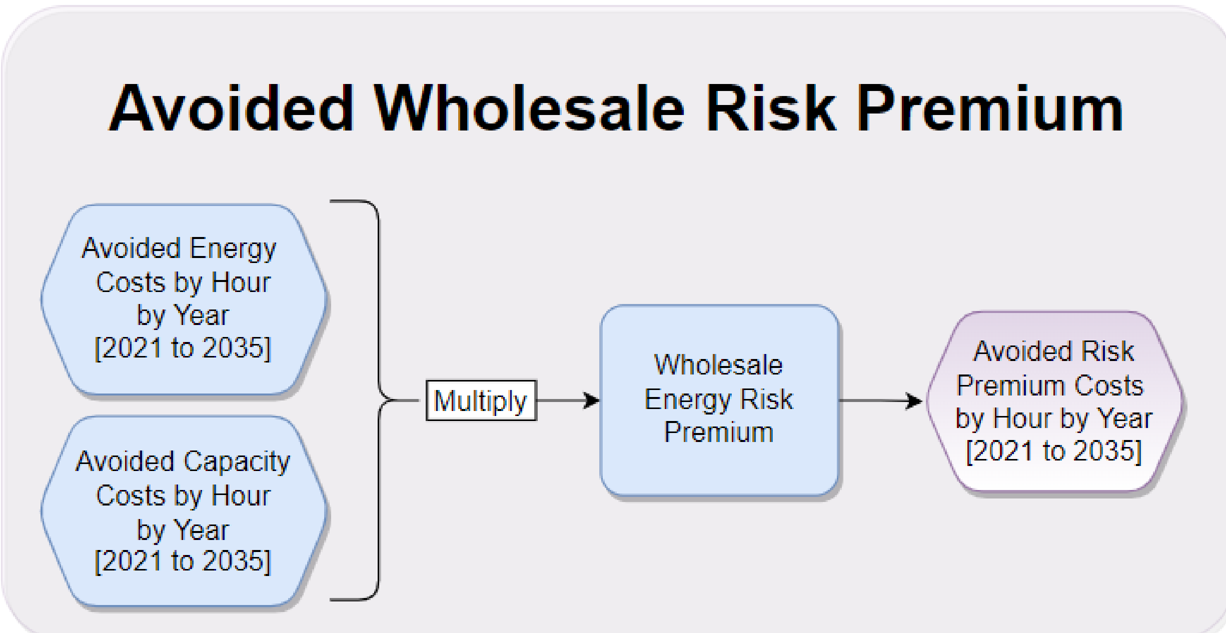
Inputs	Sources
E-G-E DRIPE Coefficients	AESC 2021 study

C.12 Hedging/Wholesale Risk Premium

C.12.1 Rationale

The full retail price of electricity is generally greater than the sum of the wholesale market prices for energy, capacity, and ancillary services. In part, this is because the wholesale suppliers of retail customer load requirements incur various market risks when they set contract prices in advance of supply delivery periods. Therefore, every reduction in wholesale energy and capacity obligations may reduce the supplier's cost to mitigate such risks.

C.12.2 Model Map



C.12.3 Avoided Cost Methodology

Step 1: Determine Risk Premium

- Use a literature review of other studies, utility-specific data, and the AESC 2021 study to determine the most appropriate value for this study[26].

Step 1: Apply to Wholesale Energy and Capacity Costs

- Apply the risk premium to wholesale hourly energy prices (historical and forecasted), including T&D line losses.

[26] AESC 2021 applies the same wholesale risk premium of 8% to avoided wholesale energy prices and to avoided wholesale capacity prices,

- Similarly, multiply wholesale hourly capacity prices (historical and forecasted), including T&D line losses, by the wholesale risk premium value.

- Calculate the total wholesale risk premium by summing of the wholesale energy risk premium and the wholesale capacity risk premium.

C.12.4 Inputs, Assumptions, and Notes

Inputs:

Inputs	Sources
Wholesale Risk Premium	AESC 2021 study, utility-specific data, and other sources

Assumptions and Notes

- In keeping with the approach used in the AESC 2021 study, the same wholesale risk premium is applied to avoided wholesale hourly energy prices and avoided wholesale hourly capacity prices.
- Retail suppliers mitigate some risk by hedging their costs in advance, but there is still uncertainty in the final price borne by the supplier. The wholesale risk premium reflects suppliers' costs to mitigate wholesale risks associated with unavailable resources and changes in load. As such, it is applied to retail sales, and thus total wholesale energy and capacity costs must be adjusted upward to account for T&D line losses.

C.13 Distribution Utility Administration Costs

C.13.1 Rationale

An increase in solar installed capacity may affect associated electric distribution utility administration costs, including NEM program administration, metering, billing, collections, unreimbursed interconnection costs, evaluation, and load research.

C.13.2 Avoided Cost Methodology

Step 1: Develop DG-Related Costs to Utilities

- Gather NEM program administration costs associated with metering and billing, collections, unreimbursed interconnection costs, evaluation, load research, etc. from the electric distribution utilities.
- The applicable cost inputs – metering, program administration, interconnection and engineering costs were bundled together as utility administration costs. The administration costs were developed on a per-installation basis and appropriately scaled based on the DG forecasts developed for each utility and segment.
- Levelize these costs over solar forecasts to estimate the program administration costs by year.

C.13.3 Inputs, Assumptions, and Notes

Assumptions:
NEM program credits for customer-generator net exports are not accounted for under this cost component, which covers costs specific to NEM program implementation and administration and are not directly attributable to DG deployment levels.

C.14 Transmission and Distribution System Upgrades

C.14.1 Rationale

In the context of this study, the Transmission and Distribution System Upgrades component is an incurred cost item. It encompasses all costs related to transmission and distribution system upgrades that are driven by the addition of net-metered DG to the grid, with the exception of those covered by DG customer payments or reimbursements. However, it is challenging within the scope of this study to isolate those transmission and distribution system upgrade costs that are attributable to DG installations or any investments funded by DG customers that result in avoided costs or benefits to other ratepayers. As such, a qualitative review was completed for this criterion and the findings are included in the main body of the report.

C.15 Environmental Externalities

C.15.1 Rationale

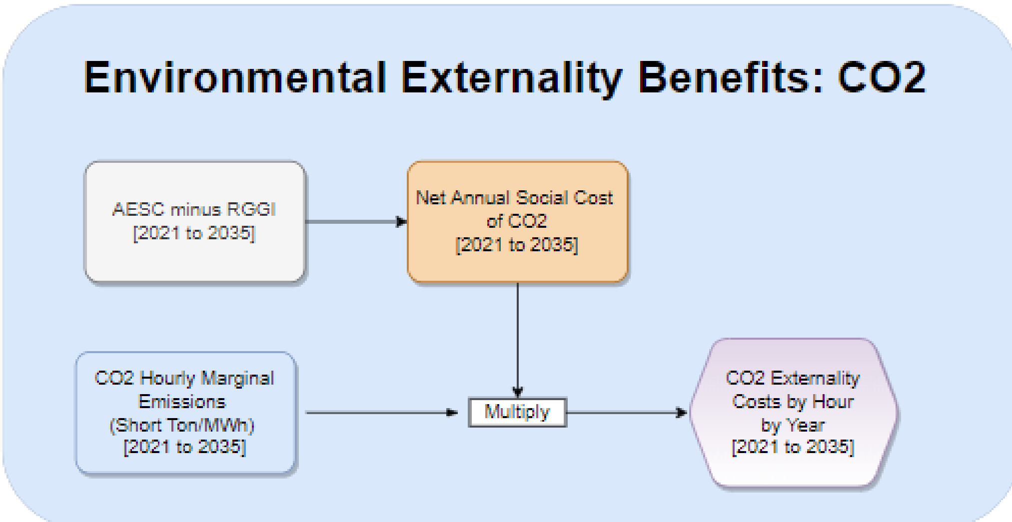
The electricity generated from a DG resource may reduce marginal emissions from fossil fuel plants. A portion of the avoided costs of such reduced emissions are already included as environmental program compliance costs embedded in wholesale energy prices. This study sensitivity focuses on evaluating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

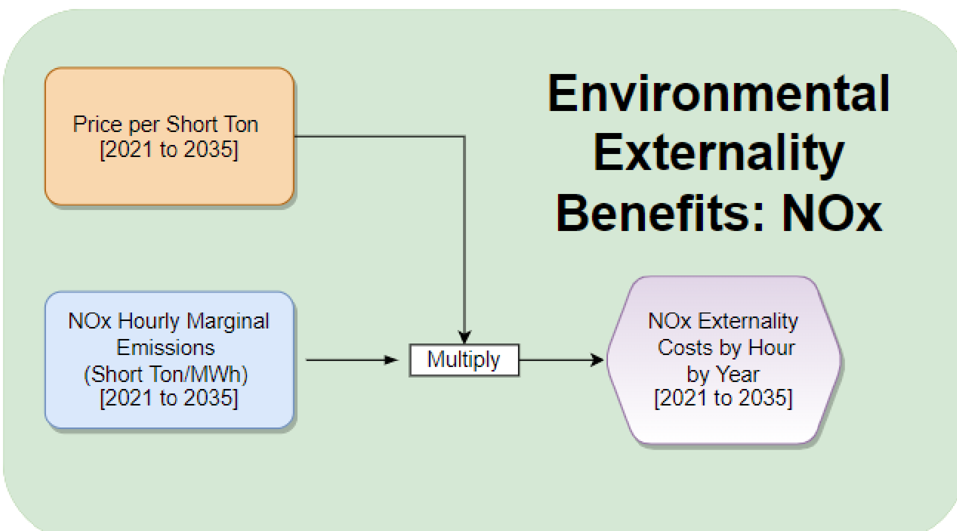
SO_2 emissions: The AESC 2021 study assumes that all coal-fired generation, the primary source of SO_2 emissions from electricity generation, is taken offline by 2025. For this analysis, the value of SO_2 emissions is assumed to be minimal and therefore it is not included in the environmental externalities value.

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.

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. 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.

C.15.2 Model Map





C.15.3 Avoided Cost Methodology

Step 1: Calculate Environmental Externality Benefit of CO_2 (2021-2035)

- Select the social cost of carbon forecast from the AESC 2021 study (October 12, 2021)[27] (based on the 2% discount rate) as the gross Social Cost of Carbon (SCC, $/short ton).[28]

---

[27] Of the two approaches to estimate the cost of carbon, the marginal abatement cost test is challenging from a regional perspective, given that several variables such as technology price, technical potential and policies change over a period of time.

[28] This AESC SCC scenario is based on the New York State SCC – which was developed while the federal SCC was suspended. We believe this is an appropriate scenario for the VDER study, in view of the regional proximity to and similarities between New York

- Calculate the net SCC for each year by calculating the difference between the forecasted gross SCC and forecasted RGGI allowance prices. As RGGI allowance prices are already embedded in wholesale energy market prices, these are subtracted from the gross SCC values to establish a net SCC over the study period.
- Multiply the net SCC by the corresponding AESC 8760 hourly marginal emission rates (short ton per MWh) (2021 to 2035), as outlined in the AESC 2021 study workbooks, to determine the environmental externality avoided cost for CO_2.

Step 2: Calculate Environmental Externality Benefit of NO_x (2021-2035)

- Note that the AESC 2021 study assumes no embedded NO_x prices, because the New England states are exempt from the CSAPR program and state specific regulations in Massachusetts and Connecticut are unlikely to be binding. Therefore, the externality benefit of NO_x is equal to the AESC price per short ton of NO_x with no further adjustment. The value of the externality benefit of NO_x for this study was $14,700 per short ton throughout the study period.
- Multiply the price per short ton of NO_x in AESC 2021 by the corresponding AESC 8760 hourly marginal emission rates (2021 to 2035), as outlined in the AESC study workbooks, to determine the environmental externality benefit for NO_x.

C.15.4 Inputs, Assumptions, and Notes

Inputs

Inputs	Sources
CO_2 Marginal Emissions Rates	AESC 2021 study
Societal Cost of Carbon (2% discount rate scenario)	AESC 2021 study (October 2021 update), NYS SCC
RGGI Allowance Price Forecast	AESC 2021 study
NO_x Marginal Emissions Rates	AESC 2021 study
Short Ton Price of NO_x	AESC 2021 study

and the New England states in terms of energy landscape and policy context. Moreover, the NYS SCC Guideline values consider the global impact of emissions, use reasonable discount rates, and consider high impact events through low discount rates. The net SCC (after removing RGGI) ranged from $111 per short ton to $128 per short ton from 2021 to 2035.

Assumptions:

- The environmental externalities benefit associated with avoided Transmission and Distribution Line Losses have been included in the environmental externalities avoided cost component because this avoided cost component is treated as a sensitivity in the study.

C.16 Distribution Grid Support Services

C.16.1 Rationale

Generally speaking, this component may be an incurred cost or an avoided cost, reflecting an increase or decrease in costs associated with distribution system support services required as DG resource penetration increases. For the purpose of this study, this criterion is assumed to represent an avoided cost stream, with any incurred costs included under the T&D System Upgrades component. This criterion was evaluated using a qualitative review.

C.17 Resilience Services

C.17.1 Rationale

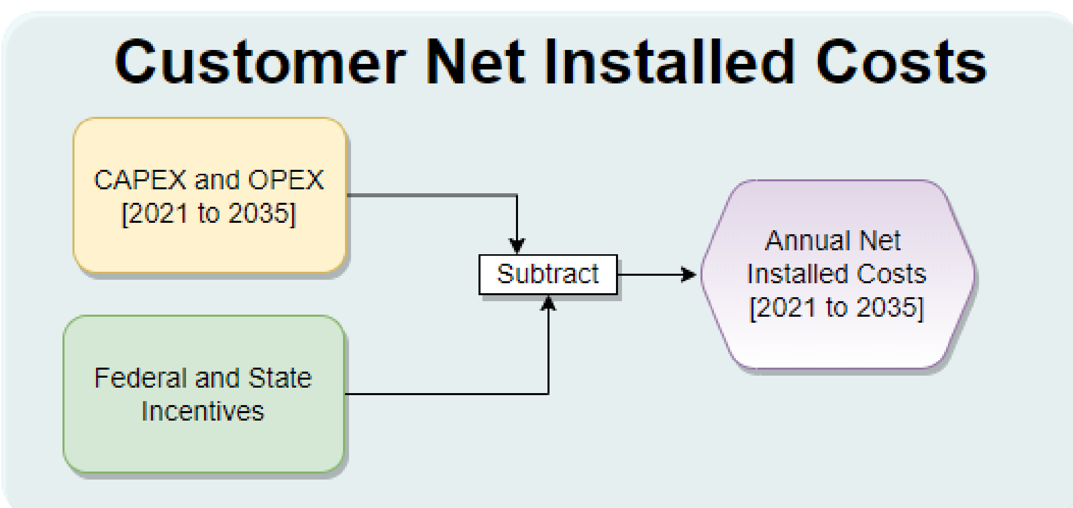
In this study, resilience services are defined as the ability of DERs to provide back-up power to a site in the event that it loses utility electricity service.[29] Resiliency has the potential to provide significant value, although this value is expected to be highly context-specific. This criterion was assessed using a qualitative review.

C.18 Customer Installed Costs

C.18.1 Rationale

This component was not considered as part of the avoided cost value stack, but 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).

C.18.2 Model Map



[29] 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.

C.18.3 Methodology

Step 1: Develop DG Customer's CAPEX and OPEX Projections

- Develop projections of upfront capital costs (CAPEX) and annual operational costs (OPEX[30]) over the lifetime of the DG system, using NREL's Annual Technology Baseline[31].

Step 2: Determine Applicable Federal and State Incentives

- Develop annual incentive projections for solar PV systems based on federal investment tax credits and New Hampshire renewable energy rebates for residential and commercial projects.
- Federal ITC assumed to be applied for residential PV systems (26% until 2022, 22%% in 2023 and 0% after) and commercial and utility-scale PV systems (26% until 2022, 22%% in 2023 and 10% after). ITC assumed to be applied to solar + storage systems as well.

Step 3: Customer Installed Costs

- Calculate customer installed costs over the study period by summing the net present value of the CAPEX and OPEX costs, minus available incentives.
- The costs are expressed as a net $/kW cost as well as a levelized cost per kWh over system production for each system type – residential and commercial solar (south facing and west facing), residential and commercial solar and energy storage and small hydro.

C.18.4 Inputs, Assumptions, and Notes

Inputs

Inputs	Sources
Solar CAPEX and OPEX Costs	NREL's Annual Technology Baseline (ATB)
Solar System Sizes: Residential, Commercial and LGHC[32]	NH Utility Data

[30] Opex costs include admin feed, labor, insurance, land lease payments, operating labour, property taxes, sit security, project management, general (scheduled and unscheduled) maintenance, the annualized present value of large component replacement (inverters) Commercial PV | Electricity | 2021 | ATB | NREL
[31] Data | Electricity | 2021 | ATB | NREL, Capex and opex costs for solar PV (residential, commercial), energy storage costs (residential, commercial) and small hydro were based on the NREL's Annual Technology Baseline
[32] System sizes are align with the system assumptions used throughout the study period.

D. High Load Growth Scenarios Methodology

The value of distributed energy resources will vary to some degree according to projected load growth in New Hampshire. In part, future electricity load forecasts will depend on the deployment of building electrification and transportation electrification technologies. Uncertainty around the future deployment of those technologies, however, translates into uncertainty regarding projected load growth in the state. The High Load Growth Scenarios (HLGS) sensitivity analysis considers several scenarios for increased load growth to investigate the impact of such future load increases on avoided cost value stack criteria.

The following steps outline the approach used to complete the HLGS analysis through the development of three scenarios that estimate a) the incremental impact of electrification on system load, and b) the incremental impact of that electrification on avoided cost criteria in the value stack.

D.1 Estimating Incremental Impact on System Load

The base value stack avoided costs are based in large part on the Avoided Energy Supply Costs in New England (AESC) 2021 study, counterfactual #2 scenario. The HLGS loads are therefore compared to the loads under AESC counterfactual #2 to assess incremental impacts. Building electrification and transportation electrification are varied under multiple scenarios under the HLGS sensitivity analysis, as described below.

The HLGS analysis included three scenarios:

1. Scenario 1: Impact of AESC building electrification (BE)[33]

2. Scenario 2: Impact of AESC building electrification and high transportation electrification[34]

3. Scenario 3: Impact of high building electrification[35] and high transportation electrification

[33] The AESC counterfactual #2 did not include the programmatic resource impacts of building electrification measures, but these impacts were included in counterfactuals #3 and #4. The building electrification measure impact included in counterfactuals #3 and #4 was added to counterfactual #2 to derive Scenario 1.

[34] The AESC included transportation electrification impacts across all four counterfactual scenarios, so some degree of transportation electrification was considered in the base avoided cost values taken from the AESC counterfactual #2 scenario. For HLGS scenarios 2 and 3, transportation electrification was assumed to exceed the AESC assumptions such that light-duty vehicle uptake aligned with a market share target of 26% by 2026, 90% by 2030, and 100% by 2035. Data availability on medium- and heavy-duty vehicle stocks and sales in New Hampshire was limited, so market share targets could not be established. Deployment was instead accelerated over AESC assumptions to align with the modified uptake trends in the light-duty sector, resulting in load impacts that exceeded AESC values by up to 58% at the mid-point of the study, but were approximately aligned with AESC assumptions by 2035.

[35] The high building electrification assumptions included an accelerated timeline for heat pump installations in residential buildings, exceeding AESC assumptions by up to 30% at the study mid-point, and 14% by the study end point.

Scenario	BE	TE
Scenario 1: Impact of BE	AESC	AESC
Scenario 2: Impact of BE and high TE	AESC	High
Scenario 3: Impact of high BE and high TE	High	High

Each scenario's hourly demand curve was compared to the hourly demand curve under the AESC 2021 study counterfactual #2 to estimate incremental load impacts.

D.2 Estimating Incremental Impacts on Avoided Costs

Although load growth may impact the total costs ($) associated with many of the value stack criteria, the focus of this analysis is to understand impacts to the avoided cost per unit energy or unit demand ($/kWh or $/kW). Avoided cost per unit energy or per unit demand impacts may arise for those avoided cost criteria that are impacted by wholesale market adjustments resulting from changes in load. Those adjustments are similar to DRIPE, and in fact the elasticity factors used to calculate impacts (described below) are a precursor to DRIPE.

To calculate the HLGS impacts on avoided costs, the change in hourly demand (or the incremental load impacts) associated with each HLGS scenario are compared to the base case, AESC counterfactual #2. Next, the change in demand is multiplied by the hourly elasticity factor to calculate the percentage change in avoided cost, as shown in the following equation:[36]

$$\%\ change\ in\ avoided\ cost = elasticity\ \times \%\ change\ in\ demand$$

The percent change in avoided cost (avoided cost impact) is calculated for the volumetric (kWh) and demand (kW) criteria. Volumetric avoided cost impacts are calculated using the change in hourly demand between the scenarios and the base case, while capacity avoided cost changes are calculated using the change in annual peak demand.

Volumetric avoided cost impacts are applied to the following avoided cost criteria (that depend on wholesale energy prices):

- Energy
- Ancillary services and load obligation charges
- Risk premium/hedging
- DRIPE Energy
- RPS compliance

[36] Price elasticity factors (and the equation used for this analysis) were calculated in the AESC 2021 study using the relationships between prices ($/MWh or $/kW-year, for energy and capacity respectively) and demand (MW).

Capacity avoided cost impacts are applied to the following cost criteria (that depend on wholesale capacity costs):

- Capacity costs
- DRIPE Capacity

A number of avoided cost criteria are expected to remain unchanged. **That is not to say that the total costs ($) will not change with increases in load, but rather that the costs per unit energy or per unit demand cost criteria are not expected to change.** These cost criteria are:

- Transmission capacity
- Distribution capacity
- Transmission charges
- Transmission and distribution line losses
- Utility administrative costs
- T&D system upgrades
- Distribution OPEX

Increases in marginal demand would also increase the high emitting resources on the margin, which could increase the emissions rates for CO_2 and NO_x under the different HLGS scenarios. Therefore, the impact on environmental externalities is modeled by conducting a regression analysis that compares the demand with the AESC marginal emissions rates to estimate the emissions levels under the three HLGS scenarios.

E. Market Resource Value Scenario Methodology

The market resource value scenario (MRVS) sensitivity analysis estimates the value of aggregated DER resources participating directly in relevant wholesale power markets for those criteria where there is a readily discernible market value or a value that is different than those established in the load reduction value estimates. Specifically, the MRVS analysis considered the ability of DERs to realize value in the wholesale power markets through provision of **energy**, **capacity**, and **ancillary services**. The methodology used for each value category is described below.

E.1 Energy Value

The market value of energy produced by aggregated DER resources is reflected by zonal LMPs for ISO-NE's New Hampshire load zone. The study team relied on the AESC 2021 wholesale energy forecasts for these values. The values were further adjusted to reflect expected near-term increases in the value of energy. Specifically, hourly price profiles were adjusted for recent increases in natural gas prices and resulting LMPs over the 2021-2025 period. Under the MRVS, the value of energy is considered to be the same as in the base avoided cost value stack.

E.2 Capacity Value

The value of capacity generated by aggregated DER resources assumes participation in ISO-NE's Forward Capacity Market (FCM). The study team relied on the AESC 2021 FCM forecast for these values. The FCM values were converted to hourly values (in $/kWh) using summer and winter reliability hours for establishing Qualified Capacity,[37] which is the basis for capacity credit for which FCM payments are made to generation resources.

E.3 Ancillary Services Value

The value of ancillary services is based on the ability of aggregated DER resources to provide reserves and regulation under ISO-NE's FERC Order 2222 compliance filing as dispatchable DER aggregations. Provision of such services typically requires that resources do *not* participate in the energy market, however, so DER provision of those services is expected to be uneconomic.[38] As such, we did not conduct a detailed quantitative analysis of ancillary services value but included qualitative insights instead.

[37] Qualified Capacity refers to the capacity that a resource is capable of providing in the summer or winter during specific capacity commitment periods. This is calculated by taking the average median production during the summer reliability hours ending 14:00-18:00 (June to September) and winter hours ending 18:00-19:00 (October to May).
[38] For 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 from ISO-NE. To provide this headroom the generator would need to be dispatched down, resulting in an energy market opportunity cost for the operator.

F. Rate and Bill Impacts Assessment

The Rate and Bill Impacts Assessment is a supplementary study to the Avoided Cost Value Stack Analysis. The assessment provides high-level analysis of the impacts of future DG deployment in New Hampshire on ratepayers, considering both the benefits and the costs that would be incurred by the utilities and load-serving entities. The overall goal of the assessment is to serve as a future-looking estimate of the direction and magnitude of the impacts of future DG deployment on all ratepayers and any potential cost-shifting between customers with and without DG. 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 projected future DG adoption on retail electricity rates for and bills issued to New Hampshire electric customers.

F.1 Modelling Approach

F.1.1 Rationale

Customers that install distributed generation resources can offset a part of their electric load and thus reduce their electric bills. Some portion of the electricity generated is self-consumed while the remaining portion is generally exported back to the utility distribution system. The electricity generated from distributed resources creates both an upward pressure on rates (due to lost utility revenues and program cost recovery) as well as a downward pressure on rates attributable to avoided utility costs.

F.1.2 Modelling Considerations

The following considerations were made while conducting the Rate and Bill Impacts Assessment:

<u>Electric Retail Rates</u>: Impacts on retail electric rates resulting from the future deployment of behind-the-meter distributed solar PV systems in New Hampshire are evaluated.

<u>Three Electric Utilities</u>: Impacts are assessed for the three electric utilities regulated by the New Hampshire PUC: Public Service Company of New Hampshire d/b/a Eversource Energy (Eversource), Liberty Utilities (Granite State Electric) Corp. d/b/a/ Liberty (Liberty), and Unitil Energy Systems, Inc. (Unitil).

<u>Three Customer Classes</u>: Residential, small general service, and large general service customer classes are modeled as a representation of customers impacted by the adoption of behind-the-meter distributed solar PV systems.

<u>Two Scenarios</u>: The analysis is conducted under two scenarios for DG compensation to illustrate the impacts of different potential DG program designs on ratepayers:

- **Net Energy Metering (NEM) Tariff Scenario:** This scenario reflects the current net-metering program, based on the alternative net metering tariff adopted by the PUC in 2017. The net export credit rate is based on the alternative net metering tariff, where monthly net exports from systems up to 100 kW capacity are compensated at 25% of the underlying distribution rate component and 100% of the underlying generation and transmission rate components, while hourly net exports from eligible systems larger than 100 kW are compensated at 100% of the underlying generation rate component.
- **Avoided Cost Value (ACV) Tariff Scenario**: An alternative net export compensation tariff approach based on the outcomes of the VDER Study value stack analysis, where customers are compensated for net exports to the grid based on the avoided cost values determined through the study.

Three Customer Archetypes: The assessment evaluated the rate and bill impacts for three customer archetypes:

- **Typical DG Customer**: Represents a typical utility customer who adopts a behind-the-meter solar PV system for each customer class.
- **Typical Non-DG Customer:** Represents a typical utility customer in each customer class who does not deploy a solar PV system.
- **Average Utility Customer**: Represents the average impacts on a utility customer, without regard to whether the customer has or does not have DG. The rate and bill impacts are computed at the rate class level where the total consumption is divided by the number of customers across each rate class and utility.

Decoupling: Utilities in the state have implemented – or plan to implement - a revenue decoupling mechanism. For simplicity, the study analysis assumes annual reconciliation (i.e., annual rate cases) and assumes that utilities will recover all costs associated with non-avoidable fixed costs. In reality, utilities may have less frequent rate cases. This simplifying assumption avoids the complexity of analysis while still meeting the objectives of the study.

F.1.3 Modelling Framework

Rate Impact Assessment

The equation below highlights the theoretical model used to assess the rate impacts of future DG deployment. The rates post-DG are impacted by the fixed costs and program costs, which are recovered over the load post-DG. When a customer-sited distributed energy resource generates electricity, the utility experiences an immediate reduction in energy consumption, thus leading to a certain amount of lost revenues. However, that generation also generates avoided cost values for the utility and load-serving entities. The “net” of these two components (i.e., the difference between lost revenues and avoided costs) is estimated to represent non-avoidable fixed costs that the utilities would need to recover from ratepayers. Additionally, the analytical framework is intended to account for rate impacts associated with the recovery of program costs and net export bill credits over fewer energy sales.

To summarize, future DG deployment is assumed to have several distinct impacts on rates:

A. Lost revenues to utilities as a result of reductions in electricity consumption.
B. Avoided costs, as indicated and quantified by the Avoided Cost Value Stack assessment.
C. Program and/or system costs incurred by utilities to accommodate DG installation and operation, which include program administration costs and the bill credits provided for net exports.
D. System costs that are recovered over lower energy sales due to the load reductions.

The “net” of these components (i.e., the difference between lost revenues and avoided costs) is estimated to represent proxy of the required fixed cost recovery

A Utilities’ revenues are reduced

B Utilities capture benefits from avoided costs

$$Rates_{Post\ DG} = Rates_{Pre\ DG} + \frac{\overbrace{(Lost\ Revenues\ - Avoided\ Costs)}^{\textit{Fixed Cost Recovery}} + \overbrace{(Admin\ Costs + Export\ Bill\ Credits)}^{\textit{Program Costs Recovery}}}{Load\ _{Post-\ DG}}$$

D Costs are recovered over fewer kWh

C Utilities need recover costs to accommodate DG / operate programs

The above framework is applied for the generation, transmission, and distribution components of rates, considering only appropriate determinants under each. For example, the program cost recovery is applied only to the distribution component of rates. In calculating the rate impacts for each customer class, avoided costs, lost revenues, and program costs are calculated across all customer classes and then redistributed back to individual customer classes based on the principle of 100% cost causation.

Additionally, the framework considers the rate components (e.g., volumetric $/kWh and demand charge $/kW) applicable to each customer class.

Bill Impacts Assessment

As a final step, pre- and post-DG bills are estimated for a typical DG customer, a typical non-DG customer, and the average utility customer in each customer class and by each utility. For each customer class, estimated consumption is multiplied by pre- and post-DG rates to assess the incremental impacts on customer bills attributable to future DG deployment.

F.2 Methodology

F.2.1 Step 1: Develop Baseline (No-DG) and DG scenarios

To assess the impacts of future DG deployment, a non-DG scenario must be developed to serve as a baseline. The non-DG scenario is a hypothetical illustration of the system in the absence of projected new DG capacity and is used to evaluate the impacts attributable to future incremental DG deployment. To develop the DG and non-DG scenarios, the following metrics are estimated for each utility and year of the study period:

- **Load (energy and demand) by utility and rate class with and without DG :** this is calculated by:

  a) Removing the impacts of any annual DG projections included in utilities' current load forecasts (Load Pre-DG), and

$$\text{Load}_{Pre-DG} = \text{Load} - \text{adjustments to remove cumulative "new" DG projections}$$

  b) Adding the DG projections used in the VDER Study (Load post-DG).

$$\text{Load}_{Post-DG} = \text{Load}_{Pre-DG} - \text{Total DG Production Forecasts}$$

- **Annual production by average DG customer in each rate class**[39]**:** Estimated by dividing total forecasted DG production in a given year by the forecasted number of DG customers.

$$Average\ DG\ Production\ per\ DG\ customer = \frac{\text{Total Forecasted DG Production (GWh)}}{\text{Total Number of Forecasted DG Customers}}$$

[39] Behind-the-meter solar PV is assumed to be the dominant distributed generation resource for this assessment.

Additionally, assumptions are made to estimate the portion of DG production consumed behind-the-meter versus that exported to the grid (see key assumptions and sources section below). Grid exports are estimated based on an assessment of system sizing practices, DG generation, and customer load patterns.

- **Electricity consumption and demand[40] for DG, non-DG, and average utility customer in each customer class:**

  To simplify the analysis, all customers in a given customer class, regardless of DG deployment, are assumed to have the same average annual electricity consumption pre-DG, as calculated by the following equation:

$$\text{Avg Consumption}_{\,Pre-DG} = \frac{\text{Total Consumption}_{Pre-DG}}{\text{Total Customers}_{Pre-DG}}$$

Consumption post-DG will be calculated as follows for different customer archetypes:

Typical DG Customer $\quad \text{Consumption}_{DG\ Customer} = \text{Avg Consumption}_{Pre\ DG} - \text{Avg DG Production}$

Typical non-DG Customer $\quad \text{Consumption}_{Non-DG\ Customer} = \text{Avg Consumption}_{\,Pre-DG}$

Average Utility Customer $\quad \text{Consumption}_{\,Avg\ Customer} = \dfrac{\text{Total Consumption}_{Post\ DG}}{\text{Total Customers}_{Post\ DG}}$

F.2.2 Step 2: Assess Rate Impacts

First, we calculate the lost revenues associated with each customer class for each utility. The lost revenue is the anticipated revenue lost due to reduced electricity sales:

$$Lost\ Revenue\ = DG\ Production\ x\ Rate_{Pre-DG}$$

[40] A coincidence factor for each customer class will be applied to the system peak demand to estimate customer billed demand (e.g., monthly peak load).

Next, we calculate the avoided costs associated with DG production. The avoided cost value is informed by the value stack assessment by each component (generation, transmission, and distribution). Environmental externalities are not included in any of the avoided cost streams.

$$Avoided\ Costs\ = DG\ Production\ x\ Avoided\ Costs_{Generation,\ Distribution,\ Transmission}$$

The net difference between the lost revenue and the avoided costs serves as a proxy for the fixed cost recovery. For each of the rate components, the following avoided costs are considered:

- Generation: Avoided energy, RPS, ancillary services, distribution and transmission line losses, and risk premium are considered pass-through components[41], while avoided capacity and DRIPE benefits are considered to have an impact on rates.
- Distribution: The avoided distribution costs include avoided distribution CAPEX and OPEX, distribution grid services, T&D system upgrades, and resiliency services.
- Transmission: Transmission capacity and transmission charges are considered under the rate and bill impacts assessment; the rate impacts assessment assumes only the portion attributable to the New Hampshire load as a percentage of the ISO-NE system, which is approximately 9.54%.

To calculate the program cost recovery, we use both the administration costs and the net export bill credits. The administration costs are the costs incurred by the utilities to administer DG programs and include metering costs, costs for full time engineers to conduct site inspections, and other administrative costs.

The export bill credits represent the compensation provided for DG net electricity exports. Under the NEM Tariff scenario, the export credit rate is based on the alternative net metering tariff, where monthly net exports from systems up to 100 kW capacity are compensated at 25% of the underlying distribution rate component and 100% of the underlying generation and transmission rate components, while hourly net exports from eligible systems larger than 100 kW are compensated at 100% of the underlying generation rate component. The compensation is the net export credits netted by the applicable avoided costs. Under the Alternative ACV Tariff scenario, the net export credits are compensated at the avoided costs determined through the value stack analysis. The compensation under this scenario is the export credit compensation netted by the applicable avoided costs, which in this case is zero.

[41] Certain cost components such as energy, ancillary services, line losses and risk premium are passed on directly from the market to the end customer through the utility. When a customer generates electricity behind the meter – the avoided energy, ancillary services, line losses and risk premium costs will affect the customer bill but won't change the utility's revenue requirement. DRIPE will affect the clearing price for wholesale energy, thereby affecting the generation rate. In line with other similar studies on rate and bill impact assessment in New Hampshire, avoided capacity costs are considered to impact rates.

$$Export\ Bill\ Credit = [(Export\ Rate - Avoided\ Cost\ Rate) x\ \%\ of\ Production\ Exported]$$

The fixed cost recovery and program cost recovery portion of the relevant revenue requirement calculation is distributed over the net system load (post-DG) and its impact is recorded against the pre-DG rate for each year of the study. Thus, the rate impacts are presented as the average annual percentage increase or decrease in rates relative to the non-DG scenario over the period 2021 to 2035 for each customer class to indicate the long-term impact of future DG deployment.

F.2.3 Step 3: Assess Bill Impacts

The pre- and post-DG customer bills are calculated for each customer archetype. As an example, the bill impacts from non-DG customers are shown as follows:

$$\text{PreDG Bills}_{\ Non-DG\ Customer} = \text{Consumption}_{Non-DG\ Customer}\ \text{x Rates}_{\ Pre-DG}$$

$$\text{PostDG Bills}_{\ Non-DG\ Customer} = \text{Consumption}_{Non-DG\ Customer}\ \text{x Rates}_{\ Post-DG}$$

$$\text{Bill Impact}_{\ Non-DG\ Customer} = \frac{Post\ DG\ Bills_{Non-DG\ Customer}}{\text{PreDG Bills}_{\ Non-DG\ Customer}} - 1$$

Although the bill impacts are calculated for each year during the study period, the bill impacts are presented as the average annual percentage increase or decrease in customers' bills attributable to future DG deployment over the period 2021 to 2035 for each of the typical customer archetypes, in each case considered to estimate bill reductions and potential cost-shifting between DG customers and non-DG customers and by the average customer.

F.3 Key Assumptions and Sources

F.3.1 Customer Class Assumptions

The retail electric customers for each utility are segregated into three broad classes: Residential, Small General Service, and Large General Service. The customer count for each rate class across the three utilities were informed by data provided by the utilities. The classification of commercial customers was based on the average annual electric sales. Small general service customers were assumed to have electric sales less than 1 million kWh, while all customers with electric sales greater than 1 million kWh were classified as large general service.

The rate and bill impacts assessment analyzes the impacts of avoided costs on generation, distribution, and transmission rate components. Environmental Externalities are not included in the rate and bill impacts assessment. For each of the three rate components, the following assumptions were made for the rate and bill impacts assessment:

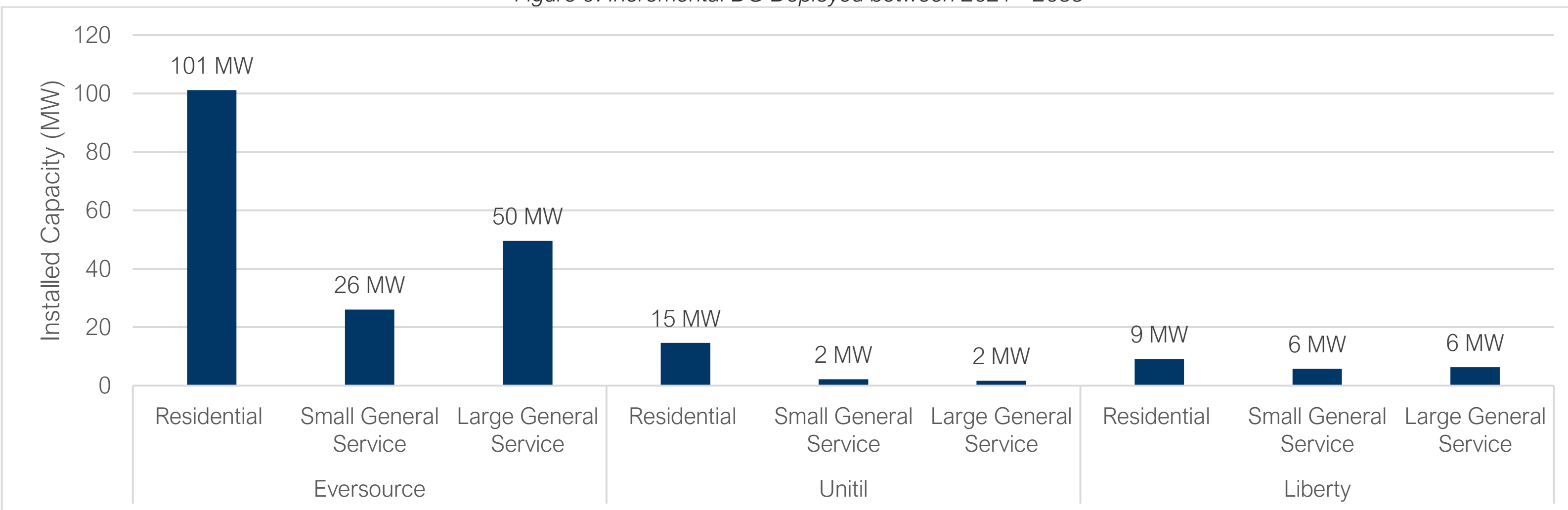
- **Generation**: Avoided energy, RPS, ancillary services, distribution and transmission line losses, and risk premium are considered pass-through components, while avoided capacity and DRIPE benefits were considered to have an impact on rates.
- **Distribution**: The avoided distribution costs include avoided distribution CAPEX and OPEX, Distribution Grid Services, T&D System Upgrades, and Resiliency Services.
- **Transmission:** Transmission Capacity and Transmission Charges are considered for the rate and bill impacts assessments; the rate impacts assessment assumes only the portion attributable to the part of New Hampshire load as a percentage of the ISO-NE system, which is approximately 9.54%.

<u>PV system sizes are based on aggregated utility data (AC kW):</u>

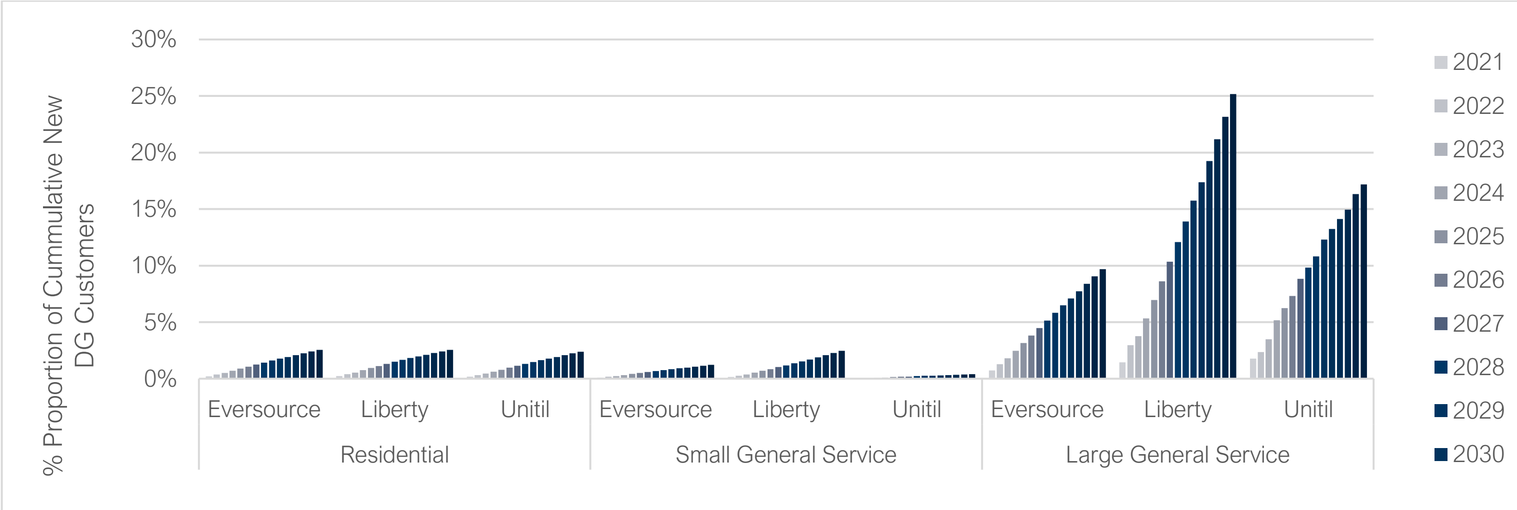
Customer Class	Eversource	Unitil	Liberty	% Self-Consumed
Residential	7.6	12.2	10.1	72% (Monthly Netting)
Small General Service	24.5	43.0	41.3	65% (Monthly Netting)
Large General Service	329.2	47.2	209.6	99% (Hourly Netting)

Incrementals DG Capacity deployed over the study period:

Figure 9: Incremental DG Deployed between 2021 - 2035



Percentage of customers with DG by 2035:



Inputs	Sources
Load Forecasts by Customer Class (energy, demand, number of customers)	Utility load forecasts
Utility and Rate Class Specific Transmission and Distribution Line Losses[42]	Utility data
Customer Rates	Utility tariffs
DG Projections by Customer Class	Utility load forecasts
DG Program Budgets	Utility interviews
Peak Coincidence by Customer Class	Utility system load data

[42] The utility and rate class specific T&D losses were used to calculate the avoided costs and lost revenues for the rate and bill impact assessment.