THE STATE OF NEW HAMPSHIRE
BEFORE THE
NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

TESTIMONY OF

David P. Littell on behalf of
Clean Energy New Hampshire

CONSIDERATION OF CHANGES TO THE CURRENT NET METERING TARIFF STRUCTURE, INCLUDING COMPENSATION OF CUSTOMER-GENERATORS

Docket No. DE 22-060

December 6, 2023

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Exhibits:

DPL-1 Appendix 1 – New Hampshire Value of Distributed Energy Resources, Final Report, submitted to the NH DOE (the "Dunsky NH VDER Study")

DPL-2 The Dunsky Report Appendices

DPL-3 Appendix 3 - New Hampshire Value of Distributed Energy Resources, Addendum, submitted to the NH DOE ("The Dunsky Update")

DPL-4 Appendix 4 – New Hampshire Location Value of Distributed Generation Study, Final Report, submitted to the New Hampshire Public Utilities Commission by Guidehouse Inc. ("The NH LVDG Study")

DPL-5 David P. Littell CV

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Please state your full name and business address.

A. My name is David Littell. My business address is 100 Middle Street, West Tower, 6th Floor, Portland, Maine 04101.

Q. For which party are you testifying, with whom are you employed, and in what capacity?

A. I am testifying as a policy expert for Clean Energy New Hampshire ("CENH") along with Thomas Beach of Crossborder Energy who is a highly regarded technical expert on rate design, ratemaking, and bill impact analysis. I am a Shareholder at Bernstein Shur Sawyer & Nelson ("Bernstein Shur"). Bernstein Shur is a New England-based law firm that advises clients across the United States and around the world.

Q. Please summarize your professional and educational background.

A. I have worked in the regulatory sector for my entire professional career. I have worked as an attorney and advisor in private practice for many years. I also had the honor of serving as deputy commissioner and then commissioner of Maine's Department of Environmental Protection, as a member of the Governor's cabinet from 2003 to 2010. From 2010 to 2015, I served as a commissioner on the Maine Public Utilities Commission. I have then subsequently advised many state commissions, energy and environmental agencies. My background is presented in more detail in **Exhibit DPL-5**.

Q. Have you ever testified before a public utility regulatory agency?

A. Yes, I have testified, often in the role of invited expert or a commission advisor.

Q. In what matters have you testified?

A. I can provide a few examples. I have testified before the Maryland Public Service Commission on matters related to Public Conference 44.[1] I have also testified before the Public Utilities Commission of Ohio on performance based regulation as part of its Power Forward Initiative.[2] I also assisted the Michigan Public Service Commission on performance based regulation.[3]

I testified to the Massachusetts Attorney General's Office ("MA AGO") in 22-GREC-01, 22-GREC-02, 22-GREC-03, 22-GREC-04, 22-GREC-05, and 22-GREC-6. I have also acted as a non-testimonial expert in other Massachusetts Department of Public Utilities dockets as a consulting expert. Again, I have undertaken similar consulting expert roles for a number of other commissions and energy offices in adjudicatory and non-adjudicatory matters.

Q. What is your expertise in Net Energy Metering ("NEM")?

A. I have worked with NEM matters for over a dozen years including as a commissioner and an expert advisor. I have also addressed more broadly distributed energy resources ("DER") valuation, integration in state regulatory tariffs and structures, and DER optionality in the wholesale markets.

Q. Do you have any other expertise in NEM?

A. I have worked on NEM matters and dockets in a number of New England states including Maine, New Hampshire, Massachusetts, and other states in New England.

[1] *See*, *In the Matter of Transforming Maryland's Electric Distribution Systems*, P.S.C. PC44 (MD 2019).

[2] *See*, Migden-Ostrander, J., Littell, D., Shipley, J., Kadoch, C., & Sliger, J., *Recommendations for Ohio's Power Forward Inquiry*, Regulatory Assistance Project (February 2018), https://www.raponline.org/wp-content/uploads/2018/02/rap-recommendations-ohio-power-forward-inquiry-2018-february-final2.pdf.

[3] *See* Littell, D. & Shipley, J., *Performance-Based Regulation Options*, Michigan Public Service Commission (July 2017),https://www.michigan.gov/-/media/Project/Websites/mpsc/workgroups/pbr/RAP_PBR_options_for_MI_PSC_7_14_171.pdf?rev=e9b44b80ad8f4322a6af9b54eab7c854

Q. What is the purpose of your testimony?

A. I am testifying as an expert witness related to New Hampshire's NEM 2.0 in support of Clean Energy New Hampshire regarding positions on the New Hampshire NEM program administered by this Commission.

Q. What do you mean by NEM 2.0?

A. In this testimony, I use NEM 2.0 as do other New Hampshire parties to refer to the alternative NEM tariff established by the Commission in 2017 in Order 26,029. The prior tariff, still in place for customers grandfathered into it, would be NEM 1.0 which I do not address in this testimony

Q. How is the remainder of your testimony organized?

A. In Section II, I discuss how NEM 2.0 provides stable revenue for residential customers and small businesses developing distributed resources. In Section III, I address how NEM 2.0 represents a moderate compromise. Section IV is an overview of current NEM 2.0. In Section V, I examine issues with NEM 2.0. Section VI reviews how NEM 2.0 supports the local economy and jobs in New Hampshire. Section VII recommends modifications to New Hampshire's Commercial distributed resource NEM Tariff. Section VIII offers other important considerations related to NEM 2.0. Finally, Section IX provides a brief conclusion.

II. CURRENT NEW HAMPSHIRE NEM PROVIDES STABLE REVENUE FOR RESIDENTIAL CUSTOMERS AND BENEFITS FOR ALL RATEPAYERS.

Q. Currently, does NEM in New Hampshire Provide Customer Revenue to support DERs which customers desire?

A. Yes. New Hampshire's two NEM programs provide a stable revenue source for residential and small commercial DERs which customers have installed. New Hampshire added 40 megawatts

("MW") of NEM resources in 2022.[4] Interest in NEM resources is seen not just in New Hampshire but in other state markets as consumers respond to energy market pricing.

Q. Can you explain the value as load reducer?

A. Both the Dunsky analysis and the Unitil and related Daymark analysis from Docket No. 22-073, discussed below, illustrate that a properly balanced distributed resource program can realize more value *for New Hampshire customers* than obligating DER participation in the ISO-NE wholesale markets. Crucially, these analyses show this approach creates value for both NEM-customers and non-NEM customers.

Treating DERs as load reducers allows for both NEM-customers and the New Hampshire NEM tariff to capture value for New Hampshire customers as a whole, in excess of what they pay for the entire NEM program. The value as a load reducer includes avoided retail supply, avoided transmission and capacity charges, price suppression for retail customers, transmission, capacity, avoided distribution capacity, and avoided line losses among other benefits. All of these values do not account for the environmental and greenhouse gas benefits which are the most commonly cited reasons to pursue DER adoption.

A. NEM 2.0 Gets More Value at Lower Cost to New Hampshire Ratepayers.

Q. What value does the NEM structure provide to New Hampshire ratepayers?

A. As just noted, the New Hampshire NEM structure provides substantial value as a load reducer. These values exceed the costs (without counting any environmental or greenhouse gas benefits) as explained fully in the testimony of Tom Beach for CENH.

[4] New Hampshire DOE, New Hampshire Renewable Energy Fund, Annual Report, Oct. 1, 2023, p. 26, on the web at: https://www.energy.nh.gov/sites/g/files/ehbemt551/files/inline-documents/sonh/2023-ref-report-to-legislature.pdf.

The NEM program in place and proposed in this testimony delivers the values identified by the General Court in the enabling statute: diversity of New Hampshire's resource mix, support for customer self-generation, reduced dependence on other sources, use of New Hampshire resources, use of renewable fuels, benefits for the environment and public health, support for competitive New Hampshire markets, private investments, in-state commercial innovation, and reducing interconnection costs. The NEM statute speaks to all these values as the General Court found:

> It is found to be in the public interest to provide for small scale and diversified sources of supplemental electrical power to lessen the state's dependence upon other sources which may, from time to time, be uncertain. It is also found to be in the public interest to encourage and support diversified electrical production that uses indigenous and renewable fuels and has beneficial impacts on the environment and public health.[5] It is also found that these goals should be pursued in a competitive environment pursuant to the restructuring policy principles set forth in RSA 374-F:3. It is further found that net energy metering for eligible customer-generators may be one way to provide a reasonable opportunity for small customers to choose interconnected self generation, encourage private investment in renewable energy resources, stimulate in-state commercialization of innovative and beneficial new technology, enhance the future diversification of the state's energy resource mix, and reduce interconnection and administrative costs.[6]

Each of these values is spoken to in the reports and analysis just discussed. Notably, these findings affirm that it was the intention of the General Court in establishing the NEM program to create a thriving market for locally generated power.

Q. Does your testimony speak only to the benefits of NEM?

A. No. While I do testify to the values being realized according to the New Hampshire Department of Energy's ("DOE") <u>New Hampshire Value of Distributed Resources</u> by Dunsky Energy + Climate Advisors (the "Dunsky NH VDER Study"), the Unitil testimony and Daymark report submitted in Docket No. 22-073, as well as other Daymark reports and analyses, I also

[5] Testimony Section B.2 below addresses the environmental and public health benefits.

[6] Section 362-A.

testify to the balance between value and costs. The costs are quite modest, and the benefits are substantial for all ratepayers. The benefits are even greater to NEM-customers. In total, the substantial net benefits are achieved at a very modest cost. Those benefits for all customers exceed the costs even without accounting for environmental benefits.

Q. When you say benefits to all customers exceed the costs, can you clarify?

A. The costs (as analyzed by the Dunsky NH VDER Study and confirmed by Tom Beach and other studies) are substantially below the value of the DERs in the NEM program.

Q. How does New Hampshire's cost to benefit compare to other New England states?

A. Since other New England states NEM programs pay more for the same DER kWh of energy, without doing quantitative analysis, it is fairly clear that New Hampshire's NEM 2.0 program procures more value per dollar than other New England states.

Q. Is New Hampshire more frugal than other New England states?

A. Yes. New Hampshire's NEM 2.0 program is both more frugal and more thrifty than other New England states. None of the recommendations in this testimony would vary New Hampshire's status as the most frugal and thrifty New England state on net energy metering.

Q. Has DER activity increased in New Hampshire?

A. DER activity increased in New Hampshire and across the region in recent years largely as a result of the price of energy. This is a natural and expected response to increase in energy prices. Price drivers for energy include a constrained gas supply: gas is increasingly being exported from the U.S. Multiple international markets, including European markets, have experienced severe supply disruptions with the February 2022 Russian invasion of the Ukraine. As a result, prices of petroleum and gas have increased and severely increased over the last year and half.

With energy prices increasing across the board in 2021, 2022, and the first half of 2023, New Hampshire has not been immune to these market trends.[7] Customers have shown more interest in alternative resources, including distributed resources, to reduce their energy expense and exposure to volatility. At the customer level, distributed resources provide a customer hedge for a percentage of their energy needs that they are able to lock-in at specific pricing.

Q. Does this increased DER activity provide customer benefits?

A. Absolutely. New Hampshire customers are able to reduce exposure to energy price volatility for a portion of their energy needs and can reduce their energy expenditures as well.

Increased DER activity also provides more customer choice for energy products and services. This is important because energy customers, like other customers, are increasingly interested in procuring services and products designed to meet specific customer needs and preferences.

Q. Do DERs provide economic development in New Hampshire?

A. Yes, of course. DER activity resulting in new project development enhances New Hampshire's economy at a local level in multiple ways, including reducing energy spending for many small and medium-sized New Hampshire businesses and municipalities, stimulating local employment and increasing local tax base.

Q. Does the increased DER activity support grid diversity?

A. As more DER development occurs, an increasing number of diverse resources will come on line in New Hampshire. While this represents a shift to a more diversified and decentralized grid in the immediate term, it also presents opportunities for future growth.

[7] *See, e.g. https://tnhdigital.com/22090/news/cost-of-heating-is-on-the-rise-in-new-hampshire-with-winter-right-around-the-corner/.*

Q. What do you mean by future growth?

A. As an example, intermittent distributed resources can later add a battery installation installed to the same point of interconnection to provide for peak management into the evening, and grid-reliability services. Such facilities can provide capacity in the form of distribution capacity, transmission capacity, and generation capacity to provide grid support across those traditionally segregated domains to meet future grid needs as well as current and future customer needs.

Q. Are there other ways diversified or decentralized resources can help customers or the grid?

A. Diverse resources are being utilized in some jurisdictions to provide localized reliability support for specific facilities or specific distribution circuits.

Q. Are utilities taking advantage of such distributed resources now?

A. Yes, certainly. Utilities in some states are proposing distributed resources. including batteries. to support each of the goals above including localized reliability. That localized reliability supports customers and the grid, even potentially during a grid outage.

Q. Coming back to NEM in New Hampshire, do you view the New Hampshire NEM program as encouraging the current market increase in DERs?

A. The New Hampshire NEM program provides a stable revenue source for specific DER developments in New Hampshire. The NEM program supports DER activity at a stable level and, has for five years under NEM 2.0. That said, as noted above the current increase in energy prices appears correlated with the increased uptick in DER activity.

III. NEM 2.0 A MODERATE AND REASONABLE COMPROMISE OF INTEREST AND NEW PRINCIPLES

A. New Hampshire Reception

Q. Was there a reaction in New Hampshire to the 2017 NEM decision?

A. Yes, the 2017 NEM decision, which I refer to as NEM 2.0, was received well in New Hampshire. The NH Business Review noted that "both sides were pleased" in 2017 while also reporting an expected 2017 boost in customers rushing to get grandfathered under NEM 1.0.[8] The New Hampshire Sustainable Energy Association also welcomed the 2017 NEM decision as a reasonable compromise:

> Recognizing the value that DER (distributed energy resources, like solar, hydro, etc.) adds to all parts of our grid–including transmission, generation, AND distribution–comports with data seen across the country and right here in NH. The reduction in the distribution export rate to 25% of the charge is a reasonable compromise and may be adjusted going forward, depending on the result of a future PUC-led, NH-specific Value of DER study.[9]

B. National Reception

Q. Was there a national reaction to the 2017 Commission NEM decision?

A. Yes, the 2017 decision was of note nationally. The New Hampshire 2017 NEM decision was received as a common ground compromise.[10] The 2017 decision on NEM eligibility was perceived as a reasonable and moderate solution for residential NEM based on information and analysis undertaken then. In reporting on the 2017 Commission decision on the new alternative tariff, *Utility Dive* characterized more extreme positions against the approved proposal:

> The new [NEM] rates are essentially a mashup of utility- and solar-backed proposals, and represent a more collaborative approach to developing new net metering rates. (emphasis

[8] NH Business Review, "PUC decision seen as big boost to NH Solar industry." June 27, 2017, on the web at: https://www.nhbr.com/puc-decision-seen-as-a-big-boost-to-nh-solar-industry/.

[9] Green Energy Times, "NHSEA on NH PUC Net Metering Decision," June 26, 2017, on the web at: https://www.greenenergytimes.org/2017/06/nhsea-on-nh-puc-net-metering-decision/.

[10] Shallenberger, Krysti (March 13, 2017). "New Hampshire utilities, solar companies file rate design settlement proposals". *Utility Dive*. Retrieved March 17, 2017.

in original).[11]

While there were settlement proposals, the Commission ultimately decided this case to develop a new NEM 2.0 tariff. This NEM 2.0 tariff was made available for small projects, largely residential but also small commercial.

Q. Are there other data sources on how the 2017 NEM 2.0 is perceived nationally?

A. Wikipedia, interestingly enough, uses New Hampshire's 2017 NEM proceeding as an example of solar companies and utilities coming together to find common ground:

> In many states, such as New Hampshire, solar companies and utility companies are coming to the negotiation table with compromises over net metering rates. In New Hampshire, proposals put forth by both the solar companies and the utility companies in March 2017 mostly found a lot of common ground.[12]

This is of course a single data point from a commonly referenced website that speaks more to perceptions than authority.

Q. Were there other national reactions to the 2017 NEM proceeding?

A. Yes, national media, including the energy press, received the New Hampshire NEM as a reasonable compromise in a matter-of-fact manner.[13]

Q. Does that mean that NEM 2.0 is just and reasonable?

A. No, as we lay out below, we believe NEM 2.0 is under-compensating DERs.

Q. What do you mean by NEM 2.0 under compensating DERs?

A. Tom Beach's analysis lays this out in detail, showing the overall system-wide avoided costs benefits for all New Hampshire customers for all rate classes, residential, SG and LG, in excess of

[11] Utility Dive, "New Hampshire Regulators Approve New Net Metering Tariffs," June 26, 2017, on the web at: https://www.utilitydive.com/news/new-hampshire-regulators-approve-new-net-metering-tariffs/445796/

[12] Wikipedia, Net Metering in the United States, on the web at: https://en.wikipedia.org/wiki/Net_metering_in_the_United_States#cite_ref-:9_62-0.

[13] *See e.g.* Energy Toolbase, New Hampshire Makes Cuts to Net Metering Program, Sept. 1, 2017, on the web at: https://www.energytoolbase.com/newsroom/blog/new-hampshire-puc-makes-cuts-to-net-metering-program

the cost to New Hampshire customers.[14]

C. New Hampshire has the Most Frugal NEM in New England

Q. Among the six New England states, which state has the most frugal NEM program?

A. If frugal is meant to denote lowest payment for solar value and services, New Hampshire's NEM program is the most frugal and thrifty. New Hampshire pays the lowest payment for both residential scale solar and commercial scale solar of any of the six New England states.

Q. You answered that New Hampshire is the most "frugal and thrifty." What does thrifty mean?

A. Thrifty here refers to the residential rate as not just lowest payments to customers, but securing the highest value for the lowest payment. Thrifty is securing more value for lower costs, which is different from frugal which is simply a reluctance to pay.

Q. Is there agreement from other parties in this docket?

A. The Joint Utilities observed that there is a balance of interests and viewpoints in the current NEM 2.0 tariffs that came out of Docket No. DE-16-576. The Joint Utilities also observe that New Hampshire's NEM structures "remain among the most balanced in the region. Other New England states continue to maintain tariffs that provide credit to customers for energy exports to the grid at rates equal to the full sum of all applicable retail kWh charges …".[15] So, the Joint Utilities characterize the NEM structures as balanced, and I use the terms frugal and thrifty, but I believe this to be the same basic point.

Q. Is the commercial rate for up to 1 MW also thrifty?

A. I would say no. Above 100 kW for commercial sized NEM projects, the NEM 2.0 tariff provides only reimbursement at the retail energy price. There is more value that is not accounted

[14] *See R. Thomas* Beach Direct Testimony for CENH, NH PUC Dock. No. DE-22-060, Dec. 6, 2023, (hereinafter Tom Beach Test.") at, *pp. 12-17*.

[15] Joint Utilities, Data Request Response No. OCA 1-002, Dock. No. DE 22-060 (Oct. 12, 2023).

for and so financial benefit for New Hampshire ratepayers is left on the table. In other words, a truly thrifty commercial rate would incentivize more DERs to provide more benefits to all ratepayers.

Q. Can you explain the other New England NEM or other tariffs?

A. Yes, as far as comparable residential NEM tariffs in New England I shortly summarize each other New England state's programs below.

Maine's programs, called Net Energy Billing take two different forms, full NEM rates are beneficial for residential and small business customers known as Maine's KWH credit. The KWH credit includes the default service, transmission, and distribution charges. Customers are required to pay a minimum bill charge and applicable demand charges based on rate class. Using the same format as the NH PUC table for New Hampshire's NEM program, Maine's KWH program[16] looks like this:

Maine (KWH Program)	
Bill Component	**Credit or Charge**
Demand Charge	Not Applicable
Min. Bill Charge	Charge
Default Service (Energy)	Full Credit
Distribution	Full Credit
Transmission	Full Credit
System Benefits	Charge
Stranded Cost	Charge

Vermont provides a blended rate for customers with generation up to 500 kW. The Vermont credits net excess generation ("NEG") customers at a blended residential rate and carries

[16] Maine also has a NEB Tariff Rate Program which is useful for commercial customers and provides customers with a monetary dollar credit on their bill equal to 75% of the applicable Transmission and Distribution charges plus the applicable standard offer rate. Because that program is structured to provide a pure monetary credit, it can offset demand charges as well.

over to the customer's next bill. Customer charge and efficiency charge are "non-bypassable", and DG customers must pay these charges. The current Vermont blended rate is $ 0.17141. The Rate Credit is subject to "Siting Adjustor Factors" depending on size and location and whether Renewable Energy Credits ("REC") are transferred.

Rhode Island provides a full credit for the default service charges, as well as charges for distribution, transmission, and transition. DG customers are always responsible for customer and demand related charges. Rhode Island's program is allowed to be sized up to the 3-year load of the customer or 10 MW. The Rhode Island program can be summarized in the same format as the New Hampshire program as follow:

Rhode Island	
Bill Component	**Credit or Charge**
Demand Charge	**Charge**
Customer Charge	Charge
Default Service (Energy)	Full Credit
Distribution	Full Credit
Transmission	Full Credit
Transition Charge	Full Credit

Massachusetts has transitioned through different iterations of NEM and SMART programs. For smaller projects, Massachusetts provides a credit for the default service charges, as well as charges for distribution, transmission, and transition. "New solar net metering facilities" credits are based on 60% of the excess kWh generated, as opposed to 100%. Calculation of Net Metering credits does not include demand side management charges or renewable energy kWh charges.

For Connecticut, the Residential Solar Investment program ended on January 1, 2022, with existing net metering customers grandfathered until December 2039. This program allowed projects up to 2 MW. Connecticut's new program is called "Residential Renewable Energy Solutions Program" and allows projects up to 25 kW AC and locks in the rate for 20 years. There are two options: Buy-all and Netting. For Buy-all, the utility purchases all energy and RECs generated. Excess generation at the Total Incentive Payment Rate, as set by Commission; fixed for the 20-year term of the tariff agreement. The total incentive payment equals the product of a customer's monthly Net Excess Generation, measured in kWh by the Production Meter, and their Total Incentive Payment Rate. For Netting, the utility purchases RECs for all KWh generated at the Commission established rate. Customers also receive a monetary credit at their applicable retail rate for net excess generation (energy exported to the grid and not consumed on-site). The current Eversource Buy-all payment for 20 years is set at $0.2943 and $0.0318 for the REC incentive plus a credit at the retail rate for net excess generation. These Connecticut rates compared to the Eversource full retail rate (Supply and Delivery) for a general residential customer at $0.32587 and a United Illuminating full retail rate (Supply and Delivery) for a general residential customers of $0.340391

Q. Is there a reason you do not provide a graphic table for Connecticut, Massachusetts, and Vermont?

A. Yes, these state programs are structurally dis-similar to the New Hampshire, Maine, and Rhode Island programs, so they are difficult to present in a comparative table without an incorrect suggestion of equivalence of some rows.

IV. NEM 2.0 OVERVIEW

Q. When was NEM 2.0 established and what was the major feature of NEM 2.0?

A. In June of 2017, following a full adjudication and extensive settlement discussions involving the Commission staff, the Commission issued a decision to create a new NEM tariff with the prominent features being a NEM tariff credit for net export value for new, small customer-generators for i) default energy service rate credit, ii) full transmission rate credit, iii) 25 percent credit of the distribution rate. The prominent feature was the reduction of credit for the distribution rate component from 100 percent credit in NEM 1.0 to 25 percent credit in NEM 2.0.

Q. Did the Commission do anything to ensure there is NEM stability for customers?

A. Yes, to meet the expressed need to stable customer NEM rates, these rates were made applicable for projects up to 2040. The Commission recognized that solar companies need tariff stability for roughly 20 years under NEM 2.0 for their commercial viability.

Q. Can you describe the current NEM tariff paradigms in New Hampshire?

A. Yes, currently NEM 2.0 provides customers with small DER systems up to 100 kWac with credit for the energy default service rates, for the transmission rates and for 25 percent of the distribution charge. These credits are for exported energy. No credit is provided for the stranded cost, system benefit, and storm recovery charges portions of retail service and of course no credit for the other 75 percent of the distribution component.

A graphic from the NH DOE showing the NEM programs is shown here:

Bill Component	NEM 1.0 (Standard NEM)	NEM 2.0 (Alternative NEM)
Customer Charge	Yes	Yes
Demand Charge (if applicable)	Yes	Yes
Default Service (Energy)	Full Credit	Full Credit
Distribution	Full Credit	25% Credit
Transmission	Full Credit	Full Credit
System Benefits	Full Credit	No Credit
Stranded Cost	Full Credit	No Credit
Storm Recovery	Full Credit	No Credit
Credit Mechanism (end of each billing cycle)	Net kWh Carried Forward	kWh converted to monetary credit. Monetary credit carried forward as a bill credit.

[17]

[17] NHPUC, What is Net Metering, Net Metering Tariff Overview 2020, on the web: https://www.puc.nh.gov/sustainable%20energy/Net%20Metering/Net_Metering.html.

NEM 1.0 is called standard NEM and was available for projects prior to September 1, 2017 NEM 2.0 refers to NEM arrangements in effect from September 1, 2017 to date.

Q. For larger systems what are the NEM arrangements?

A. For customers net metering with systems larger than 100 kWac up to 1 MWac, or up to 5 MWac for projects whose off-takers are municipal or county electric meters, those systems can get credit only for the default energy service charge. No other NEM credit is provided for energy exported to the grid. That singular credit is shown here:

Bill Component	NEM 1.0 (Standard NEM)	NEM 2.0 (Alternative NEM)
Customer Charge	Yes	Yes
Demand Charges	Yes	Yes
Default Service (Energy)	Full Credit	Full Credit
Distribution	No Credit	No Credit
Transmission	No Credit	No Credit
System Benefits	No Credit	No Credit
Stranded Cost	No Credit	No Credit
Storm Recovery	No Credit	No Credit
Credit Mechanism (end of each billing cycle)	Net kWh Carried Forward	kWh converted to monetary credit. Monetary credit carried forward as a bill credit.

V. <u>NEM 2.0 ISSUES WITH IT FOR ATTENTION?</u>

Q. Are there issues with NEM 2.0?

A. Yes, while New Hampshire net metering program(s) get a lot of value for the NEM tariff credits provided (more than any other New England state), they undervalue the resource. That, in and of itself, is not as categorically bad as obtaining higher value for lower cost is valuable to customers as a whole (all customers). The result is that DERs that are cost effective and would generate benefits for all ratepayers are almost certainly underdeveloped in New Hampshire.

A. NEM 2.0 Undercompensates Solar Compared to Value.

1. New Hampshire Specific and New England Value of Distributed Solar, Hydro Studies

Q. Has New Hampshire undertaken an evaluation of the value of solar and other distribution resources?

A. Yes, the New Hampshire Commission and later the DOE administered an evaluation of the value of distributed resources. The study came out of the prior NEM 2.0 docket and was conducted by the Commission and DOE. This evaluation, the Dunsky NH VDER Study, received cooperation and substantial amount of information from the electric distribution companies but was undertaken independent of the electric distribution companies and solar companies.

Q. What were the high-level findings?

A. The Dunsky NH VDER Study modeled a New Hampshire system wide net avoided value to customers of 11¢ - 18¢ per kWh for energy produced in 2021 across different DERs evaluated. By 2023, this value would be 10¢ - 23¢ per kWh.[18]

Q. Is this the Dunsky NH VDER Study particularly insightful beyond being specific to New Hampshire?

A. First, the Dunsky NH VDER Study was administered by the New Hampshire Commission and later DOE, so it's an objective study commissioned by a New Hampshire state agency.

To come to the insightful question: yes, the Dunsky NH VDER Study focuses on the difference in which value manifests and is assessed in a restructured market environment. Value has both a perspective aspect: are you measuring value to the customer, value to the utility, value to the grid system, value to the public.

[18] Dunsky Energy + Climate Advisors, New Hampshire Value of Distributed Resources, October of 2022, p. ix, together with its Appendices and the Addendum attached hereto as Exhibits 1-3.

Third, the Dunsky NH VDER Study recognizes that value to customers is much greater when deployed as a load reducer at the retail level rather than solely as a wholesale market resource. Other studies get at this issue, but the Dunsky NH VDER Study does a particularly good job of laying out this distinction.

Q. Who are the others who recognize this load reducer concept?

A. For example, in New Hampshire, Unitil has recognized this concept in their Kingston Solar testimony, in Docket No. 22-073 which I will get to shortly.

Q. For those who want to just measure the value of DERs as wholesale ISO-NE assets, what does the Dunsky NH VDER Study tell us?

A. The Dunsky NH VDER Study quite clearly illustrates that the distributed assets evaluated are undervalued and undersold when valued only in the ISO wholesale markets. Tom Beach refines the Dunsky model to use a marginal line loss factor and a more accurate avoided distribution capacity cost calculated from FERC Form 1 data, and finally allocated marginal distribution costs among a broader set of hours of the year.[19] Mr. Beach's adjustments seem accurate as a further refinement of the Dunsky analysis. I note some refinements increase and some decrease the NEM value.

Mr. Beach then likewise refines the Dunsky rates and bills impact analysis with the following improvements:

1. to use the same solar profile as was used in the avoided cost model,
2. to ensure avoided generation capacity and demand-reduction induced price effect ("DRIPE") is counted,
3. to avoid the double avoided risk premium calculation,
4. to use only the 25% distribution value for NEM export payments per the NEM 2.0 tariff,
5. to not assume commercial customers can avoid their demand charges, and

[19] Tom Beach Test. at pp. 4-11.

6. to use the same transmission revenue adjustment as in the benefit/cost analysis.

As with benefit/cost analysis, these refinements are both positive and negative as to customer bill impact. All refinements of the Dunsky model by Mr. Beach appear accurate.

Q. Why is it the case that the wholesale markets undervalue distributed resources?

A. There are multiple reasons, but the short answer is that the market design of these markets only allow for slivers of DER value to be measured and recognized. Restructured markets were not designed in the late 1990s with DERs in mind. Furthermore, many of the values that DERs can provide are realized on the distribution system, which remains a regulated monopoly, not exposed to wholesale markets.

Q. Are there other significant findings and conclusions in the Dunsky NH VDER Study?

A. The Dunsky NH VDER Study concludes that solar combined with storage as a DER combination has more value now and will have even greater value in the future for New Hampshire's grid and customers.[20]

Q. Why is that so?

A. Solar plus storage allows more flexibility and likelihood for the solar + storage DER to generate during hours of the ISO-NE peak energy supply hours, ISO-NE capacity peak, ISO-NE transmission peak, local distribution peaks, and to be available for reliability events. So the Dunsky NH VDER Study makes sense.

Q. Do other New Hampshire studies reach similar conclusions?

A. Yes, the Unitil evaluation reaches a similar conclusion for ISO-NE peak energy supply hours, ISO-NE capacity peak, ISO-NE transmission peak, local distribution peaks.

[20] *Id.* at 32.

Q. For renewable resources, does the location of the DER make a valuation difference?

A. Yes of course. I have three related answers, all of which are yes:

1. For small wind turbines, the value of the wind resource and orientation in the specific location is important.
2. Location within the distribution system can have a significant locational value component. But the aspect is addressed by another New Hampshire study and not by the Dunsky NH VDER Study. I address that shortly.
3. For solar resources the orientation of fixed solar panels matters in two different ways:
   a. Orientation of the panels toward the south will produce the most total kWh of generation because of the sun's orientation.
   b. Orientation more toward the southwest or even mostly west may have more of a grid or reliability benefit even with less total solar kWh. The Dunsky NH VDER Study does a nice job of illustrating the other non-supply valuation elements that make a more westward orientation more valuable because when there are load peaks in the evening those westward systems provide greater solar coincidence.[21]

Q. Does the Dunsky NH VDER Study examine customer costs?

A. The customer cost analysis which the Dunsky NH VDER Study undertakes reaches conclusions regarding costs for non-NEM customers and NEM customers. For non-NEM customers, there is an increased bills that are quite modest (estimated at 0.5% to 1%),[22] and I think the Joint Utilities take the same general posture on costs to non-NEM customers without endorsing or agreeing with the Dunsky NH VDER Study conclusions as to non-NEM customer costs. For NEM customers, there are cost savings; the NEM program results in large NEM customer cost reductions, which is why it has likely become more utilized in recent years.

[21] *Id.* at 26-28. The Dunsky NH VDER Study states: "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." *Id.* at 28.

[22] *Id.* at 48.

Q. Does the Dunsky NH VDER Study identify other notable benefits?

A. The Dunsky NH VDER Study identifies two notable benefits that it does not quantify.

The first is grid reliability and support services that DERs can provide. Because most DERs are inverter-based, new inverters have substantial capacity to provide reactive power, voltage, power quality and power factor correction.[23] If not enabled immediately, New Hampshire utilities and the Commission have the ability to utilize these grid reliability and support abilities in the future on a circuit by circuit basis as necessary – of course working with the DER owners. There is substantial potential reliability benefit to be had if the Commission and/or utilities decide to utilize such DER capabilities.

Q. What is the other notable benefit?

A. The second non-quantified benefit identified by the Dunsky NH VDER Study is resiliency value. Solar + storage can support customer islanding with a switch the same way a generator does now. DERs can also support microgrid configurations for businesses or neighbors, microgrids for critical public safety facilities, and controlled load shedding. While DERs will require further investments to support further customer and grid resilience, those future investments can be less as a result of DER deployments now.[24] DER deployments enable future customer and grid resilience optionality.

Q. Do other New Hampshire studies or analysis support the Dunsky approach?

A. The analysis presented to the Commission by Unitil regarding the Kingston Solar project was different, but has a common recognition with the Dunsky NH VDER Study approach in that:

1. Operation of a distributed resource as a load reducer produces more New Hampshire customer value,
2. There are avoided energy costs,
3. There are avoided regional capacity costs,

[23] *Id.* at 42.

[24] *Id.* at 42.

4. There are local transmission benefits and likely avoided costs,
5. There are regional transmission benefits and likely avoided costs,
6. There can be renewable energy certificate ("REC") savings.

The Kingston project testimony assumed a 22 percent capacity factor. Unitil estimated the solar project would provide regional capacity savings of approximately 37 percent of its nameplate (1.85 MW of the 4.875 MW capacity) would generate on the annual historic ISO-NE peak-hour. Likewise 0.6 MW of the 4.875 MW (12% of nameplate) was estimated to contribute to the monthly system peak providing local transmission benefits, ancillary service benefits, and regional transmission costs savings.[25] The net result was an analysis of a project that would return more value to ratepayers than the utility revenue requirement. Similarly, customer owned DERs, at least solar generation allowed under the New Hampshire Tariff, on average, return more value to all ratepayers than the NEM 2.0 tariff credits to NEM customers.

Q. With ISO-NE markets being what they are in New England, is the value as a load reducer greater than wholesale market value?

A. Yes, the Dunsky NH VDER Study and the Unitil Testimony in the Kingston Solar proceeding[26] both illustrate that value as a load reducer is greater than value as a wholesale market asset in the ISO-NE markets.

Q. Why is the value as load reducer greater for distributed resources in New England than in the ISO-NE wholesale markets?

A. In New England, it is easier to realize value as a load reducer where all value manifests itself when presented to the retail customer. The ISO-NE wholesale markets allow for individual components – or slivers – of value to be realized, but do not allow multiple values to be realized

[25] Unitil Energy Systems Inc., Joint Direct Testimony of Andre J. Francoeur, Todd R. Diggens, Christropher J. Goulding, and Jeffrey M. Pentz, Ex. FDGP-1, NH PUC Dock. 23-073.

[26] Unitil Energy Systems Inc., Joint Direct Testimony of Andre J. Francoeur, Todd R. Diggens, Christropher J. Goulding, and Jeffrey M. Pentz, Ex. FDGP-1, NH PUC Dock. 23-073.

for distributed resources. Moreover, avoided retail level value and avoided line losses present additional value to retail customers that is not represented in the ISO-NE markets. For that reason, both the Dunsky analysis and the Unitil analysis illustrate that a properly balanced distributed resource program can realize more customer value than participation in the ISO-NE wholesale markets will.

Q. Do the studies confirm this load reducer value concept?

A. Yes, the value and cost analysis by Dunsky, by Tom Beach, and by Daymark on behalf of Unitil all tend to confirm there is more value as a load reducer than as an ISO-NE market asset.

2. New Hampshire Locational Value of Distributed Resources Study

Q. Has any other New Hampshire specific study of the distribution values of distributed resources taken place?

A. Yes, coming out of the prior NEM docket, the Commission contracted with Guidehouse to conduct a detailed examination of the distribution system capacity value of distributed generation across different circuits and substations in New Hampshire, the New Hampshire Locational Value of Distributed Generation Study[27] (the "NH Locational Distribution Value Study").

Q. What do you mean by detailed examination?

A. Guidehouse examined the New Hampshire utilities actual circuit and substation from 696 locations and identified 122 of those locations with capacity deficiencies. This review looked backward five years and forward ten years using the utilities planning criteria. Of those 122 locations, a subset were examined for winter and summer peaking, mid-day and late-day peaking, contingency overloads and performance violations at under base, low and high load scenarios. That is what I mean by a detailed New Hampshire specific examination.

[27] Guidehouse, New Hampshire Locations Value of Distributed Generation Study, Final Report for the New Hampshire Public Utilities Commission, July 31, 2020, attached hereto and incorporate herein as DPL-4.

Q. What is the potential significance of this NH Locational Distribution Value Study for a NEM tariff?

A. The NH Locational Distribution Value Study is a New Hampshire-specific review of the distribution system capacity value that distributed generation may be able to provide. The study is location specific, of course, and shows the value of avoided distribution capacity investments ranges from under $1 per kW/hr to over $4,000 per kW/hr.

Q. Why is this important for New Hampshire NEM tariff setting?

A. The NH Locational Distribution Value study shows that there is distribution system value on specific New Hampshire distribution circuits and substations, even exceeding $4,000 per kW/hr. That value is in avoiding or deferring distribution system capacity upgrades.

Q. How does that connect to the current NEM tariff?

A. The NEM 2.0 tariff provides 25 percent distribution credit for distributed generation that qualifies for NEM. The NH Locational Distribution Value Study illustrates that distribution system value for ratepayers can exceed this amount substantially on some circuits and for some substations. We need to be cautious not to overinterpret this study as it is locationally specific and subject to the inputs of the study, but given the robust inputs of New Hampshire-specific distribution grid data, it meaningfully suggests the NEM 2.0 tariff is under-compensating DERs for their distribution benefits.

Q. Is the follow up information provided in this docket consistent generally with the NH Locational Distribution Value Study?

A. Yes, the data responses in this case, such as Eversource Data Response to CENH 1-007, in terms of actual distribution system peak load/capacity projects are consistent with the NH Locational Distribution Value Study potential avoided distribution capacity analysis.

3. Maine VOS – 2015

Q. Have other New England Commissions undertaken value of solar valuation studies?

A. Yes, Maine undertook a Maine Distributed Solar Valuation Study ("Maine Solar Value Study") that was issued by the Maine Commission in 2015.

Q. What did the Maine Solar Value Study conclude?

A. First just to be clear, the Maine Solar Value Study used a different methodology than the Dunsky NH VDER Study and based avoided market costs on 2015 data. The price of energy supply is now much higher than in 2015 so that Maine calculated value would be more than double.

With that caveat, the 25 Year Levelized valuation for solar in CMP territory was calculated at 33.7 cents/kWh. That includes environmental pollution reductions avoided costs from reduced public health and environmental impacts using EPA's models and data.

Q. How would the Maine results be different today?

A. As noted, the price of energy supply is much higher in 2021-2023 than in 2015, almost double, so the avoided energy supply cost element would produce a higher evaluation. The net social cost of carbon estimate would also be higher as the U.S. government has revised the prior estimates for social cost of carbon since 2015.

On the other hand, the environmental value of reduced sulfur dioxide ("SO_2"") would be lower. That lower value is due to less SO_2 being avoided because less coal is being used and dispatched among the national and New England generation fleets. Less coal producing SO_2 means that there is less environmental impact to "avoid" through clean generation. The same is not true of NO_x which is produced in large degree by gas turbines which together with renewables are pushing coal out of many generation fleets.

Q. Is this Maine Solar Value Study applicable in New Hampshire?

A. This is a different study using a different methodology. Clean Power Research is a reputable energy consulting firm, and the firm and research was Commissioned by the Maine Public Utilities Commission staff. While this report was done by Maine staff, I note it was during Maine Governor Paul LePage's tenure and his appointment of the majority of the Maine Commission, so it was certainly not done by advocates for solar or renewables.

I would say the Maine Solar Value Study is an important point of reference along with the Dunsky NH VDER Study. The Maine Solar Value Study was also undertaken by the Commission, like the Dunsky NH VDER Study, so not an advocacy piece which provides a higher level of credibility.

Q. Have there been other studies for New England states?

A. Yes. Speaking of work done by advocates for advocacy purposes, there are analyses undertaken by and for clean energy groups that show the value of solar.

The first example I would cite as advocacy in the context of a Commission matter, is Daymark Energy Advisors' analysis performed for the Coalition for Community Solar Access (the "Daymark Maine NEB Report").[28] This study was done in the context of a Maine Public Utilities Commission Report to the legislature identifying potential Maine net metering costs of $160.8 million based on a full retail value NEM paradigm in Maine that allows for virtual net metering of off-site projects (as well as repackaging of existing DG into the NEM up to 5 MWs). From a customer perspective the Maine NEM paradigm is more favorable than New Hampshire NEM 2.0 because it can offset 100% of distribution costs.

[28] Daymark Energy Advisors, *Cost and Benefits of Maine's Net Energy Billing Program*, prepared for the Coalition for Community Solar Access (hereinafter "Daymark Maine NEB Report") March 11, 2021.

The Daymark Maine NEB Report models $1.8 billion in value of solar for the $160.8 million of costs. Daymark did not assess the distribution value as part of this analysis, so this $1.8 billion in value of solar for the $160.8 million of costs does not include distribution savings. On the other hand, these benefits include savings on standard supply offer, transmission savings, capacity, economic development and jobs benefits and environmental benefits[29].

A second of those studies was performed for Clean Energy New Hampshire, Renewable Energy Vermont, and Vote Solar by Synapse. This study focused on the total wholesale savings achieved in New England attributed to the actual behind the meter ("BTM") production of solar. This study used actual data from known solar generation to look backwards based on actual energy and capacity pricing data. The study did not look at transmission level savings nor any retail distribution or other retail level savings.

Nonetheless, this study concluded that savings from BTM solar amounted to 13.5 cents/kWh for wholesale energy and capacity alone and from 20.5 cents to 37.1 cents per kWh with pollutants included in the calculation.[30] The 13.5 cents/kWh savings for wholesale energy and capacity is substantial at the wholesale level and obviously more substantial if environmental and carbon reduction benefits are counted. Again, this is not compensating DERs for the value they are providing to the grid as load reducers.

B. Other Reliability and Environmental Benefits Not Counted by Tom Beach.

1. Reliability

Q. Do distributed resources provide a reliability benefit?

A. Yes, undoubtedly so. These resources provide reliable capacity on a system-wide basis.

[29] *Id.*

[30] Patrick Knight, Steve Letendre, PhD, Erin Camp, PhD, Synapse Energy Economics, *Solar Savings in New England from 2014 to 2019, a small-scale solar in New England produced wholesale energy market benefits of $1.1 billion*, Dec. 2020.

Individually there is a risk of loss of generation from any one project, just like a circuit. But in aggregate there is a reliability benefit.

Q. Has ISO-NE recognized this benefit?

A. Yes, for quite a while ISO-NE portrayed distributed resources as a threat to grid reliability, but recently ISO-NE has recognized the reliability benefit that distributed resources are provided in New England, even solar in the winter time.

Q. In what context did this occur?

A. ISO-NE recognized this benefit in the context of explaining why it can now retire the Mystic Station that had been running under out-of-market reliability contracts for a number of years.

Q. Did ISO-NE explicitly reference BTM distributed resources as a reason for allowing the Mystic Generation Station to shutdown?

A. Yes, ISO-NE cited the acceleration of BTM resources on slides 3 and 8 of its explanation for why the ISO is now comfortable with allowing Mystic to shutdown.[31] The ISO-NE Chief Operating Officer has been quoted as saying ISO-NE is surprised to see this amount of substantial winter capacity produced by BTM resources. These resources, while intermittent, act as fuel-savers. When BTM solar is produced during cold winter days, the region's dispatchable resources are able to conserve limited on-site fuel or gas under contract. This means the region can endure longer cold snaps during times of greatest winter system constraint.

Q. What is the economic value of this reliability benefit?

A. Since the New England region has been paying tens of millions each month to support a single uneconomic cold plant in Everett, Massachusetts, we have unfortunate experience with

[31] ISO-NE states "Acceleration of behind-the-meter (BTM) PV nameplate capacity" as one of the factors now allowing Mystic to closedown." ISO-NE, *Winter 2024-2025 Analysis; With and Without Everett Marine Terminal*, May 4, 2023, on the web at: https://www.iso-ne.com/static-assets/documents/2023/05/npc-2023-05-04-coo-rpt-winter-2024-25-analysis-with-and-without-everett.pdf

paying too much.

The economic costs for this reliability benefit can be measured against the cost of maintaining the Mystic plant, which again was too much in my view. So it could also be compared to the cost of generator capacity in winter or summer. The Dunsky NH VDER Study and Tom Beach analyses do that.

Q. Is this reliability benefit seasonal?

A. Yes, and this is the winter capacity assessment by ISO-NE. It bears emphasis that this ISO capacity assessment is for winter reliability, which is when the solar resource is weakest. As a result, the summer reliability contribution would be much higher in dealing with summer peaks. ISO-NE remains a summer peaking system, but that is projected to change over the next two decades.

Q. Would this reliability contribution be counted in the value of solar studies you discuss?

A. No, not generally speaking because the Mystic/Everett Terminal costs were out-of-market costs known as uplift. So those costs were not accounted for in the capacity market analysis conducted by the energy consulting firms discussed previously. So this reliability benefit is a substantial value adder for the region.

Q. Are there other recognized reliability benefits for New Hampshire DERs?

A. Yes, ISO-NE speaks to the ability to keep the New England Power grid online through emergencies in various seasons. The Dunsky NH VDER Study identifies local grid reliability support services such as voltage support, power factor correction and power quality as noted above.[32]

[32] Dunsky VDER Study at 42.

2. Environmental Values

a. Greenhouse Gas Reductions

Q. Are there greenhouse gas reductions from New Hampshire NEM program(s)?

A. Yes, most New Hampshire NEM resources are renewable, as is true nationally. These renewable resources directly offset fossil unit generation in New England. Gas turbines and combustion turbines are the generation most often on the margin in New England, so more solar, hydro and wind overwhelmingly displaces carbon dioxide emissions from gas generation.

Q. Are there other greenhouse gas benefits?

A. Yes, the upstream gas pipelines, storage, distribution, processing and extraction systems all have fugitive emissions that are either by design (for safety) or by leakage and accidental releases. In aggregate these releases of gas are substantial and composed of methane, a greenhouse gas much more potent for greenhouse gas warming than carbon dioxide. Some analyses conclude that the impact of this gas/methane leakage upstream negates any greenhouse gas benefits of using gas instead of coal. While these upstream methane release analyses vary, they agree the upstream fugitive methane releases are a big issue in terms of greenhouse gas warming potential.

The benefit of displacing generation is that there is a similar reduction in upstream fugitive methane emissions. So methane emissions are also reduced within New Hampshire, New England, and nationally.

b. Pollution Reductions

Q. Are there other pollution reduction benefits?

A. Yes NO_x emissions from gas combustion are substantial. NO_x is one of the five Clean Air Act's primary Criteria air pollutants because of its negative public health impacts. NO_x also mixes in sunlight with volatile organics that are prevalent from human sources (e.g. gasoline, paints, etc. and from natural sources) in New England to create ground level-ozone, which is another of the five Clean Air act's primary Criteria air pollutants. When ozone levels go up in the summer and spring, hospital admissions and mortality increase by statistically measurable amounts.

Q. Do NEM resources reduce NO_x and Ozone Pollution?

A. Yes, again, most New Hampshire NEM resources are renewable, as is true nationally. These renewable resources directly offset fossil unit generation in New England. Gas turbines and combustion turbines are the generation most often on the margin in New England so more solar, hydro and wind displaces NO_x emissions from gas generation as it does carbon dioxide.

VI. <u>NEM 2.0 SUPPORTS NEW HAMPSHIRE'S ECONOMY</u>

A. Maryland Value of Solar Study.

Q. Do net metering arrangements provide state level economic benefits?

A. Yes, there's little question that net metering programs support state and local economic development. The projects are labor-intensive to install, so they generate quite a bit of construction, engineering, site work employment and incomes.

Q. Are there studies that support this your finding?

A. Yes, several values of solar studies have examined economic benefits including economic growth, jobs, indirect economic benefits from solar or distributed energy resource programs.

Q. What are the results of these studies?

A. Four studies that I know of have looked at the solar value to economic development. The studies that quantified the benefits are Maryland's and a study undertaken for the Sierra Club in Arkansas.

The Maryland Value of Solar Study was undertaken by Daymark Energy Advisers, a reputable consulting firm, for the Maryland Public Service Commission. That Maryland Value of Solar Study concluded that Maryland's net metering scheme was forecasted to generate 22,563 job-years, over $2.03 billion in value added for the Maryland economy, and $1.34 billion in labor income. While the Maryland NEM program is more lucrative and Maryland is a larger state, these numbers are indicative of strong state gross domestic product, employment, and value impacts. The fact that Maryland's NEM program is more lucrative would tend to produce greater gross economic benefits from NEM activity. But I note that a thriftier program that pays less for a kWh of distributed generation would generate more net benefits to all ratepayers (net benefits to all ratepayers = value of solar stack components - cost to all ratepayers of NEM payments) , and certainly more net benefits to NEM customers (net benefits to NEM customers = value of solar value stack components + avoided payments for NEM credit components - cost to all ratepayers of NEM payments).

The Arkansas Study was undertaken by Crossborder Energy, also a reputable energy consulting firm.[33] This Arkansas solar study estimated an economic development value of $33.60 per MWh. Other studies touch on economic development benefits, but these Maryland and Arkansas studies provide a quantified value.

Q. Are there long-term economic development benefits beyond construction jobs?

A. Yes, the largest benefit if macroeconomic. Rather than exporting payments for fuel out of New Hampshire, customer revenue is invested in New Hampshire based economic investments. In addition to solar installation, engineering, construction, and electrician employment, solar installations require operations and maintenance expenses. This is particularly true of commercial scale installations. Contracts will be kept in place for commercial installations that provide permanent local jobs for those servicing these facilities.

[33] R. Thomas Beach and Patrick G. McGuire. *The Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc.* Crossborder Energy, pp. 28-29.

Q. Are there New Hampshire specific studies illustrating the economic benefits of distributed resources?

A. Yes, Daymark Energy Advisors performed an analysis of economic benefits for Unitil Energy Systems, Inc. submitted to the Commission in Docket No. 23-073. The analysis examined the economic benefits of a single 4.875 MWac commercial-scale solar project. The Daymark study for Unitil found that a single 4.875 MW solar installation would produce 95 employment job years with $7,461,200 in labor income and total New Hampshire economic output increase of $12,069,045.[34]

While each analysis has differences in methodology, assumptions, and models, the combination of the New Hampshire Unitil Study, the Maryland Value of Solar Study, and the Arkansas Crossborder Study illustrate the substantial state and local economic benefits of a balanced NEM program.

VII. NEW HAMPSHIRE NEM TARIFFS

A. 0 to 100 Kilowatts – Simple Small Tariff.

Q. Are there recommendations you would make to improve the small NEM tariff for customers in the 0 to 100 kW system range?

A. Yes, first, DERs of this size are typically residential or small business installations. Here and below I have a number of recommendations. First, I would recommend increasing the distribution credit to 50 percent of distribution value.

The basis for this recommendation is very conservative. Tom Beach's analysis shows that there are positive benefits for all Eversource classes from NEM 2.0. While that analysis could support a 100 percent distribution value, we suspect the New Hampshire approach to its NEM

[34] Daymark Energy Advisors, Inc., *Indirect Benefits of Kingston Solar*, prepared for Unitil Energy Systems, Inc. NHPUC, Dock. No. 23-073, Ex. GPP-2, p. 8 of 31, March 31, 2023

tariff will continue to be frugal and err on the conservative side. We are also asking for a 20-year period for any new NEM customer to be grandfathered under a NEM 3.0 tariff. For that reason, we adopt a conservative approach to ensure the benefits unquestionably exceed the costs over a 20-year period.

Q. Do you have other recommendations for the small NEM rate tariff?

A. Yes, as just noted, CENH recommends an extension beyond 2040 for customers who sign new NEM agreements after the effective date of this proceeding. Consistent and stable structures for treatment over a number of years will be important for new NEM customers. Customers who invest in NEM facilities should continue to be able to avail themselves of that NEM rate structure for 20 years after the date after the date that they commence generating.

Q. Why would the New Hampshire Commission want to increase any amount of NEM credits?

A. First, the increases CENH and I are suggesting are modest. Second, if New Hampshire establishes a NEM tariff that allows more customers to invest in DERs, those NEM customers will receive substantial benefits, which will be reinvested in New Hampshire's economy. As long as that NEM tariff still results in net benefits to all ratepayers, such a decision would be consistent with the NEM enabling statute, which directs the PUC to support the ability for New Hampshire customers to invest in their own generation. So the Commission can capture marginally more benefits (again in excess of costs) with a modest increase from 25 percent to 50 percent distribution credit.

B. Large Customer-Generators

Q. Are NEM customers up to 1 MW a large NEM tariff system?

A. As a general category of NEM customers, other than municipal NEM which can be installed up to 5 MWac BTM or offshore which systems we do not address here, 1 MW is New

Hampshire's largest system size that qualifies for NEM. As a point of reference, other states allow larger NEM tariff systems.

Q. Are other states' net metering schemes more lucrative for NEM customers in these larger capacity projects?

A. Yes, generally other New England states' NEM programs provide more credit for NEM commercial customers.

Q. Are you recommending that New Hampshire adopt other New England states' approaches?

A. No. New Hampshire has its own approach to NEM that has worked in New Hampshire. I am recommending incremental changes to create more opportunity for DER deployment, which will generate more value for all ratepayers. Our analysis has shown that New Hampshire's structure is foregoing some value—even for non-NEM participants—by undercompensating large customer generators in particular.

Q. How does the value illustrated by the Dunsky and Daymark stack up to costs paid?

A. NEM 2.0 does not support larger commercial scale systems well.

Q. Can you identify the shortcomings?

A. NEM 2.0 does not support projects above 100 kW and below 1 MW well. I call these commercial sized DER projects. These commercial sized DER projects only receive the value of New Hampshire's default electricity supply. This is an obvious and easily accounted for avoided cost value and should be maintained.

Commercial sized DER projects up to 1 MW deliver transmission value and distribution value too. Tom Beach's analysis is quite clear on this value as just over or under cost for all ratepayers.

Q. How could an NEM 3.0 provide better support for commercial sized DER projects up to 1 MW?

A. The Commission can provide some transmission value for commercial sized DERs comparable to that for projects below 100 kWh. Notably, Unitil's analysis recognized there is transmission charge reduction value, though in the range of 12 percent. The Dunsky VDER Study calculated the transmission value at 50 percent so we propose that amount of transmission credit.

Q. Is there another way the Commission can provide a NEM 3.0 with better support for commercial sized DER projects?

A. The Commission can provide some amount of distribution credit. There undoubtedly is a distribution value for projects from 100 kW to 1 MW.

Q. What are you recommending for New Hampshire's large customer generator NEM program?

A. I am recommending recognizing that NEM customers over 100 kW provide transmission and distribution value as well as other values such as reliability and resilience and line loss reductions as the DER resource is located much closer to load.

Q. Specifically, what is CENH's recommendation for NEM customers over 100 kW?

A. Since Tom Beach's analysis shows benefits to all ratepayers for large commercial projects, we request the Commission provide enhanced credit to NEM customers with projects 100 kW to 1 MW. Specifically, we request the following export credits for projects over 100 kW: full default energy service credit, a distribution credit at 50 percent of the volumetric distribution rate, and a volumetric ($ per kWh) adder of 50% of the avoided transmission costs for a solar profile in the years 2021-2035 as determined by the avoided cost model, this adder averages $0.024 per kWh over 2021-2035. The transmission adder is needed so that large customers who install solar and who pay transmission costs in demand charges receive some benefit for avoiding transmission costs as recognized by the Dunsky NH VDER Study.

Q. Have you looked at the bill impact for this change to NEM for facilities 100 kW to 1 MW?

A. Tom Beach did so in his analysis and concluded the bill impact is very small, with the program continuing to provide net benefits for non-participating customers.[35]

Q. Are you recommending the same NEM 20-year period for new NEM customers for facilities over 100 kW?

A. Yes, I am. It's important that a NEM tariff provides sufficient stability for distributed projects to be financed.

Q. If commercial sized projects are granted some distribution and transmission credit, will they be compensated with similar NEM schemes to other New England states?

A. No, even with some additional distribution and transmission credit, New Hampshire's NEM program would remain the most frugal and thrifty in New England

C. Consider Value for Solar + Storage.

Q. Are there some DERs that are more valuable than others?

A. Yes, the Dunsky NH VDER Study does a good job of illustrating that some DERs are more valuable for customers and/or for grid purposes than others. DERs, like all resources, have different capabilities—not to be confused with Forward Capacity Market capacity. Different types of DERs have different capabilities as well. Those different capabilities translate into different customer and grid value propositions.

Q. What is an example illustrated in the Dunsky NH VDER Study?

A. The Dunsky NH VDER Study illustrates the superior value of solar + storage to solar alone. While solar alone can hit early and mid-afternoon system peaks to provide substantial value,

[35] Tom Beach Testimony at p. 19.

solar alone cannot hit the later evening peaks. If storage is added to solar, that extends the ability to hit supply peak pricing, capacity and transmission peaks. That adds substantial value.

Q. Does the Dunsky NH VDER Study quantify that solar + storage value?

A. Yes, the Dunsky NH VDER Study uses its model to produce a quantified value. I take that value as illustrative rather than literally of course. Nonetheless, the Dunsky model is a substantial and expertly modeled illustration of the value of solar + storage.

Q. What is your recommendation for solar + storage.

A. Since the Dunsky NH VDER Study modeling shows that solar + storage systems will increase the value up to 5¢/kWh more over the time period, I would recommend that solar + storage systems receive 2¢ more per kWh than ordinary solar systems for exports.

Q. Why 2¢ more for solar + storage NEM systems?

A. There are several reasons. On the positive side, solar + storage is more valuable as discussed and will become more so over time. That additional value goes beyond the DER value illustrated in the Dunsky NH VDER Study analysis to provide more grid flexibility, resilience, and future capabilities. On the negative side, I am not recommending a higher amount to frugally obtain more valuable capacity at a lower price and because I recommend forty percent of the future value. That seems like a reasonable approach here for higher value systems that will produce superior customer value over the long run.

Q. Should a NEM customer be obligated to use the battery for peak times?

A. That obligation would be hard to enforce or even track without advanced metering infrastructure as well as complementary data and utility management systems. For that reason, I am not recommending at this point in time that the program impose such an obligation. However, if such a rate were to result in deploying more customer-owned battery storage, that resource would be readily available to be enrolled in demand response programs and advanced rate structures as the utilities' billing and data management systems are upgraded.

D. Consider Value of West-Facing Systems.

Q. Does the Dunsky NH VDER Study show that other DERs are more valuable than others?

A. Yes, the Dunsky NH VDER Study illustrates that west facing systems are more valuable than south facing systems.

Q. What is illustrated in the Dunsky NH VDER Study for west-facing systems?

A. The Dunsky NH VDER Study illustrates the superior value of west-facing solar to south facing solar alone. While south-facing solar can hit early and mid-afternoon system peaks to provide substantial value, west-facing solar can hit later afternoon peaks. That adds more avoided cost value than south-facing solar.

Q. Does the Dunsky NH VDER Study quantify West facing solar value?

A. Yes, the Dunsky NH VDER Study uses its model to produce a quantified value. I take that value as illustrative rather than literally of course. Nonetheless, the Dunsky model is a substantial and expertly modeled illustration of the value of west-facing solar.

Q. What is your recommendation for west-facing solar?

A. The modeled values in the Dunsky NH VDER Study are roughly 1¢ or more for west-facing solar compared to south-facing solar so I propose an additional 1¢ value for exports from systems facing westward at 225 to 315 degrees azimuth.[36]

Q. Does this mean that non-NEM customers will pay a cent more each kWh than a southward facing system would generate?

A. No. When you face a system west, it produces less actual kWh. So the total number of kWh will go down appreciably due to a west-facing orientation. While you are getting greater value out

[36] Dunsky NH VDER Study, pp. 26-28.

of each kWh under the NEM system, you are paying for a lower quantity. So you get higher value and lower costs.

VIII. OTHER ISSUES RELATED TO NEM 2.0.

A. Grandfathering.

1. NEM 1.0 and NEM 2.0.

Q. How were customers who opted into NEM 1.0 treated during the transition to NEM 2.0?

A. NEM 1.0 customers were grandfathered, for a certain time period, into the earlier program. But only those customers in NEM 1.0 were allowed to continue. New customers had to move forward under NEM 2.0.

Q. Is grandfathering current customers important?

A. Yes, CENH supports the arrangements put in place for NEM 1.0 customers. Those customers made investments based on understandings of the program in place at the time, e.g. prior to 2017. CENH agrees that continuing to honor those arrangements is important.

Q. Do you have recommendations for how to treat NEM 2.0 customers in the future?

A. Yes, two recommendations. The first is to provide a 20-year time frame for any NEM customer from the date they energize. For customers turning systems on in 2020, that would mean 20 years to at least 2040. For customers turning systems on in 2022, that would mean 20 years to 2042.

Q. What is the second recommendation?

A. The second recommendation is that, assuming NEM 3.0 is any different than NEM 2.0, to ask for the same effective grandfathering for NEM customers taking NEM 3.0 after the Commission's new program becomes effective, so 20 years of NEM for new customers.

Q. Are there other considerations for grandfathering and rate revisions?

A. Yes, rate design principles, often called the Bonbright principles and their progeny, generally endorse simplicity, customer understanding, stability, and of course economic efficiency among other principles. These principles support grandfathering and incremental NEM improvements here.

2. Projects Built Under NEM 2.0 through 2050.

Q. How would you treat projects built under NEM 2.0 later than 2020?

A. Again, we are suggesting a 20-year NEM tariff agreement stability. So for projects starting on NEM 2.0 later than 2020, we are suggesting those agreements be allowed to stay in place for 20 years.

C. Value as Load Reducer.

Q. Should the NEM program be re-oriented around realizing only market values?

A. No, as noted above, the ISO-NE programs only recognize a couple to several thin slivers of value. That is a function of how the restructured markets work.

Q. What is the alternative to using the wholesale market value?

A. The alternative, at least one alternative, is to continue the NEM program to recognize multiple value elements including as a load reducer. Reducing retail load has direct benefits for all ratepayers. The Dunsky NH VDER Study does a nice job of illustrating how value as a load reducer is superior to value as an ISO-NE market resource for the DERs evaluated.

D. Highest Value for Lowest Cost.

Q. What are your thoughts on NH's approach to NEM value and costs?

A. The New Hampshire approach to NEM has been to pursue DER value at low cost. New Hampshire has been less generous for NEM customers than other states, but has been successful in securing DER growth for very modest cost impacts on non-NEM customers.

Q. Are your recommendations in this testimony consistent with that New Hampshire approach to NEM?

A. Yes, we are not recommending NEM programs like other New England states. The CENH recommendations here are incremental suggestions to secure DER value at a continued very modest cost.

Q. Would maintaining NEM at the NEM 2.0 levels secure the same DER value?

A. No, the level of support for commercial sized solar, above 100 kW is leaving value underdeveloped. Our recommendations are to provide incremental support there in line with the NEM 2.0 program for smaller DER projects up to 100 kW.

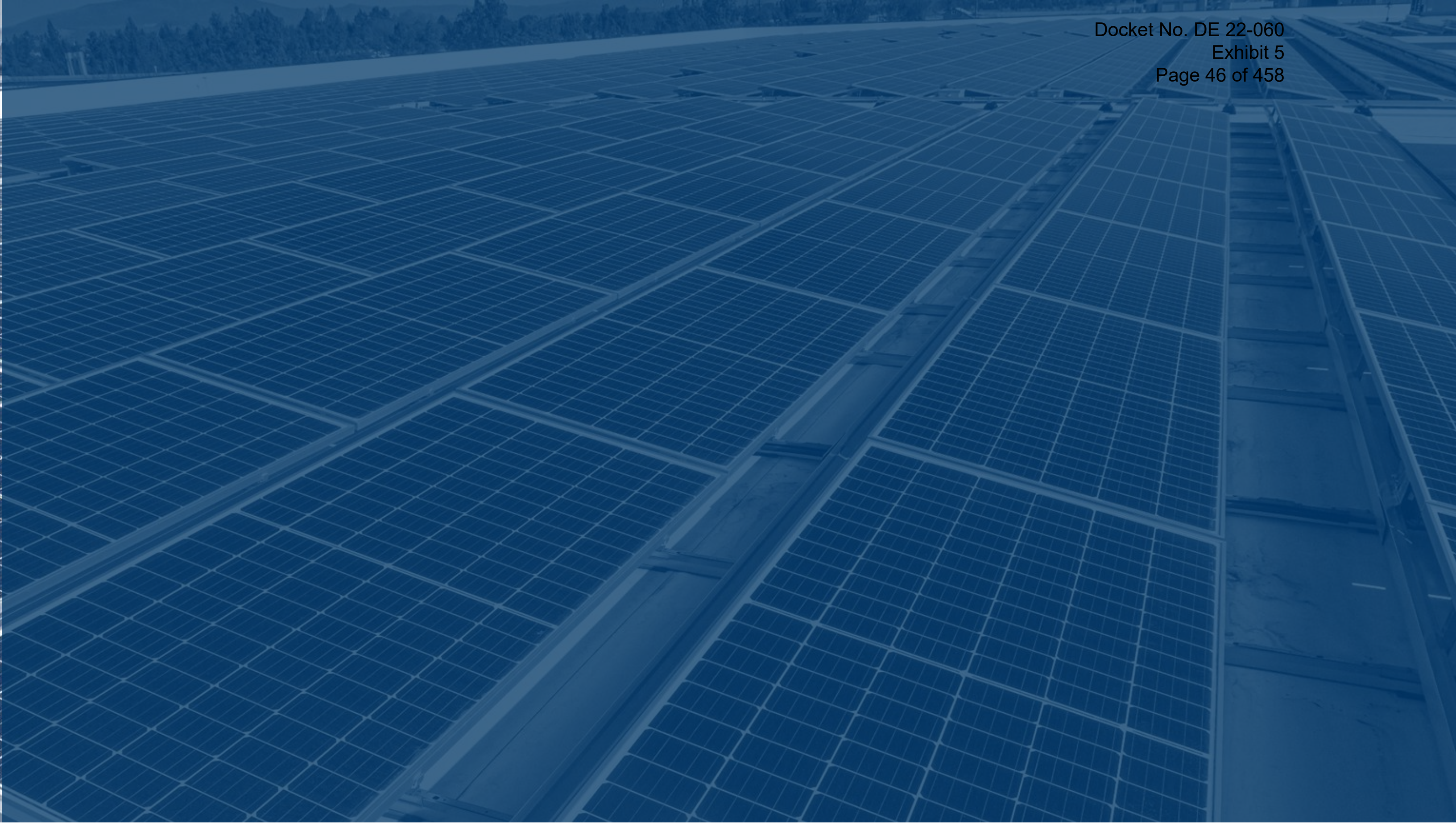
IX. CONCLUSION

Q. Can you summarize your testimony?

A. Yes. New Hampshire can both ensure NEM-customers and all customers receive the benefits of distributed generation with modest revisions to the NEM 2.0 tariff. The revisions CENH recommends in this testimony are to: 1) conservatively modify the residential and small commercial NEM tariff (up to 100 kW) to allow distribution credit of 50 percent, 2) continue to have commercial customers imports and exports netted hourly and modify the large commercial NEM tariff (100 kW to 1 MW) to allow credits at the sum of: a) full credit for default energy service, b) 50 percent distribution credit, and c) a volumetric transmission adder set at 50% of the solar-weighted avoided transmission cost from 2021-2035 from the Dunsky model, and 3) allow a stable 20 years of benefit from the energization of the customer facility for a 20-year NEM contract.

Q. Does this conclude your testimony?

A. Yes. I incorporate the appendices listed in the Table of Contents into this testimony and attached hereto. Thank you.



New Hampshire Value of Distributed Energy Resources

Final Report

Submitted to:

New Hampshire Department of Energy

New Hampshire Department of Energy

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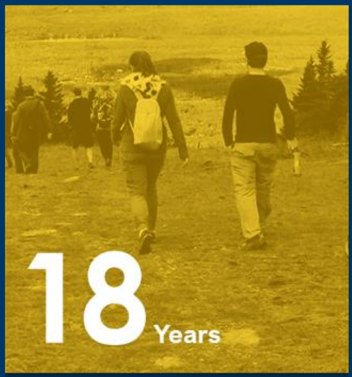
About Dunsky



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

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

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List of Acronyms

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

EXECUTIVE SUMMARY

Introduction

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

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

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

Methodology Overview

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

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$)

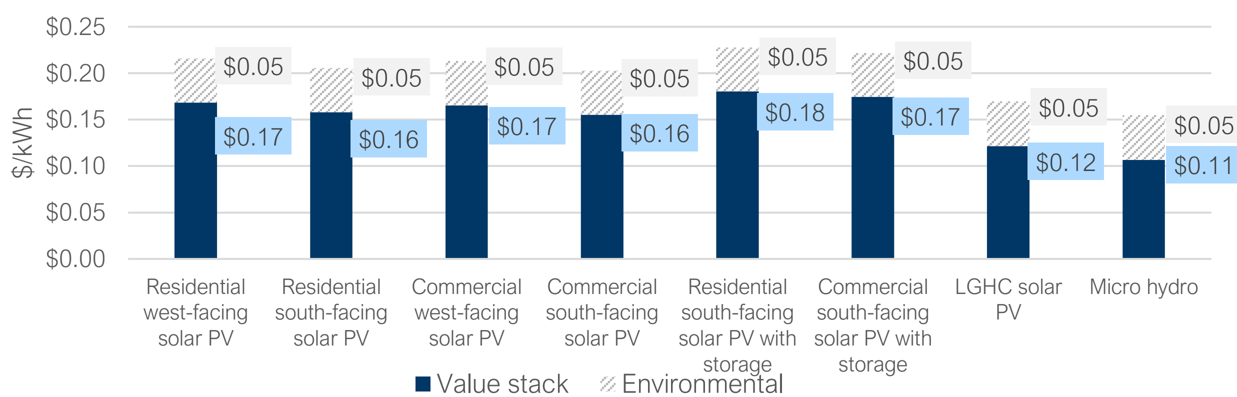
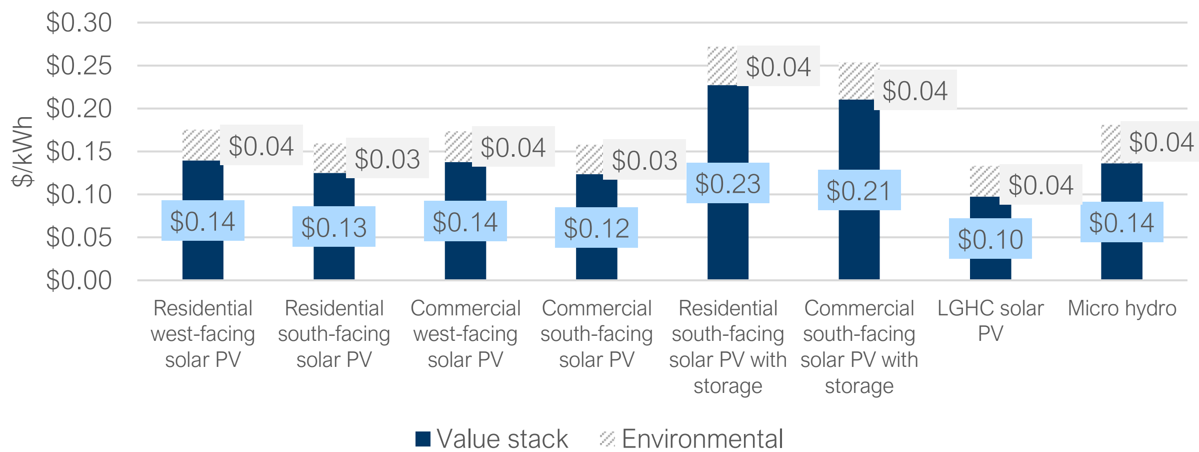


Figure 2. Average Annual Value Stack with Environmental Externalities Sensitivity by DG System Type, 2035 (2021$)



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$)

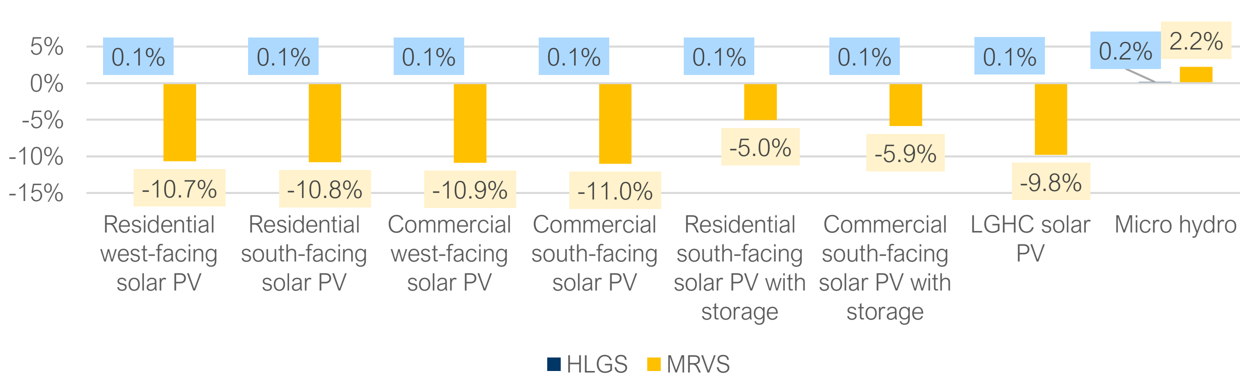
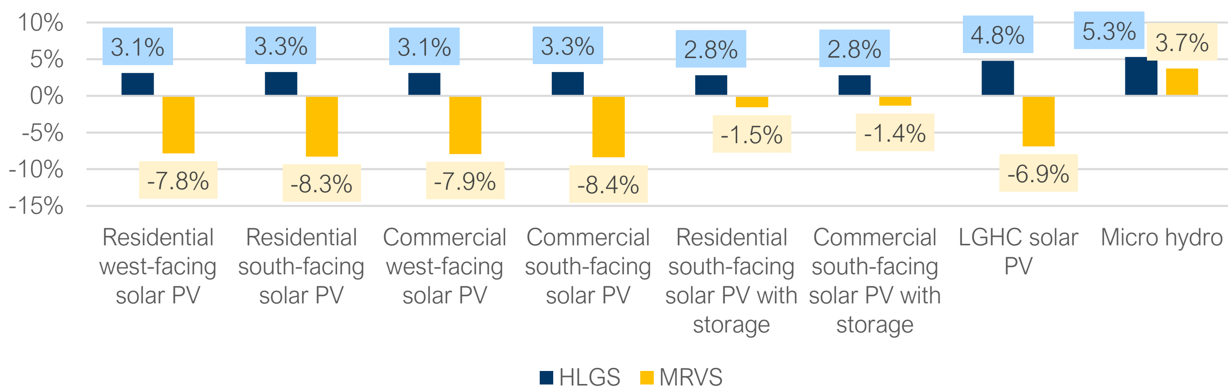


Figure 4. Average Annual Change from Baseline Value Stack Under the HLGS and MRVS, 2035 (2021$)



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.

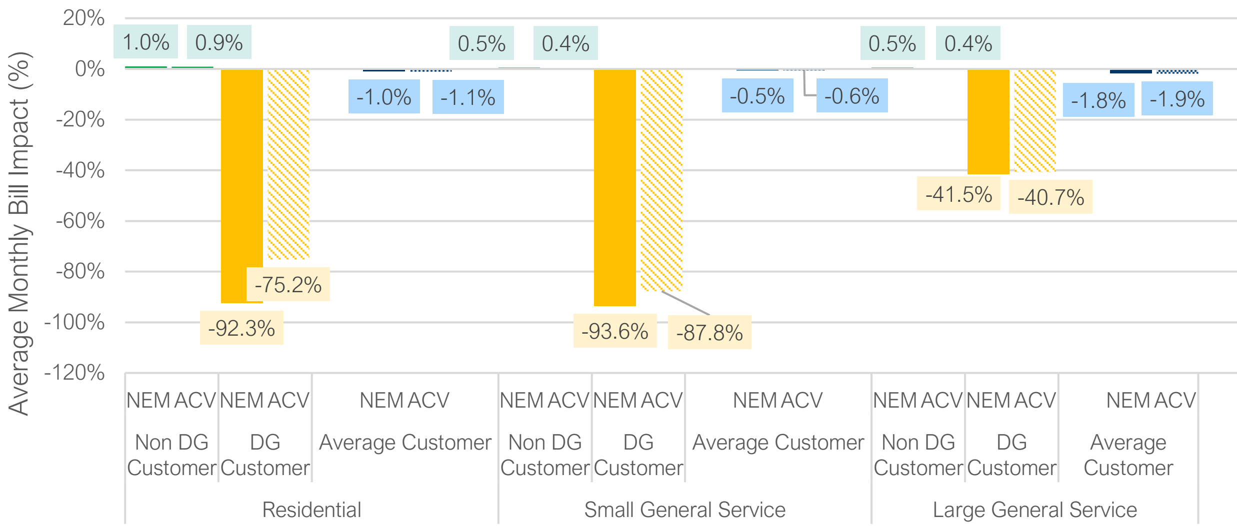
Customer-installed costs are included in this study. In the future, these costs may be used to evaluate how NEM crediting and compensation may affect reasonable opportunities to invest in DG and receive fair compensation, as contemplated by House Bill 1116 (2016).[1]

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)



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

Methodology Summary

2.1 – Methodology Overview

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

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

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

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

2.2 – Technology Neutral Value Stack

2.2.1 – Base Value Stack Criteria

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

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

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

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

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

2.2.1.1 – Energy

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

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

2.2.1.2 – Capacity

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

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

2.2.1.3 – Ancillary Services and Load Obligation Charges

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

Two assumptions underpin the valuation of this criteria element:

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

[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

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.

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

2.2.1.5 – Transmission Charges

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.

Evaluated using **quantitative methods unrelated to AESC**

2.2.1.6 – Transmission Capacity

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.

Evaluated using **qualitative review**

[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**

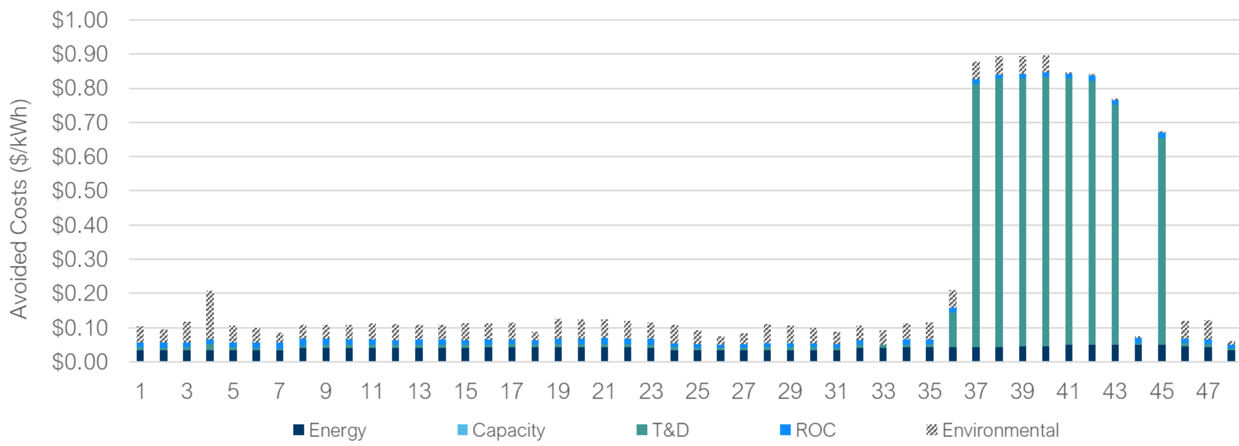
2.2.2 – Example Value Stack

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

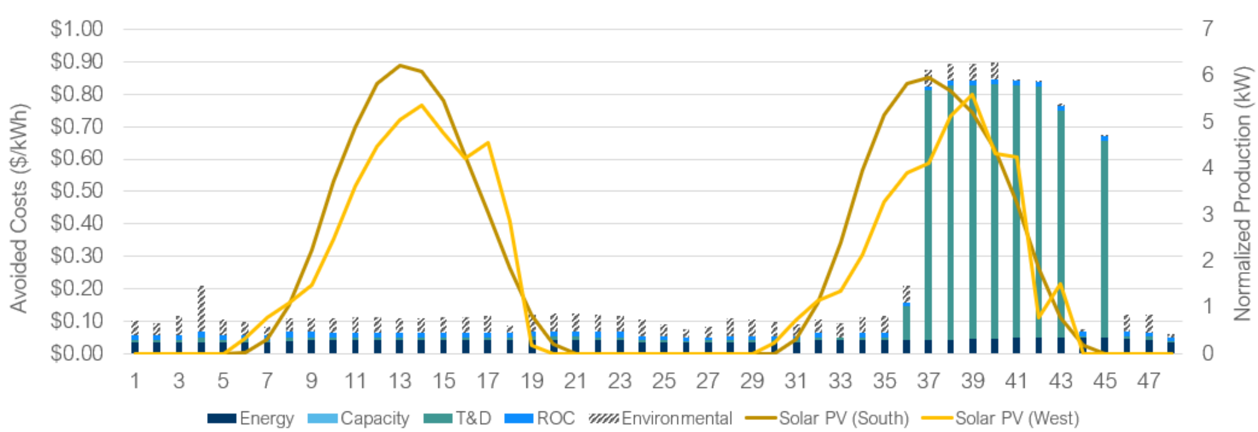
of-river hydro facility located in New Hampshire. The month-to-month variation in hydro generation was developed using New Hampshire-specific hydro data from the U.S. DOE EIA.[23] Because hydro facilities vary in size and capacity factors, for modelling purposes, we assumed a small hydro facility of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

.

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

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

C Utilities need recover costs to accommodate DG / operate programs

D Costs are recovered over fewer kWh

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.

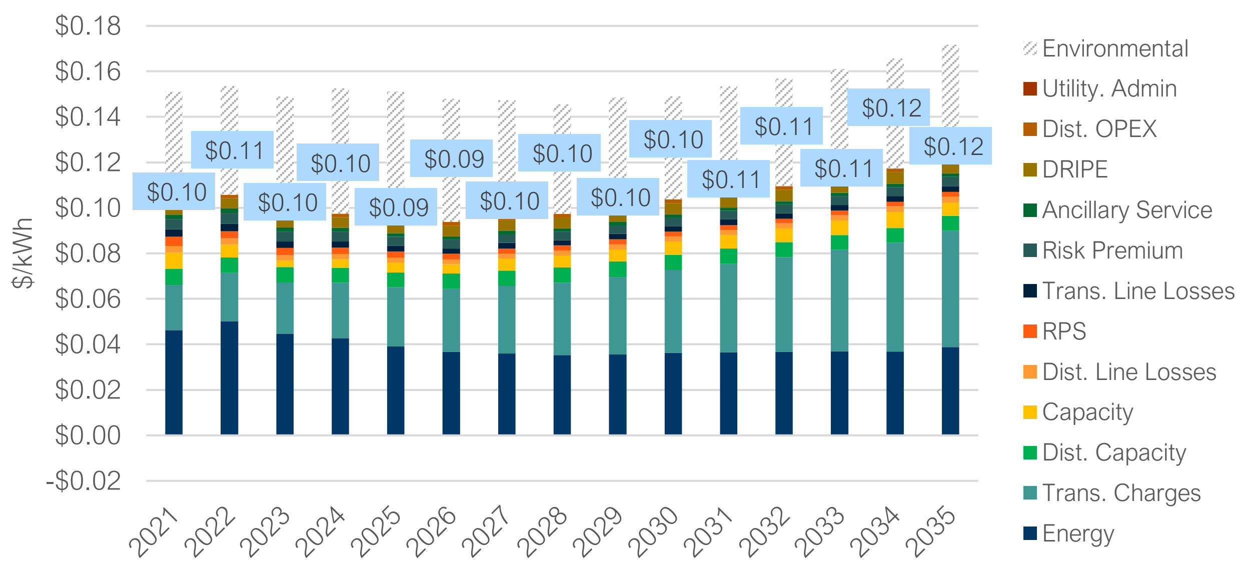
Changes to bills are assessed under two scenarios: the NEM scenario and the ACV scenario described above. The results are largely focused on presenting the average per cent increase/decrease in customers' monthly bills attributable to DG over the period 2021 to 2035 for each of the typical customer archetypes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

3.1 – 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]

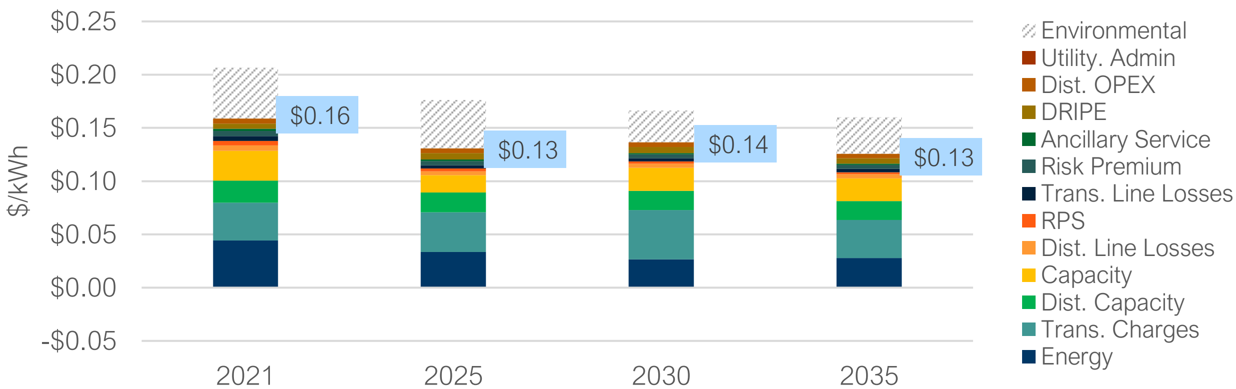
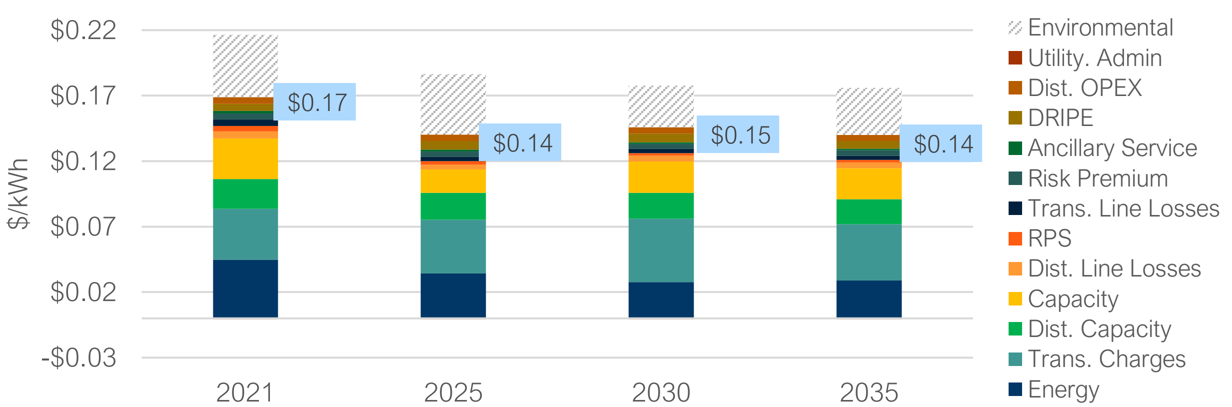


Figure 11. Average Annual Avoided Cost Value for Residential West-Facing Solar PV Array Installed in 2021 (2021$) [a]



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-

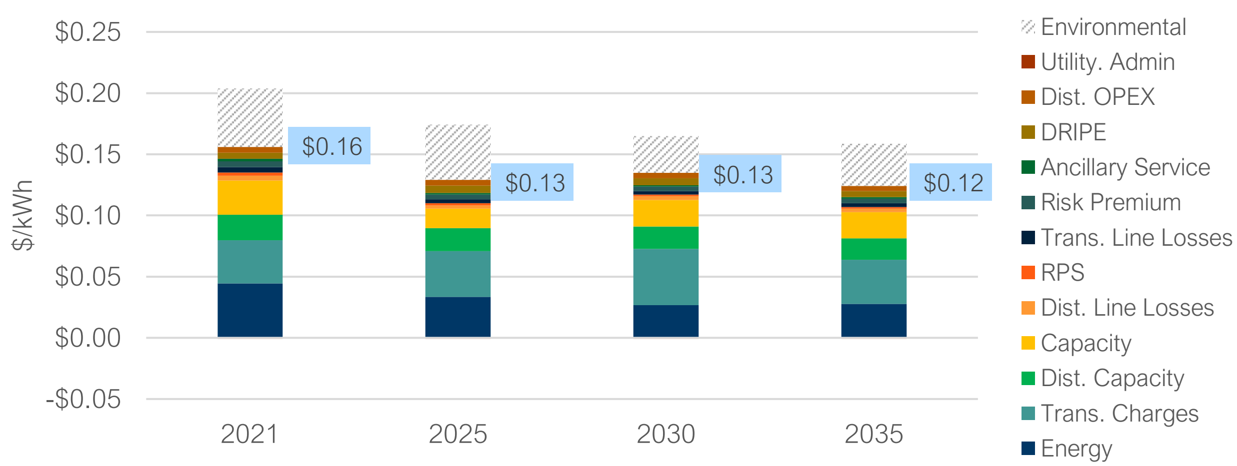
[38] When considering all study years, not only those highlighted in the graphs above, and excluding environmental externalities.

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).

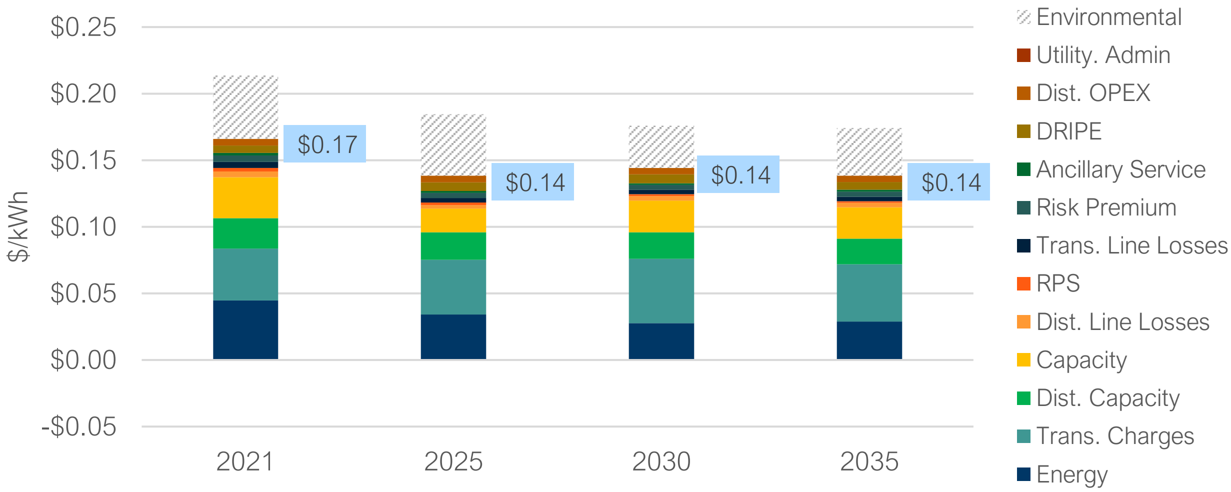
Figure 12 and Figure 13 below show the average annual avoided cost value of commercial south-facing and west-facing systems, respectively, for several years during the study period. The results shown are for systems installed in 2021, and all values are in real 2021 dollars.

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

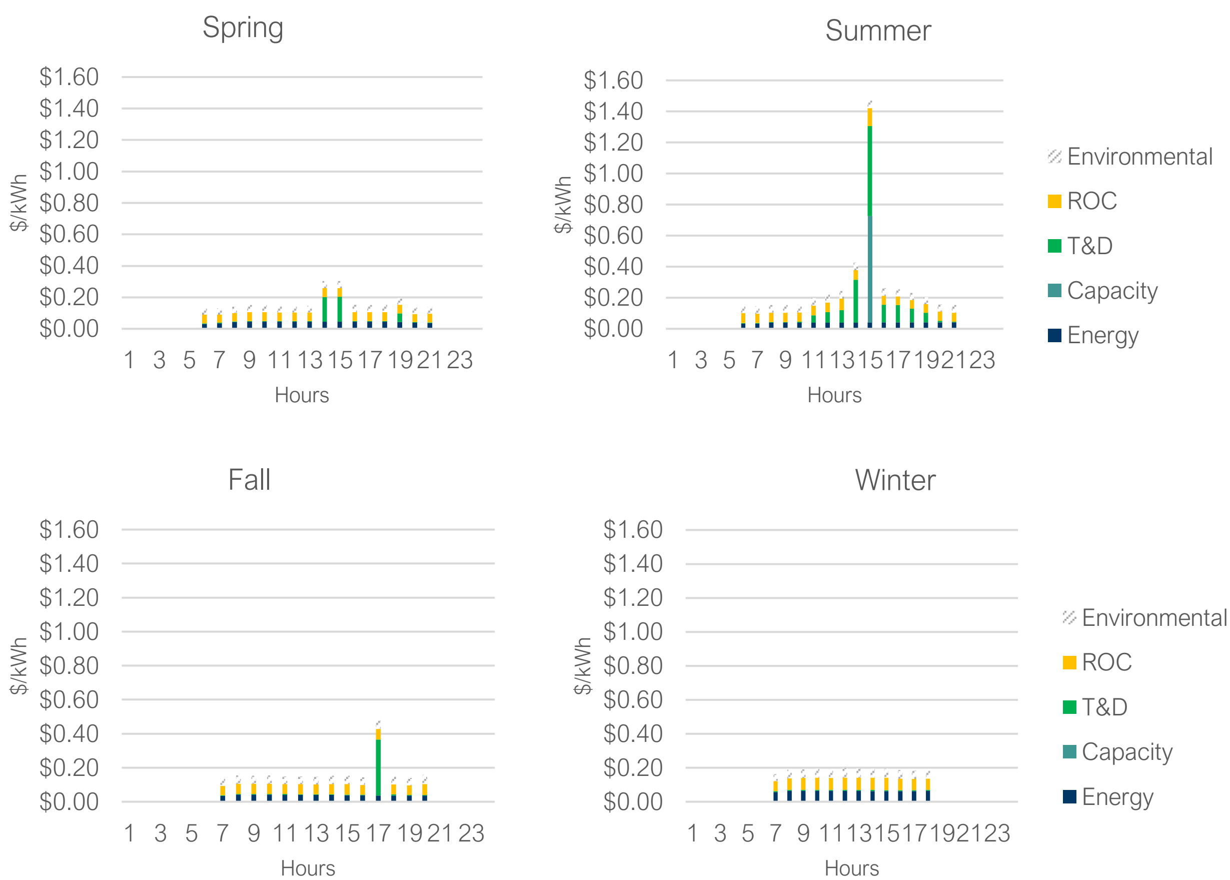
West-facing commercial solar PV systems produce 6%-10% more value than south-facing commercial solar PV systems, again due to their production having greater coincidence with evening system peaks. Commercial solar PV systems with the same orientation as residential systems have the same avoided costs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

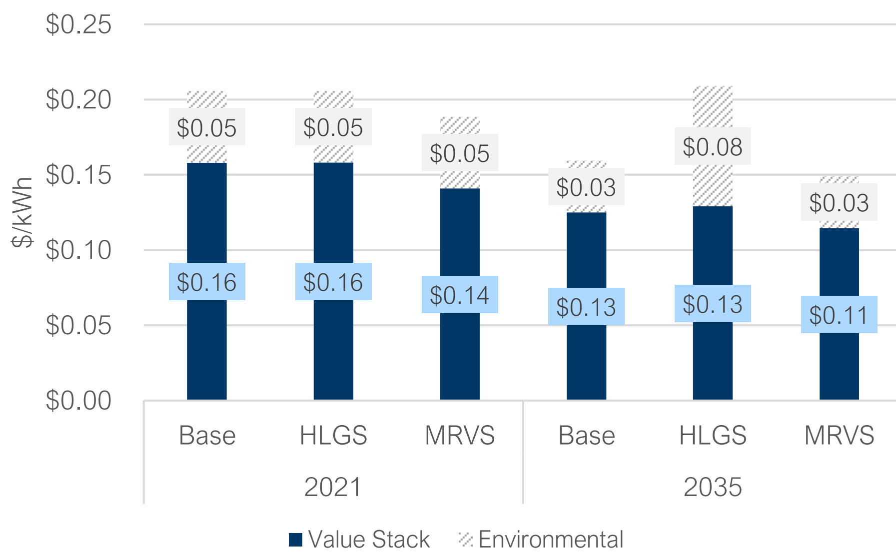
[43] The HLGS analysis includes three load growth scenarios which vary with respect to assumed levels of transportation and building electrification. Scenario 3 – the results of which are highlighted above – assumes higher-than-AESC transportation and building electrification. These scenarios are described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

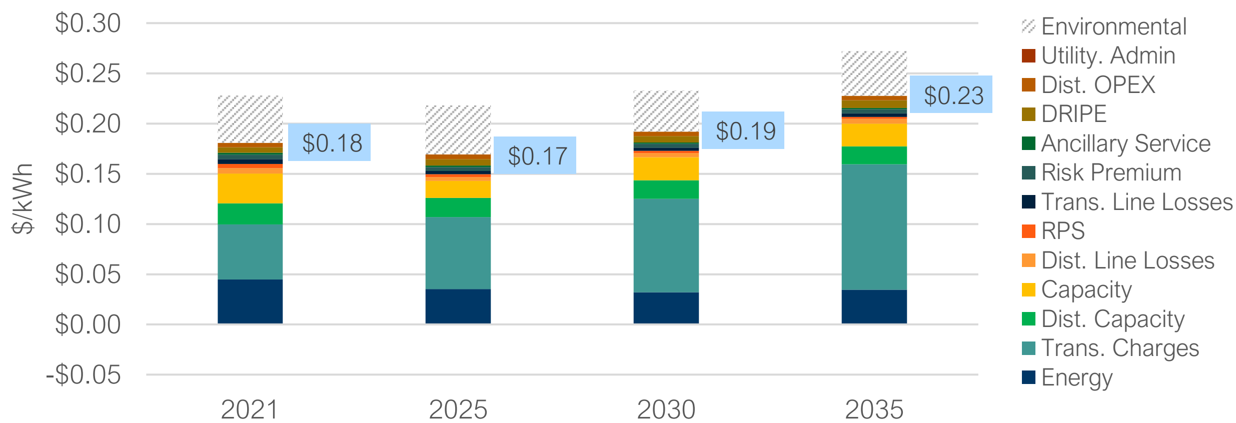
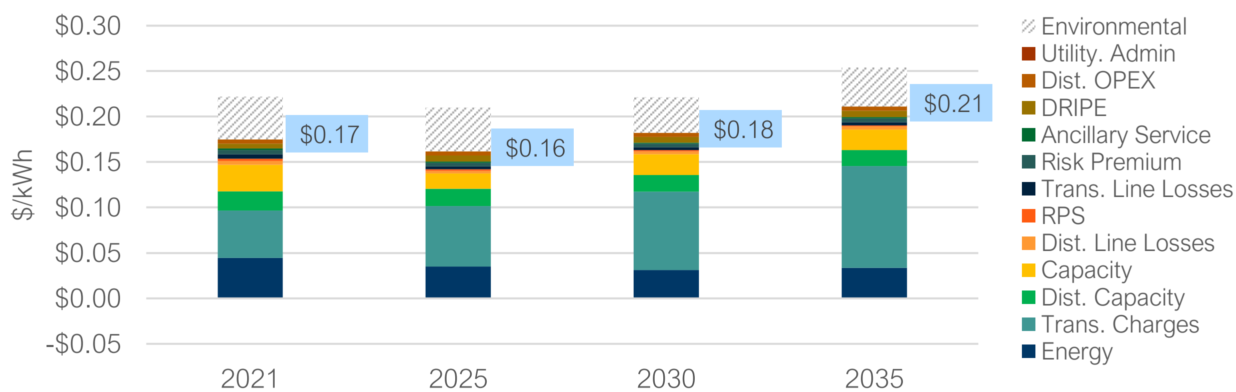


Figure 17. Average Annual Avoided Cost Value for Commercial South-Facing Solar PV Array Paired with Storage Installed in 2021 (2021$)[a]



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.

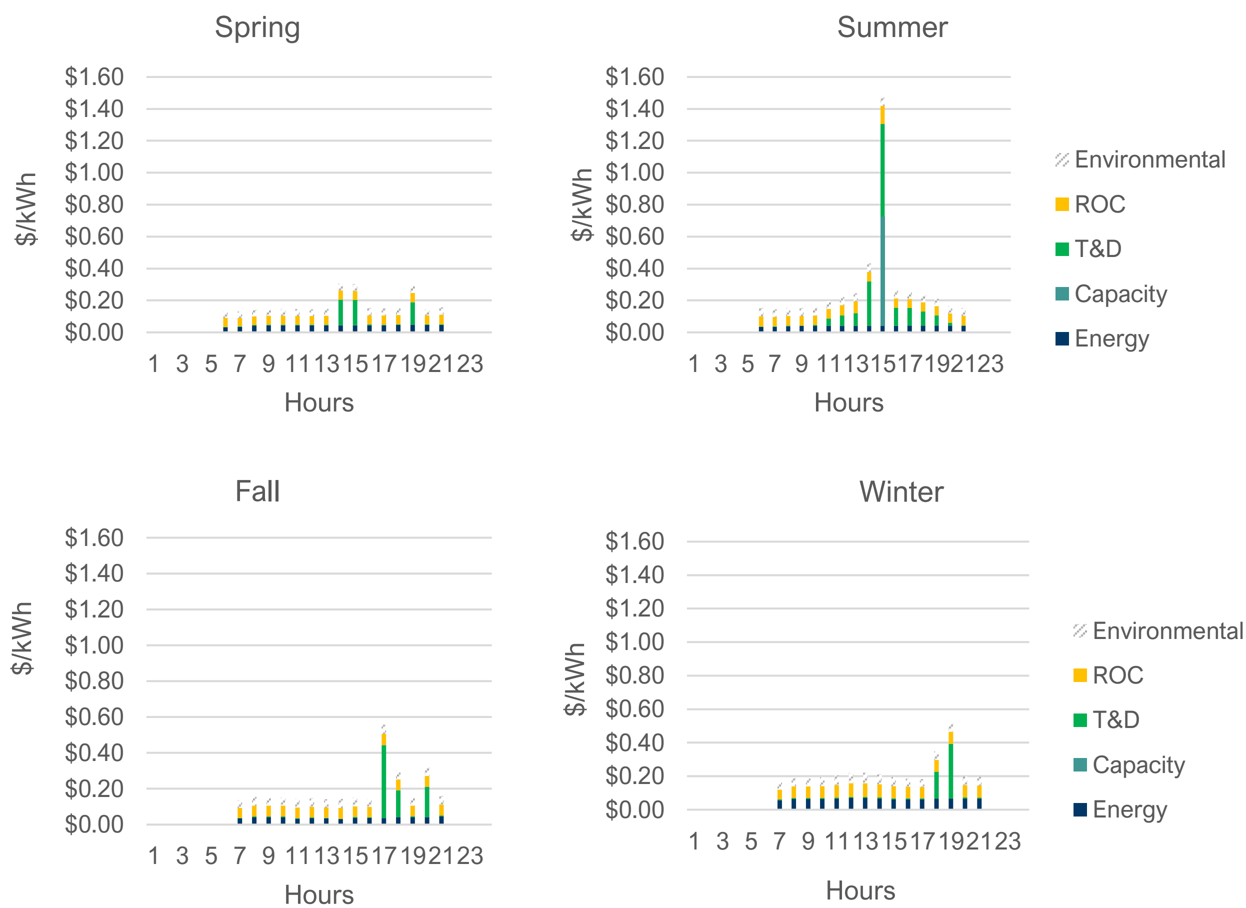
In any given year, residential solar PV systems paired with storage generate between 14% and 82% greater base avoided cost value than solar-only systems; commercial solar PV systems paired with storage generate 12% to 70% greater base avoided cost value.[47] The battery storage system is assumed to be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

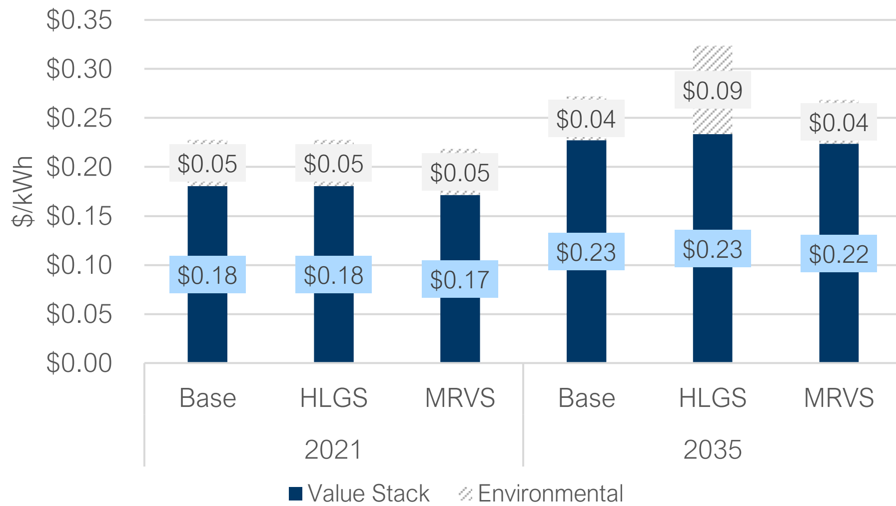
Figure 18. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Paired with Storage Installed in 2021, Year 2021 Shown (2021$)



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$)

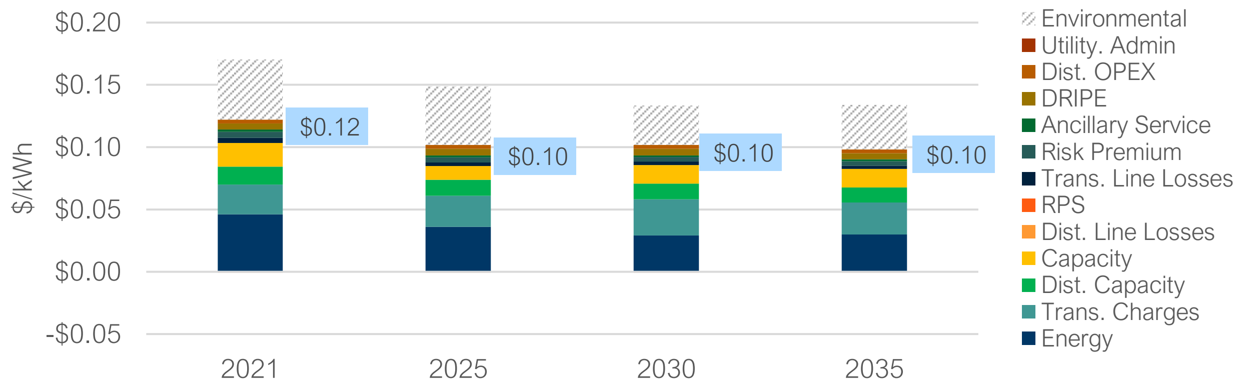


In 2021, the HLGS has approximately the same value (less than 1% difference) as the base value stack, excluding environmental externalities. This increases to nearly 3% higher value by 2035 - again, excluding environmental externalities – as increased transportation and building electrification load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

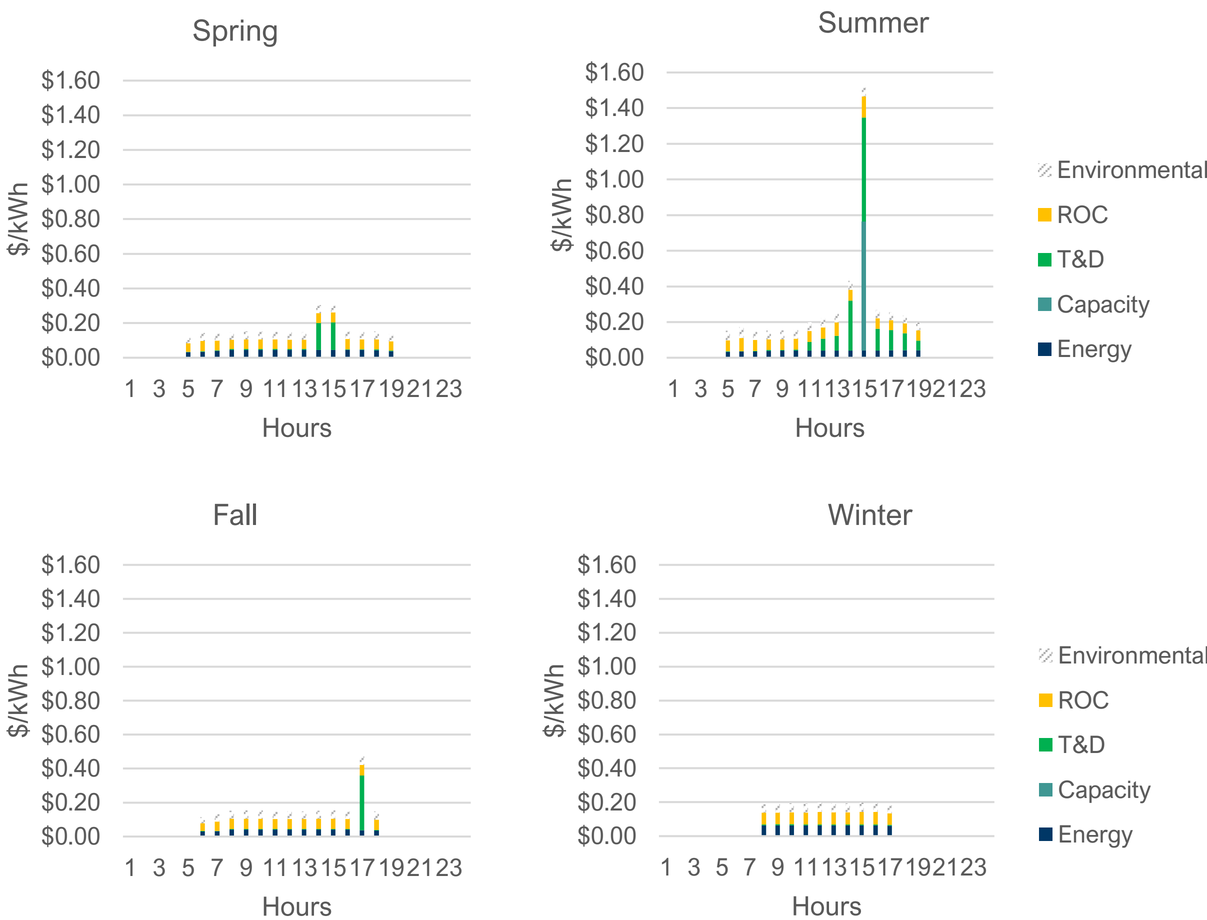
The LGHC solar avoided cost value trends mirror the residential and commercial solar-only system results, declining across the study period largely due to declining energy avoided costs. In a given year, LGHC avoided cost values are lower than residential or commercial systems. Because there is assumed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

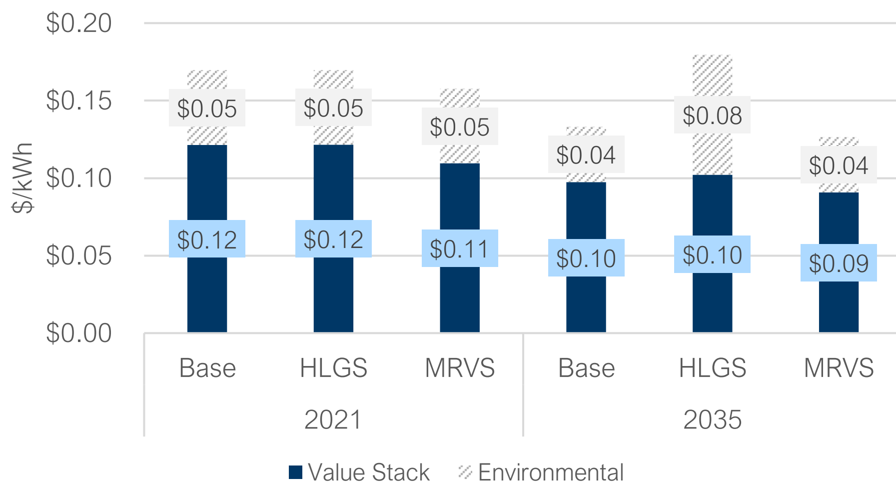
Figure 21. Average Hourly Seasonal Avoided Cost Values for Large Group Host Commercial Solar PV Array Installed in 2021, Year 2021 Shown (2021$)



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$)



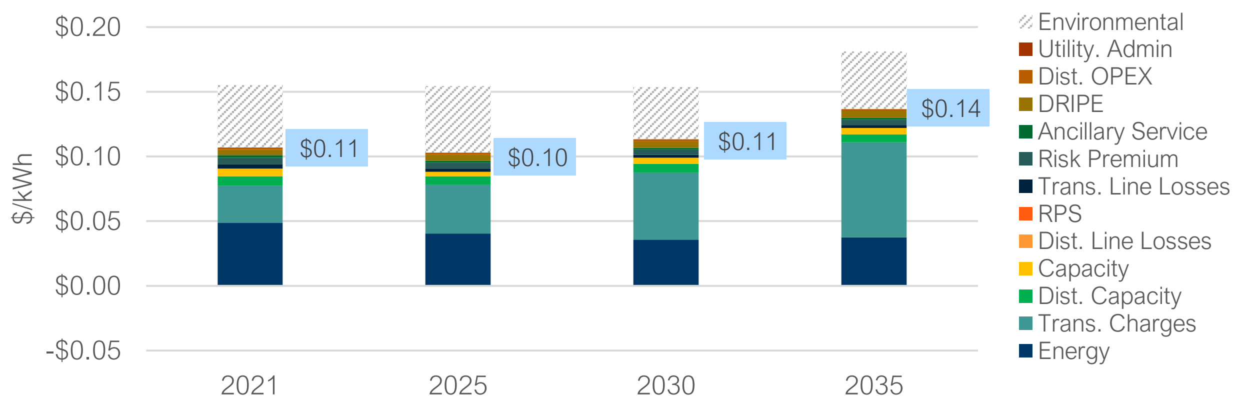
In 2021, the high load growth scenario has approximately the same value (less than 1% difference) as the base avoided cost value stack. In 2035, the high load growth scenario results in 5% higher value excluding environmental externalities. The value increases under the high load growth scenario as increased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

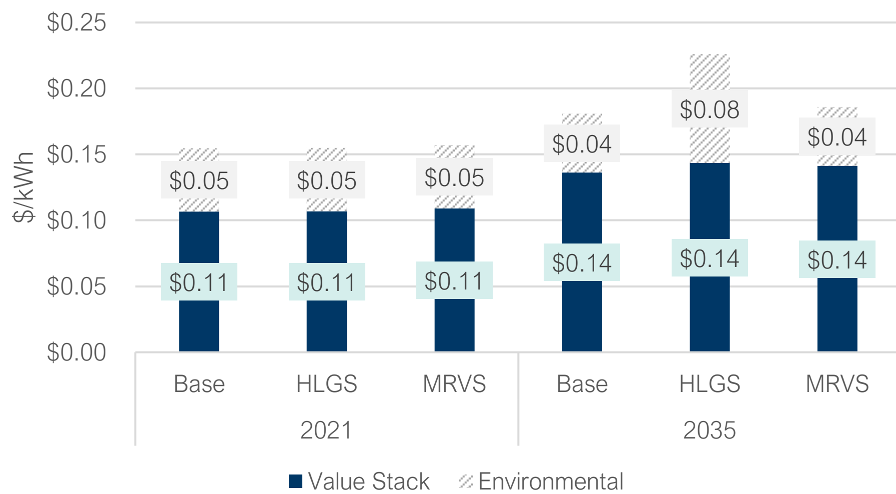
[53] The base avoided cost value stack refers to the value stack excluding environmental externalities.
[54] Here, T&D includes the following quantified avoided cost criteria: transmission charges, distribution capacity, distribution operating expense, transmission line losses, and distribution line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

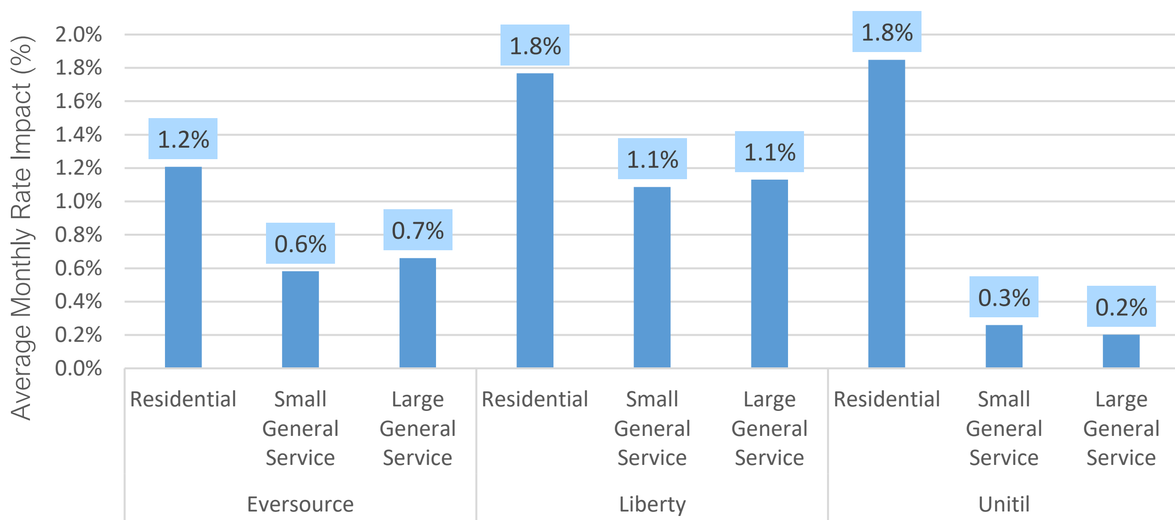
3.4.1.1 – Rate Impacts

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]

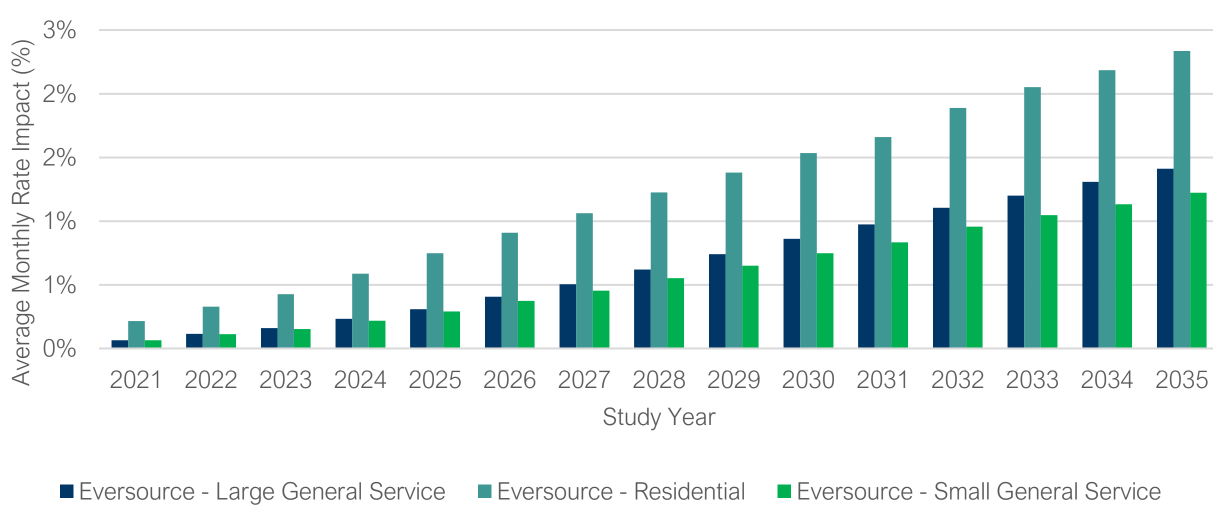
[66] New Hampshire Department of Energy. Net Energy Metering Tariff. Available online: https://www.energy.nh.gov/sites/g/files/ehbemt551/files/inline-documents/sonh/net-metering-tariff-2020-overview.pdf
[67] System archetype definitions are described in methodology section 2.6.1 – Define DG System Archetypes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

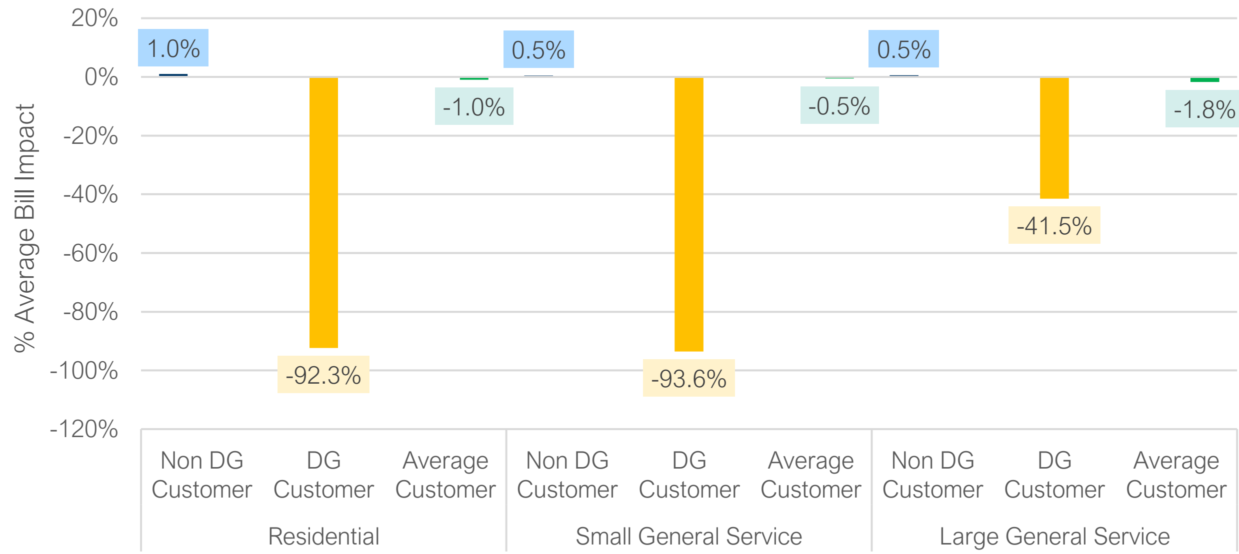
Figure 27. Average Monthly Rate Impact for Utility Customers in Eversource Territory Under NEM Scenario (Relative to no-DG scenario)



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.

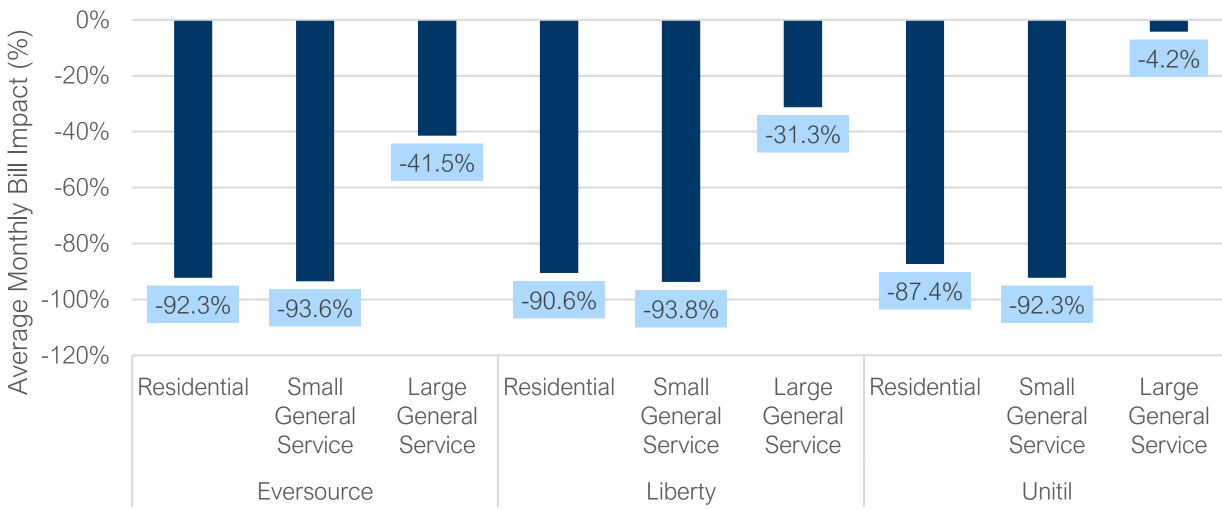
DG Customers

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]

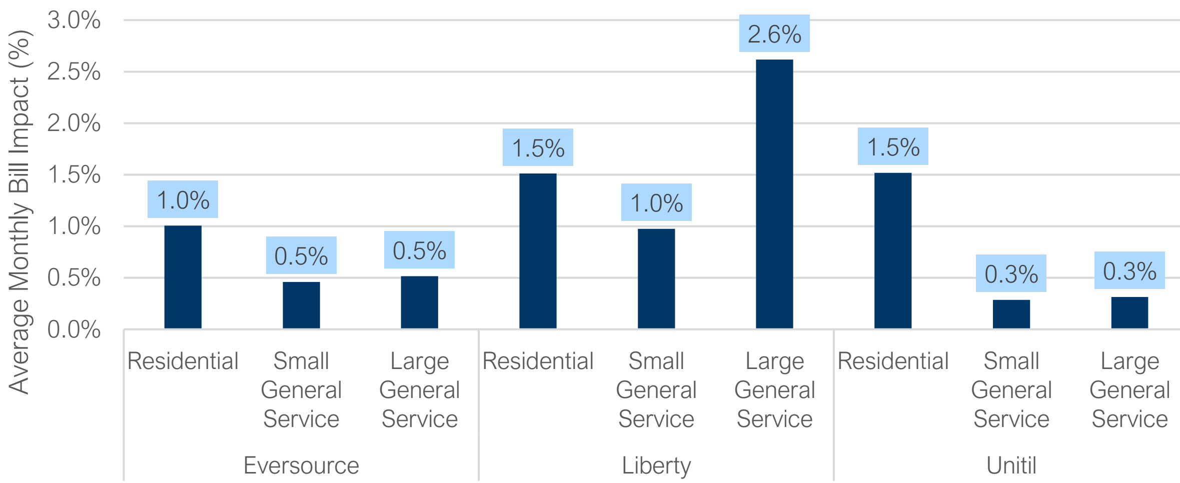


Non-DG Customers

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]

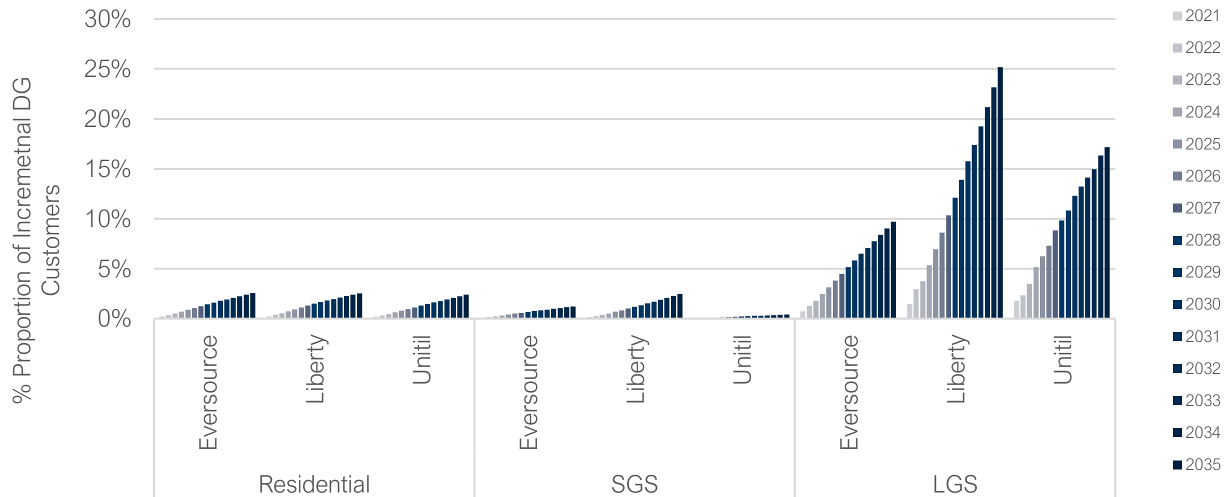


Average Customers

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.

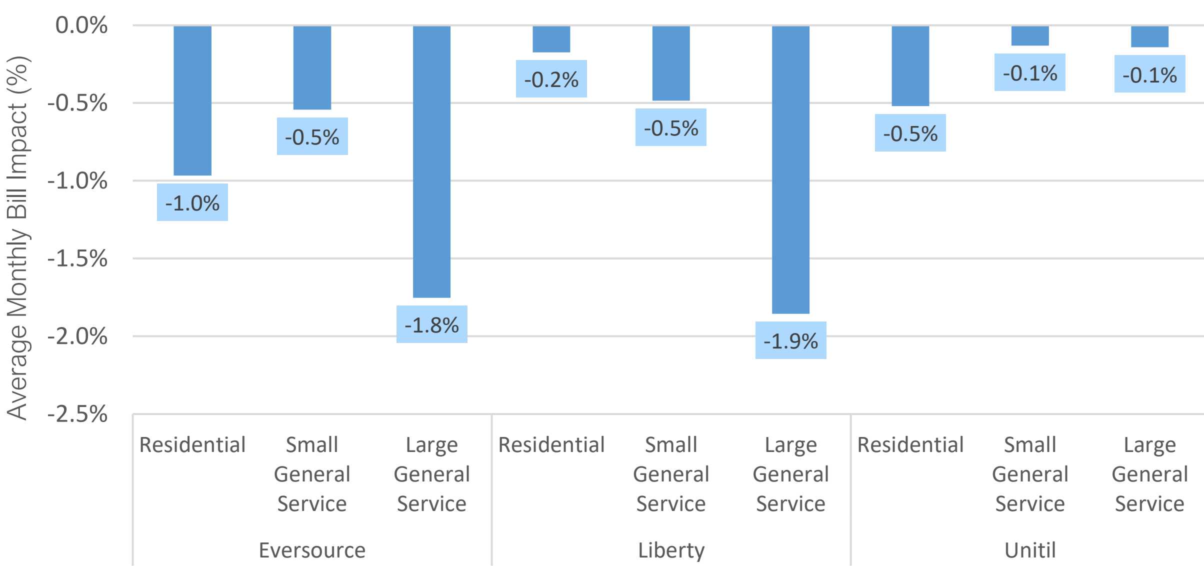
[72] Averaged across the study period

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.

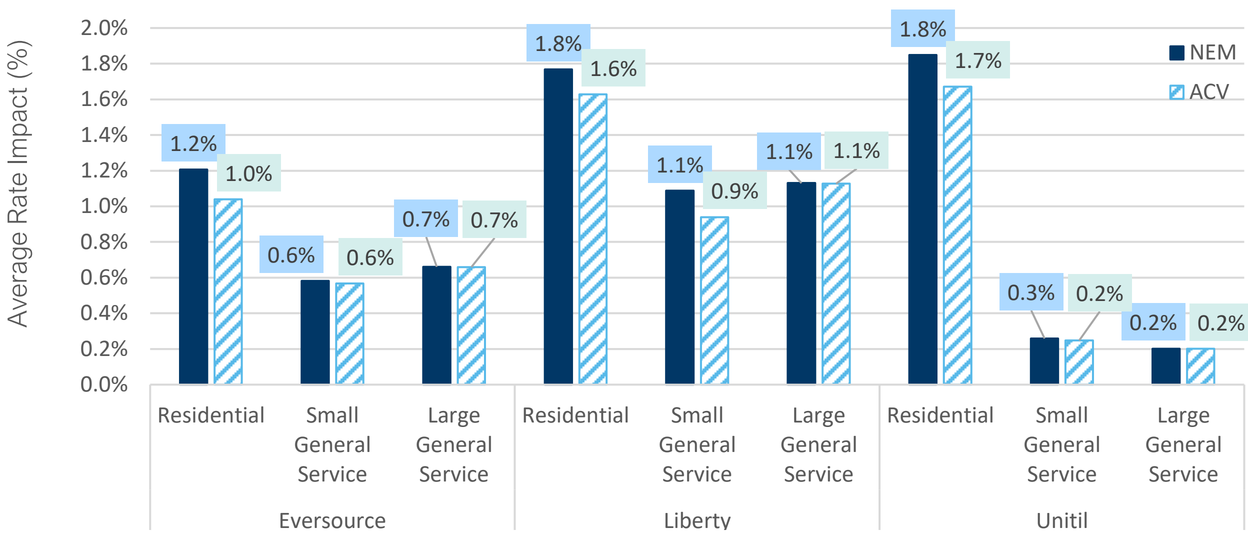
It is important to note that the analysis does not consider any impacts that the transition to an ACV Tariff compensation model may have on DG economics and deployment trends in New Hampshire (i.e., the same level of future DG deployment is assumed under both scenarios).

3.4.2.1 – Rate Impacts

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

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

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



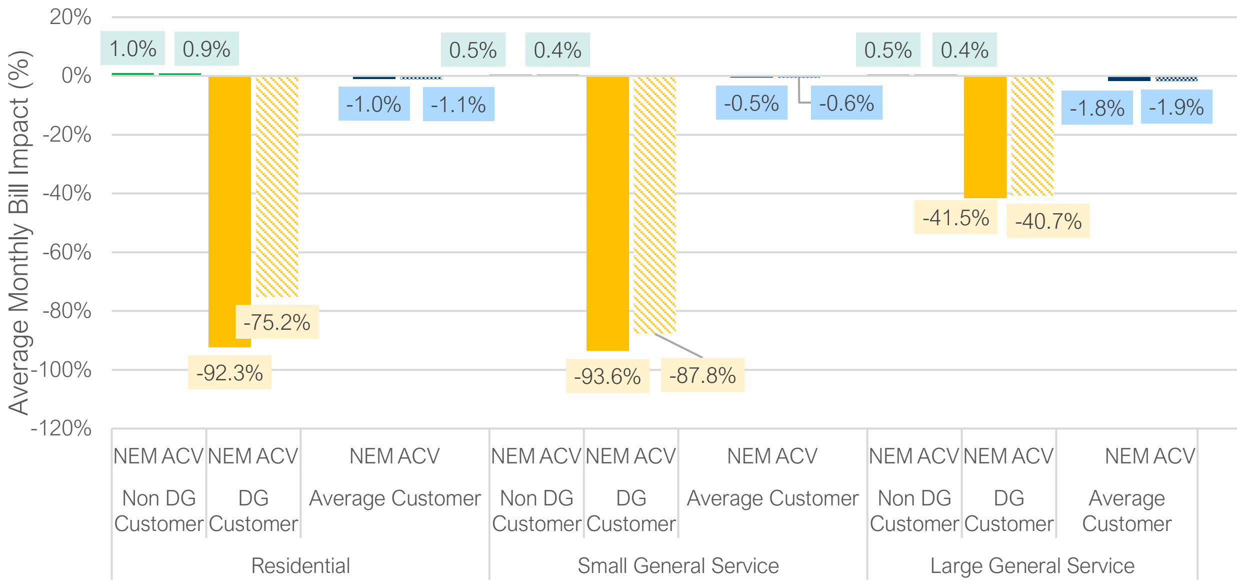
3.4.2.2 – Bill Impacts

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

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

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

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

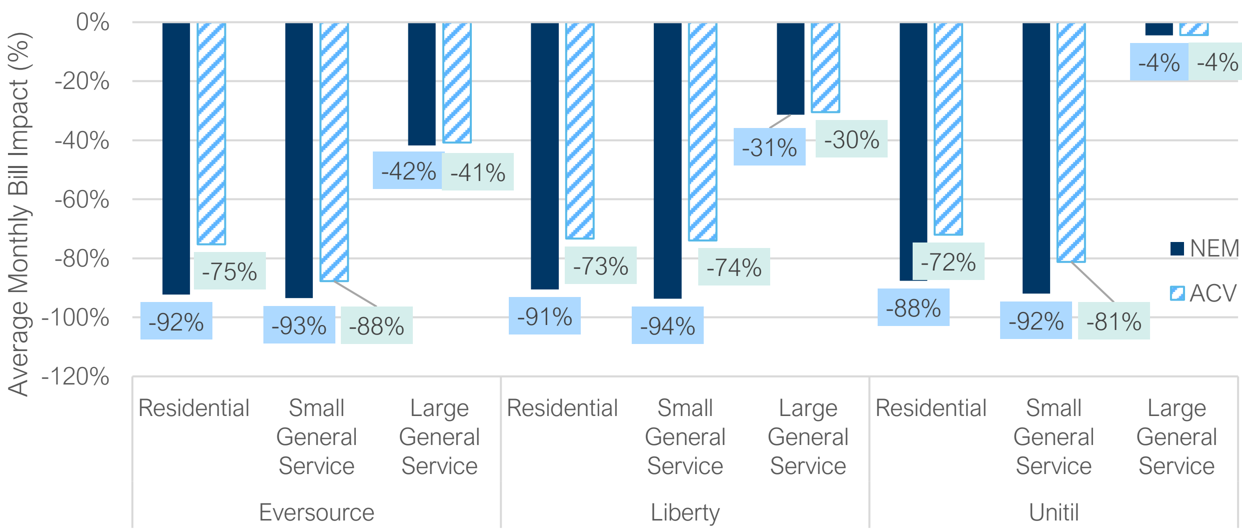


DG Customers

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

[77] Averaged across the study period

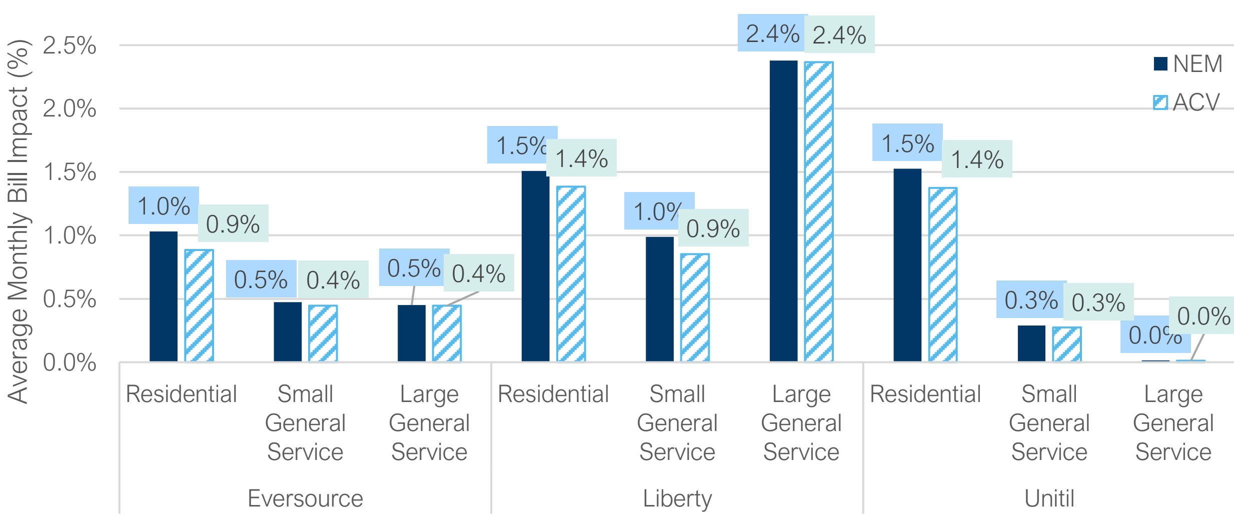
Figure 35. Average Monthly Bill Impact for DG Customer Under NEM and ACV Scenarios (2021-2035)(Relative to no-DG Scenario)[78]



Non-DG Customers

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

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

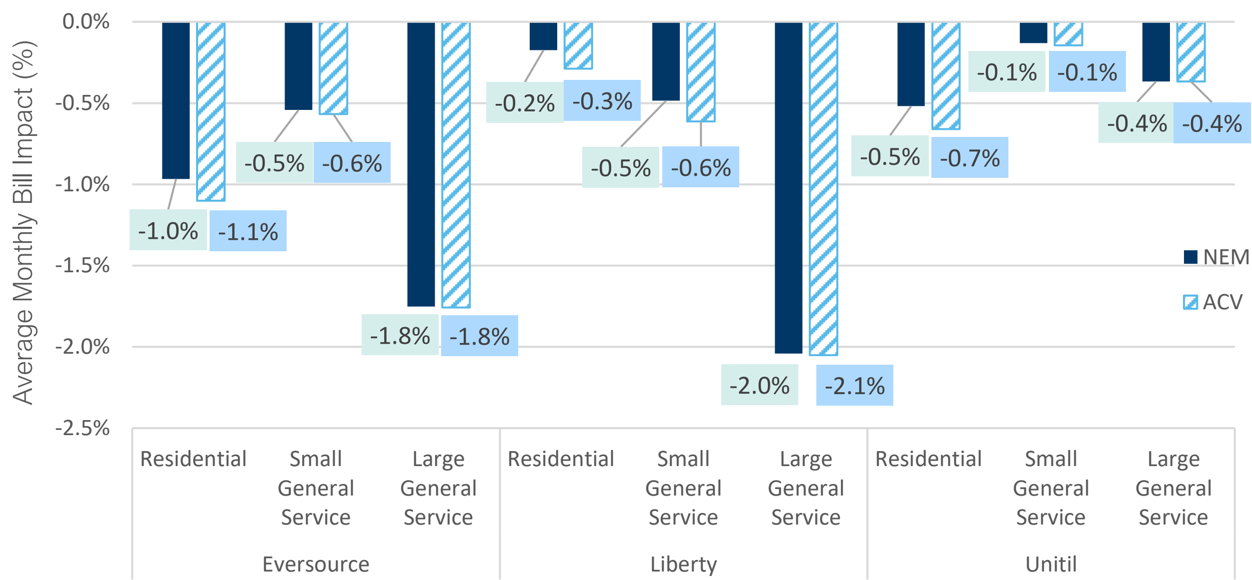


[78] Averaged across the study period
[79] ibid

Average Customers

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

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



[80] Averaged across the study period

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$)

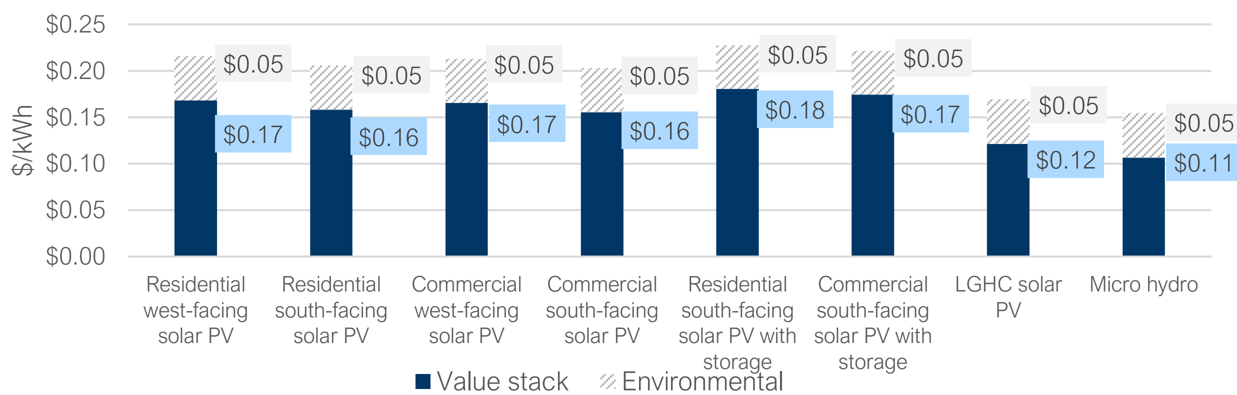
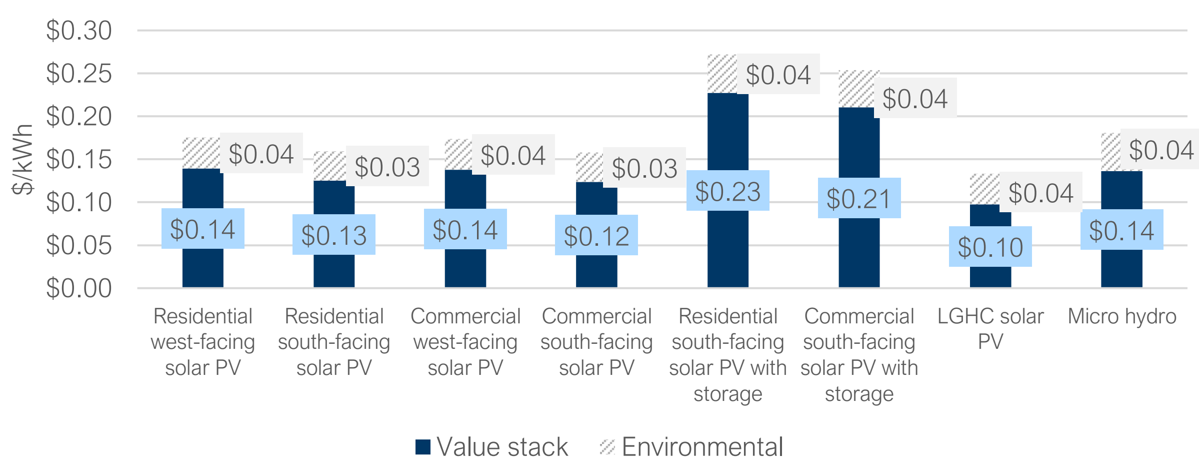


Figure 39. Average Annual Value Stack with Environmental Externalities Sensitivity by DG System, 2035 (2021$)



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$)

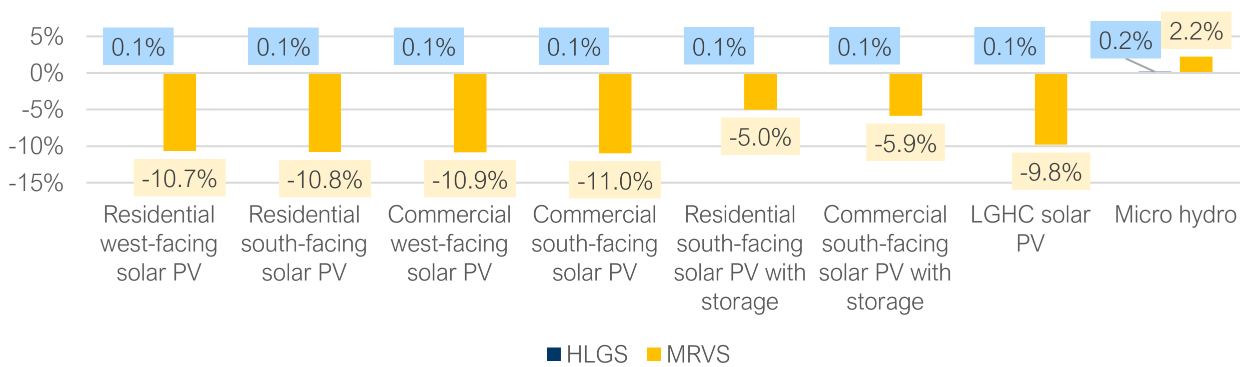
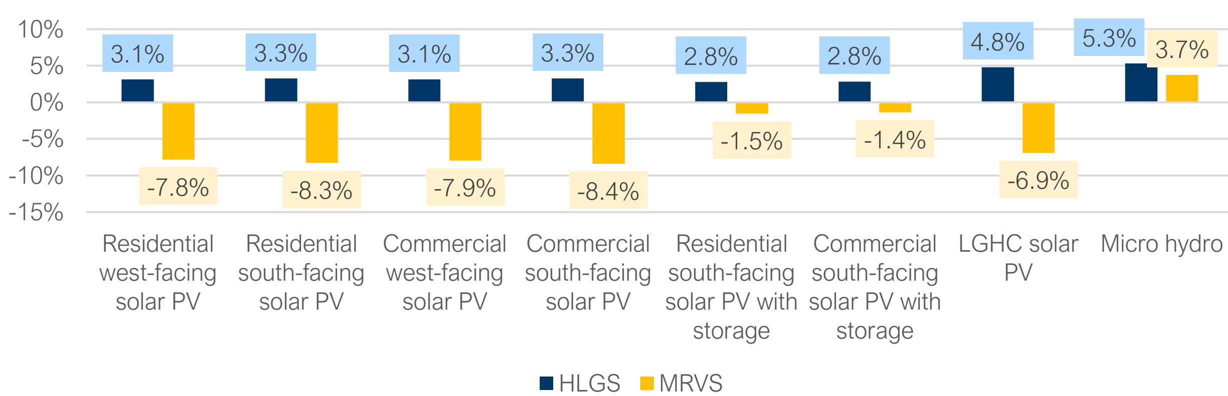


Figure 41. Average Annual Change from Baseline Value Stack Under the HLGS and MRVS, 2035 (2021$)

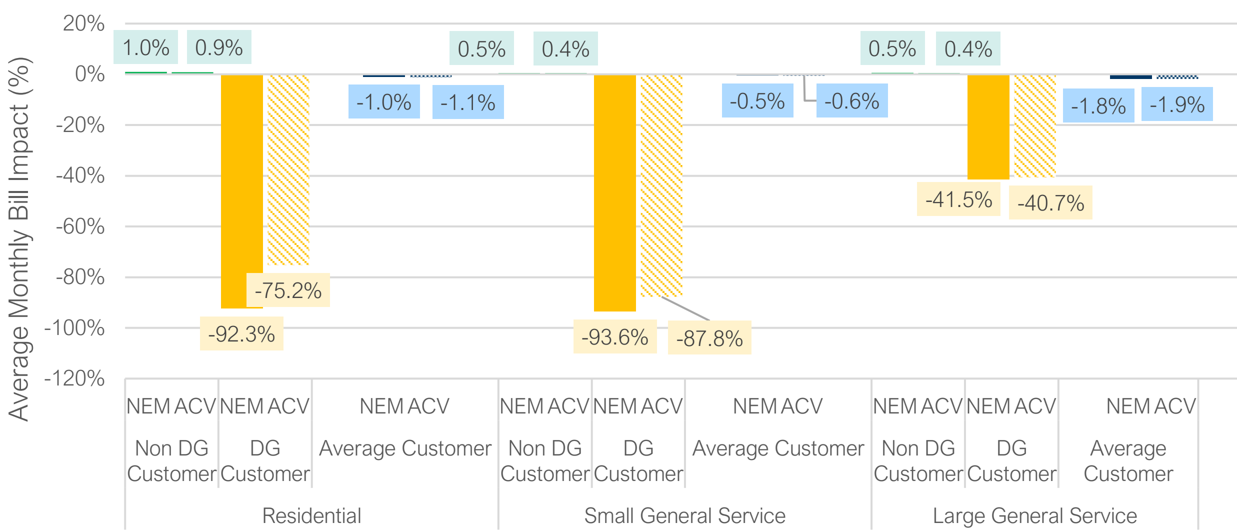


Net-metered DERs are expected to provide additional value beyond what is shown here, notably for those value stack criteria addressed qualitatively in this study: transmission capacity (for non-pool transmission facilities), transmission and distribution system upgrades, distribution grid support services,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

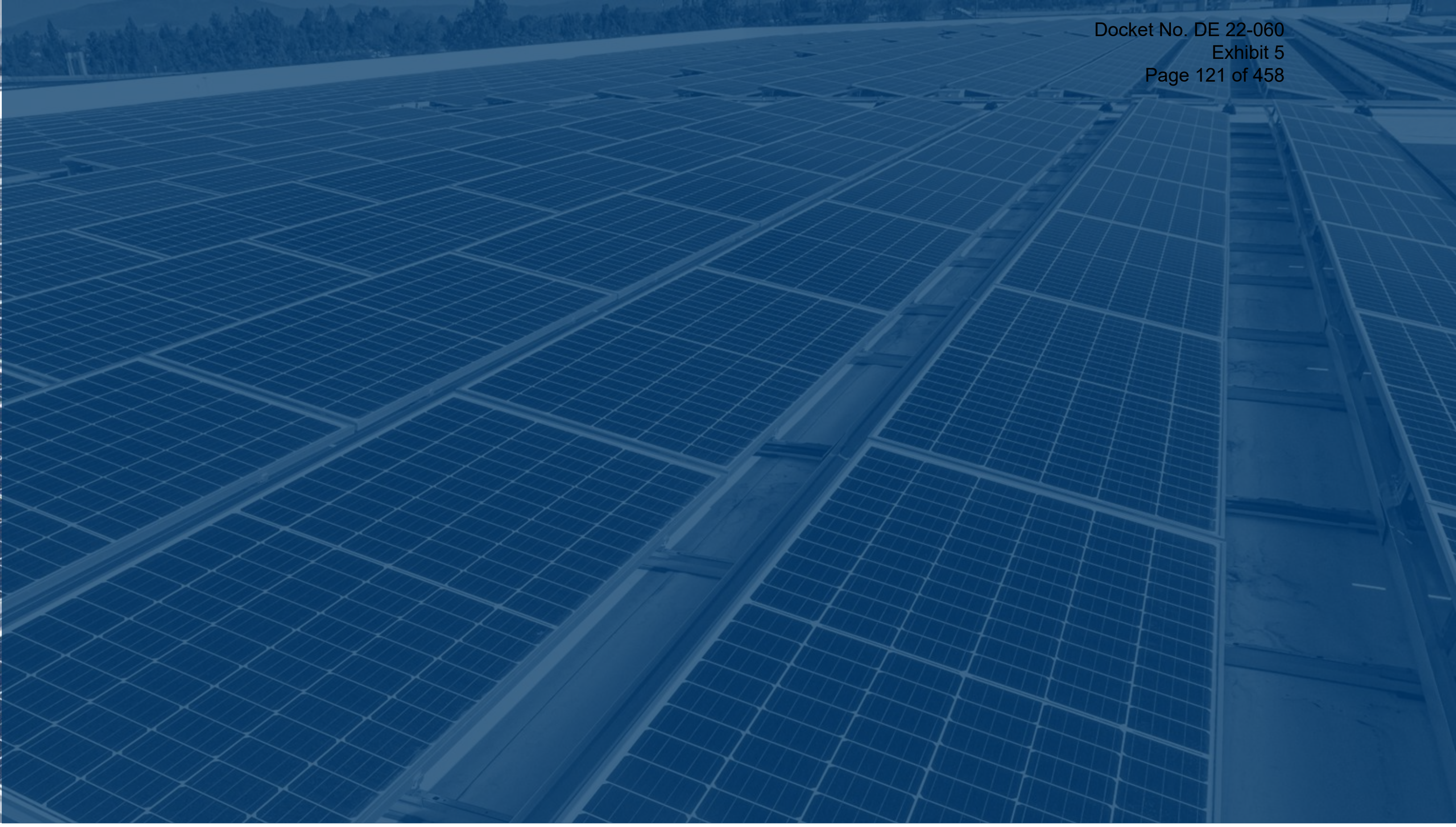
Customer installed costs are included in this study. In the future, these costs may be used to evaluate how NEM crediting and compensation may affect reasonable opportunities to invest in DG and receive fair compensation, as contemplated by House Bill 1116 (2016).[81]

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

New Hampshire Department of Energy

www.energy.nh.gov

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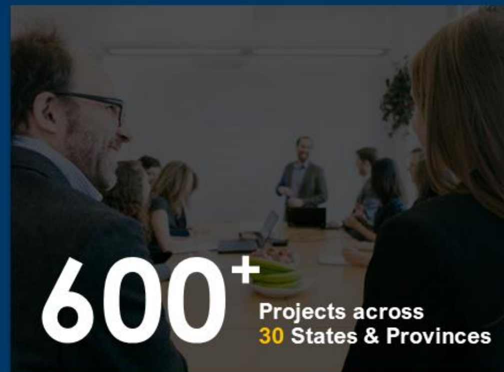
With support from Power Advisory

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.

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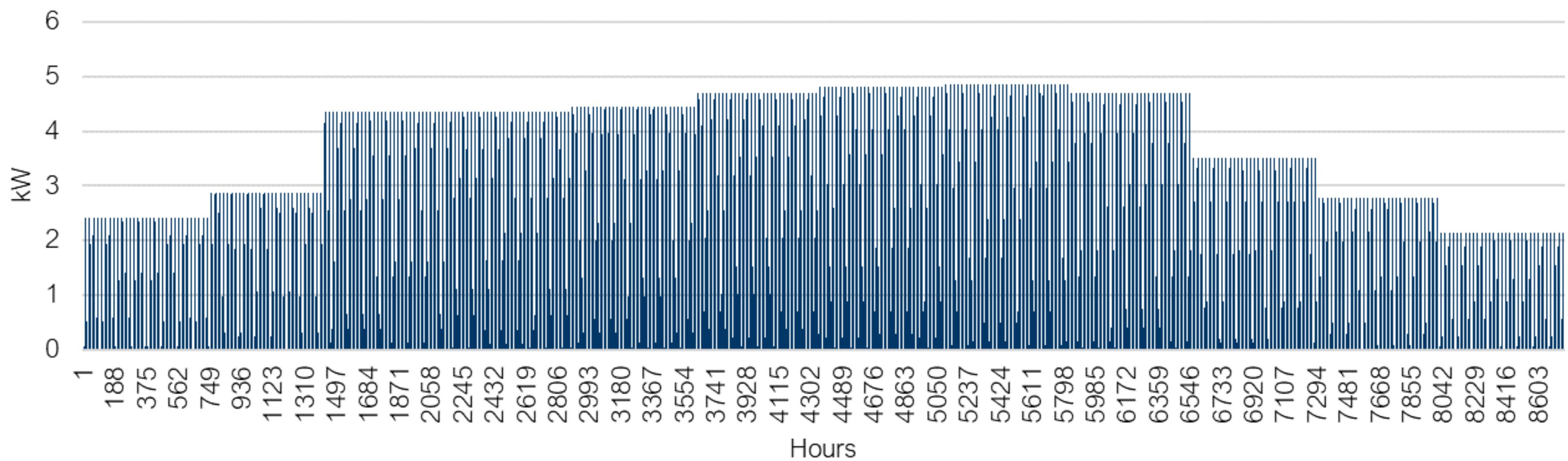


Figure 2. 8,760 Profile for Residential West-Facing Solar PV Array, 7.8 kW DC (6.5 kW AC), Azimuth 270, tilt 37.86, assumed location: Concord, New Hampshire

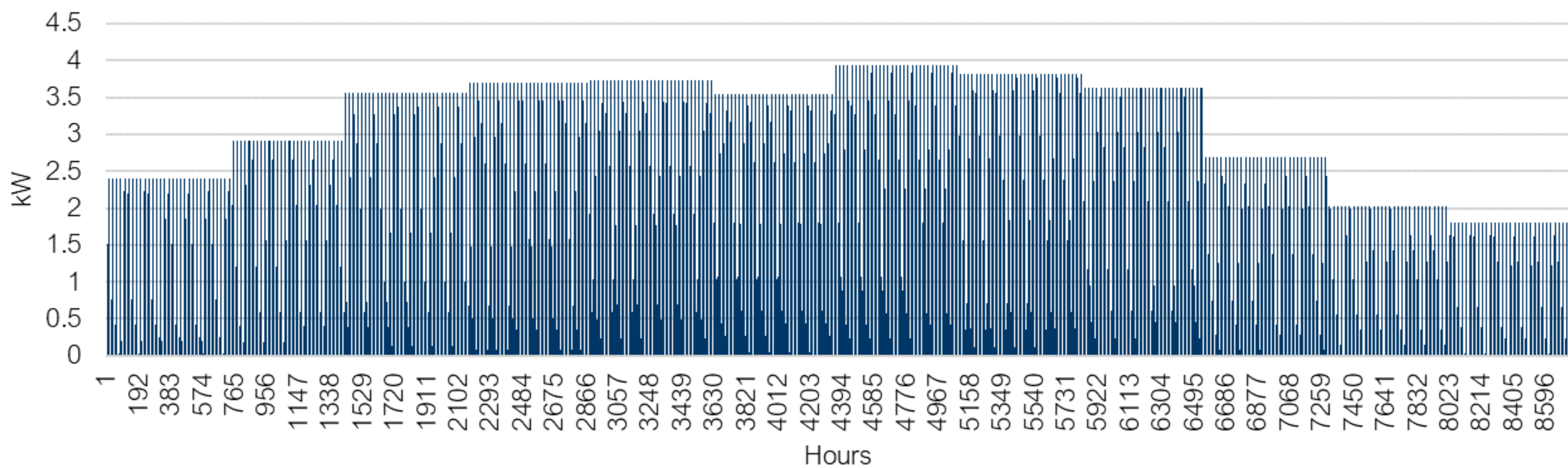


Figure 3. 8,760 Profile for Commercial South-Facing Solar PV Array, 36 kW DC (30 kW AC), Azimuth 180, tilt 37.86, assumed location: Concord, New Hampshire

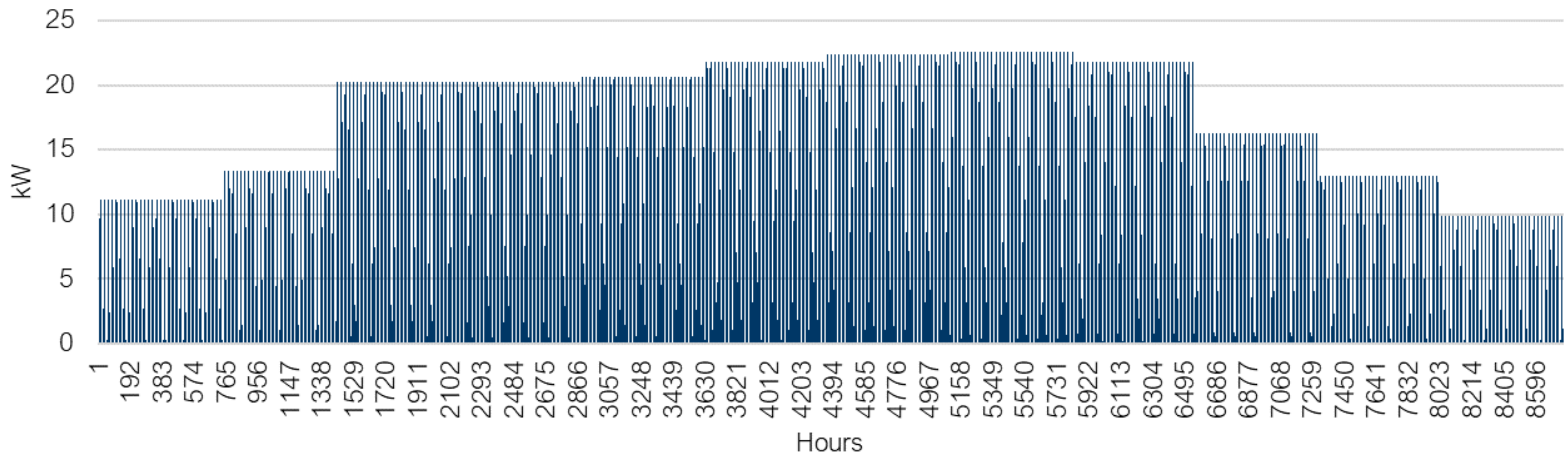


Figure 4. 8,760 Profile for Commercial West-facing Solar PV Array, 36 kW DC (30 kW AC), Azimuth 270, tilt 37.86, assumed location: Concord, New Hampshire

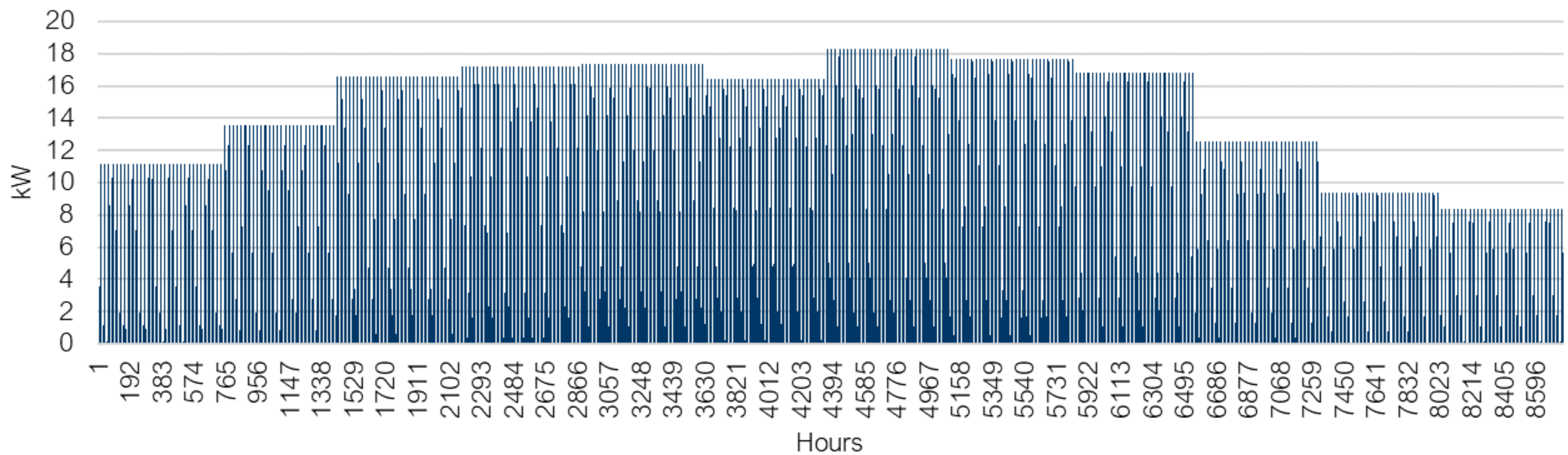


Figure 5. 8,760 Profile for Residential South-Facing Solar PV Array Paired with Storage, 7.8 kW DC (6.5 kW AC), 4-hour duration 10 kWh/2.5kW storage system, Azimuth 180, tilt 37.86, assumed location: Concord, New Hampshire

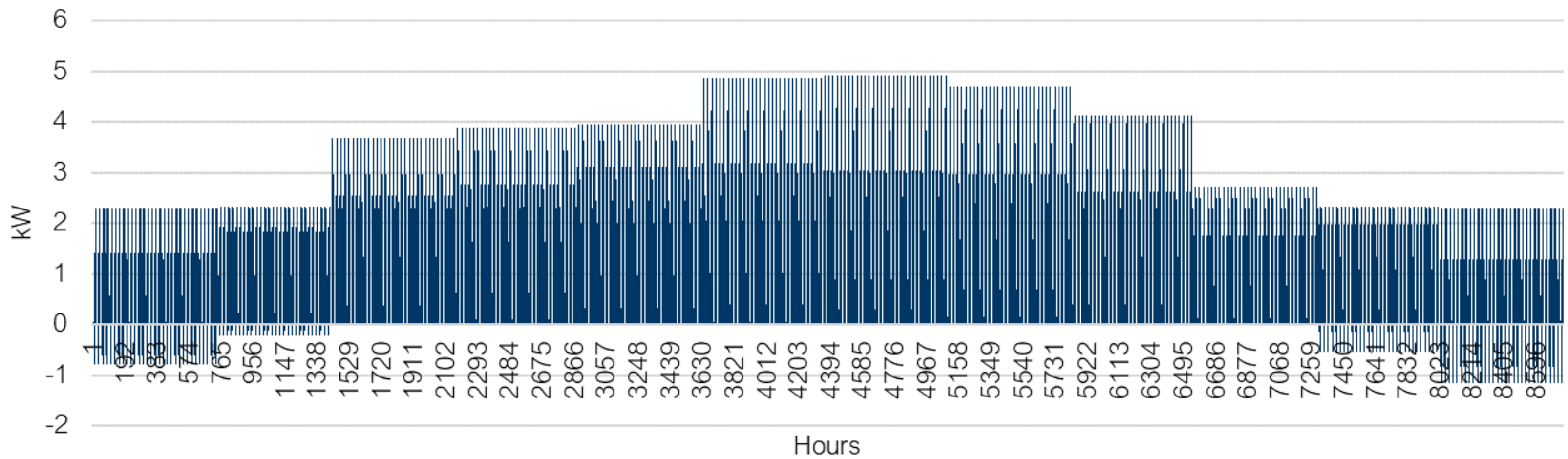


Figure 6. 8,760 Profile for Commercial South-facing Solar Paired with Storage, 36 kW DC Solar (30 kW AC), 4-hour duration 40 kWh/10kW storage system, Azimuth 180, tilt 37.86, assumed location: Concord, New Hampshire

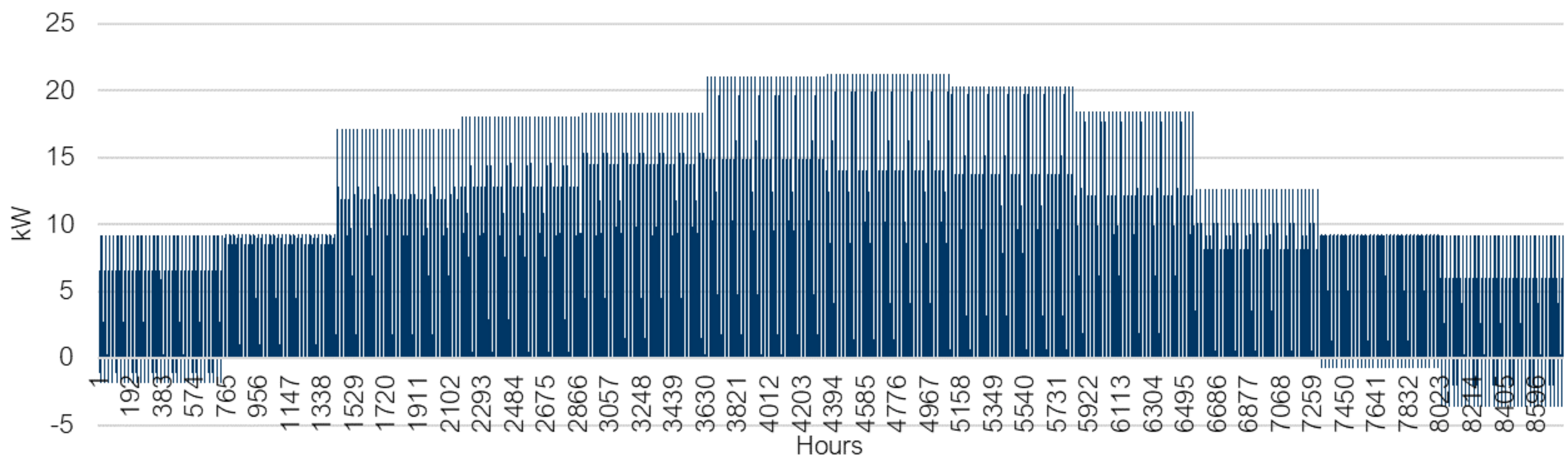


Figure 7. 8,760 Profile for Large Group Host Commercial Solar, 195 kW DC (162 kW AC), Azimuth 180, tilt 37.86, assumed location: Concord, New Hampshire

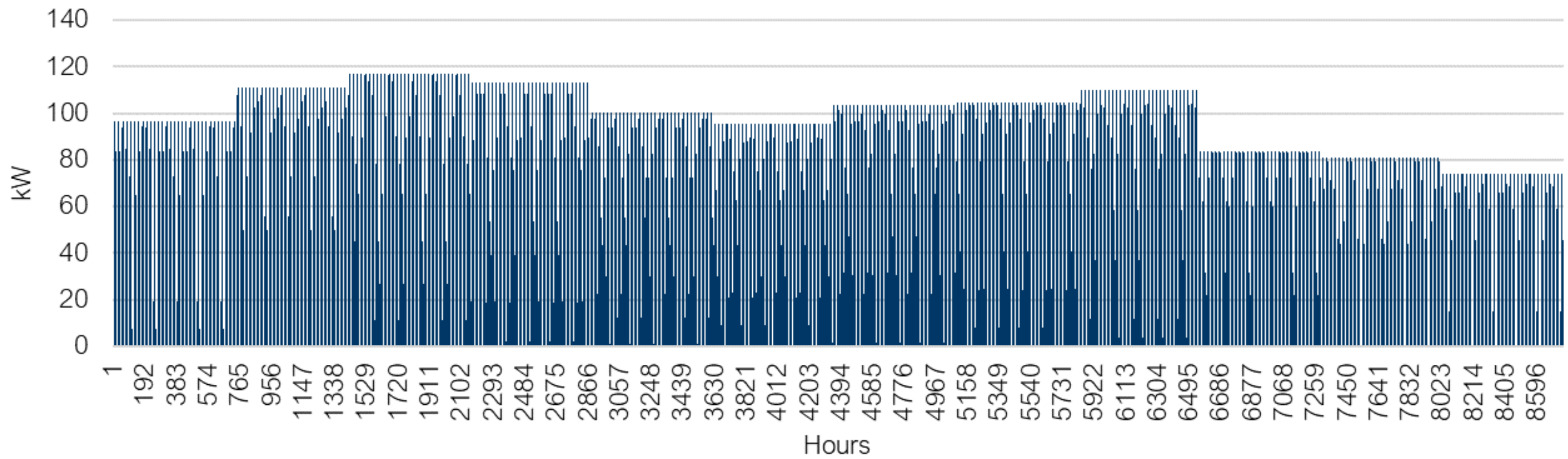
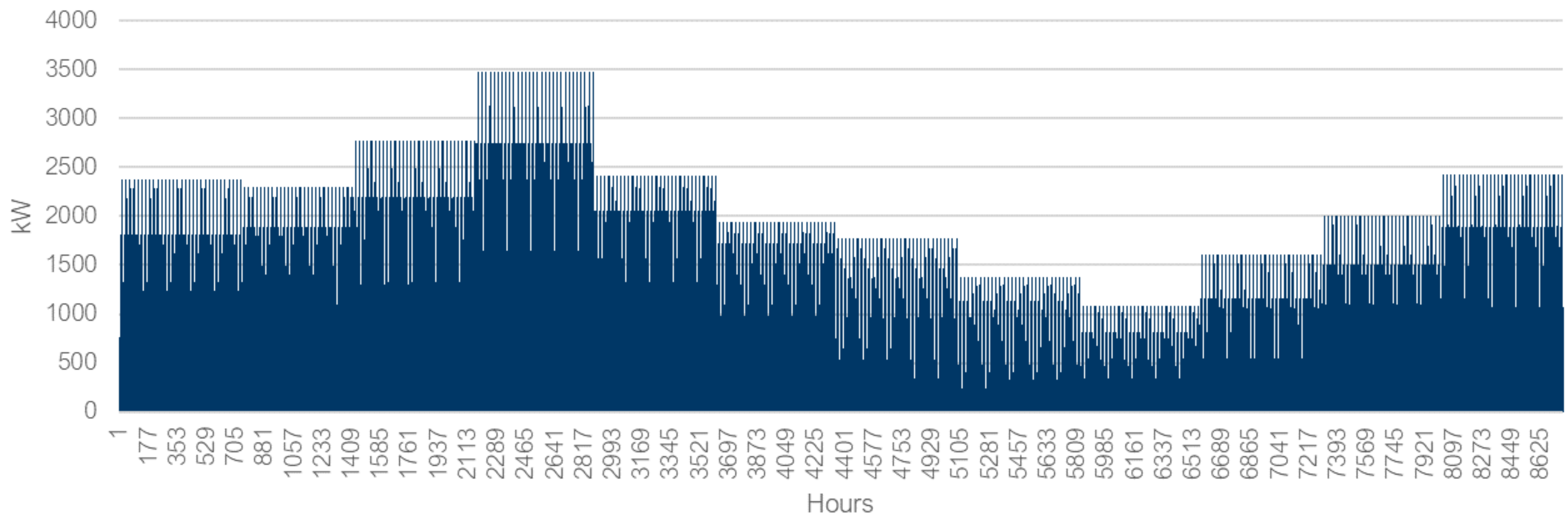


Figure 8. 8,760 Profile for Micro Hydro, 3 MW



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

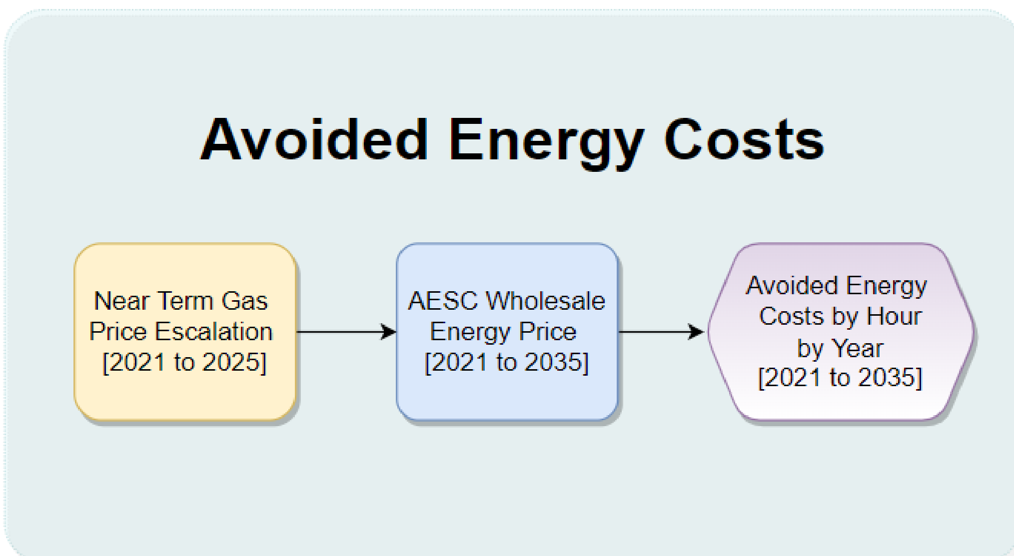
C. Detailed Base Value Stack Methodologies

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.

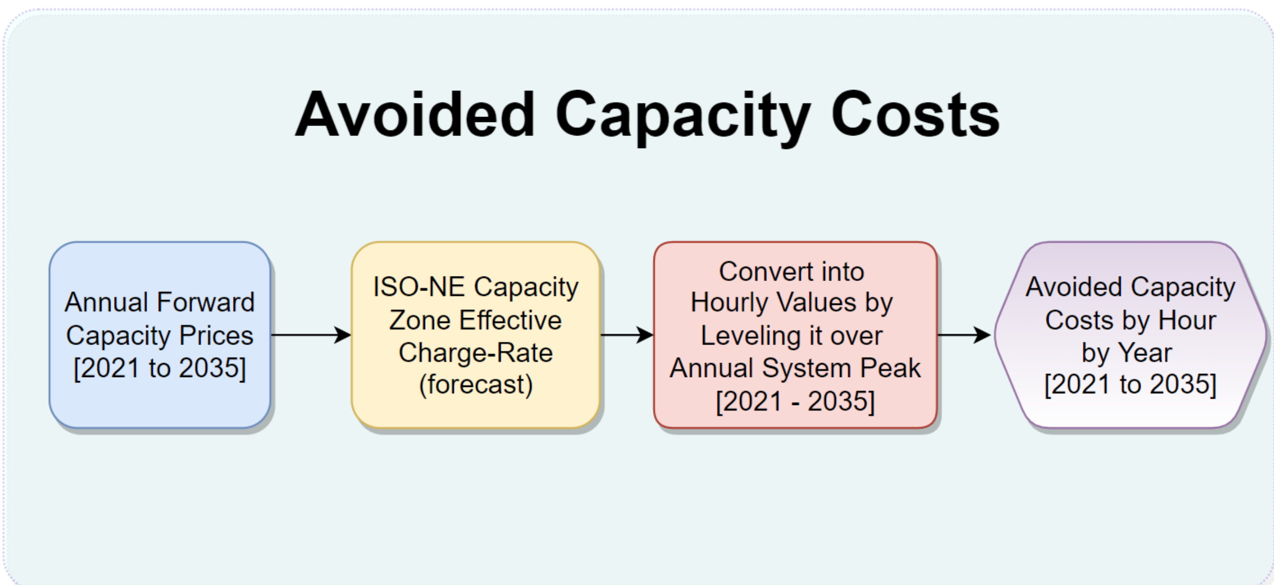
[4] For the NH VDER Study, the ideal avoided cost values would be estimated under a counterfactual scenario that includes region-wide EE, ADR, BE, and transportation electrification impacts along with non-New Hampshire distributed generation impacts. This scenario, unfortunately, is not readily available. 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.

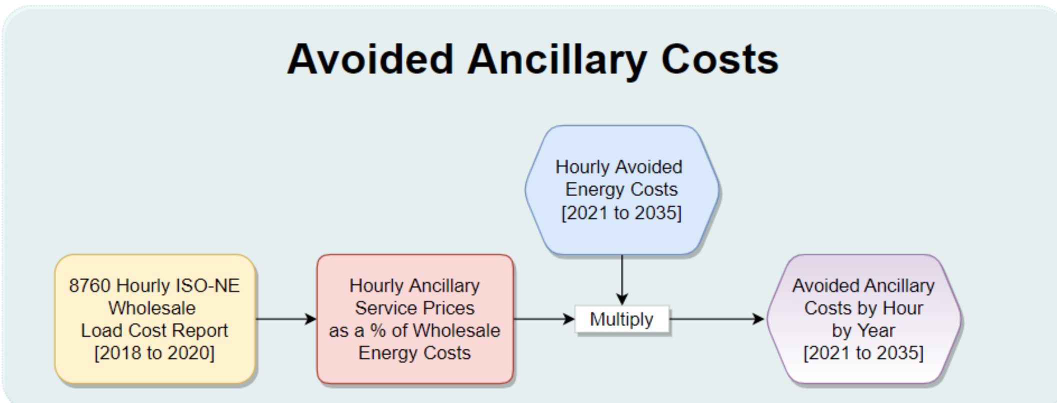
[7] Because Forward Capacity Auctions are held three years in advance, the actual cost of capacity procured on the market at the time that it is needed can vary from the FCA clearing price. The effective charge rate is a factor that is forecasted by ISO-NE which represents the difference between the 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

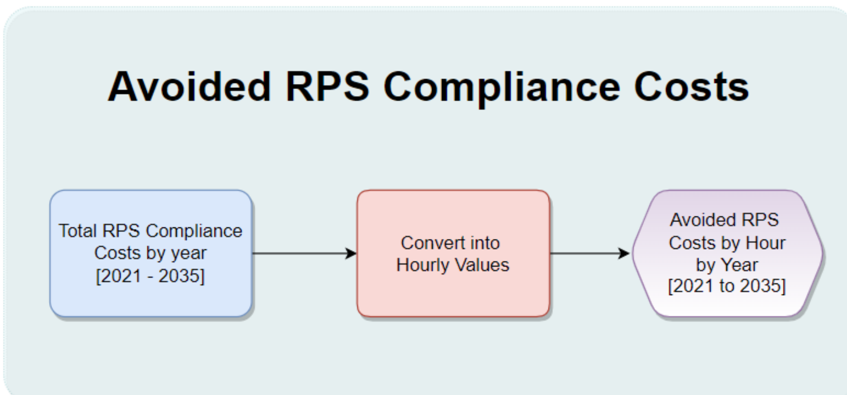
Inputs	Sources
Wholesale Hourly Energy Prices	AESC 2021 study (Counterfactual #2)
Wholesale Ancillary and Load Charges	ISO-NE wholesale monthly reports by zone

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)

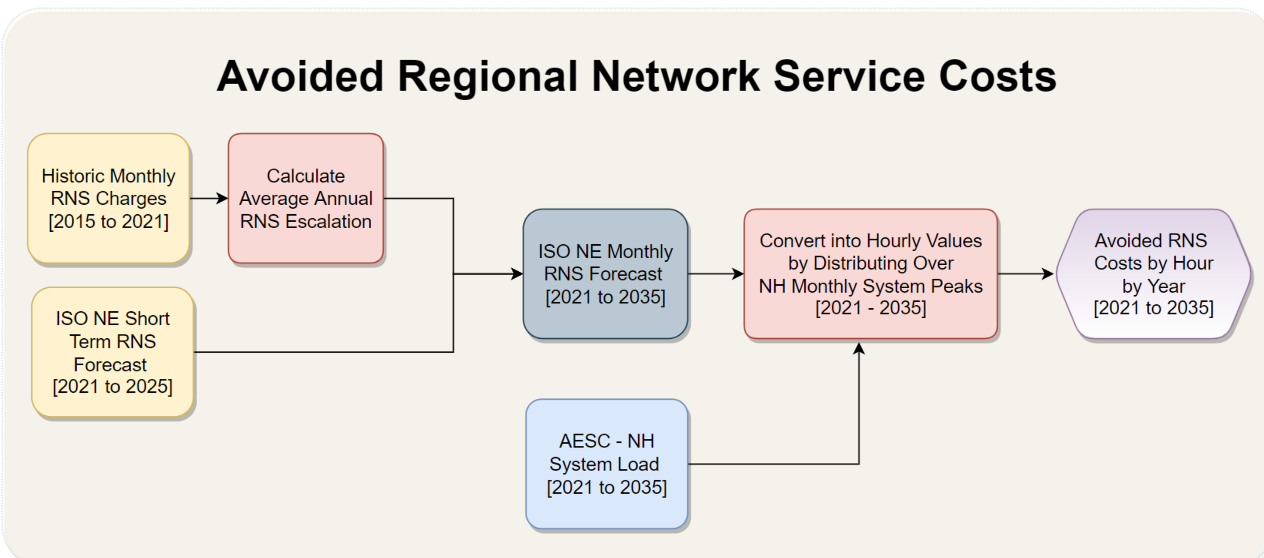
[12] For the purpose of the value stack assessment, we calculated the hourly netting from a south-facing solar PV system then applied this assumption to the west-facing and south-facing solar with storage systems within a given sector. Although the current NEM tariff in New Hampshire uses monthly netting 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

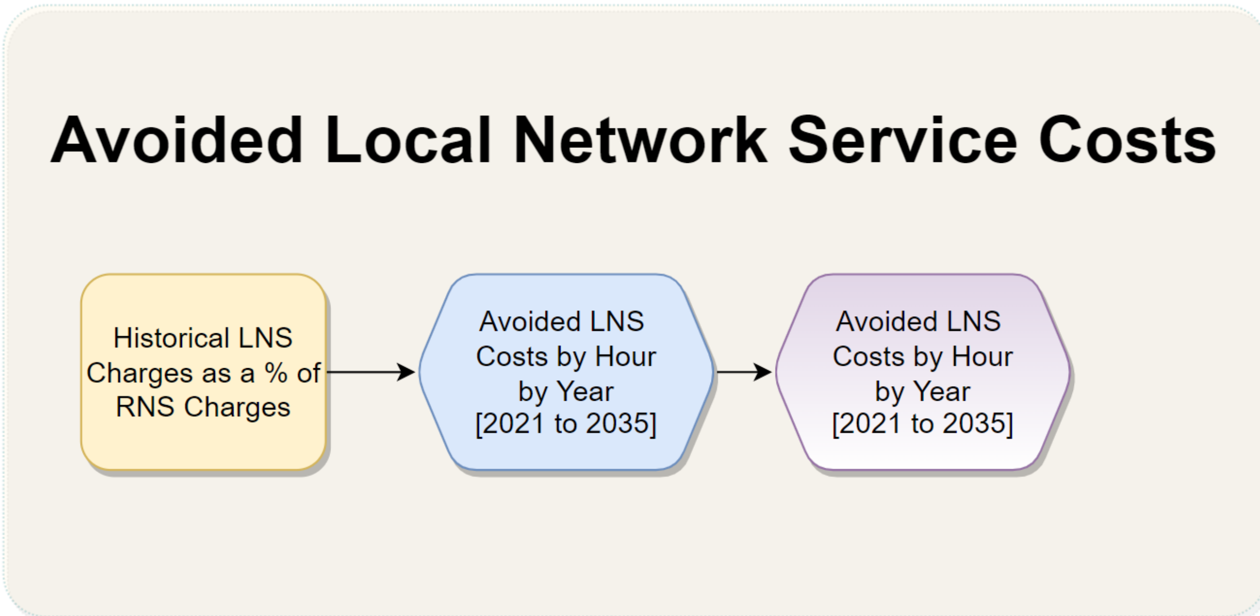
C.5.1 Rationale

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

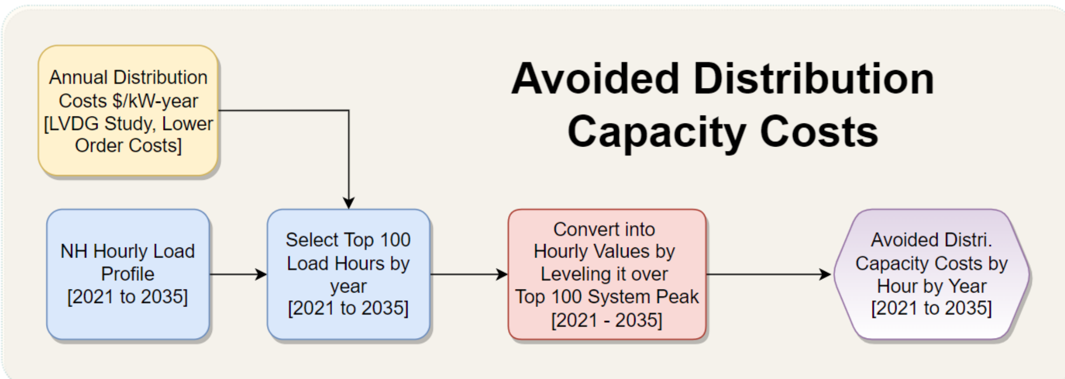
C.7.1 Rationale

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

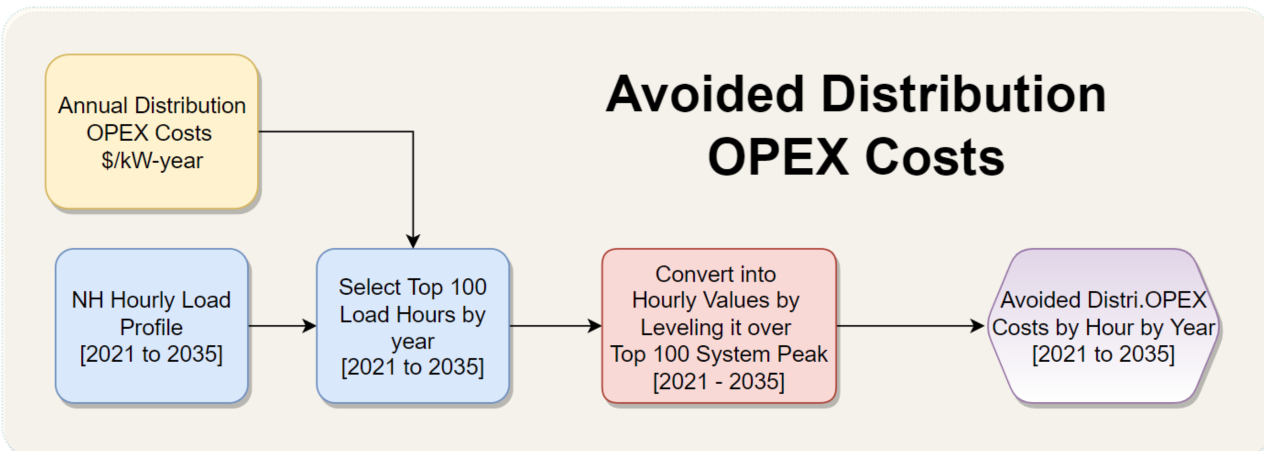
Inputs	Sources
Distribution Capital Expenditure Proxy Value	Utility data and interviews
	LVDG Study
NH System Load Profiles	Utility Data Requests
	AESC 2021 study forecasts

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

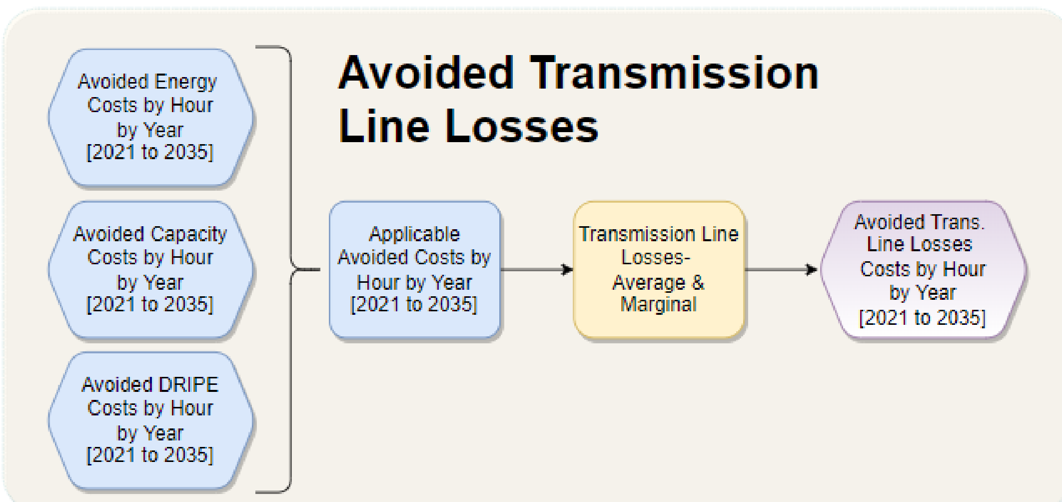
Inputs	Sources
Distribution OPEX Expenditure Proxy Value	Utility data and interviews
	FERC Form 1 Filings
NH System Load Profiles	Utility Data Requests
	AESC 2021 study forecasts

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

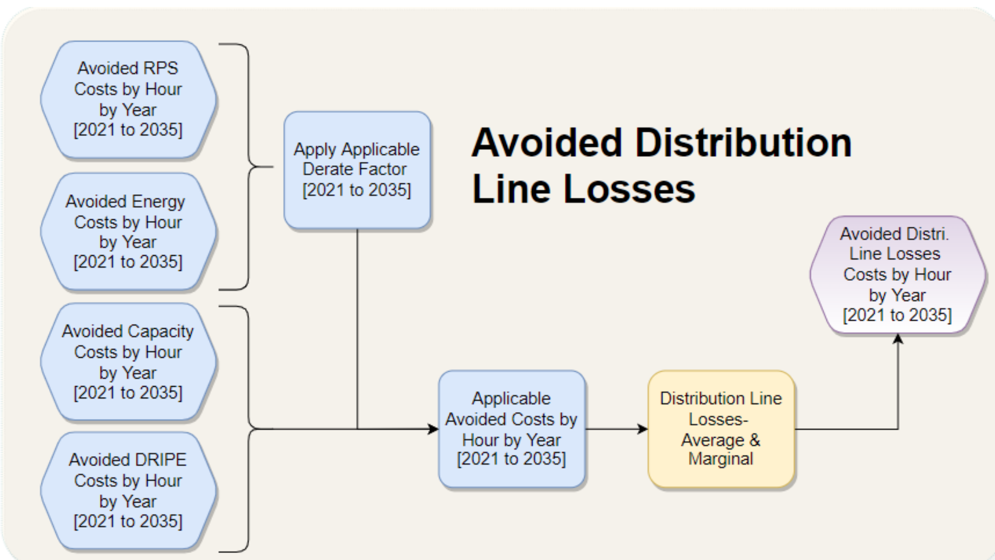
[21] This is consistent with the approach laid out in Table 136 in the AESC.

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

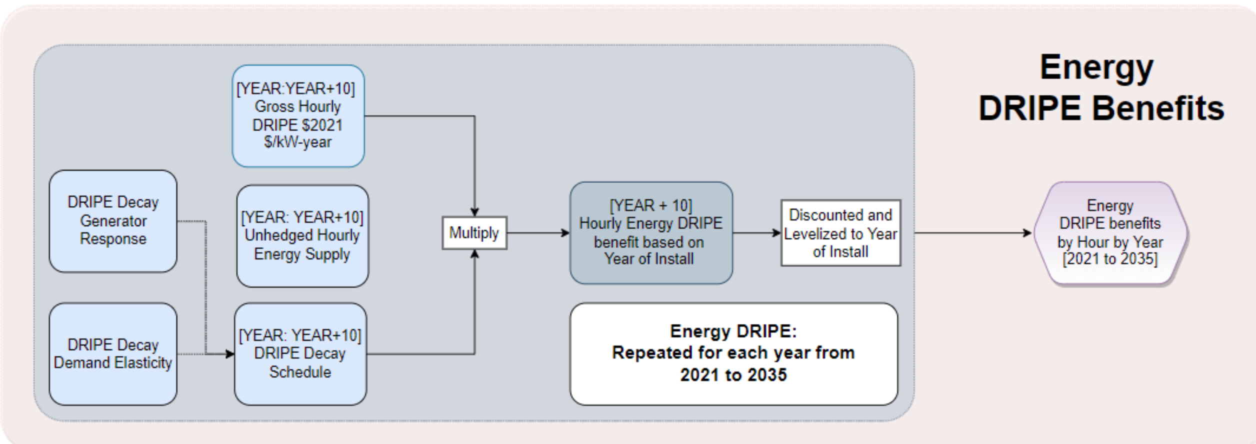
Inputs	Sources
Distribution Line Losses	AESC 2021 study, NH Utility (primary), RAP Study (secondary)
NH System Load Profiles	AESC 2021 study, NH Utilities

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

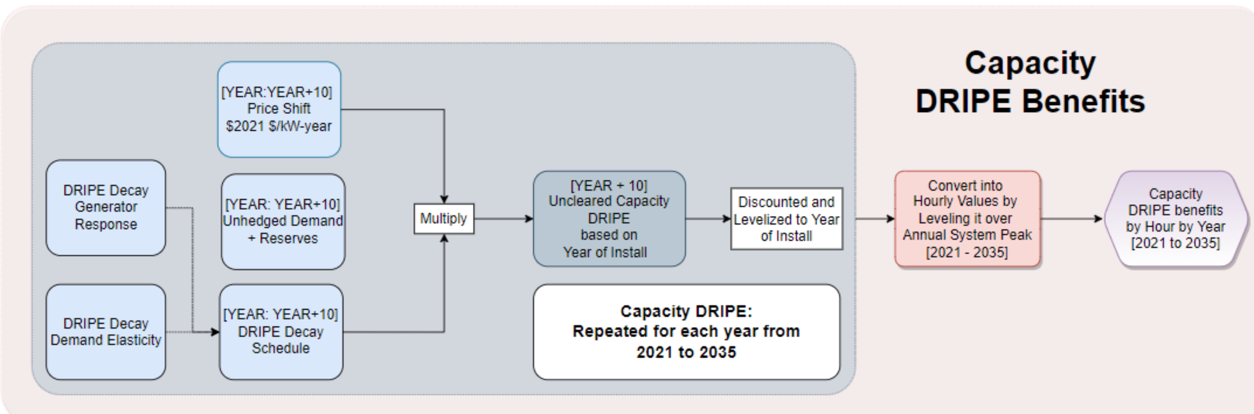
- For systems installed in 2021, the annual energy DRIPE persist through 2031. This is because the AESC assumes that the DRIPE effect decays over time because owners of existing generating resources, in response to lower energy and capacity prices, would allow their assets to become less efficient and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

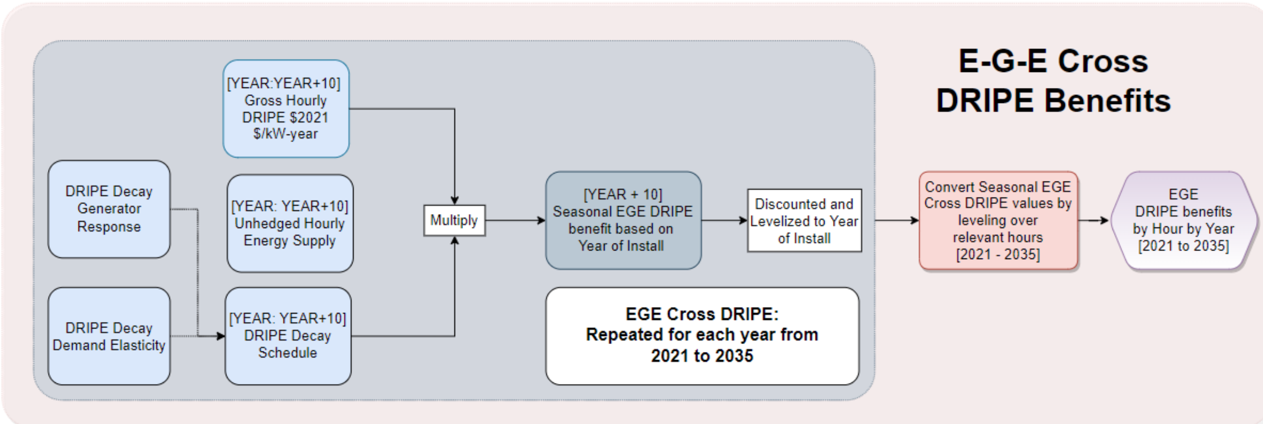
- For systems installed in 2021, the annual capacity DRIPE persist through 2031. This is because the AESC 2021 study assumes that the DRIPE effect decays over time because owners of existing generating resources, in response to lower energy and capacity prices, would allow their assets to become less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

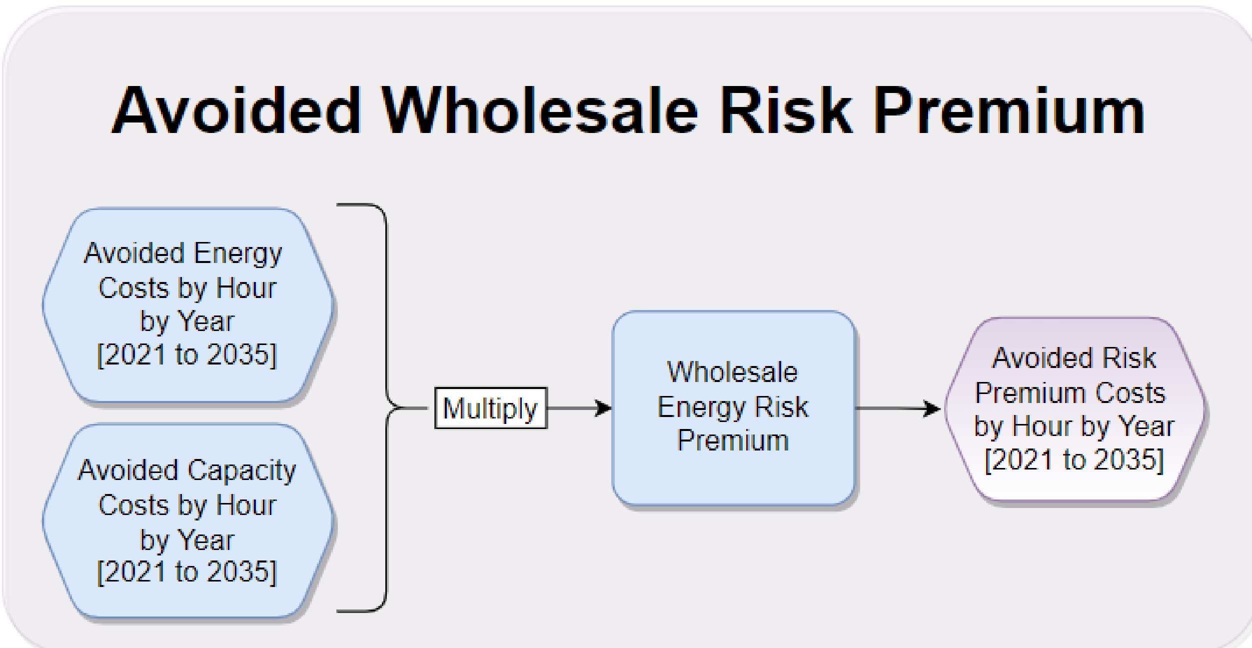
Inputs	Sources
E-G-E DRIPE Coefficients	AESC 2021 study

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

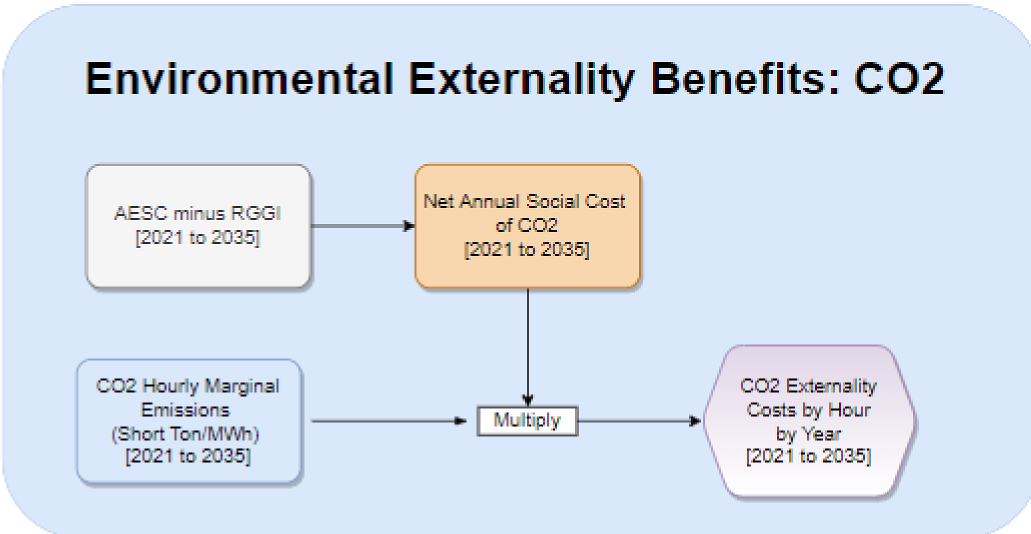
The electricity generated from a DG resource may reduce marginal emissions from fossil fuel plants. A portion of the avoided costs of such reduced emissions are already included as environmental program compliance costs embedded in wholesale energy prices. This study sensitivity focuses on evaluating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

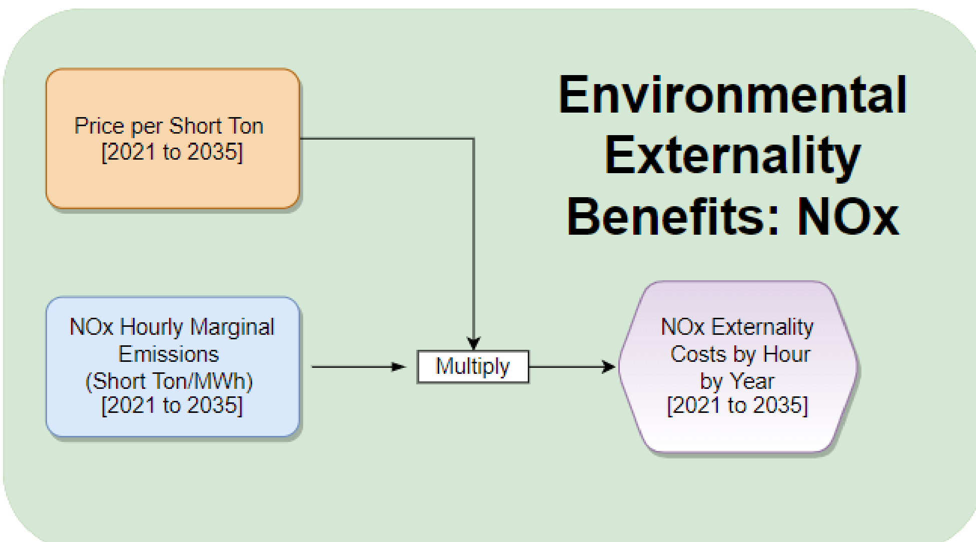
SO_2 emissions: The AESC 2021 study assumes that all coal-fired generation, the primary source of SO_2 emissions from electricity generation, is taken offline by 2025. For this analysis, the value of SO_2 emissions is assumed to be minimal and therefore it is not included in the environmental externalities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

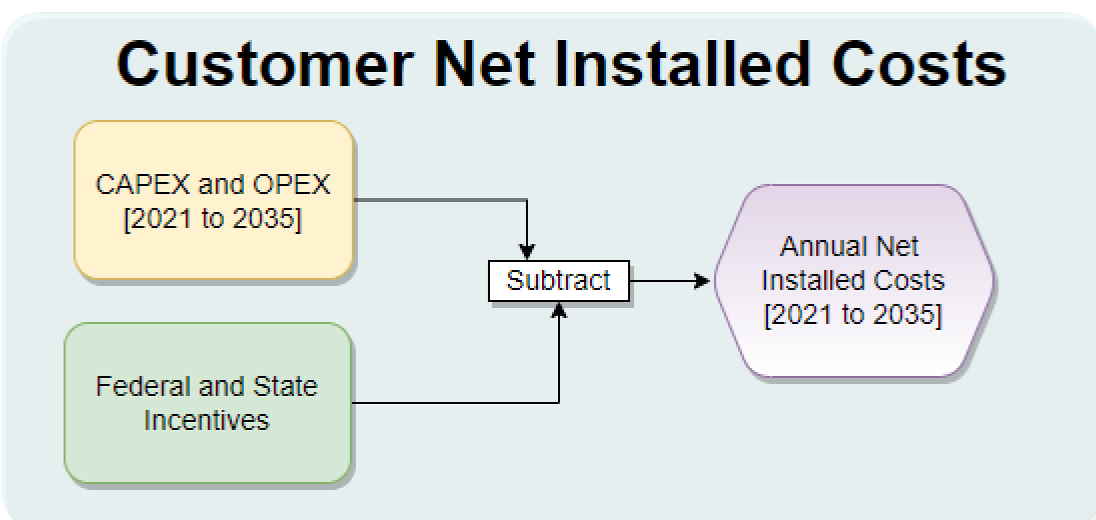
In this study, resilience services are defined as the ability of DERs to provide back-up power to a site in the event that it loses utility electricity service.[29] Resiliency has the potential to provide significant value, although this value is expected to be highly context-specific. This criterion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

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

Three Electric Utilities: 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).

Three Customer Classes: 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.

Two Scenarios: 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

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

C Utilities need recover costs to accommodate DG / operate programs

D Costs are recovered over fewer kWh

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	$\text{Consumption}_{DG\ Customer} = \text{Avg Consumption}_{Pre\ DG} - \text{Avg DG Production}$
Typical non-DG Customer	$\text{Consumption}_{Non-DG\ Customer} = \text{Avg Consumption}_{\,Pre-DG}$
Average Utility Customer	$\text{Consumption}_{\,Avg\ Customer} = \dfrac{\text{Total Consumption}_{Post\ DG}}{\text{Total Customers}_{Post\ DG}}$

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:

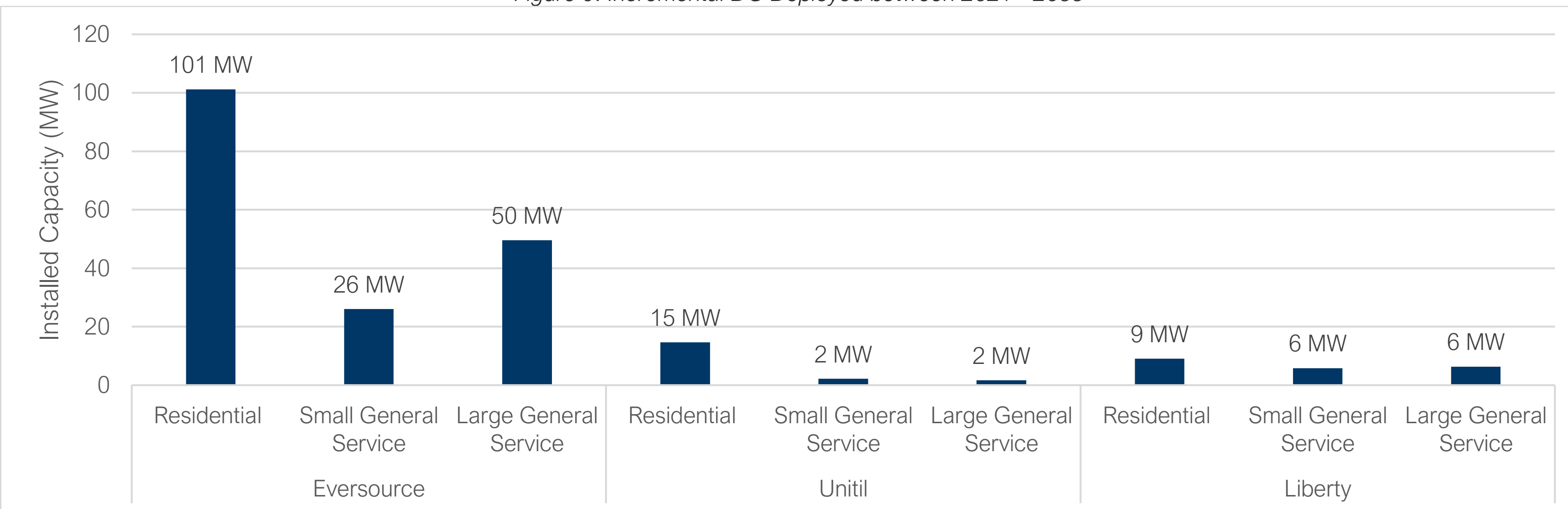
- Generation: Avoided energy, RPS, ancillary services, distribution and transmission line losses, and risk premium are considered pass-through components, while avoided capacity and DRIPE benefits were considered to have an impact on rates.
- Distribution: The avoided distribution costs include avoided 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>

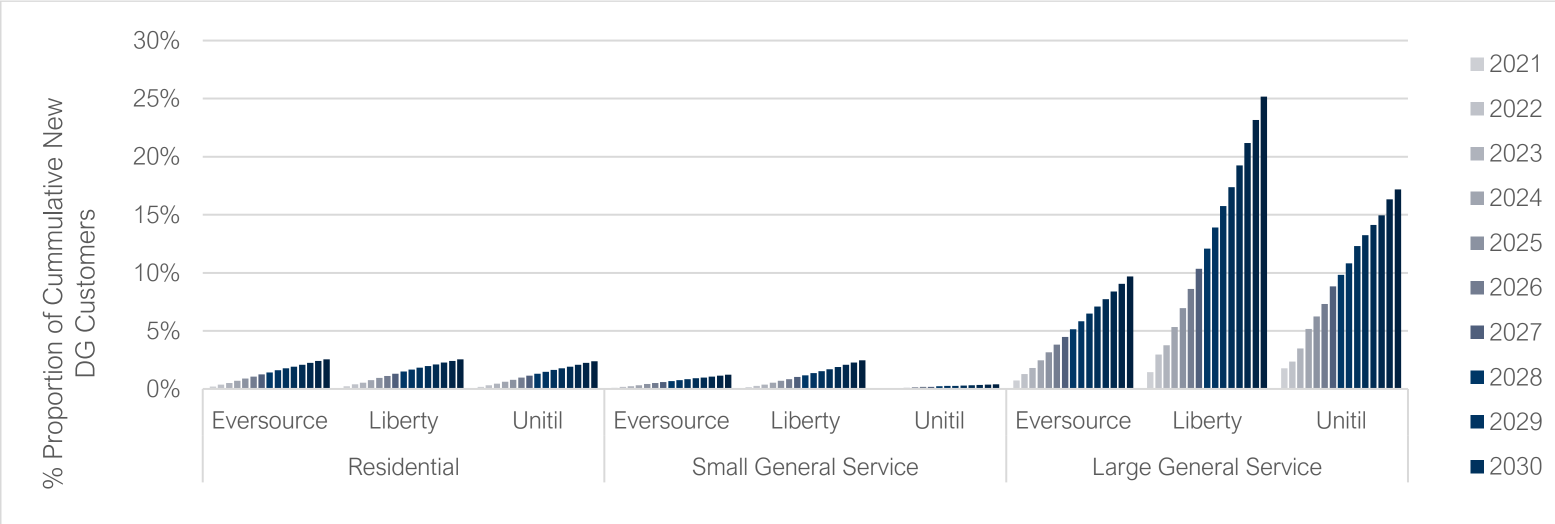
Customer Class	Eversource	Unitil	Liberty	% Self-Consumed
Residential	7.6	12.2	10.1	72% (Monthly Netting)
Small General Service	24.5	43.0	41.3	65% (Monthly Netting)
Large General Service	329.2	47.2	209.6	99% (Hourly Netting)

Incremental DG Capacity deployed over the study period:

Figure 9: Incremental DG Deployed between 2021 - 2035

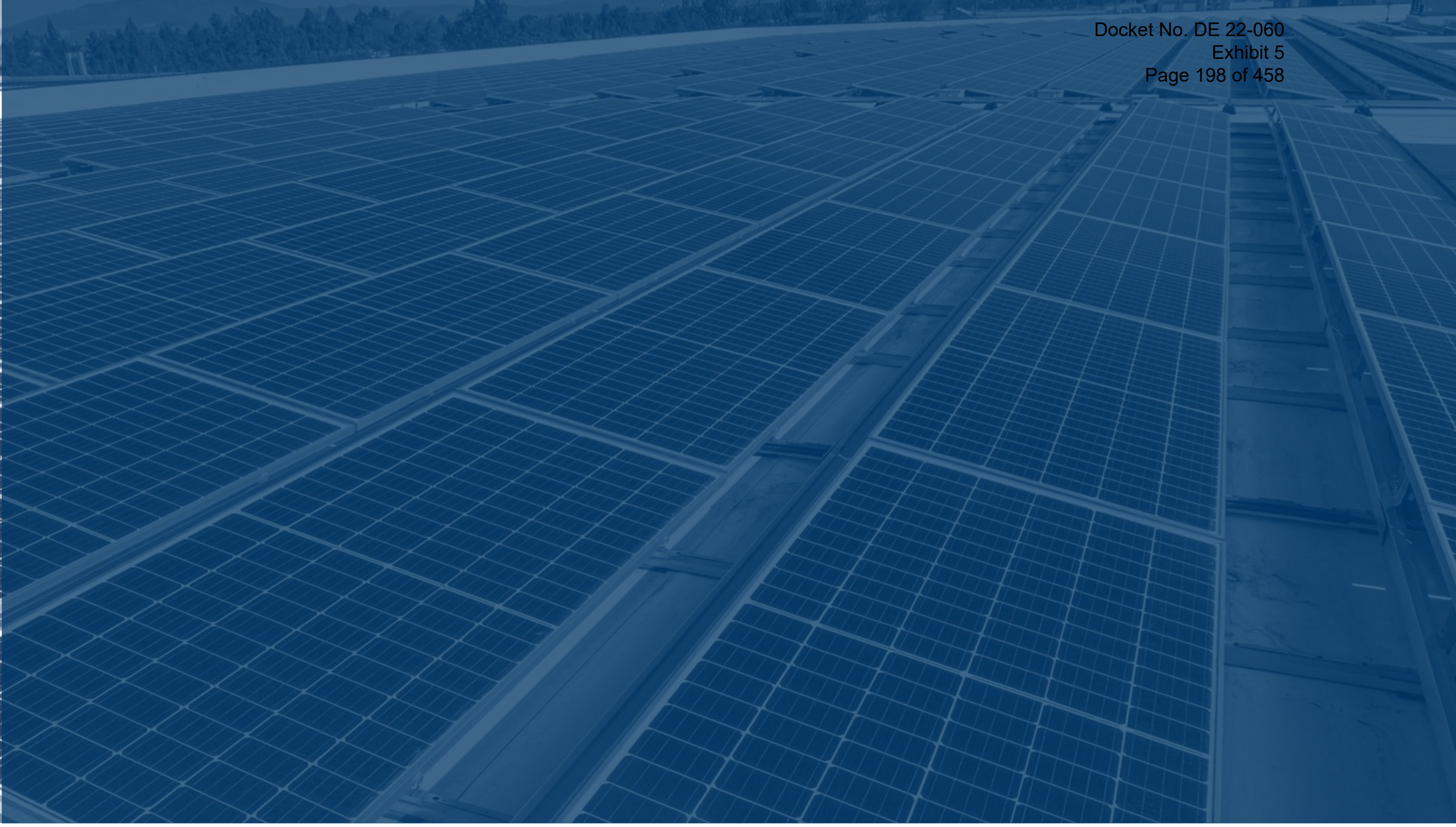


Percentage of customers with DG by 2035:



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.



New Hampshire Value of Distributed Energy Resources

Addendum

Submitted to:

New Hampshire Department of Energy

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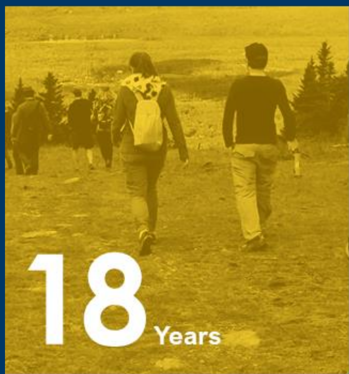
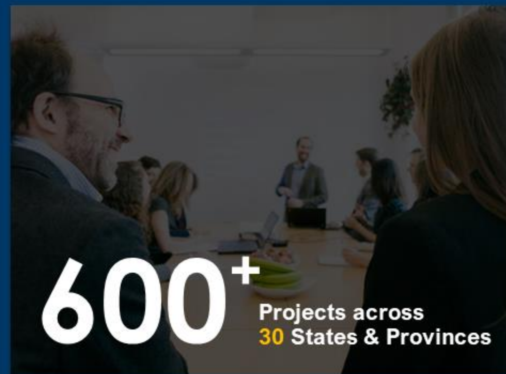
With support from Power Advisory

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.

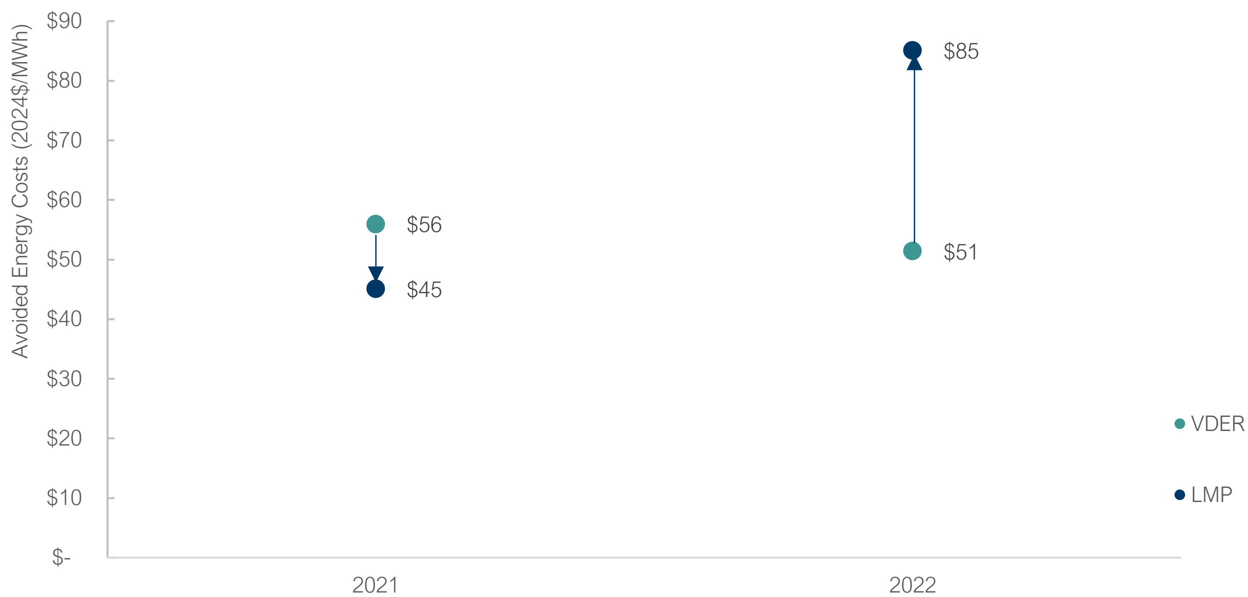
Table of Contents

A. Introduction

Since the completion of the New Hampshire Value of Distributed Energy Resources Study Report in October 2022, several factors, such as supply chain constraints caused by COVID-19, strained infrastructure, and the ongoing Russian invasion of Ukraine, have led to an unparalleled surge in natural gas prices and energy supply costs. To provide a more current estimate of the avoided costs captured by distributed energy resources and the resulting study findings, the below addendum updates a number of relevant study values and results.

As seen in the figure below, the historic Locational Marginal Price (LMP) prices in 2021 and 2022 varied significantly compared to the estimates used in the original study. In 2021, the average LMP observed in the ISO-NE market was 20% lower than the avoided energy cost forecasted in the original VDER study. On the other hand, in 2022, the average LMP observed in the ISO-NE market was 66% higher than the avoided energy cost forecasted in the original VDER study. Thus the study results are subject to various factors that can lead to discrepancies between predicted prices and actual historical prices, including constraints in natural gas supply, transmission, and changes in system demand.

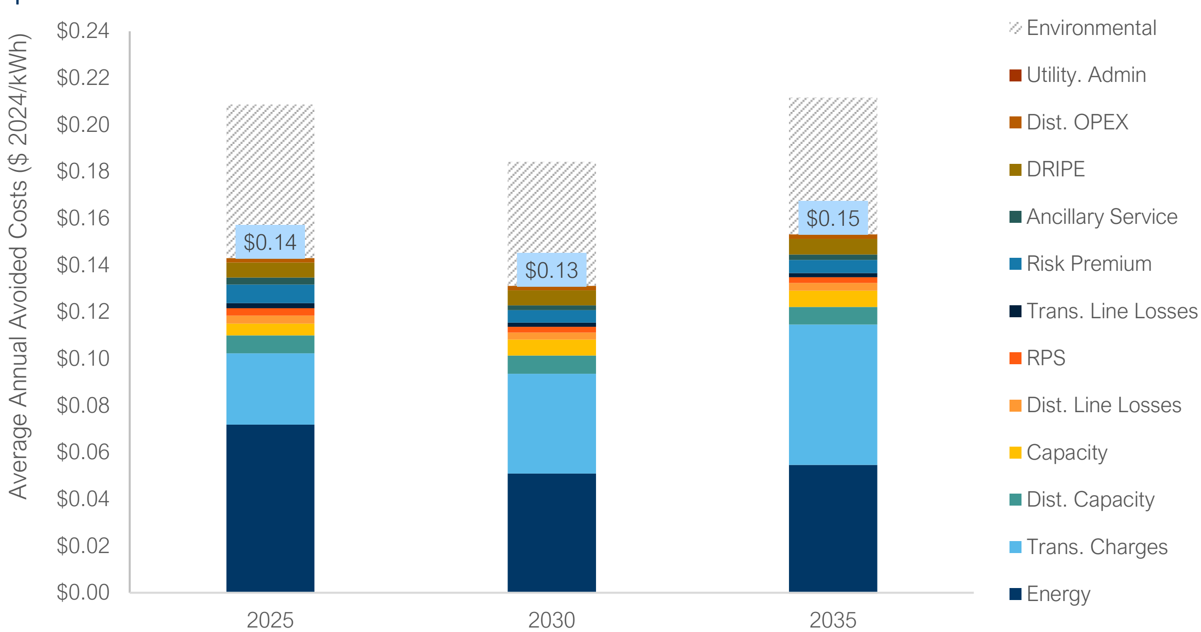
Actual v/s Predicted Avoided Energy Costs



B. Overall Results

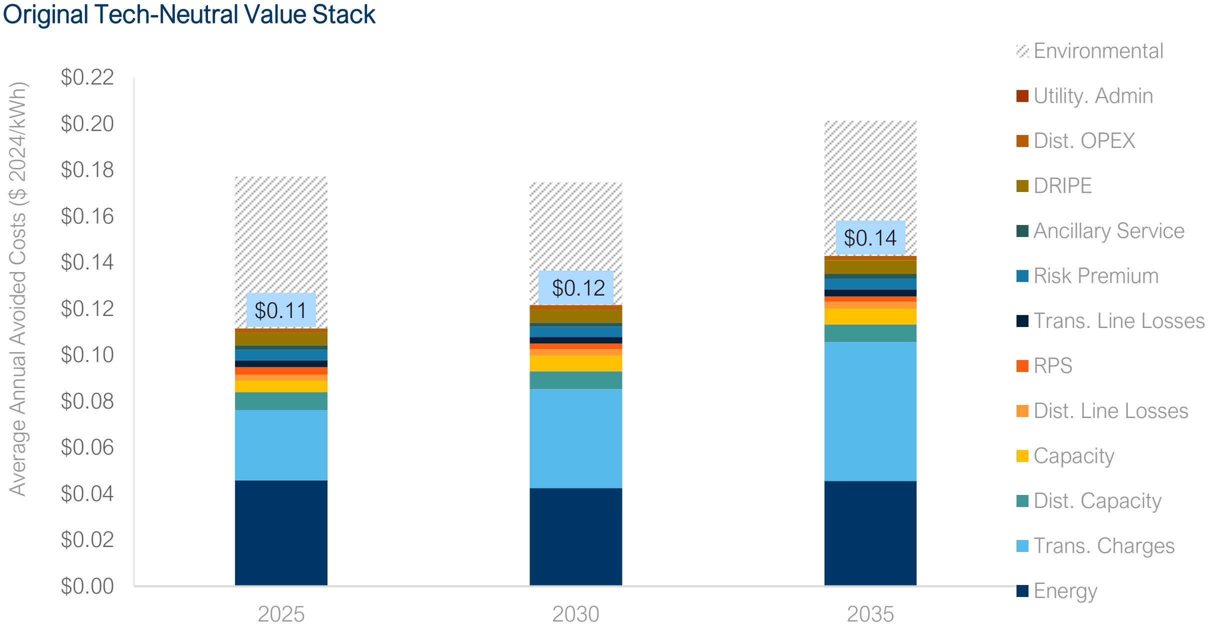
B.1 Comparison Between the Original and Updated Technology Neutral Value Stack

Updated Tech-Neutral Value Stack

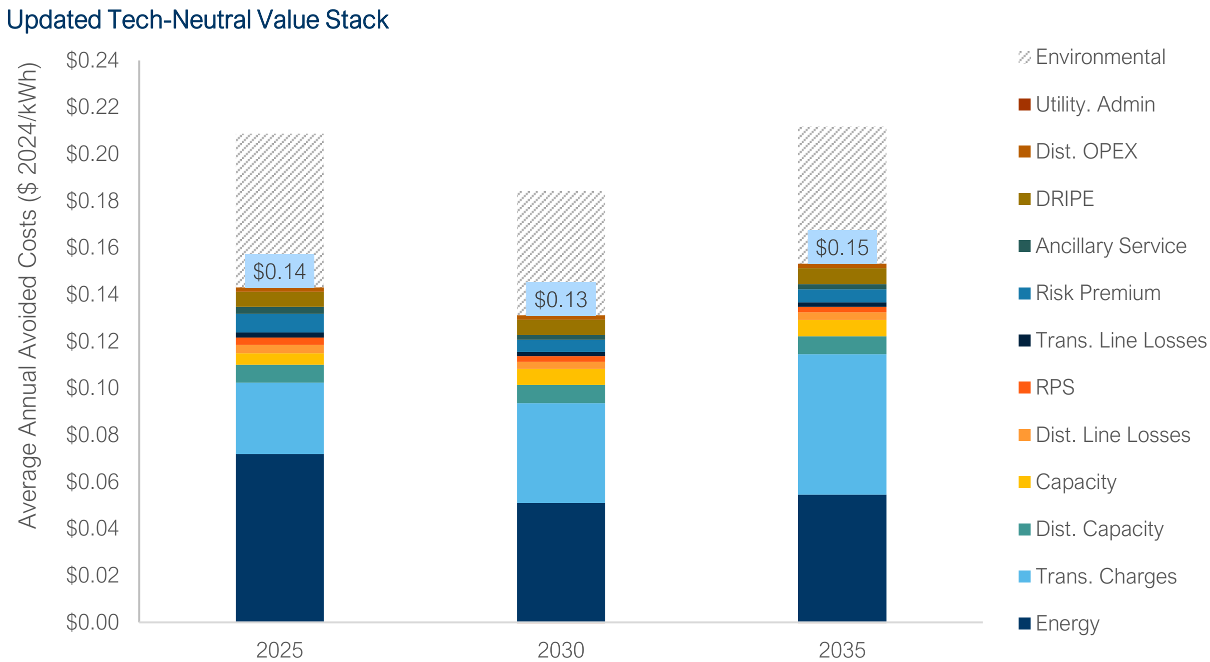


Compared to the original tech-neutral value stack, the total avoided costs (excluding environmental benefits) are, on average, about 17% higher in the initial years and about 5% higher in the later part of the study.

Original Tech-Neutral Value Stack



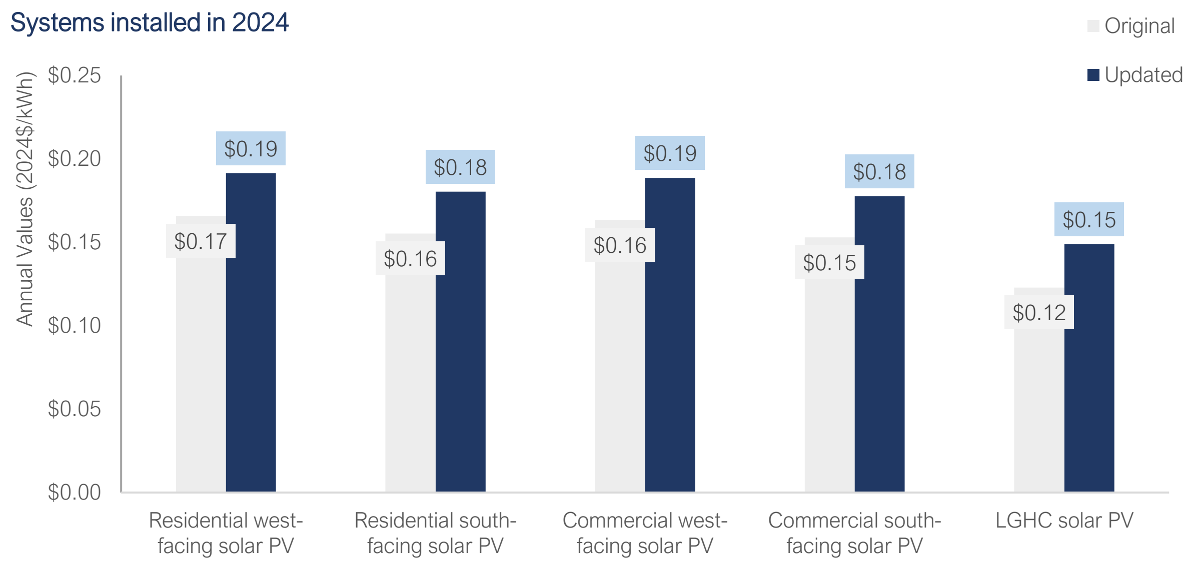
B.2 Updated Technology Neutral Value Stack

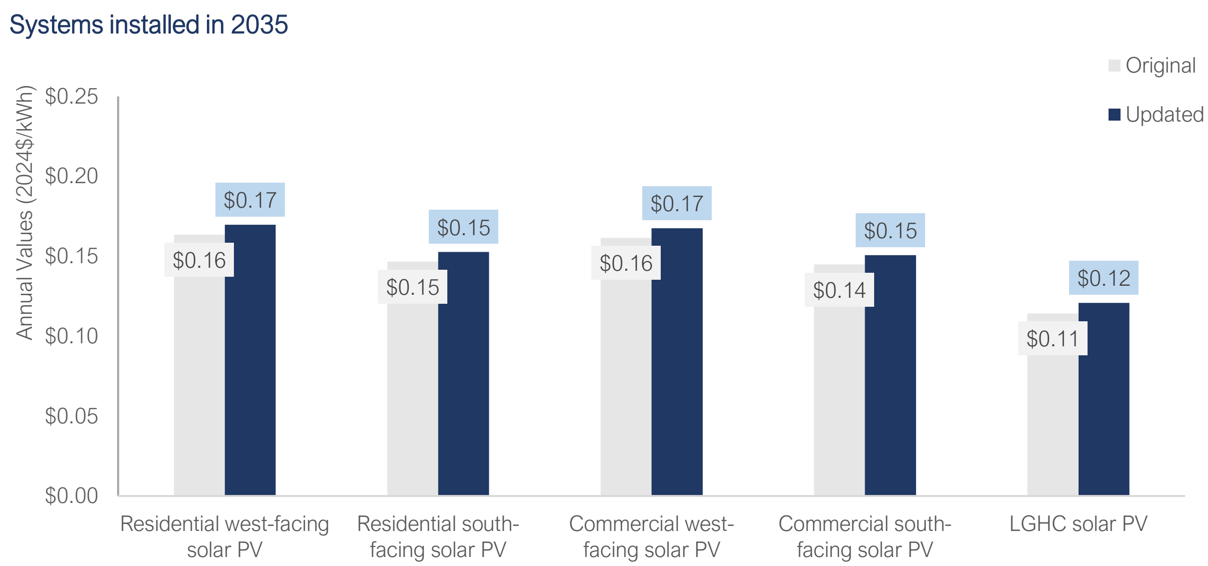


The updated avoided energy costs can make up to 50% of the overall tech-neutral value. Consistent with the original study, this value decreases gradually over time. The current high prices are due to the impact of high natural gas prices, which has been factored into the modified AESC energy forecast. However, the value of energy is expected to decrease over time as lower-cost resources like offshore wind and solar become more prevalent.

Transmission charges are forecasted to increase over time, increasing avoided cost value. Overall, Energy, Transmission Charges, Distribution Capacity, and Capacity Charges represent 80%-85% of the average annual DER avoided costs benefits (excluding environmental).

B.3 Value Captured by Solar PV Systems





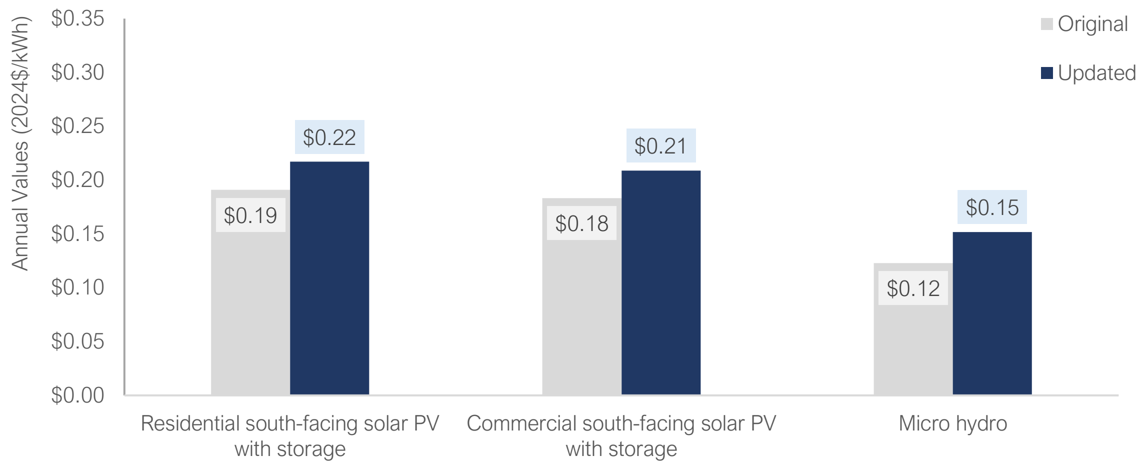
The value of solar-only systems tends to decrease over time due to the decreasing energy avoided costs. However, the updated total avoided costs in 2024 are approximately 15-20% higher than the original study. This increment gradually decreases to 5% by 2035.

Systems facing west can generate 6-11% more avoided cost value. However, the deployment of such systems is anticipated to be limited as customers are presently encouraged to prioritize south-facing installations that maximize volumetric production.

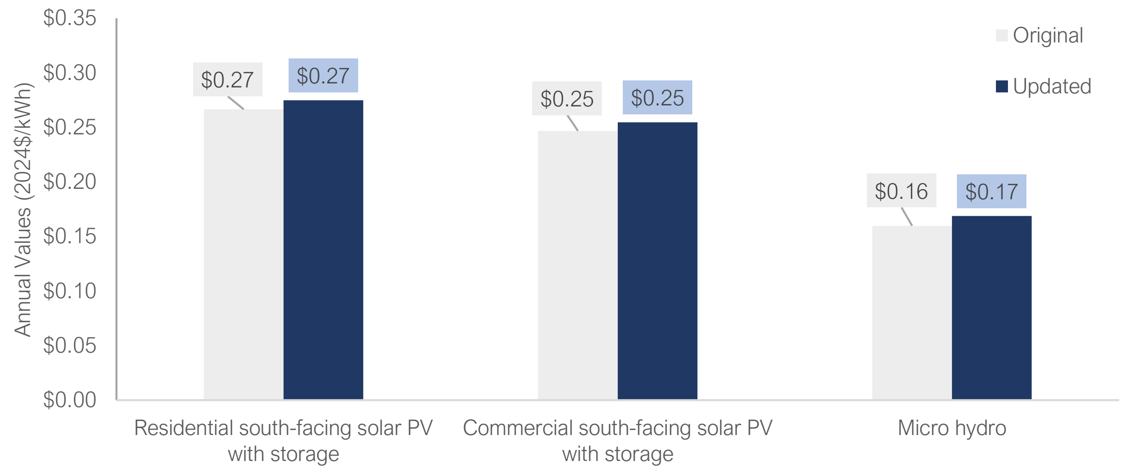
Commercial systems achieve less total value than residential systems. This is primarily due to reduced line loss and reduced RPS avoided cost value (due to a lower % of the energy consumed behind the meter) associated with commercial systems.

B.4 Value Captured by DG Systems

Systems installed in 2024



Systems installed in 2035



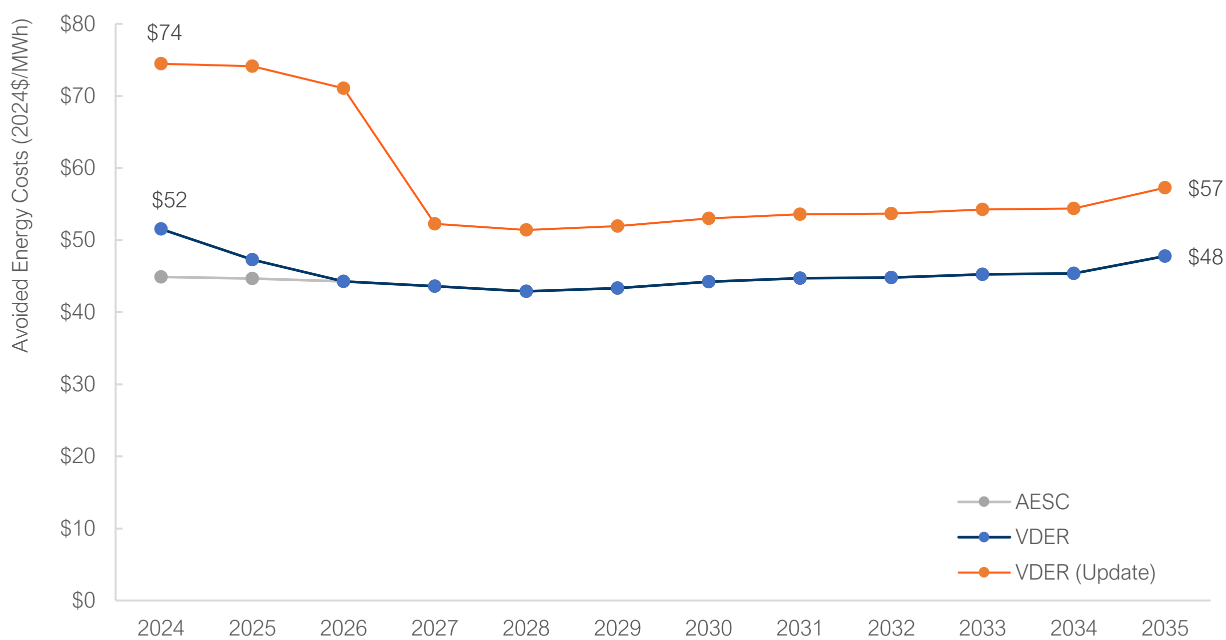
Over time, the value of solar paired with storage and micro-hydro systems increases significantly. The reason behind this is that these systems are able to capture transmission-avoided costs more effectively. Furthermore, as the transmission avoided costs continue to increase over the study period, the overall value captured by these systems also increases. Compared to the original study, solar-coupled storage assets have a total avoided cost of about 13% higher in 2024, whereas micro hydro facilities have an increased updated total avoided cost of 20%.

C. Updates to the Value Stack Components

C.1 Avoided Energy Costs

Key Update: The significant increase in natural gas prices due to COVID-19 and the conflict in Ukraine has resulted in a substantial rise in energy supply costs. To reflect this, the latest natural gas price forecast is being utilized to determine updated projections for wholesale energy costs. Consequently, we anticipate an expected increase of 20-60% in avoided energy costs compared to the initial projections in the VDER study. The results have been updated to reflect $2024 real values[1].

Near term escalations in avoided energy costs



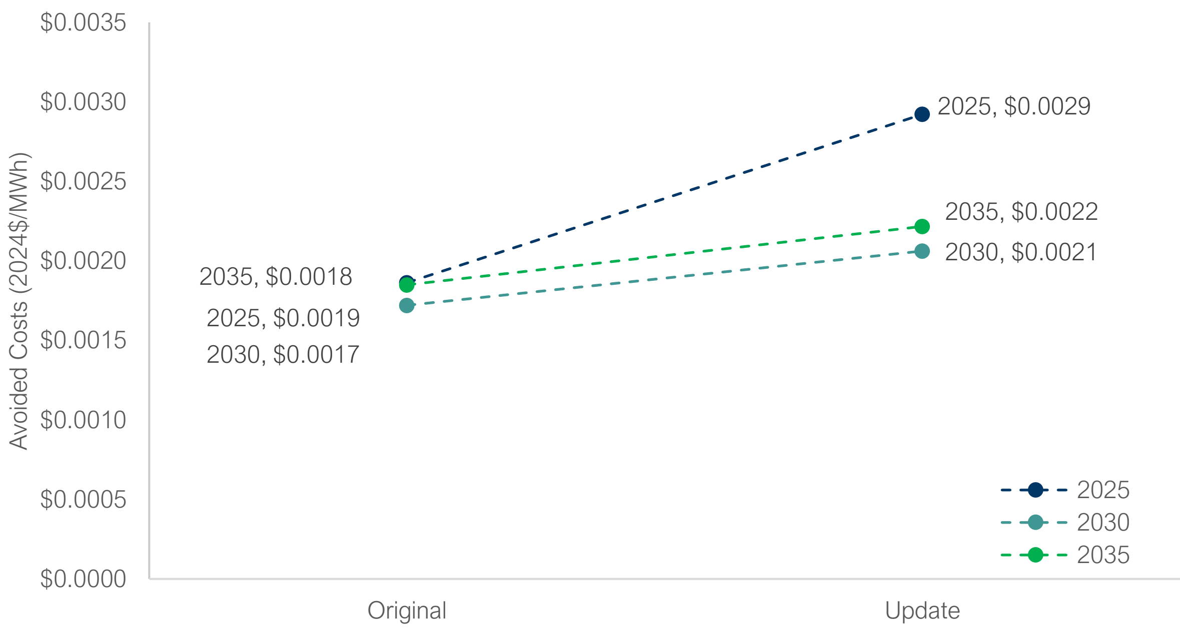
C.2 Avoided Capacity Costs

Key Updates: Updated to $2024 real values.

[1] The $2024 real was estimated based on a change in the CPI from first quarter of 2023 to 2024 based on historical trends. The inflation was based on the relative change in the 2021 CPI (271) to 2024 CPI (estimated 317).

C.3 Ancillary Services and Load Obligation Charges

Key Updates: The model assumes that ancillary services and load obligation charges are tied to energy costs – an update in wholesale energy costs will result in updated values to this value stack component. Further, the results were updated to $2024 real values.



C.4 RPS Compliance

Key Updates: Updated to $2024 real values.

C.5 Transmission Charges

Key Updates: Updated to $2024 real values.

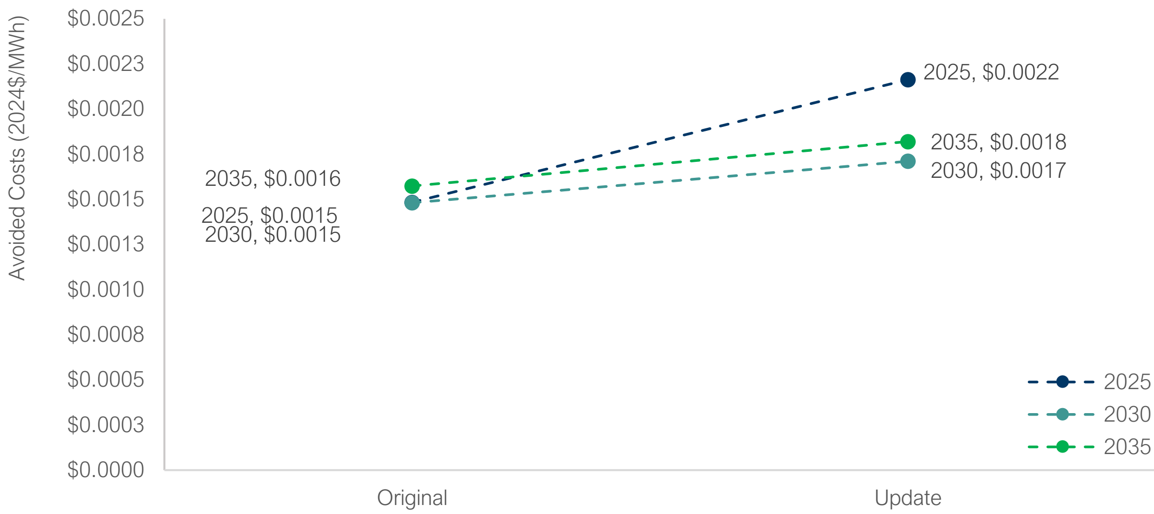
C.6 Distribution System Operating Expenses

Key Updates: Updated to $2024 real values.

C.7 Transmission Line Losses

Key Updates: The avoided transmission line loss is a cumulative value, incorporating line loss values from all relevant avoided cost criteria: energy, capacity, and wholesale market price suppression. An update to wholesale energy costs will result in an update to the avoided transmission line loss component.

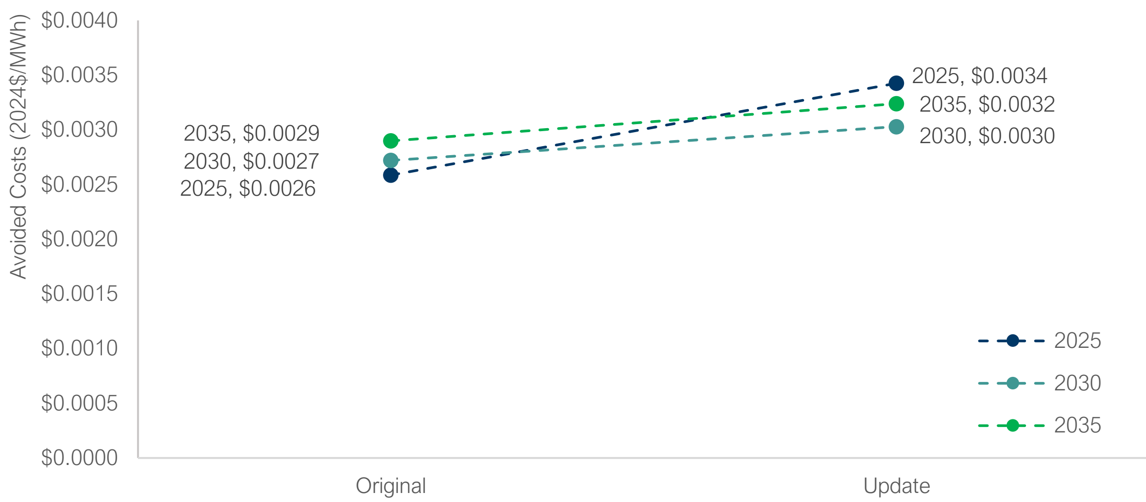
Transmission Line Loss



C.8 Distribution Line Losses

Key Updates: The avoided distribution line loss is a cumulative value, incorporating line loss values from all relevant avoided cost criteria: energy, capacity, and wholesale market price suppression. An update to wholesale energy costs will result in an update to the avoided distribution line loss component.

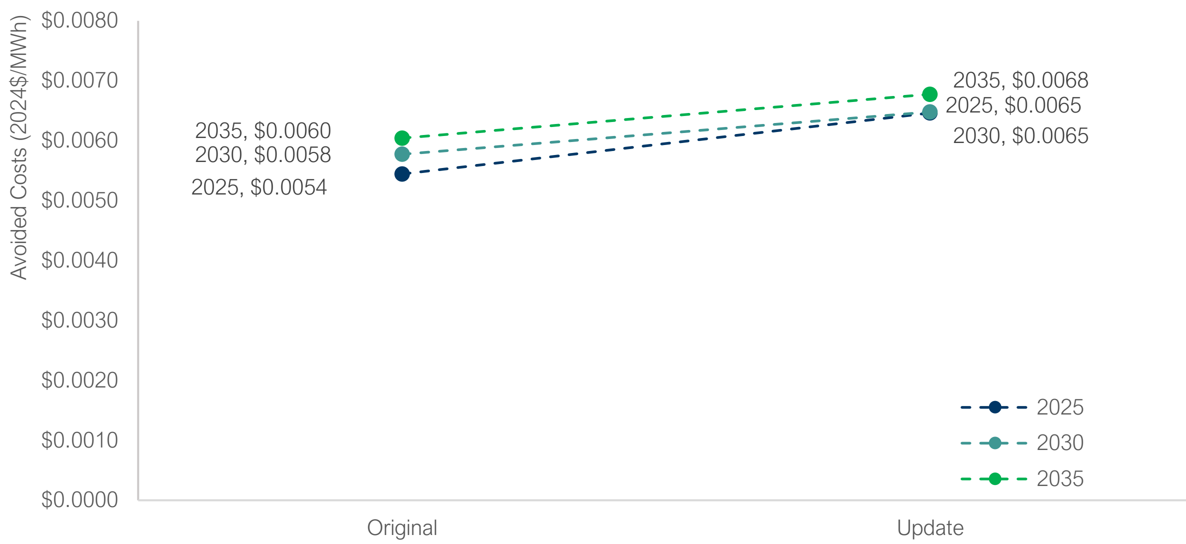
Distribution Line Loss



C.9 Wholesale Market Price Suppression

Key Updates: The electricity produced at the customer-generator's site reduces the overall energy and capacity procured through wholesale, resulting in lower market clearing prices. This price suppression effect, the Demand Reduction Induced Price Effect, or DRIPE, is ultimately passed on to all market participants. Since DRIPE is tied to wholesale energy costs, updated values are provided for this component. Further, the results were updated to $2024 real values.

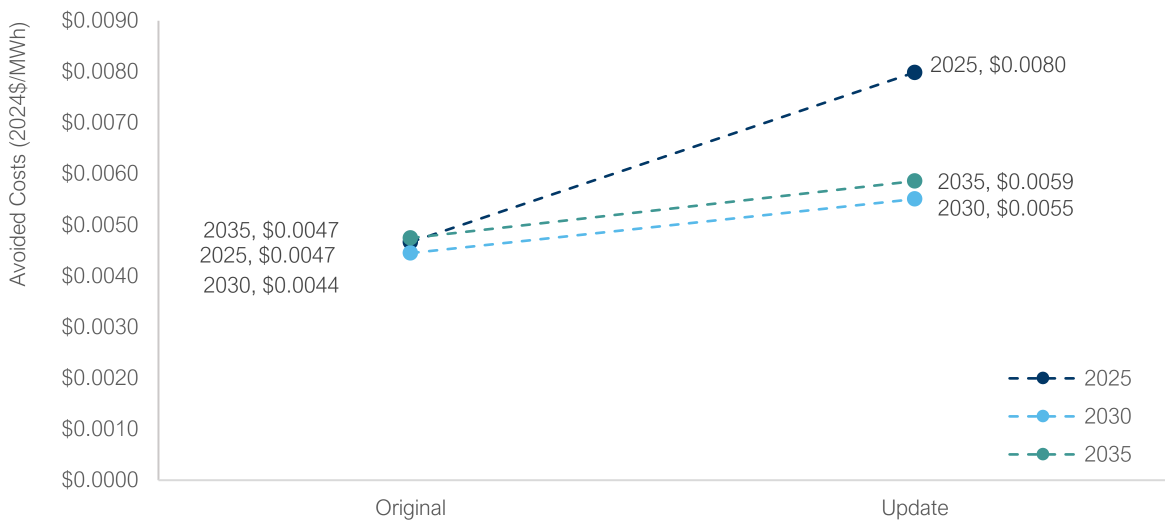
DRIPE



C.10 Wholesale Risk Premium

Key Updates: The full retail price of electricity is generally greater than the sum of the wholesale market prices for energy, capacity, and ancillary services. This is partly because the wholesale suppliers of retail customer load requirements incur various market risks when they set contract prices before supply delivery periods. Therefore, every wholesale energy and capacity obligation reduction may reduce the supplier's cost to mitigate such risks. As a result, an update to wholesale energy and ancillary service costs will result in an update to the wholesale risk premium charges. To account for increased risk in fuel supply in the near term, the near-term wholesale risk premiums were assumed to be 11%, higher than in the original study, leading to higher avoided costs. Over the study period, it was assumed that risk premiums would fall back to the default assumption in the AESC (8%). Further, the results were updated to $2024 real values.

Wholesale Risk Premium



C.11 Distribution Utility Administration Costs

Key Updates: Updated to $2024 real values.

C.12 Environmental Externalities

Key Updates: Updated to $2024 real values.

C.13 Distribution Grid Support Services

Key Updates: Updated to $2024 real values.

C.14 Resilience Services

Key Updates: Updated to $2024 real values.

C.15 Customer Installed Net Costs

Key Updates: Updated to $2024 real values.

D. Results Tables (Updated)

D.1 Technology-Neutral Value Stack

Table 1: Average Annual Technology-Neutral Value Stack ($/kWh) (2024$)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.073	0.072	0.069	0.051	0.050	0.050	0.051	0.051	0.051	0.052	0.052	0.055
Transmission Charges	0.028	0.030	0.033	0.035	0.037	0.040	0.043	0.046	0.049	0.052	0.056	0.060
Distribution Capacity	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008
Capacity	0.005	0.005	0.005	0.006	0.006	0.006	0.007	0.007	0.007	0.007	0.008	0.007
Distribution Line Losses	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	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002
Transmission Line Losses	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Risk Premium	0.010	0.008	0.007	0.005	0.005	0.005	0.006	0.006	0.006	0.006	0.006	0.006
Ancillary Services	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
DRIPE	0.007	0.006	0.006	0.006	0.006	0.006	0.006	0.007	0.007	0.007	0.007	0.007
Distribution OPEX	0.002	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
Environmental Externality	0.065	0.066	0.064	0.060	0.057	0.057	0.053	0.055	0.055	0.056	0.057	0.058
Total – Excluding Environmental	0.143	0.143	0.140	0.122	0.123	0.127	0.131	0.135	0.138	0.142	0.147	0.153
Total – Including Environmental	0.208	0.208	0.204	0.182	0.180	0.183	0.184	0.189	0.193	0.198	0.204	0.211

Table 2. Average Annual Technology-Neutral Value, Minimum Hourly Value, and Maximum Hourly Value ($/kWh) (2024$)

	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)
Energy	0.072	0.0168	0.1409	0.051	-0.0118	0.2030	0.055	-0.0115	0.2229
Transmission Charges	0.030	-	22.8093	0.043	-	32.0500	0.060	-	45.0344
Distribution Capacity	0.008	-	0.7197	0.008	-	0.7183	0.008	-	0.7057
Capacity	0.005	-	43.3843	0.007	-	59.8000	0.007	-	60.9725
Distribution Line Losses	0.003	0.0003	5.8434	0.003	-0.0001	6.7546	0.003	-0.0001	6.8874
RPS	0.003	0.0032	0.0032	0.002	0.0025	0.0025	0.002	0.0024	0.0024
Transmission Line Losses	0.002	0.0004	1.9425	0.002	-0.0003	2.2448	0.002	-0.0003	2.2890
Risk Premium	0.008	0.0017	1.4468	0.006	-0.0010	0.8698	0.006	-0.0009	0.9733
Ancillary Services	0.003	0.0005	0.0095	0.002	-0.0008	0.0082	0.002	-0.0008	0.0129
DRIPE	0.006	0.0002	8.3451	0.006	-0.0009	9.4254	0.007	-0.0009	10.0161
Distribution OPEX	0.002	-	0.1741	0.002	-	0.1741	0.002	-	0.1741
Utility Admin	-	-0.0019	-	-	-0.0020	-	-	-0.0020	-
Environmental Externality	0.066	-0.0094	0.1875	0.053	-	0.1399	0.058	-	0.1315

D.2 Residential and Commercial Solar PV

Table 3. Average Annual Avoided Cost Value for Residential South-Facing Solar PV Array Installed in 2024 ($/kWh) (2024$)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.065	0.062	0.058	0.041	0.038	0.038	0.038	0.038	0.037	0.037	0.037	0.040
Transmission Charges	0.042	0.044	0.047	0.045	0.048	0.052	0.055	0.058	0.049	0.041	0.044	0.043
Distribution Capacity	0.022	0.022	0.023	0.023	0.023	0.023	0.022	0.022	0.021	0.021	0.021	0.021
Capacity	0.018	0.019	0.018	0.023	0.023	0.023	0.026	0.026	0.026	0.027	0.030	0.026
Distribution Line Losses	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
RPS	0.003	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002
Transmission 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
Risk Premium	0.011	0.009	0.007	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006
Ancillary Services	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
DRIPE	0.008	0.008	0.007	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
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
Environmental Externality	0.057	0.054	0.048	0.044	0.039	0.038	0.036	0.036	0.036	0.037	0.038	0.041
Total – Excluding Environmental	0.185	0.183	0.178	0.161	0.161	0.164	0.169	0.172	0.161	0.155	0.161	0.157
Total – Including Environmental	0.242	0.237	0.225	0.205	0.200	0.203	0.205	0.207	0.197	0.192	0.199	0.198

Table 4. Average Annual Avoided Cost Value for Residential West-Facing Solar PV Array Installed in 2024 ($/kWh) (2024$)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.066	0.064	0.059	0.042	0.040	0.039	0.039	0.039	0.039	0.039	0.039	0.041
Transmission Charges	0.047	0.049	0.052	0.048	0.051	0.054	0.057	0.061	0.050	0.046	0.049	0.051
Distribution Capacity	0.025	0.024	0.025	0.025	0.025	0.025	0.024	0.024	0.023	0.023	0.023	0.023
Capacity	0.020	0.021	0.020	0.025	0.025	0.026	0.028	0.029	0.029	0.030	0.033	0.028
Distribution Line Losses	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.006	0.005
RPS	0.003	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002
Transmission Line Losses	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Risk Premium	0.011	0.009	0.008	0.007	0.006	0.006	0.007	0.007	0.007	0.007	0.007	0.007
Ancillary Services	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
DRIPE	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.007	0.007	0.007	0.007	0.007
Distribution OPEX	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006
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
Environmental Externality	0.057	0.055	0.049	0.046	0.042	0.041	0.038	0.038	0.039	0.040	0.040	0.043
Total – Excluding Environmental	0.196	0.195	0.191	0.172	0.172	0.175	0.181	0.184	0.171	0.169	0.175	0.174
Total – Including Environmental	0.253	0.250	0.240	0.218	0.214	0.216	0.219	0.222	0.210	0.208	0.216	0.217

Table 5. Average Annual Avoided Cost Value for Commercial South-Facing Solar PV Array Installed in 2024 ($/kWh) (2024$)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.065	0.062	0.058	0.041	0.038	0.038	0.038	0.038	0.037	0.037	0.037	0.040
Transmission Charges	0.042	0.044	0.047	0.045	0.048	0.052	0.055	0.058	0.049	0.041	0.044	0.043
Distribution Capacity	0.022	0.022	0.023	0.023	0.023	0.023	0.022	0.022	0.021	0.021	0.021	0.021
Capacity	0.018	0.019	0.018	0.023	0.023	0.023	0.026	0.026	0.026	0.027	0.030	0.026
Distribution Line Losses	0.003	0.004	0.003	0.004	0.003	0.004	0.004	0.004	0.004	0.004	0.004	0.004
RPS	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001
Transmission 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
Risk Premium	0.011	0.009	0.007	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006
Ancillary Services	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
DRIPE	0.008	0.008	0.007	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
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
Environmental Externality	0.057	0.054	0.048	0.044	0.039	0.038	0.036	0.036	0.036	0.037	0.038	0.041
Total – No Environmental	0.182	0.180	0.175	0.159	0.159	0.162	0.167	0.170	0.159	0.153	0.159	0.155
Total – Including Environmental	0.239	0.234	0.223	0.203	0.198	0.201	0.203	0.205	0.195	0.190	0.197	0.196

Table 6. Average Annual Avoided Cost Value for Commercial West-Facing Solar PV Array Installed in 2024 ($/kWh) (2024$)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.066	0.064	0.059	0.042	0.040	0.039	0.039	0.039	0.039	0.039	0.039	0.041
Transmission Charges	0.047	0.049	0.052	0.048	0.051	0.054	0.057	0.061	0.050	0.046	0.049	0.051
Distribution Capacity	0.025	0.024	0.025	0.025	0.025	0.025	0.024	0.024	0.023	0.023	0.023	0.023
Capacity	0.020	0.021	0.020	0.025	0.025	0.026	0.028	0.029	0.029	0.030	0.033	0.028
Distribution Line Losses	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	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001
Transmission Line Losses	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Risk Premium	0.011	0.009	0.008	0.007	0.006	0.006	0.007	0.007	0.006	0.007	0.007	0.007
Ancillary Services	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
DRIPE	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.007	0.007	0.007	0.007	0.007
Distribution OPEX	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006
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
Environmental Externality	0.057	0.055	0.049	0.046	0.042	0.041	0.038	0.038	0.039	0.040	0.040	0.043
Total – No Environmental	0.193	0.192	0.188	0.170	0.170	0.173	0.179	0.181	0.169	0.167	0.173	0.172
Total – Including Environmental	0.250	0.247	0.237	0.216	0.211	0.214	0.217	0.220	0.208	0.206	0.214	0.215

Table 7. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Installed in 2024 – Spring ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Spring	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.045	-	0.003	0.117	0.103	0.025	-	0.002	0.035	0.026
	7	0.047	-	0.003	0.096	0.081	0.029	-	0.002	0.051	0.042
	8	0.058	-	0.004	0.068	0.051	0.033	-	0.002	0.044	0.034
	9	0.060	-	0.004	0.066	0.049	0.031	-	0.002	0.037	0.028
	10	0.059	-	0.004	0.061	0.045	0.025	-	0.002	0.025	0.017
	11	0.057	-	0.004	0.055	0.039	0.022	-	0.002	0.022	0.014
	12	0.057	-	0.004	0.057	0.041	0.023	-	0.002	0.026	0.018
	13	0.057	-	0.004	0.056	0.040	0.023	-	0.002	0.027	0.019
	14	0.058	-	0.223	0.057	0.041	0.023	-	0.002	0.027	0.019
	15	0.059	-	0.004	0.059	0.043	0.024	-	0.002	0.025	0.016
	16	0.061	-	0.004	0.068	0.051	0.030	-	0.002	0.035	0.025
	17	0.064	-	0.004	0.081	0.063	0.041	-	0.003	0.067	0.055
	18	0.064	-	0.004	0.082	0.063	0.048	-	0.003	0.086	0.072
	19	0.061	-	0.077	0.072	0.054	0.051	-	0.004	0.089	0.075
	20	0.055	-	0.004	0.062	0.044	0.049	-	0.003	0.093	0.079
	21	0.054	-	0.004	0.051	0.033	0.049	-	1.361	0.093	0.078
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

Table 8. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Installed in 2024 – Summer ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Summer	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.047	-	0.003	0.116	0.103	0.032	-	0.002	0.061	0.053
	7	0.048	-	0.003	0.096	0.082	0.038	-	0.003	0.071	0.061
	8	0.055	-	0.004	0.085	0.069	0.042	-	0.003	0.064	0.053
	9	0.055	-	0.004	0.080	0.064	0.042	-	0.003	0.064	0.053
	10	0.055	-	0.006	0.078	0.063	0.040	-	0.006	0.058	0.048
	11	0.055	-	0.051	0.077	0.061	0.038	-	0.050	0.054	0.044
	12	0.056	-	0.073	0.078	0.062	0.039	-	0.071	0.056	0.046
	13	0.056	-	0.086	0.077	0.061	0.041	-	0.084	0.059	0.049
	14	0.056	-	0.355	0.078	0.062	0.042	-	0.612	0.063	0.053
	15	0.057	0.433	0.675	0.183	0.064	0.042	0.663	0.233	0.071	0.052
	16	0.058	-	0.124	0.080	0.063	0.046	-	0.122	0.071	0.059
	17	0.059	-	0.121	0.074	0.057	0.055	-	1.098	0.198	0.070
	18	0.060	-	0.095	0.062	0.044	0.063	-	0.094	0.089	0.073
	19	0.060	-	0.067	0.058	0.040	0.071	-	0.067	0.087	0.070
	20	0.059	-	0.012	0.064	0.046	0.066	-	0.012	0.089	0.073
	21	0.058	-	0.004	0.063	0.046	0.059	-	0.004	0.088	0.073
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

Table 9. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Installed in 2024 – Fall ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Fall	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	0.049	-	0.003	0.087	0.072	0.044	-	0.003	0.081	0.070
	8	0.060	-	0.004	0.085	0.066	0.051	-	0.004	0.079	0.065
	9	0.060	-	0.004	0.083	0.064	0.050	-	0.004	0.072	0.058
	10	0.059	-	0.004	0.083	0.065	0.043	-	0.003	0.059	0.046
	11	0.058	-	0.004	0.081	0.063	0.042	-	0.003	0.056	0.044
	12	0.058	-	0.004	0.080	0.063	0.043	-	0.003	0.059	0.047
	13	0.058	-	0.004	0.079	0.062	0.044	-	0.003	0.064	0.051
	14	0.057	-	0.004	0.080	0.062	0.045	-	0.003	0.069	0.056
	15	0.056	-	0.004	0.081	0.064	0.044	-	0.003	0.067	0.054
	16	0.055	-	0.004	0.079	0.062	0.048	-	0.003	0.081	0.067
	17	0.054	-	0.466	0.071	0.054	0.051	-	0.004	0.094	0.080
	18	0.053	-	0.007	0.055	0.038	0.052	-	0.003	0.095	0.081
	19	0.053	-	0.003	0.053	0.038	0.052	-	0.003	0.096	0.083
	20	0.053	-	0.003	0.047	0.031	0.051	-	1.505	0.096	0.083
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

Table 10. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Installed in 2024 – Winter($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Winter	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	0.116	-	0.007	0.093	0.063	0.078	-	0.005	0.086	0.067
	8	0.123	-	0.008	0.104	0.071	0.085	-	0.006	0.089	0.067
	9	0.121	-	0.008	0.102	0.069	0.085	-	0.006	0.086	0.063
	10	0.119	-	0.008	0.098	0.066	0.071	-	0.005	0.067	0.048
	11	0.117	-	0.008	0.095	0.064	0.067	-	0.005	0.061	0.042
	12	0.117	-	0.008	0.095	0.063	0.066	-	0.005	0.062	0.043
	13	0.117	-	0.008	0.095	0.064	0.065	-	0.005	0.061	0.042
	14	0.118	-	0.008	0.096	0.064	0.067	-	0.005	0.063	0.044
	15	0.119	-	0.008	0.098	0.065	0.068	-	0.005	0.062	0.042
	16	0.122	-	0.008	0.102	0.067	0.078	-	0.006	0.077	0.055
	17	0.126	-	0.008	0.102	0.068	0.094	-	0.007	0.100	0.076
	18	0.127	-	0.008	0.106	0.073	0.099	-	0.007	0.104	0.080
	19	-	-	-	-	-	-	-	-	-	-
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

D.3 Residential and Commercial Solar PV Paired with Storage

Table 11. Average Annual Avoided Cost Value for Residential South-Facing Solar PV Array Paired with Storage Installed in 2024 ($/kWh) (2024$)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.067	0.066	0.063	0.045	0.045	0.045	0.046	0.046	0.046	0.046	0.047	0.049
Transmission Charges	0.075	0.085	0.091	0.092	0.098	0.104	0.111	0.118	0.120	0.126	0.134	0.149
Distribution Capacity	0.023	0.022	0.023	0.023	0.023	0.023	0.022	0.022	0.021	0.021	0.021	0.021
Capacity	0.019	0.020	0.020	0.025	0.024	0.025	0.027	0.028	0.028	0.029	0.032	0.027
Distribution Line Losses	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.006	0.006	0.006	0.006	0.006
RPS	0.003	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002
Transmission Line Losses	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.003	0.003	0.003	0.003	0.003
Risk Premium	0.011	0.009	0.008	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.008	0.008
Ancillary Services	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
DRIPE	0.009	0.009	0.008	0.008	0.008	0.008	0.008	0.009	0.010	0.010	0.010	0.010
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
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
Environmental Externality	0.055	0.058	0.057	0.053	0.052	0.052	0.048	0.050	0.050	0.051	0.052	0.053
Total – Excluding Environmental	0.222	0.231	0.230	0.216	0.221	0.228	0.238	0.248	0.249	0.257	0.269	0.281
Total – Including Environmental	0.277	0.289	0.287	0.270	0.273	0.281	0.286	0.297	0.299	0.307	0.321	0.334

Table 12. Average Annual Avoided Cost Value for Commercial South-Facing Solar PV Array Paired with Storage Installed in 2024 ($/kWh) (2024$)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.067	0.065	0.062	0.045	0.044	0.044	0.045	0.045	0.045	0.045	0.045	0.048
Transmission Charges	0.070	0.079	0.084	0.085	0.090	0.096	0.102	0.109	0.109	0.113	0.121	0.133
Distribution Capacity	0.023	0.022	0.023	0.023	0.023	0.023	0.022	0.022	0.021	0.021	0.021	0.021
Capacity	0.019	0.020	0.020	0.024	0.024	0.025	0.027	0.028	0.027	0.029	0.032	0.027
Distribution Line Losses	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	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001
Transmission Line Losses	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.003	0.003	0.003
Risk Premium	0.011	0.009	0.008	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
Ancillary Services	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
DRIPE	0.009	0.009	0.008	0.008	0.008	0.008	0.008	0.009	0.009	0.009	0.009	0.009
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
Utility Admin	0.000	0.000	0.000	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001
Environmental Externality	0.056	0.058	0.055	0.052	0.050	0.050	0.047	0.048	0.048	0.049	0.050	0.051
Total – Excluding Environmental	0.214	0.221	0.220	0.206	0.210	0.217	0.226	0.234	0.234	0.240	0.251	0.260
Total – Including Environmental	0.269	0.279	0.275	0.258	0.260	0.267	0.272	0.282	0.282	0.288	0.301	0.312

Table 13. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Paired with Storage Installed in 2024 - Spring ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Spring	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.045	-	0.003	0.117	0.103	0.025	-	0.002	0.035	0.026
	7	0.047	-	0.003	0.096	0.081	0.029	-	0.002	0.051	0.042
	8	0.058	-	0.004	0.068	0.051	0.033	-	0.002	0.044	0.034
	9	0.060	-	0.004	0.066	0.049	0.031	-	0.002	0.037	0.028
	10	0.059	-	0.004	0.061	0.045	0.025	-	0.002	0.025	0.017
	11	0.056	-	0.004	0.056	0.040	0.022	-	0.002	0.022	0.015
	12	0.057	-	0.004	0.057	0.042	0.023	-	0.002	0.026	0.019
	13	0.057	-	0.004	0.056	0.040	0.023	-	0.002	0.028	0.020
	14	0.058	-	0.227	0.057	0.041	0.023	-	0.002	0.027	0.019
	15	0.059	-	0.004	0.059	0.043	0.024	-	0.002	0.025	0.016
	16	0.061	-	0.004	0.068	0.051	0.030	-	0.002	0.035	0.025
	17	0.064	-	0.004	0.081	0.063	0.041	-	0.003	0.067	0.055
	18	0.067	-	0.004	0.084	0.064	0.050	-	0.003	0.085	0.071
	19	0.068	-	0.202	0.080	0.060	0.056	-	0.004	0.086	0.070
	20	0.068	-	0.004	0.077	0.058	0.057	-	0.451	0.086	0.071
	21	0.069	-	0.221	0.075	0.055	0.057	-	0.919	0.089	0.073
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

Table 14. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Paired with Storage Installed in 2024 - Summer ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Summer	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.047	-	0.003	0.116	0.103	0.032	-	0.002	0.061	0.053
	7	0.048	-	0.003	0.096	0.082	0.038	-	0.003	0.071	0.061
	8	0.055	-	0.004	0.085	0.069	0.042	-	0.003	0.064	0.053
	9	0.055	-	0.004	0.080	0.064	0.042	-	0.003	0.064	0.053
	10	0.055	-	0.006	0.078	0.063	0.040	-	0.006	0.058	0.048
	11	0.055	-	0.051	0.077	0.061	0.038	-	0.049	0.053	0.044
	12	0.056	-	0.073	0.078	0.062	0.039	-	0.071	0.057	0.046
	13	0.056	-	0.088	0.077	0.061	0.041	-	0.085	0.060	0.049
	14	0.056	-	0.358	0.078	0.062	0.042	-	0.618	0.063	0.053
	15	0.057	0.433	0.675	0.183	0.064	0.042	0.663	0.233	0.071	0.052
	16	0.058	-	0.124	0.080	0.063	0.046	-	0.122	0.071	0.059
	17	0.059	-	0.122	0.074	0.057	0.055	-	1.106	0.201	0.070
	18	0.060	-	0.098	0.062	0.044	0.064	-	0.097	0.089	0.073
	19	0.060	-	0.072	0.058	0.040	0.072	-	0.072	0.088	0.070
	20	0.060	-	0.020	0.064	0.046	0.069	-	0.021	0.091	0.073
	21	0.058	-	0.004	0.063	0.046	0.059	-	0.004	0.088	0.073
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

Table 15. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Paired with Storage Installed in 2024 - Fall ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Fall	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	0.049	-	0.003	0.087	0.072	0.044	-	0.003	0.081	0.070
	8	0.060	-	0.004	0.085	0.066	0.051	-	0.004	0.079	0.065
	9	0.060	-	0.004	0.083	0.064	0.050	-	0.004	0.072	0.058
	10	0.059	-	0.004	0.083	0.065	0.043	-	0.003	0.059	0.046
	11	0.046	-	0.003	0.071	0.059	0.029	-	0.002	0.040	0.033
	12	0.052	-	0.003	0.077	0.062	0.036	-	0.003	0.050	0.040
	13	0.051	-	0.003	0.077	0.062	0.037	-	0.003	0.056	0.046
	14	0.045	-	0.003	0.073	0.061	0.032	-	0.002	0.057	0.049
	15	0.056	-	0.004	0.081	0.064	0.044	-	0.003	0.067	0.054
	16	0.055	-	0.004	0.079	0.062	0.048	-	0.003	0.081	0.067
	17	0.053	-	0.578	0.069	0.053	0.051	-	0.003	0.094	0.080
	18	0.061	-	0.211	0.061	0.041	0.059	-	0.004	0.093	0.076
	19	0.062	-	0.004	0.056	0.036	0.060	-	0.488	0.093	0.076
	20	0.062	-	0.238	0.060	0.040	0.060	-	0.994	0.095	0.077
	21	0.066	-	0.005	0.078	0.056	0.063	-	0.005	0.097	0.078
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

Table 16. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Paired with Storage Installed in 2024 - Winter($/kWh) (2024$)

			2024					2035				
Season		Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Winter		1	-	-	-	-	-	-	-	-	-	-
		2	-	-	-	-	-	-	-	-	-	-
		3	-	-	-	-	-	-	-	-	-	-
		4	-	-	-	-	-	-	-	-	-	-
		5	-	-	-	-	-	-	-	-	-	-
		6	-	-	-	-	-	-	-	-	-	-
		7	0.116	-	0.007	0.093	0.063	0.078	-	0.005	0.086	0.067
		8	0.123	-	0.008	0.104	0.071	0.085	-	0.006	0.089	0.067
		9	0.121	-	0.008	0.102	0.069	0.085	-	0.006	0.086	0.063
		10	0.119	-	0.008	0.098	0.066	0.071	-	0.005	0.067	0.048
		11	0.116	-	0.008	0.098	0.066	0.074	-	0.005	0.071	0.050
		12	0.113	-	0.007	0.102	0.069	0.084	-	0.006	0.085	0.062
		13	0.113	-	0.007	0.100	0.067	0.085	-	0.006	0.087	0.063
		14	0.115	-	0.008	0.098	0.066	0.079	-	0.006	0.081	0.058
		15	0.119	-	0.008	0.098	0.065	0.068	-	0.005	0.062	0.042
		16	0.122	-	0.008	0.102	0.067	0.078	-	0.006	0.077	0.055
		17	0.126	-	0.008	0.102	0.068	0.094	-	0.007	0.100	0.076
		18	0.124	-	0.229	0.095	0.060	0.107	-	0.007	0.105	0.077
		19	0.124	-	0.466	0.095	0.059	0.108	-	1.443	0.107	0.078
		20	0.123	-	0.008	0.101	0.065	0.107	-	0.007	0.109	0.080
		21	0.123	-	0.008	0.105	0.070	0.105	-	0.007	0.111	0.082
		22	-	-	-	-	-	-	-	-	-	-
		23	-	-	-	-	-	-	-	-	-	-
		24	-	-	-	-	-	-	-	-	-	-

D.4 Large Group Host Commercial Solar PV

Table 17. Average Annual Avoided Cost Value for Large Group Host Commercial Solar PV Array Installed in 2024 ($/kWh) (2024$)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.070	0.067	0.063	0.045	0.042	0.041	0.042	0.041	0.040	0.041	0.040	0.043
Transmission Charges	0.028	0.030	0.031	0.029	0.031	0.033	0.035	0.037	0.031	0.027	0.029	0.030
Distribution Capacity	0.015	0.015	0.016	0.016	0.016	0.016	0.015	0.015	0.015	0.015	0.014	0.014
Capacity	0.012	0.013	0.013	0.016	0.016	0.016	0.018	0.018	0.018	0.019	0.021	0.018
Distribution Line Losses	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
RPS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Transmission Line Losses	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Risk Premium	0.010	0.008	0.007	0.006	0.005	0.005	0.005	0.005	0.005	0.005	0.006	0.006
Ancillary Services	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
DRIPE	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.006	0.006	0.006	0.006	0.007
Distribution OPEX	0.004	0.004	0.004	0.004	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
Environmental Externality	0.059	0.056	0.050	0.046	0.041	0.041	0.038	0.038	0.038	0.039	0.040	0.043
Total – Excluding Environmental	0.152	0.149	0.144	0.124	0.123	0.125	0.128	0.129	0.122	0.120	0.123	0.124
Total – Including Environmental	0.211	0.205	0.194	0.170	0.164	0.165	0.166	0.167	0.160	0.159	0.163	0.166

Table 18. Average Hourly Seasonal Avoided Cost Values for Large Group Host Commercial Solar PV Array Installed in 2024 – Spring ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Spring	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	0.045	-	0.001	0.108	0.097	0.026	-	0.001	0.037	0.030
	6	0.044	-	0.001	0.095	0.084	0.024	-	0.001	0.029	0.022
	7	0.055	-	0.001	0.086	0.073	0.032	-	0.001	0.048	0.040
	8	0.063	-	0.002	0.065	0.051	0.035	-	0.001	0.042	0.034
	9	0.062	-	0.002	0.062	0.049	0.032	-	0.001	0.035	0.028
	10	0.060	-	0.002	0.057	0.044	0.025	-	0.001	0.023	0.017
	11	0.058	-	0.002	0.050	0.038	0.022	-	0.001	0.019	0.014
	12	0.058	-	0.002	0.053	0.041	0.023	-	0.001	0.023	0.018
	13	0.058	-	0.002	0.052	0.039	0.023	-	0.001	0.024	0.019
	14	0.058	-	0.218	0.054	0.041	0.024	-	0.001	0.024	0.019
	15	0.059	-	0.002	0.056	0.042	0.024	-	0.001	0.022	0.016
	16	0.061	-	0.002	0.064	0.050	0.030	-	0.001	0.032	0.025
	17	0.065	-	0.002	0.078	0.063	0.042	-	0.001	0.065	0.055
	18	0.064	-	0.002	0.078	0.063	0.048	-	0.001	0.083	0.072
	19	0.055	-	0.001	0.060	0.047	0.048	-	0.001	0.093	0.081
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

Table 19. Average Hourly Seasonal Avoided Cost Values for Large Group Host Commercial Solar PV Array Installed in 2024 – Summer ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Summer	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	0.046	-	0.001	0.107	0.098	0.030	-	0.001	0.048	0.042
	6	0.048	-	0.001	0.119	0.109	0.038	-	0.001	0.076	0.069
	7	0.049	-	0.001	0.096	0.085	0.040	-	0.001	0.074	0.066
	8	0.055	-	0.001	0.082	0.069	0.044	-	0.001	0.064	0.054
	9	0.055	-	0.001	0.077	0.065	0.043	-	0.001	0.063	0.054
	10	0.055	-	0.004	0.075	0.063	0.041	-	0.004	0.057	0.049
	11	0.055	-	0.051	0.073	0.061	0.038	-	0.049	0.052	0.044
	12	0.056	-	0.071	0.074	0.062	0.040	-	0.070	0.054	0.047
	13	0.056	-	0.088	0.073	0.061	0.041	-	0.086	0.057	0.049
	14	0.056	-	0.358	0.075	0.063	0.042	-	0.618	0.061	0.053
	15	0.057	0.458	0.609	0.179	0.064	0.043	0.700	0.163	0.063	0.053
	16	0.058	-	0.130	0.077	0.064	0.047	-	0.127	0.070	0.061
	17	0.059	-	0.121	0.071	0.057	0.055	-	1.095	0.202	0.071
	18	0.060	-	0.101	0.057	0.043	0.065	-	0.099	0.087	0.073
	19	0.060	-	0.058	0.054	0.040	0.069	-	0.057	0.084	0.069
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

Table 20. Average Hourly Seasonal Avoided Cost Values for Large Group Host Commercial Solar PV Array Installed in 2024 – Fall ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Fall	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.044	-	0.001	0.092	0.082	0.036	-	0.001	0.071	0.065
	7	0.045	-	0.001	0.082	0.071	0.041	-	0.001	0.079	0.070
	8	0.058	-	0.002	0.080	0.065	0.049	-	0.001	0.076	0.065
	9	0.059	-	0.002	0.079	0.064	0.049	-	0.001	0.068	0.057
	10	0.058	-	0.002	0.080	0.066	0.042	-	0.001	0.055	0.045
	11	0.059	-	0.002	0.078	0.064	0.043	-	0.001	0.055	0.045
	12	0.058	-	0.002	0.077	0.063	0.043	-	0.001	0.057	0.047
	13	0.059	-	0.002	0.076	0.062	0.046	-	0.001	0.063	0.052
	14	0.059	-	0.002	0.077	0.063	0.047	-	0.001	0.068	0.057
	15	0.058	-	0.002	0.078	0.064	0.046	-	0.001	0.066	0.055
	16	0.059	-	0.002	0.078	0.063	0.051	-	0.001	0.080	0.068
	17	0.053	-	0.456	0.067	0.054	0.051	-	0.001	0.092	0.080
	18	0.053	-	0.001	0.051	0.039	0.051	-	0.001	0.093	0.082
	19	-	-	-	-	-	-	-	-	-	-
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

Table 21. Average Hourly Seasonal Avoided Cost Values for Large Group Host Commercial Solar PV Array Installed in 2024 – Winter ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Winter	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	-	-	-	-	-	-	-	-	-	-
	8	0.123	-	0.003	0.101	0.070	0.085	-	0.002	0.087	0.067
	9	0.121	-	0.003	0.099	0.069	0.085	-	0.002	0.084	0.064
	10	0.119	-	0.003	0.094	0.066	0.070	-	0.002	0.064	0.047
	11	0.118	-	0.003	0.091	0.064	0.066	-	0.002	0.057	0.041
	12	0.117	-	0.003	0.091	0.063	0.066	-	0.002	0.059	0.043
	13	0.117	-	0.003	0.092	0.064	0.065	-	0.002	0.058	0.042
	14	0.118	-	0.003	0.093	0.064	0.067	-	0.002	0.061	0.045
	15	0.118	-	0.003	0.094	0.065	0.071	-	0.002	0.064	0.046
	16	0.121	-	0.003	0.099	0.068	0.083	-	0.002	0.081	0.059
	17	0.126	-	0.003	0.099	0.068	0.094	-	0.003	0.097	0.075
	18	-	-	-	-	-	-	-	-	-	-
	19	-	-	-	-	-	-	-	-	-	-
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

D.5 Micro Hydro

Table 22. Average Annual Avoided Cost Value for Micro Hydro System ($/kWh) (2024$)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.076	0.075	0.072	0.052	0.051	0.051	0.051	0.052	0.052	0.051	0.051	0.053
Transmission Charges	0.042	0.045	0.048	0.051	0.055	0.058	0.062	0.066	0.072	0.077	0.082	0.088
Distribution Capacity	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.007	0.007	0.007
Capacity	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	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
RPS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Transmission Line Losses	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Risk Premium	0.010	0.008	0.007	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Ancillary Services	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
DRIPE	0.007	0.007	0.007	0.006	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
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
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
Environmental Externality	0.060	0.061	0.060	0.055	0.053	0.054	0.048	0.050	0.052	0.050	0.052	0.053
Total – Excluding Environmental	0.154	0.154	0.152	0.133	0.135	0.139	0.143	0.148	0.154	0.159	0.164	0.171
Total – Including Environmental	0.214	0.215	0.212	0.187	0.188	0.193	0.191	0.198	0.205	0.209	0.216	0.225

Table 23. Average Hourly Seasonal Avoided Cost Values for Micro Hydro System – Spring ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Spring	1	0.055	-	0.001	0.080	0.067	0.032	-	0.001	0.049	0.041
	2	0.053	-	0.001	0.080	0.068	0.032	-	0.001	0.048	0.040
	3	0.053	-	0.001	0.082	0.069	0.029	-	0.001	0.039	0.032
	4	0.052	-	0.001	0.082	0.070	0.029	-	0.001	0.036	0.029
	5	0.054	-	0.001	0.083	0.070	0.027	-	0.001	0.028	0.021
	6	0.055	-	0.001	0.086	0.074	0.028	-	0.001	0.031	0.024
	7	0.058	-	0.002	0.083	0.070	0.034	-	0.001	0.048	0.039
	8	0.063	-	0.002	0.064	0.050	0.034	-	0.001	0.041	0.033
	9	0.062	-	0.002	0.061	0.047	0.031	-	0.001	0.034	0.027
	10	0.058	-	0.002	0.055	0.043	0.025	-	0.001	0.022	0.016
	11	0.056	-	0.001	0.049	0.037	0.022	-	0.001	0.019	0.014
	12	0.056	-	0.001	0.052	0.040	0.023	-	0.001	0.023	0.018
	13	0.056	-	0.001	0.051	0.039	0.023	-	0.001	0.024	0.019
	14	0.056	-	0.220	0.052	0.040	0.023	-	0.001	0.024	0.018
	15	0.058	-	0.002	0.055	0.042	0.024	-	0.001	0.022	0.016
	16	0.060	-	0.002	0.063	0.049	0.029	-	0.001	0.032	0.024
	17	0.065	-	0.002	0.078	0.062	0.041	-	0.001	0.064	0.054
	18	0.068	-	0.002	0.081	0.065	0.050	-	0.001	0.082	0.071
	19	0.069	-	0.222	0.079	0.062	0.056	-	0.002	0.081	0.069
	20	0.069	-	0.002	0.075	0.059	0.057	-	0.441	0.083	0.070
	21	0.068	-	0.255	0.072	0.055	0.057	-	0.949	0.085	0.072
	22	0.067	-	0.002	0.077	0.061	0.053	-	0.001	0.089	0.077
	23	0.066	-	0.002	0.084	0.068	0.048	-	0.001	0.084	0.073
	24	0.057	-	0.002	0.084	0.070	0.041	-	0.001	0.073	0.064

Table 24. Average Hourly Seasonal Avoided Cost Values for Micro Hydro System – Summer ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Summer	1	0.048	-	0.001	0.077	0.067	0.039	-	0.001	0.067	0.060
	2	0.048	-	0.001	0.083	0.074	0.037	-	0.001	0.064	0.057
	3	0.047	-	0.001	0.098	0.088	0.035	-	0.001	0.058	0.052
	4	0.047	-	0.001	0.103	0.093	0.035	-	0.001	0.059	0.053
	5	0.047	-	0.001	0.113	0.103	0.035	-	0.001	0.062	0.055
	6	0.047	-	0.001	0.112	0.102	0.033	-	0.001	0.059	0.053
	7	0.048	-	0.001	0.091	0.081	0.037	-	0.001	0.066	0.058
	8	0.054	-	0.001	0.080	0.068	0.040	-	0.001	0.057	0.049
	9	0.055	-	0.001	0.076	0.064	0.041	-	0.001	0.059	0.051
	10	0.055	-	0.004	0.074	0.062	0.038	-	0.003	0.053	0.046
	11	0.055	-	0.042	0.072	0.061	0.037	-	0.041	0.049	0.042
	12	0.055	-	0.059	0.073	0.061	0.038	-	0.058	0.052	0.045
	13	0.056	-	0.072	0.072	0.061	0.040	-	0.071	0.055	0.048
	14	0.056	-	0.354	0.074	0.062	0.041	-	0.622	0.059	0.052
	15	0.056	0.334	0.590	0.150	0.063	0.041	0.511	0.143	0.060	0.050
	16	0.057	-	0.116	0.076	0.063	0.045	-	0.114	0.068	0.058
	17	0.059	-	0.114	0.071	0.057	0.054	-	1.053	0.175	0.070
	18	0.060	-	0.090	0.058	0.044	0.063	-	0.089	0.086	0.073
	19	0.060	-	0.063	0.055	0.040	0.070	-	0.062	0.085	0.070
	20	0.059	-	0.014	0.060	0.046	0.067	-	0.015	0.087	0.073
	21	0.059	-	0.023	0.060	0.046	0.064	-	0.023	0.088	0.074
	22	0.058	-	0.010	0.071	0.056	0.059	-	0.010	0.090	0.077
	23	0.057	-	0.002	0.080	0.067	0.052	-	0.001	0.089	0.079
	24	0.049	-	0.001	0.079	0.069	0.043	-	0.001	0.080	0.072

Table 25. Average Hourly Seasonal Avoided Cost Values for Micro Hydro System – Fall ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Fall	1	0.060	-	0.002	0.086	0.070	0.054	-	0.001	0.085	0.072
	2	0.058	-	0.002	0.096	0.080	0.053	-	0.001	0.085	0.072
	3	0.059	-	0.002	0.102	0.087	0.053	-	0.001	0.086	0.073
	4	0.058	-	0.002	0.106	0.091	0.052	-	0.001	0.087	0.075
	5	0.058	-	0.002	0.104	0.089	0.051	-	0.001	0.088	0.076
	6	0.056	-	0.002	0.085	0.070	0.050	-	0.001	0.083	0.071
	7	0.057	-	0.002	0.081	0.066	0.052	-	0.001	0.085	0.072
	8	0.064	-	0.002	0.082	0.065	0.056	-	0.002	0.082	0.068
	9	0.063	-	0.002	0.081	0.064	0.053	-	0.001	0.073	0.060
	10	0.062	-	0.002	0.082	0.066	0.047	-	0.001	0.062	0.050
	11	0.062	-	0.002	0.080	0.065	0.047	-	0.001	0.059	0.048
	12	0.062	-	0.002	0.079	0.063	0.047	-	0.001	0.063	0.051
	13	0.062	-	0.002	0.078	0.062	0.049	-	0.001	0.066	0.054
	14	0.063	-	0.002	0.079	0.063	0.051	-	0.001	0.071	0.059
	15	0.063	-	0.002	0.080	0.064	0.051	-	0.001	0.071	0.058
	16	0.062	-	0.002	0.080	0.063	0.055	-	0.002	0.082	0.069
	17	0.063	-	0.178	0.076	0.059	0.060	-	0.002	0.092	0.077
	18	0.065	-	0.302	0.060	0.043	0.062	-	0.002	0.089	0.074
	19	0.065	-	0.002	0.055	0.038	0.063	-	0.636	0.090	0.075
	20	0.064	-	0.239	0.060	0.043	0.062	-	0.858	0.092	0.076
	21	0.065	-	0.002	0.072	0.053	0.062	-	0.002	0.095	0.079
	22	0.066	-	0.002	0.082	0.064	0.062	-	0.002	0.096	0.079
	23	0.066	-	0.002	0.084	0.065	0.061	-	0.002	0.093	0.076
	24	0.060	-	0.002	0.083	0.067	0.056	-	0.002	0.090	0.076

Table 26. Average Hourly Seasonal Avoided Cost Values for Micro Hydro System – Winter ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Winter	1	0.111	-	0.003	0.095	0.067	0.078	-	0.002	0.083	0.064
	2	0.111	-	0.003	0.096	0.069	0.074	-	0.002	0.077	0.059
	3	0.111	-	0.003	0.097	0.070	0.071	-	0.002	0.072	0.054
	4	0.111	-	0.003	0.098	0.071	0.071	-	0.002	0.071	0.053
	5	0.111	-	0.003	0.098	0.071	0.070	-	0.002	0.068	0.050
	6	0.111	-	0.003	0.093	0.065	0.074	-	0.002	0.077	0.059
	7	0.112	-	0.003	0.092	0.063	0.083	-	0.002	0.089	0.069
	8	0.121	-	0.003	0.100	0.069	0.089	-	0.002	0.091	0.069
	9	0.120	-	0.003	0.098	0.068	0.086	-	0.002	0.086	0.065
	10	0.118	-	0.003	0.094	0.066	0.073	-	0.002	0.067	0.050
	11	0.117	-	0.003	0.092	0.064	0.068	-	0.002	0.060	0.044
	12	0.116	-	0.003	0.091	0.064	0.069	-	0.002	0.062	0.046
	13	0.116	-	0.003	0.092	0.064	0.068	-	0.002	0.061	0.045
	14	0.117	-	0.003	0.093	0.065	0.070	-	0.002	0.066	0.049
	15	0.117	-	0.003	0.094	0.065	0.073	-	0.002	0.067	0.049
	16	0.119	-	0.003	0.098	0.068	0.084	-	0.002	0.083	0.061
	17	0.122	-	0.003	0.097	0.066	0.100	-	0.003	0.101	0.076
	18	0.124	-	0.222	0.091	0.059	0.107	-	0.003	0.102	0.076
	19	0.124	-	0.460	0.091	0.059	0.108	-	1.438	0.104	0.078
	20	0.123	-	0.003	0.097	0.065	0.107	-	0.003	0.106	0.080
	21	0.123	-	0.003	0.101	0.070	0.105	-	0.003	0.108	0.082
	22	0.121	-	0.003	0.102	0.071	0.102	-	0.003	0.105	0.080
	23	0.120	-	0.003	0.102	0.070	0.097	-	0.003	0.101	0.076
	24	0.111	-	0.003	0.093	0.064	0.087	-	0.002	0.094	0.073

E. Stakeholder Questions and Response

E.1 Allocation of Distribution Avoided Costs

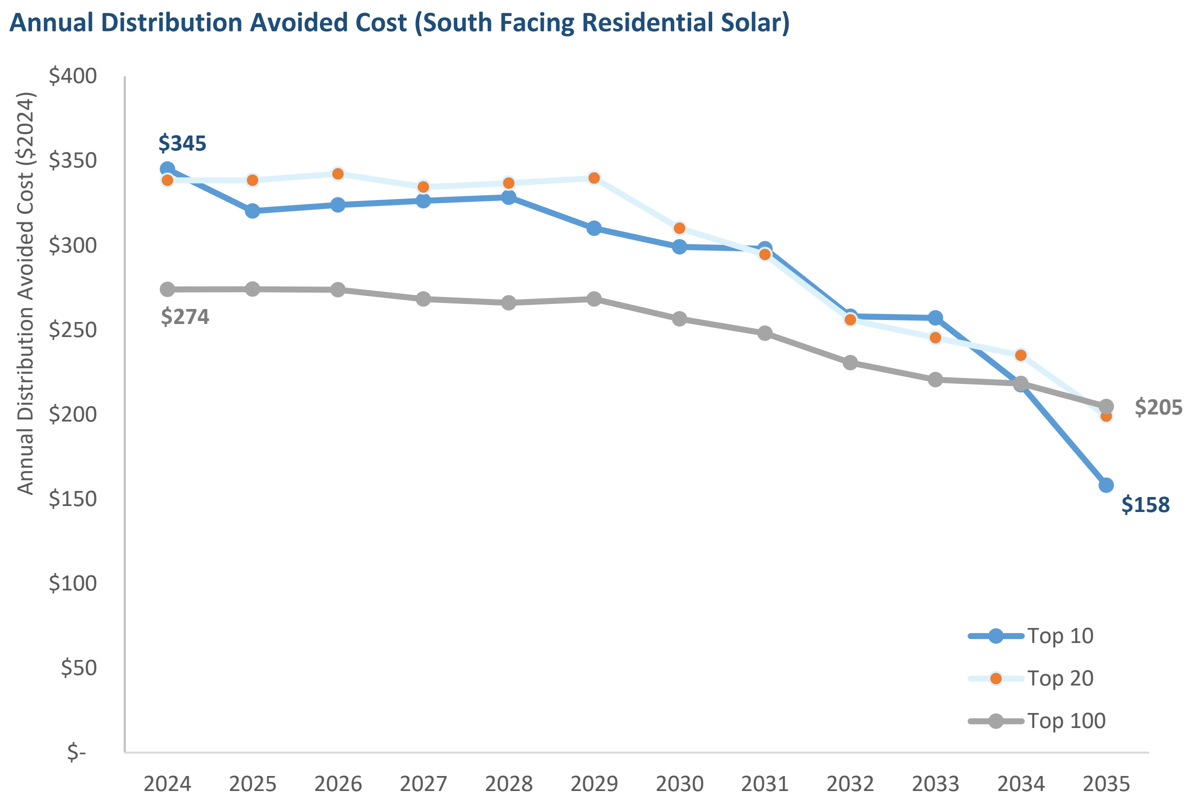
Stakeholder Question: Did Dunsky request hourly substation load data from the IOUs as an alternative to system load data? Dunsky could use a method such as the peak capacity allocation factor (PCAF) approach. This approach was used in The Alliance for Solar Choice (TASC) testimony DE 16-576. See Appendix D, pages D-6 to D-8 of the attached, for the details of that approach.

Dunsky Response:

- Dunsky did not request hourly substation load data from the IOUs as an alternative to system load data. As part of the VDER assessment, we focused on developing system-wide distribution avoided costs rather than substation-specific avoided costs. Distribution substations and circuits can peak at different times than the system, so we leveraged the LVDG study to estimate an average system-wide distribution avoided cost value.
- The approach laid out by TASC focuses on the avoided distribution costs from solar, and our goal was to develop tech-neutral avoided costs. However, we adopted a similar approach to the one described in DE 16-576 (Appendix D), wherein we proportionally allocated the distribution value across the top 100 hours. We recognize that it is challenging to predict the system peak hour; thus, by distributing the avoided distribution costs across the top 100 hours, we can approximate the avoided distribution costs from a DER.

The avoided Dist. Capacity and OPEX Costs ($/kW-year) are based on the LVDG study and utility data. However, the spread of the annual distribution avoided costs across specific hours in a given year will impact the value stack and the value captured by DG systems, as shown in the table below. The selection of the hours is based on the top load hours for the system.

Distribution Approach	Annual Distribution Avoided Cost $/kW-year ($2024)	Distribution Value Over Specific Hours ($/kWh) ($2024)	Key Characteristics
Top 10 Hours	$82 - $84	$8.2 - $8.4	In 2021, these hours occurred in Mid-August (HE 13 –17), and by 2035 the distribution hours could shift later into the evening (HE 14 –21).
Top 20 Hours	$82 - $84	$4.1 - $4.2	July-August (HE 13 –17), by 2035, shift later into the evening (HE 14 –21).
Top 100 Hours	$82 - $84	$0.82 - $0.84	Current Approach, all top 100 load hours occur in Summer.
Summer Top 20 Hours	$82 - $84	$4.1 - $4.2	Similar to the Top 20 hours.
Summer Targeted	$82 - $84	$0.82 - $0.84	Top 100 load hours occur in Summer.
Winter Top 20 Hours	$82 - $84	$4.1 - $4.2	Jan-Dec (HE 18-19), by 2035, shift later into the night (HE 19 – 20).
Winter Targeted	$82 - $84	-	None of the Top 100 load hours occur in Winter



In the VDER study, the distribution avoided costs were spread over the top 100 load hours in the year. Under this valuation method, the annual distribution value that a typical residential PV system can capture is about $234.

Spreading the distribution costs over fewer hours could lead to an increased distribution value for residential solar in the initial part of the study period. For example, reducing the number of distribution hours to 10 approximates a 25% increase in distribution value in 2024.

However, the distribution peak shift into the evening could decrease the distribution value across the study period. In 2035, the distribution value under the top 10 hours is about 23% lower than the current assumption of 100 hours. Therefore, spreading the distribution value over more hours (~100) results in greater certainty of annual distribution avoided cost, albeit at a lower value.

E.2 Treatment of Settlement-Only Generators

Stakeholder Question: Are capacity and energy revenues received by the utilities properly accounted for and deducted for any claimed “costs” of net metering, and was this revenue from small hydro group hosts considered and accounted for in the VDER study?

Dunsky Response:
As a part of the RBI assessment, Dunsky evaluated the incremental impact of customer-sited solar for residential, commercial, and large commercial customers on retail rates. In New Hampshire, customer-sited solar greater than 100 kW could enter the ISO-NE market as settlement-only generators (SOGs) and receive energy and capacity payments for the excess energy (not consumed behind the meter) exported to the grid. As of April, there were 20 net metered SOGs (3 Hydro, 17 Solar) with a maximum capacity of 10.9 MW (1.9 MW Hydro, 9.0 MW Solar).

Energy: When net-metered small-scale solar facilities generate energy, the utility receives wholesale energy revenue for that generation. However, the avoided energy is simply a pass-through component, meaning that it doesn't have any impact on rates. Even though the utility is compensated at the wholesale market, the lost revenue from energy generated by the DG will be equal to the avoided costs. This means that the SOG payment wouldn't affect rates, specifically this portion of it.

Capacity: The utility receives capacity payments for net metered SOGs, but the capacity payments are limited. Only a few net-metered Hydro facilities have Forward Capacity Auction (FCA) obligations and receive monthly payments. Most SOGs without FCA obligations only receive payments under the Pay-For-Performance structure for generation during scarcity events. Avoided capacity is not considered a passthrough component (in line with the Synapse NH RBI Energy Efficiency assessment); thus can impact rates. The current RBI assessment assumes that a utility's fixed cost for generation is the sum of avoided costs from Capacity and DRIPE. If the utility receives capacity payments, the fixed cost for generation should decrease, thereby reducing the upward impact on rates. However, few systems are bid into the ISO-NE as SOGs, so the impact should be minimal.

The RBI assessment assumes that the pre-DG rates include the impact of existing small hydro facilities and that no new facilities come online. Large group host community solar could impact the rates; however, the assessment excluded these assets from the analysis given the challenges associated with developing a robust market adoption of community solar.

Guidehouse

New Hampshire Locational Value of Distributed Generation Study

Final Report

Prepared for:

New Hampshire Public Utilities Commission

Submitted by:

Guidehouse Inc.
77 South Bedford Street | Suite 400 | Burlington, MA 01803

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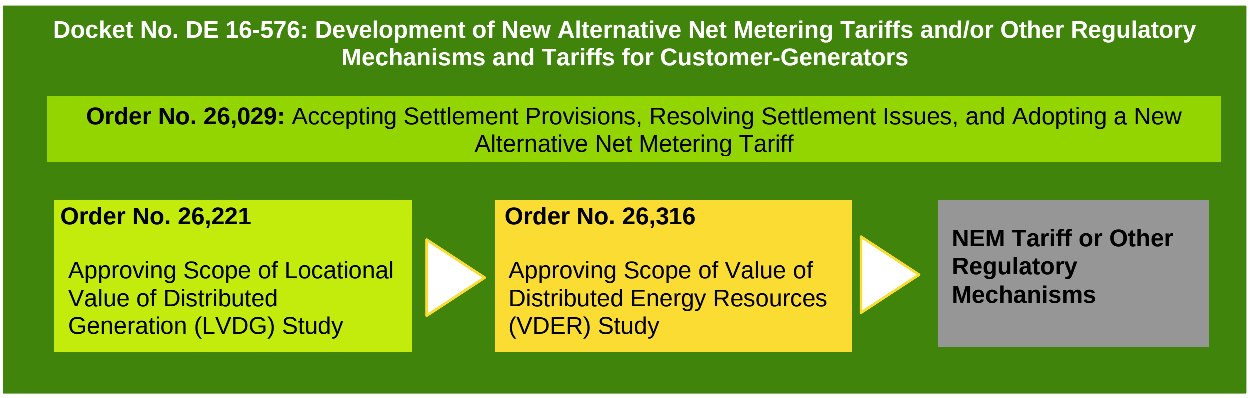
Table of Contents

Executive Summary

The New Hampshire Public Utilities Commission (the Commission) engaged Guidehouse to conduct a Locational Value of Distributed Generation (LVDG) study for electric distribution companies (EDCs) under its jurisdiction. The LVDG study falls under the Commission's ongoing net metering docket. In its February 2019 order,[1] the Commission approved the LVDG study scope and authorized the study to inform the development of future net energy metering (NEM) tariffs or other regulatory mechanisms in the state. This report presents the LVDG study methodology, parameters, assumptions, analysis, results, and conclusions.



Source: New Hampshire Public Utilities Commission

The study evaluates the distribution-level locational value of load reductions potentially achievable by distributed generation (DG) for New Hampshire's three regulated EDCs: Public Service Company of New Hampshire d/b/a Eversource Energy, Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities, and Unitil Energy Systems, Inc. The LVDG study analysis identifies and quantifies technology-neutral load reduction opportunities for each of the three regulated EDCs, relying heavily on data and information provided by the EDCs. Several meetings were held with LVDG stakeholders, the EDCs, and Commission Staff to review results as the study proceeded.

The study covers a timeframe of 5-years' historical, and 10-years' forward-looking, beginning in year 2020. Distribution system capacity constraints are analyzed under base, low, and high load growth scenarios. The study focuses on significant distribution system capacity deficiencies to be addressed through planned or potential capital investments, such as replacements or upgrades of substations or circuits. No minimum investment threshold level for the cost of upgrades is required for a location to be evaluated; however, small capital investments such as pole top distribution transformers and capacitors will be included in an upcoming separate system-wide Value of Distributed Energy Resources (VDER) study and are not covered in the LVDG study.

[1] NHPUC Docket No. DE 16-576, Order Approving Scope of Locational Value of Distributed Generation Study, Order No. 26,221 (February 20, 2019).

When evaluating load reductions to avoid capital investments, the study considers three specific NEM-eligible DG technologies: solar photovoltaic (PV), solar PV paired with energy storage, and hydroelectric generation, all with capacities rated up to one megawatt (MW).

The study methodology includes three steps:

- **Step 1:** Location Identification – Identify potential locations with expected capacity constraints requiring investments over the study timeframe, including base, low, and high load growth sensitivity analysis.
- **Step 2:** Estimation of Investment Costs for Avoidance – Determine the value of potential avoided capacity investments at the selected locations.
- **Step 3:** Economic Analysis and Mapping of DG Production Profiles with Distribution Capacity Needs – Perform economic analysis to estimate the benefit of capacity avoidance and map representative DG production profiles with distribution system capacity needs.

The Step 1 analysis reviews 696 locations and identifies 122 locations on the EDC distribution systems (i.e., circuits and substations) with capacity deficiencies, where capital investments potentially could be avoided through load reduction attributable to NEM-eligible DG. It should be noted that a transformer may have been reviewed at both the substation and circuit level, so the total locations reviewed may not equal the total quantity of equipment on an EDC's distribution system.

The study uses three load forecasts, base, low, and high, for each of the EDCs to complete a sensitivity analysis of the capacity deficiencies identified. The primary load growth forecast refers to what was developed and used by each EDC to identify planning criteria violations, referred to as the Base Case. The base, low, and high load growth forecasts varied among the three EDCs. Under the Base Case load growth scenario, 45 actual or potential capacity deficient locations were identified; 77 additional locations were identified under the high load growth scenario. Under the low load growth scenario, 26 locations would have capacity deficiencies during the study timeframe.

From the 122 locations identified, a subset was selected for detailed analysis. The subset of locations includes:

- Locations from each EDC's service territory and regions
- Future and historical projects, including circuits, and bulk and non-bulk substations
- Winter and summer peaking locations
- Midday and late-day peaking locations
- Locations with identified capacity deficiencies under various load growth forecasts
- Locations with small and large capacity deficiencies
- Locations with normal and contingency overloads or performance violations

- Locations where data was available to comprehensively analyze each site to determine the cost of traditional capacity solutions

The subset of locations selected for detailed analysis are listed in the table below.

EDC	Description	Region	Type of Investment	Load Growth Forecast Scenario	Historical or Future	First Year of Capacity Deficiency[2]
Eversource	Pemigewassett (Pemi)	Northern	Substation (Bulk)	Base	Future	2020
	Portsmouth	Eastern	Substation (Bulk)	Base	Future	2020
	South Milford	Southern	Substation (Bulk)	Base	Future	2020
	Monadnock	Western	Substation (Bulk)	Base	Future	2020
	East Northwood	Eastern	Substation (Non-Bulk)	High	Future	2021
	Rye	Eastern	Substation (Non-Bulk)	High	Future	2022
	Bristol	Northern	Substation (Non-Bulk)	Base	Historical	2015
	Madbury ROW	Eastern	Circuit (34.5 kV)	Base	Future	2020
	North Keene	Northern	Circuit (12.47 kV)	High	Future	2028
	Londonderry	Southern	Circuit (34.5 kV)	Base	Historical	prior to 2014
Liberty	Vilas Bridge	Walpole	Substation (Non-Bulk)	Base	Future	2020
	Mount Support	Lebanon	Substation (Bulk)	Base	Historical	2014
	Golden Rock	Salem	Substation (Bulk)	Base	Historical	2019
Unitil	Bow Bog	Capital	Substation (Non-Bulk)	High	Future	2024
	Dow's Hill	Seacoast	Substation (Bulk)	High	Future	2020
	Kingston	Seacoast	Substation (Bulk)	Base	Historical	prior to 2014

For each location, comprehensive data was analyzed to determine cost estimates for traditional utility investments designed to meet specific locational capacity needs. For each historical distribution capacity project, the study applies the assumptions, including EDC planning criteria that existed at the time the project was initially proposed or placed into service, to determine utility investment costs that might have been avoided. It should be noted that a number of the forward-looking locational capacity deficiencies and related investment costs are driven by a recent change in Eversource's system planning criteria.

Location	Year Considered	Revenue Requirement	Total Hours of Capacity Deficiency	Total Annual MWh of Capacity Deficiency	Maximum $/kW/hr	Relative $/kW/hr Value Ranking
Pemi Substation (Bulk)	2020	$9,074,650	326	509	$2.45	11
Portsmouth Substation (Bulk)	2020	$3,037,438	1,966	7,446	$0.04	16
South Milford Substation (Bulk)	2020	$15,976,924	6,696	41,928	$0.05	14
Monadnock Substation (Bulk)	2020	$17,374,146	15	10.53	$203.68	6
East Northwood Substation (Non-Bulk)	2021	$242,995	3	0.07	$256.77	5
Rye Substation (Non-Bulk)	2022	$3,644,926	2	0.10	$3,185.54	2
Bristol Substation (Non-Bulk)	2020	$1,457,970	5	0.43	$301.37	4
Madbury ROW Circuit (34.5 kV)	2020	$2,429,950	7	14	$17.03	8
North Keene Circuit (12.47 kV)	2028	$1,858,912	1	0.11	$1,128.25	3
Londonderry Circuit (34.5 kV)	2020	$747,210	467	115.81	$1.01	13
Vilas Bridge Substation (Non-Bulk)	2020	$2,715,803	909	247.68	$2.91	10
Mount Support Substation (Bulk)	2020	$7,557,017	1,329	21,484	$0.04	15
Golden Rock Substation (Bulk)	2020	$8,983,404	164	434	$3.14	9
Bow Bog Substation (Non-Bulk)	2026	$299,375	5	0.27	$128.17	7
Dow's Hill Substation (Bulk)	2022	$525,674	2	0.008	$4,483.12	1
Kingston Substation (Bulk)	2020	$14,371,184	203	789	$2.00	12

The study analyzes the potential value of capacity deficiency avoidance resulting from load reduction, including the time-differentiated value of avoiding traditional capacity investments on an hourly basis, using the Real Economic Carrying Charges (RECC) methodology. The RECC method creates a stream of annual values over the lifetime of an investment by calculating the total and annual revenue requirements. The revenue requirement in the first year the investment is needed increases annually at a fixed rate of inflation.

The time-differentiated revenue requirement is determined by spreading the first-year revenue requirement across the hours of locational capacity deficiency using a weighted average approach. Those hourly capacity avoidance values are determined on a technology-neutral basis, based on locational load reduction.

The study also evaluates the alignment of DG production profiles with capacity deficiency profiles for the three NEM-eligible DG technologies. For solar PV, the study develops a 24-hour average solar PV production profile using the National Renewable Energy Laboratory's (NREL) PVWatts Calculator and data. Solar paired with energy storage assumes the system stores excess energy during hours of production and discharges the energy during non-production hours of deficiency. The production profile for hydro represents a run-of-river hydro unit and is based on historical generation data.

The LVDG study findings and conclusions are summarized below:

- Out of 696 total potential locations, 122 distribution system substations or lines were identified as candidate locations for detailed analysis of capacity investment avoidance opportunities under base, low, and high load growth forecast scenarios. Of the 122 locations considered, 13 are historical and 109 are future, with 77 triggered only in the High Case during the study time horizon.
- The projected capacity deficiencies for the three EDCs beginning in 2020 total approximately 107 MW, increasing to 147 MW by 2029, under the base load forecast. Total capacity deficiencies in 2029 for the low load growth forecast are 63 MW and for the high load growth forecast are 317 MW. A substantial number of capacity deficiencies occur in 2020, the first year of the forward-looking period covered by the study, in large part due to recent changes in planning criteria implemented by Eversource.
- Of the 16 locations selected for detailed analysis, five are historical investments. Five of the 16 locations have first year capacity deficiencies that occur during both winter and summer months; the remaining 11 are summer peaking only.
- The cost of traditional distribution system investments to address capacity deficiencies at the selected locations, expressed in terms of a revenue requirement, ranges from less than $1 million to over $14 million. The total value of traditional capacity investments at the 16 selected locations is approximately $75 million.

- The economic value of capacity investment avoidance varies significantly among the 16 locations based on a theoretical analysis of capacity avoidance using the RECC approach. The maximum hourly economic value of capacity investment avoidance ranges from under $1 per kilowatt (kW) per hour to over $4,000 per kW per hour. The greatest driver for that variance is the total number of hours over which capacity deficiencies occur at a specific location. The lower value is generally indicative of a capacity deficiency that occurs over a large number of hours, while the higher value is generally indicative of a capacity deficiency that occurs during fewer hours.
- Related findings from the capacity deficiency analysis and evaluation of DG production profiles are summarized as follows:
  - The number of hours of capacity deficiency varies significantly by location, with some locations with fewer than 15 hours of deficiency per year, while other locations are capacity deficient for several thousand hours per year.
  - Most locations have capacity deficiencies during late afternoon or early evening hours. Solar PV production profiles do not fully align with those hours of capacity deficiency. Solar PV paired with energy storage typically can produce electricity during most or all hours during which there are locational capacity deficiencies.
  - Hydro production profiles typically align with hours of capacity deficiency, but with lower production during summer months as compared to winter months.

The study does not attempt to identify a specific solution or set of DG technologies that would meet the capacity needs at any selected location, nor to estimate the actual capacity of each DG technology that might be required at a given location to meet the specific capacity need. In this sense, the study does not attempt to perform a non-wires solution (NWS) analysis to meet the identified locational capacity need.

Potential avoided distribution system capacity costs related to power quality and lower distribution elements, such as distribution transformers and capacitors, will be considered on a system-wide level within the VDER study, and are not considered in this study. The LVDG study is not intended to determine a system-wide value of DG, but the results of this study are expected to be used in the VDER study.

The LVDG study results are not intended to predetermine future NEM tariff design or applicable rates, but rather to inform further NEM tariff development proceedings before the Commission. The study results and identification of locations and costs of potential avoided capacity investments may be relevant in a number of other contexts before the Commission, such as grid modernization, future utility rate cases, and future least cost integrated resource plans.

1.0 Introduction

The New Hampshire Public Utilities Commission (the Commission) engaged Guidehouse to conduct a Locational Value of Distributed Generation (LVDG) study for electric distribution utilities under its jurisdiction. The LVDG study falls under the Commission's ongoing net metering docket and its February 2019 order approving the LVDG study scope and authorizing the study, which (in conjunction with other studies and pilots) will inform the development of future net metering tariffs or other regulatory mechanisms in the state.[2] This report presents the LVDG study methodology, analysis details, results, and conclusions.

The required electrical capacity to reliably serve customer loads (i.e., capacity need) has historically been met using traditional utility transmission and distribution (T&D) investments (e.g., substations, circuits, poles, wires, transformers, etc.). Those traditional investments are determined using approved electric distribution company (EDC) system T&D planning criteria.

The LVDG study is based on a series of analytical steps to evaluate and estimate the locational value of potentially avoidable distribution system capacity upgrades at various locations. These analytical steps use the EDCs' planning criteria as well as their approaches to estimation of the costs of providing a traditional solution to meet identified capacity needs.

The LVDG study considers three DG technologies—solar photovoltaic (PV), solar PV paired with energy storage, and small hydroelectric (hydro)—each of which is eligible under the EDCs' net energy metering (NEM) tariffs. The study analyzes distribution capacity needs over a 10-year future planning horizon, and over a 5-year historical period, at locations across the state to develop a locational list of capacity needs. The study includes sensitivity analyses that consider low and high scenarios for load growth, incorporating a number of variables. A subset of locations was selected for detailed analysis. For the subset, cost estimates for traditional utility investments to meet locational capacity needs were determined.

The study analyzes the potential value of capacity deficiency avoidance resulting from load reduction. Avoided costs at each location are then distributed across the years of capacity need within the planning horizon and allocated to the annual hours of capacity need based on hourly load deficiency analysis. The hourly capacity avoidance values represent a technology neutral value for meeting distribution capacity deficiencies during each hour of need. Lastly, DG production profiles for the three specific NEM-eligible technologies are developed and used to illustrate the coincidence of DG hourly production with hours of locational capacity need.

The study does not attempt to identify a specific solution or set of DG technologies that would meet the capacity needs at the selected locations, nor to estimate the actual

[2] NHPUC Docket No. DE-16-576, Order Approving Scope of Locational Value of Distributed Generation Study, Order No. 26,221 (February 20, 2019).

capacity of each DG technology that might be required at a given location to meet the specific need. In this sense, the study does not attempt to perform a non-wires solution (NWS) analysis to meet the identified locational capacity needs.

The Introduction subsections,1.1 through 1.6:

- Present the objectives of the study within the regulatory context
- Illustrate the analysis timeframe used for the study
- List the EDCs within New Hampshire and data and related information used in the study
- Describe the DG technology reviewed
- Provide an overview of the study approach and report structure

The subsequent sections of the report present the analytical steps used to perform the LVDG analysis, and results and conclusions.

1.1 Regulatory Context

The Commission engaged Guidehouse to conduct the LVDG study with respect to the electric distribution systems owned and operated by the three EDCs under its jurisdiction. The purpose and subsequent authorization of the LVDG study is outlined in the Commission's orders issued in its ongoing net metering docket.[3]

In its June 2017 order,[4] the Commission required actions be taken to collect data and develop a comprehensive record to inform future net metering tariff modifications or alternative compensation mechanisms. That order also required the Commission to undertake a Value of Distributed Energy Resources (VDER) study. The objective of the VDER study is to fulfill Order No. 26,316,[5] which approved the scope and timeline of a study of the system-wide value of distributed energy resources in New Hampshire. The results of the VDER study are intended to inform further action in the net metering docket, as well as having potential relevance in other contexts such as matters involving distributed generation integration, utility system planning, and grid modernization.

[3] NHPUC Docket No. DE-16-576, Development of New Alternative Net Metering Tariffs and/or Other Regulatory Mechanisms and Tariffs for Customer-Generators. Available at: https://www.puc.nh.gov/regulatory/Docketbk/2016/16-576.html

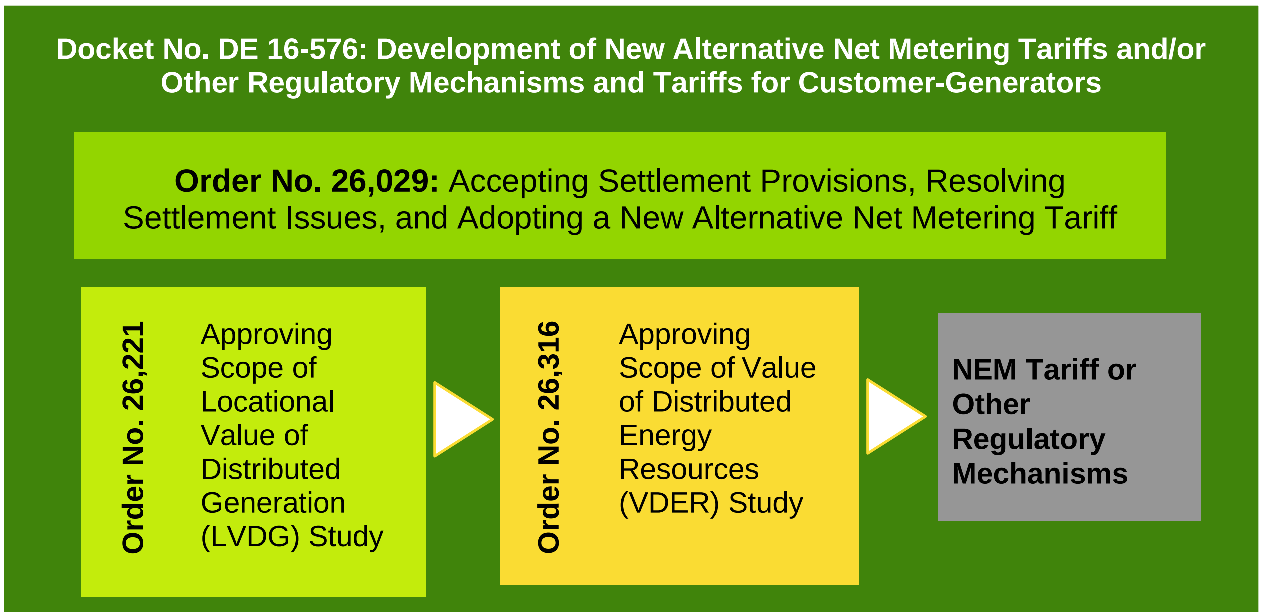
[4] NHPUC Order No. 26,029, Order Accepting Settlement Provisions, Resolving Settlement Issues, and Adopting a New Alternative Net Metering Tariff, June 23, 2017. Available at: https://www.puc.nh.gov/regulatory/Docketbk/2016/16-576/ORDERS/16-576_2017-06-23_ORDER_26029.PDF (approving the adoption of a new alternative net energy metering tariff, designed to be in effect for a period of years while additional data is collected and analyzed, pilot programs are implemented, and a value of distributed energy resource study (VDER Study) is conducted.)

[5] NHPUC Order No. 26,316, Approving Scope of Value of Distributed Energy Resources, December 18, 2019. Available at: https://www.puc.nh.gov/Regulatory/Docketbk/2016/16-576/ORDERS/16-576_2019-12-18_ORDER_26316.PDF

In April 2018, the Commission directed its staff and stakeholders to focus on studying the locational value of distributed generation rather than developing NWS pilots.[6] The objective of the LVDG study is to fulfill Order No. 26,221,[7] which approved the scope and timeline of a study of the locational value of DG in New Hampshire.

The LVDG study results will be available for consideration as inputs to the VDER study. Both studies will inform future net energy metering tariffs and alternative compensation mechanisms. However, dollar value results of the LVDG study cannot be directly applied to a compensation mechanism. Results of the LVDG study may also be useful for consideration in the Least Cost Integrated Resource Plan dockets and in the Grid Modernization docket.[8]

Figure 1. Regulatory Context



Source: New Hampshire Public Utilities Commission

Stakeholder review and input were solicited as part of the LVDG study process through three public stakeholder workshops, which presented analysis updates throughout the

[6] NHPUC Order No. 26,124, Order Addressing Non-Wire Alternative Pilot Program, April 30, 2019. Available at: https://www.puc.nh.gov/regulatory/Docketbk/2016/16-576/ORDERS/16-576_2018-04-30_ORDER_26124.PDF

[7] NHPUC Order No. 26,221, Approving Scope of Locational Value of Distributed Generation Study, February 20, 2019. Available at: https://www.puc.nh.gov/regulatory/Docketbk/2016/16-576/ORDERS/16-576_2019-02-20_ORDER_26221.PDF

[8] NHPUC Docket No. IR 15-296, Investigation into Grid Modernization. Order No. 26,358. (May 22, 2020)(Stating "There will likely be synergies between the Commission's ongoing Locational Value of Distributed Generation Study and the locational value analysis that will take place as part of the LCIRP process. We anticipate that the deliverables associated with step one (net load forecasting and equipment criteria violation identification) and step two (identify cost of traditional solution) of the Locational Value of Distributed Generation Study may inform the analysis occurring in each utility's LCIRP, and in some cases, future annual updates."
https://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/ORDERS/15-296_2020-05-22_ORDER_26358.PDF

study period. Each workshop was attended by EDC representatives, other parties in the NEM proceeding, and interested stakeholders. During those three workshops, questions and feedback from attendees were addressed.

1.2 Study Scope and Analysis Parameters

The LVDG study parameters and methodology address the Commission-approved Locational Value of Distributed Generation Study scope, which includes the following elements:

Relationship to VDER: The LVDG study has been conducted as a separate analysis from the VDER study. Findings from the LVDG study will be used in conjunction with the VDER study to inform future NEM tariff development and DG compensation proceedings.

Technologies Considered: The study focuses on DG that is eligible for NEM and interconnected to a New Hampshire EDC, including solar PV, solar PV paired with energy storage, and hydroelectric.

Eligible Avoided Costs: The study considers the value of avoided distribution investment costs due to capacity constraint elimination through load reduction at a number of locations on the New Hampshire electrical distribution grid. Potential avoided or deferred distribution system costs related to power quality and lower distribution elements, including distribution transformers and capacitor banks, were not considered. All investment costs are based on actual EDC expenditures for the capacity-related component of historical projects. For forward-looking locations, EDC budget estimates were used. For forward-looking locations where budget data is not available, EDC unit cost data was applied to estimate project costs. A subset of locations was selected for detailed study of potentially avoidable distribution investments. The detailed study provides an indicative set of potential avoided cost values; however, the results are not extrapolated to all locations with violations or deficiencies across the state. Accordingly, the LVDG study is not intended to determine a system-wide value for DG, as those system-wide, lower order distribution investment deferrals will be considered within the distribution components of the VDER study.

Timeframe: The study examines avoided investment costs over a fifteen-year timeframe. The study baseline reviews the past 5 years of load and investment data to establish historical expenditures. The final agreed-upon study includes the optional study period extension of a further 5-year projection, extending the future study horizon to 10 years. Thus, a 15-year study period was used: 5 years of historical analysis and 10 years of future analysis.

Geographic Scope: The geography includes the distribution systems of the three regulated EDCs in New Hampshire.

Distribution System Analysis Level: The analysis covered the distribution systems of the three EDCs. For the purposes of this study, this is defined as: Sub-transmission (13 kV-69 kV), Substation, and Distribution Circuits.[9]

Load Growth Projections: Baseline analysis was performed using load growth projections developed by each utility for its planning processes. However, in all cases regardless of utility practice, the load growth projection uses a counterfactual Base Case analysis that excluded future projections of historically observed growth in net-metered DG investment. The study incorporates both a high load growth scenario and low load growth scenario to define sensitivity parameters around the Base Case analysis. The low load growth scenario includes assumptions about increased levels of energy efficiency and conservation and other assumptions about average weather conditions. The high load growth scenario includes assumptions regarding aggressive electric vehicle adoption, low levels of energy efficiency and conservation, and other assumptions about extreme weather conditions.

Investment Threshold: The analysis focuses on significant distribution system capacity needs and planned or potential investments and excludes small program investments that are part of a system benefit initiative, such as pole top distribution transformers and capacitors. Those small program investments may be included in the separate system-wide VDER analysis.

Locations for Review: Projects considered for detailed review include locations with capacity constraints identified in the EDC's 5-year historical spending reports and investments included in forward-looking capital investment plans. Projects considered also included those identified through a 10-year forward-looking capacity deficiency analysis. These projects include those:

- Identified through forward-looking load growth projections and screening using utility normal (N-0) planning criteria.
- Identified as capacity-related investments through review of 5-year historical spending and planning materials such as EDC budgets and capacity planning studies.
- Identified as contingency (N-1) investments.[10]
- With non-load growth-related investment needs (e.g., asset management) that also include a capacity component. Where both load and non-load investments are

[9] Although the study evaluates the value of avoiding distribution system investments for lines and substations rated 34.5kV and below, the analysis includes the impact of avoiding these investments on sub-transmission assets rated up to 69kV.
[10] Contingency investments are those that are needed to address capacity deficiencies that occur when a single component fails or is out of service, causing overloads on the other equipment. A common example is a substation equipped with two transformers, where a loss of one of the two transformers will cause the remaining in-service transformer to become overloaded.

made for the same project, only incremental investment costs caused by capacity increases are considered.

A selection of these analysis parameters are expanded upon in the subsections that follow, in which additional detail is provided to facilitate understanding of the analysis steps presented in later sections.

1.3 Analysis Timeframe

Figure 2 illustrates the study analysis timeframe. The analysis looks ahead 10 years into the future, and also looks back at 5 years of historical data, thus using a 15-year study timeframe overall.

Figure 2. LVDG Analysis Timeframe

Source: Guidehouse

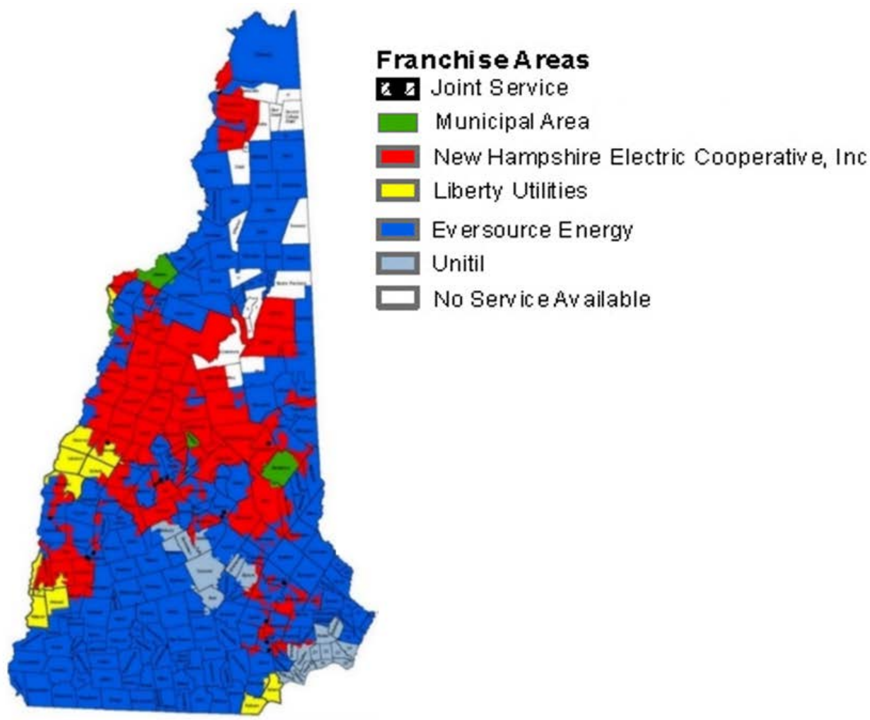
For locational analysis of various EDC distribution system capacity upgrade projects that were examined, two distribution planning assumptions that existed at the time the project was initially proposed or placed into service were applied. First, load forecasts for future projects are based on current load growth projections, whereas for historical projects, the load growth projections originally used by the EDC to justify the project were applied. Second, the capacity planning criteria applied to evaluate historical projects is based on documented planning criteria at the time the project was originally proposed.[11]

[11] Note that smaller, *normal course* distribution investments are excluded from the analysis, as they are included in the approved scope of the separate VDER study. The VDER study scope provides that potential avoided distribution costs related to power quality and lower distribution elements, including distribution transformers and capacitor banks, will be considered on a systemwide level. Accordingly, those potential avoided costs are not considered in this LVDG study, as it is not intended to determine a systemwide value for DG.

1.4 Electric Distribution Companies

The study evaluates the locational value of DG for the three regulated EDCs in New Hampshire: Public Service Company of New Hampshire d/b/a Eversource Energy (Eversource), Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities (Liberty), and Unitil Energy Systems, Inc. (Unitil). The study excludes publicly owned utilities such as electric cooperatives and municipally owned systems.[12] Those three EDCs serve retail customers throughout the state, including most of the larger towns and cities. Figure 3 displays the service territories of each of the three EDCs. It is within those areas that historical and future distribution capacity deficiencies are identified. The study assesses the value of avoided distribution capacity investments at the selected locations within those EDC service territories. [13]

Figure 3. EDC Franchise Service Territories



Source: New Hampshire Public Utilities Commission, [State of New Hampshire Electric Utility Franchise]

Table 1 presents the number of electric customers and sales by EDC. Eversource serves the greatest number of customers in New Hampshire (over 80% of the state's total customers served) across all regions of the state, whereas Liberty's service territory is located in the western and southern sections of the state, and Unitil primarily serves the seacoast and capital areas. In later sections, regions within each EDC's

[12] The impact of publicly-owned utilities served by lines owned by the EDCs is considered, where applicable.
[13] Throughout the study, a traditional investment is considered "avoided" if the need for the investment is eliminated due to load reduction within the study timeframe.

service territory are assessed to identify distribution capacity avoidance opportunities on a locational basis.

Table 1. EDC Statistics

EDC	Number of Electric Customers	2019 Peak Demand (MW)	2019 Energy Sales (GWh)
Eversource	534,000	1,639	7,681
Liberty	44,517	188	0.899
Unitil	78,223	240	1.154

Source: Eversource, Liberty, Unitil

In New Hampshire, the electric distribution system delivers electric service at voltages of 34.5 kV and below.[14] For purposes of the study, locational capacity investments are defined as lines, circuits, and/or substations that are used to deliver electricity to retail customers.[15]

1.5 Distributed Generation Technologies

The study evaluates specific NEM-eligible technologies: solar PV, solar PV paired with energy storage, and hydroelectric. As of April 2020, approximately 112 MW of DG was interconnected and eligible for net metering in the EDC service territories. Technologies currently interconnected include solar, wind, hydroelectric, and residential solar with storage.

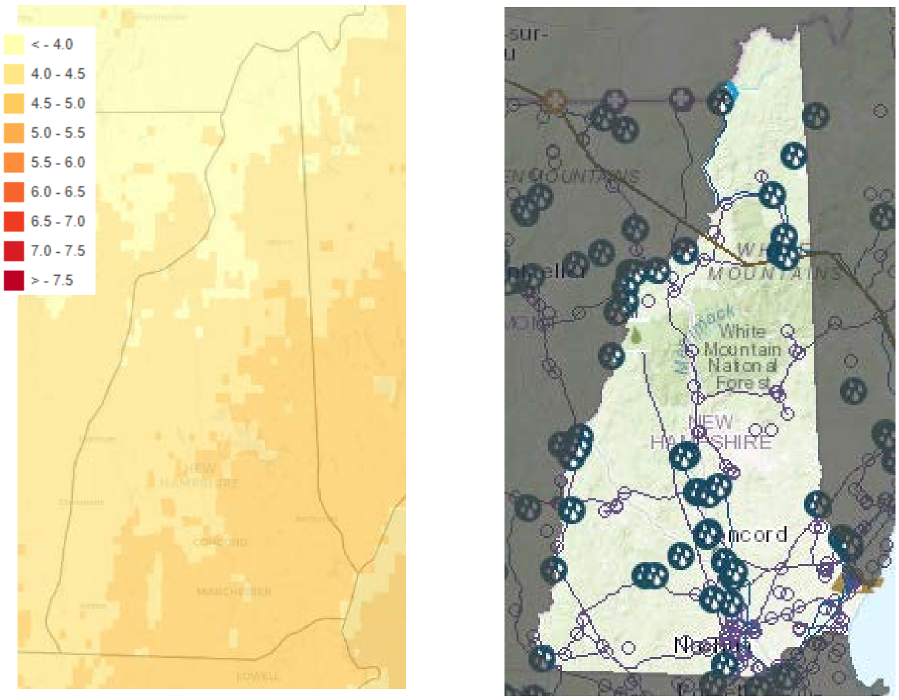
Figure 4 presents solar energy potential and the existing hydroelectric sites across New Hampshire.[16] Although specific locations of all existing or proposed solar PV installations are not shown on the map, solar potential exists across the state while NEM-eligible hydro is limited to streams and rivers suitable for project development.[17,18]

As of 2019, there were a total of 88 conventional hydroelectric generation facilities operating in New Hampshire and reporting to the Energy Information Administration (EIA) as part of Form EIA-860 on an annual basis. Those hydroelectric generation facilities include NEM-eligible and non-NEM-eligible facilities that are too large to qualify for net metering. Of the 88 facilities, 37 of them, representing close to 4% of the total

[14] The term “lines” refers to distribution circuits operating at voltages 34.5kV and below. The terms “circuit” and “feeders” have the same meaning and are used interchangeably throughout this report.
[15] Although the study limits distribution facilities to those rated 34.5kV and below, some investments may include equipment rated to operate at higher voltages, such as distribution substation power transformers rated 115/34.5kV, and new 115kV lines that are needed to deliver power and energy to those substations. Further, some lines rated 34.5kV serve a dual function of supplying lower voltage substations and delivering power and energy to retail customers. Lines that provide dual functionality often are referred to as right-of-way (ROW) lines. Most of the ROW lines are owned and operated by Eversource.
[16] Note: it is understood that solar and other DG developers pay costs associated with installation and interconnection; these costs are not considered in the LVDG study but will be evaluated as relevant to system-wide values in the VDER study.
[17] The study did not assess where NEM-eligible hydroelectric generation is suitable from a hydrological or permitting perspective, but recognizes that some locations may be suitable and other locations may encounter constraints and barriers that restrict or prohibit any potential hydroelectric development.
[18] Note that the amount of solar PV capacity that can be installed at a particular utility location is subject to “hosting capacity” limits and other interconnection policies. Hosting capacity and interconnection requirements are not considered in the study.

New Hampshire installed hydroelectric capacity of approximately 500 MW, have nameplate capacity equal to or less than 1.0 MW, making them potentially eligible for net metering. Hydroelectric includes a variety of generators, ranging from small run-of-river plants to large facilities with extensive reservoirs, such as the Comerford and Moore plants located along the Connecticut River in northwest New Hampshire. For this study, the seasonal hourly output of several existing hydroelectric facilities is used to understand the seasonal and locational variations that can be expected from smaller net-metered hydroelectric facilities.

Figure 4. Solar Irradiance and Hydro Sites[19] in New Hampshire



Source: National Renewable Energy Lab (NREL), https://maps.nrel.gov/nsrdb-viewer

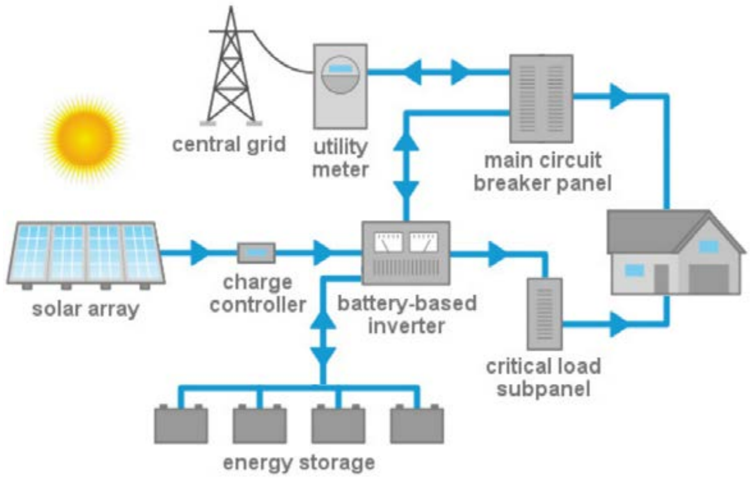
Source: Energy Information Administration (EIA), https://www.eia.gov/state/?sid=NH#tabs-4

Figure 5 is an illustrative diagram of a solar PV array paired with battery storage for a residential application. In the analysis below, the pairing of solar PV production coincidence with energy storage is shown to possess the potential to produce output from renewable DG for hours during which capacity deficiencies occur, particularly at locations that peak in the late afternoon or early evening.[20]

[19] This map of hydroelectric generating facilities shows major facilities (greater than 5 MW and others not eligible for NEM) as well as smaller facilities, and is included for illustrative purpose only, as it shows significant waterways as well as transmission facilities.

[20] Solar PV-generated electricity can be diverted into an energy storage facility at times when the solar energy exceeds onsite load and then discharged at other times when it can effectively serve onsite or off-site load. In this manner, solar generated energy can be used at times when the solar PV array is not producing electricity.

Figure 5. Solar PV plus Storage Diagram



Source: Solar Power Now, https://solar-power-now.com/solar-power-storage/

1.6 Study Approach and Report Structure

The study approach consisted of three analytical steps:

- **Step 1:** Location Identification – Identify potential locations with expected capacity constraints and historical locations with past capacity constraints
- **Step 2:** Estimation of Investment Costs for Avoidance – Determine the value of potential avoided capacity investments at those locations
- **Step 3:** Economic Analysis and Mapping of DG Production Profiles with Distribution Capacity Needs – Perform economic analysis to estimate the benefit of avoidance and map representative DG production profiles with distribution capacity needs

This approach also allowed intermediate results to be provided to the LVDG stakeholder group through workshops during which questions and feedback from attendees were addressed. The three steps have also been used to organize the study report, with Section 2.0 covering Step 1, and so on. In addition, Section 5.0 summarizes findings and conclusions determined through the study and its analysis.

2.0 Location Identification (Step 1)

This section describes the analysis performed to identify locations on each EDC's distribution system (i.e., lines and substations) with capacity deficiencies, where capital investments potentially could be avoided through load reduction attributable to NEM-eligible DG.[21] Summary and aggregate location data is presented throughout this

[21] "Lines" refers to distribution circuits rated 34.5kV and below.

section. A complete list of all identified forward-looking locations is available in Appendix B.

1. The study scope required in-depth analysis for a subset of locations. The process applied to determine locations for detailed analysis included identifying and assessing all locations with qualifying capacity deficiencies.
2. Specific locations were then selected for further analysis under each load forecast that resulted in a planning criteria violation.

The selection process for specific locations is intended to ensure a sufficient number of distribution substations and lines are chosen for each of the three EDCs to evaluate the locational value of DG across the state for both historical and forward-looking capacity investments.

2.1 Screening Analysis

In Step 1, a screening analysis of all distribution lines and substations to identify locations where capacity deficiencies exist within the 10-year forward-looking study horizon was conducted. Line and equipment rating data for all sub-transmission and distribution assets was obtained from each of the EDCs for both normal (N-0) and contingency (N-1) conditions. Data values and methodologies to derive capacity deficiencies were confirmed through follow-up interviews with the EDCs and consultation with Commission Staff. Table 2 lists the total number of lines and substations that the study evaluated in the screening analysis.

Table 2. Number of Distribution Substation and Lines

EDC	Substations (Bulk & Non-Bulk)[22]	Distribution Lines (34.5 kV)	Distribution Lines (<34.5 kV)
Eversource	131	180	181
Liberty	14	0	61
Unitil	25	41	58

Source: Guidehouse

The study undertook the following steps for each EDC to perform the screening analysis of candidate locations to determine the value of avoided capacity investments:

1. Develop high and low load forecasts using the EDC's Base Case load forecast as a baseline (Section 2.2), to facilitate high and low sensitivity analysis
2. Analyze each EDC's capital plans and budgets to determine the cost of avoided capacity investments

[22] Bulk substations are those served by 115 kV transmission on the high side of the substation transformer; non-bulk substations are those served by 69 kV transmission or below on the high side of the substation transformer. The low side voltage of bulk substations ranges from 4.16kV to 34.5kV; whereas the low side voltage of non-bulk substations typically is 13.8kV or below.

3. Conduct a load versus capacity balance analysis to determine thermal capacity deficiencies for each year of the study:
    a. Assess forward-looking planning criteria versus historical practices
    b. Identify normal (N-0) and contingency (N-1) violations
4. Determine the magnitude and timing of capacity deficits for each of the three load forecast scenarios (low, base, and high), by location
5. Hold follow-up discussions with each EDC to confirm forecasted capacity deficiencies
6. Select a subset of locations for more detailed analysis

The Commission Staff and the EDCs then reviewed the results to confirm that the 16 locations selected:

- Include examples from each EDC's service territory and regions
- Provide a sample of future and historical projects, including circuits and bulk and non-bulk substations
- Include locations with identified deficiencies under various load growth forecasts
- Include winter and summer peaking locations
- Include midday and late-day peaking locations
- Include locations with small and large capacity deficiencies
- Include locations with normal and contingency overloads or performance violations
- Include locations where data is available to comprehensively analyze each site to determine the cost of traditional capacity solutions

More detail on the methodology and assumptions for load forecasting and violation screening is found in Appendix A.

2.2 Load Forecasts

Three load forecasts for the period of 2020-2029 were used to assess the range of capacity deficiencies and the associated value of load reductions at relevant locations.

- **Base Case:** The Base Case load forecast used the base load forecasts developed by each EDC with some minor modifications to consider the counterfactual case of no explicit additional future DG. This case is to account for business as usual assumptions.
- **High Case:** The High Case load forecast was based on the Base Case and included assumptions for aggressive penetration of electric vehicles (EV) in New Hampshire and lower than anticipated energy efficiency (EE) adoption and conservation. The High Case forecast also used the "Extreme" weather load

forecasts developed by each EDC and the counterfactual assumption of no additional future DG.

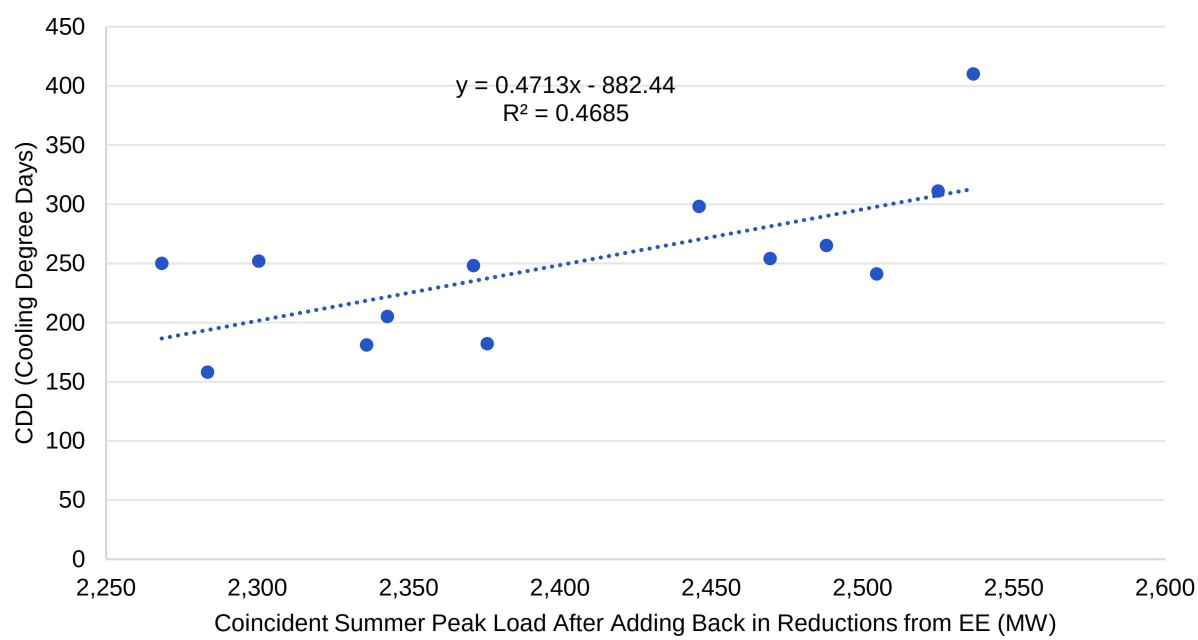
- **Low Case:** The Low Case load forecast was based on the Base Case and considered a lower estimate of electric load growth due to increases in levels of EE and overall increases in energy conservation activities. The Low Case used the "Average" weather load forecasts developed by each EDC and the counterfactual assumption of no additional future DG.

The following sections describe the load forecasting approach. First, analysis of the impact of economic factors on peak loads in New Hampshire is discussed. Then, the specific assumptions for each of the three load growth forecast cases is addressed. Finally, the resulting three load forecasts for each of the three EDCs are summarized.

2.2.1 Overview of Analysis of Factors on Peak Load Forecasts

The load forecast analysis for the Low and High Cases included a review of New Hampshire historical summer peaks coincident with the ISO-NE peak and historical economic variables. First, the study reviewed the past 28 years of coincident historical New Hampshire summer peaks using information available from ISO New England (ISO-NE) to determine the correlation between statewide economic factors and load. ISO-NE considers multiple variables for developing its New England and States Long-Run Energy Models. The three variables closely tied to economic factors include total state population, total real personal income, and real total gross state product. Limited correlation was found with data available on peak loads and statewide economic factors. The study focused on total real personal income, but also considered the other variables. A summary of the analysis of these variables is available in Appendix A.1.

Figure 6. Cooling Degree Days vs. Coincident Summer Peak Load After Adding Back in Peak Load Reductions from EE (2006-2018)



Source: ISO-NE, https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/

The study also reviewed the impact of weather conditions on historical peaks to determine if those conditions drove variations in peak loads over time. Figure 6 shows the results of this analysis. As Figure 6 displays, a strong correlation was found between cooling degree days and coincident summer peak load from 2006-2018.

Projections of future temperature conditions in the low and High Cases were not included, given that there is significant uncertainty about future temperature trajectories. However, the study team used the "Extreme" weather forecasts developed by the EDCs to inform the High Case and the "Average" weather forecasts developed by the EDCs to inform the Low Case. Those forecasts considered the impacts of historical extreme (95/5)[23] and average (50/50) temperatures on system peak load to develop load forecasts that have a lower or higher probability of occurrence than the base case (90/10). Economic growth assumptions did not impact the low or High Case forecasts due to the very low correlation of economic growth with summer peak load over the past 12 years.

The study also reviewed data on beneficial electrification related to building use and heating for consideration in the High Case. However, data specific to New Hampshire on beneficial electrification was not sufficient to include in the analysis. Beneficial electrification related to building use and heating is something that could be considered for future inclusion. The effect of electric vehicle adoption was considered in the High Case for this study.

The following sections address the base, low, and High Case load forecasts assumptions in greater detail.

2.2.2 Base Case Load Forecast

Table 3 presents a high level summary of each EDC's load forecast methodology (i.e., Base Case) in use at the time this study was conducted, including assumptions for peak weather probability, existing DG, future DG, economic growth, EVs, and EE as compared to an industry standard practice Base Case summarized in the first column. Existing DG is embedded in all EDC load forecasts; the study made no adjustment to remove the existing DG. Eversource is the only utility that explicitly includes future DG growth in its forecast, based on ISO-NE projections, which was removed from the study forecasts to establish the counterfactual case.

[23] Electric utility load forecasts are generally separated into three weather forecast scenarios, each scenario with a probability or likelihood of occurrence. The figures in parenthesis following a forecast represent that likelihood. In the case of an extreme weather forecast a (95/5) represents a 1 in 20 year likelihood (or 5% probability) that the extreme load level will be exceeded.

Table 3. Summary of EDC Base Forecast Methodology

	Industry Standard Practice	Eversource	Liberty	Unitil
Peak Weather Probability	90/10	90/10	Liberty uses 95/5 extreme load forecast for the Base Case.	90/10 (System) – Past 5 years trend line for distribution system
Existing DG	Existing DG included	Existing DG included	Existing DG included	Existing DG included
Future DG	No future DG included	Very modest incremental amount of PV added based on internal Eversource projections.	No future DG explicitly included in system level load forecast	No future DG explicitly included in system level load forecast
Economic Growth	Average	Moody's Analytics New Hampshire level state profile	Employment and number of households from Moody's Analytics used in regression analysis	Economic growth not explicitly considered
EVs	None	None	None	None
Energy Efficiency	Average	Historical EE is implicitly included in system level forecast. Forecasted incremental EE is explicitly included based on internal Eversource projections.	Historical EE is implicitly included in system level forecast	Historical EE is implicitly included in system level forecast

Source: Guidehouse, Eversource, Liberty, Unitil

The forecast methodology uses ISO-NE's forecast of EE impacts from 2019 to 2028 on New Hampshire summer peak demand to inform base level forecasted EE, as shown in Table 4.

Table 4. Energy Efficiency Forecast

Year	EE Summer Peak MW Reduction
2019	120
2020	140
2021	159
2022	175
2023	190
2024	204
2025	215
2026	225
2027	233
2028	240

Source: ISO-NE

2.2.3 High Case Load Forecast

The high load forecast is based on low EE participation, extreme weather, and aggressive EV penetration. Economic factors were not considered in view of the poor correlation between statewide economic factors and summer peak loads. Table 5 shows a summary of the high load forecast methodology for each EDC.

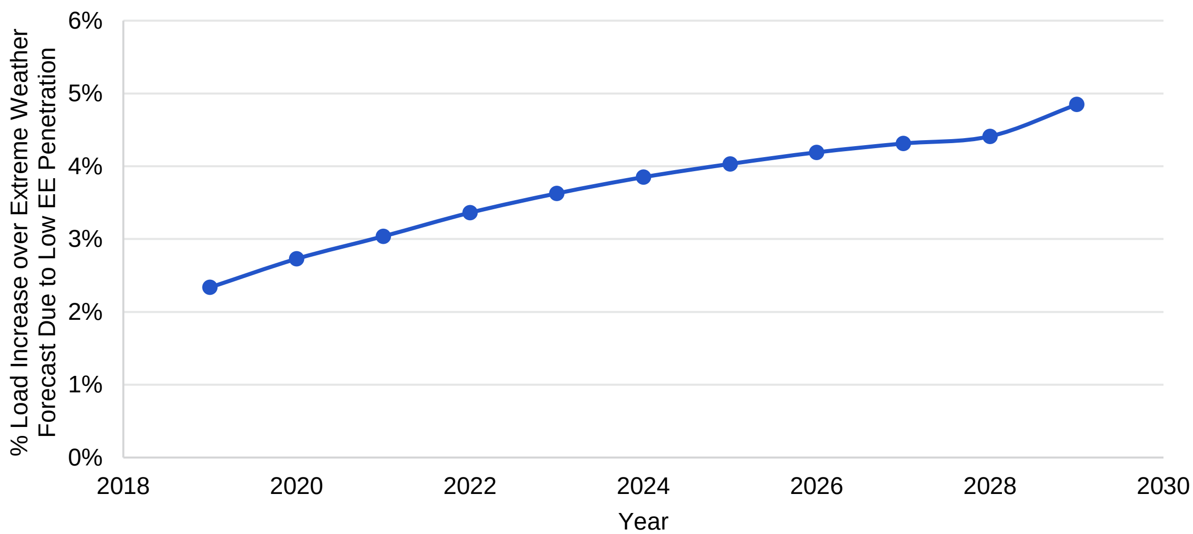
Table 5. Summary of EDC High Load Forecast Methodology

	Eversource	Liberty	Unitil – Seacoast	Unitil – Capital
Aggressive EV	✓	✓	✓	✓
Low EE	✓	✓	✓	✓
Extreme Weather (95/5)	✓	✓	✓	✓

Source: Guidehouse

To determine the impact of lower than forecasted EE participation, the forecasted EE summer peak MW reduction statewide for the Base Case (see Table 4) was left unchanged for the High Case. To determine the higher load (net of EE and PV impacts) for the High Case forecast, the extreme weather (95/5) load forecast provided by each EDC was used. The resulting lower percentage of EE penetration for the High Case is derived by dividing the Base Case EE forecast by the increased extreme weather forecast, as shown in Figure 7 (for example, the 3.9% shown in 2024 is 50% of 7.8%, which is 2,445 MW of EE reduced load in 2024 divided by 2,645 MW gross projected load in that year).[24]

Figure 7. High Case – Load Impact from Low Energy Efficiency Penetration



Source: Guidehouse

The forecast methodology referenced a 2019 Navigant Research (now Guidehouse Insights) report that forecast EV population under different scenarios for the US and Canada. Guidehouse Insights developed a forecast of total battery EV (BEV) population for New Hampshire for three scenarios. The study leveraged the aggressive scenario

[24] Load and energy efficiency numbers sourced from the 2019 CELT Forecast Detail: ISO-NE Control Area, New England States, RSP Sub-areas, and SMD Load Zones.

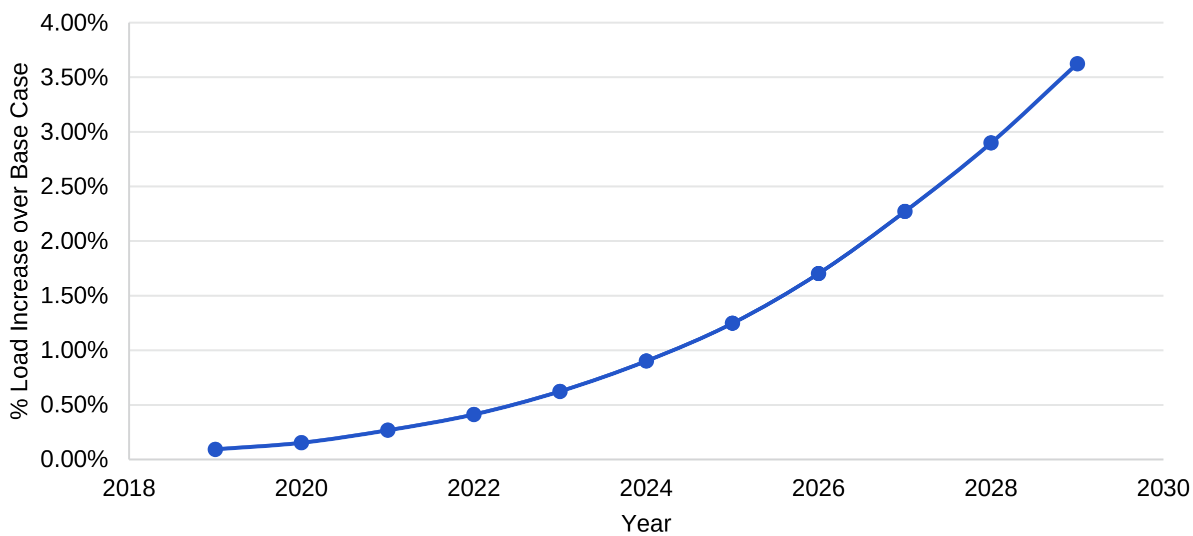
for the High Case analysis, as shown in Table 6 and Figure 8. In this analysis, there is a large decrease in battery price and the continuation of national incentives for EVs.

Table 6. EVs Load Forecast[25]

Scenario	Quantity of BEV by 2029
Conservative	69,200
Base	76,900
Aggressive	82,600

Source: Guidehouse

Figure 8. High Case – Load Impact from Aggressive EV Growth



Source: Navigant Research (now Guidehouse Insights): Market Data: EV Geographic Forecast – North America

2.2.4 Low Case Load Forecast

The low load forecast is based on high EE participation, average weather forecast, and no EV penetration. Similar to the high load growth forecast, economic factors were not considered in view of the poor correlation between statewide economic factors and summer peak loads. Table 7 shows a summary of low load forecast methodology for each EDC.

[25] Using results of Guidehouse Insights' Vehicle Adoption Simulation Tool (VASTTM) for other regions, the study assumed 1.2 kWpc/BEV to develop a peak load impact.

Table 7. Summary of EDC Low Load Forecast Methodology

	Eversource	Liberty	Unitil – Seacoast	Unitil – Capital
No EV	✓	✓	✓	✓
High EE	✓	✓	✓	✓
Average Weather (50/50)	✓	✓	✓	✓

Source: Guidehouse

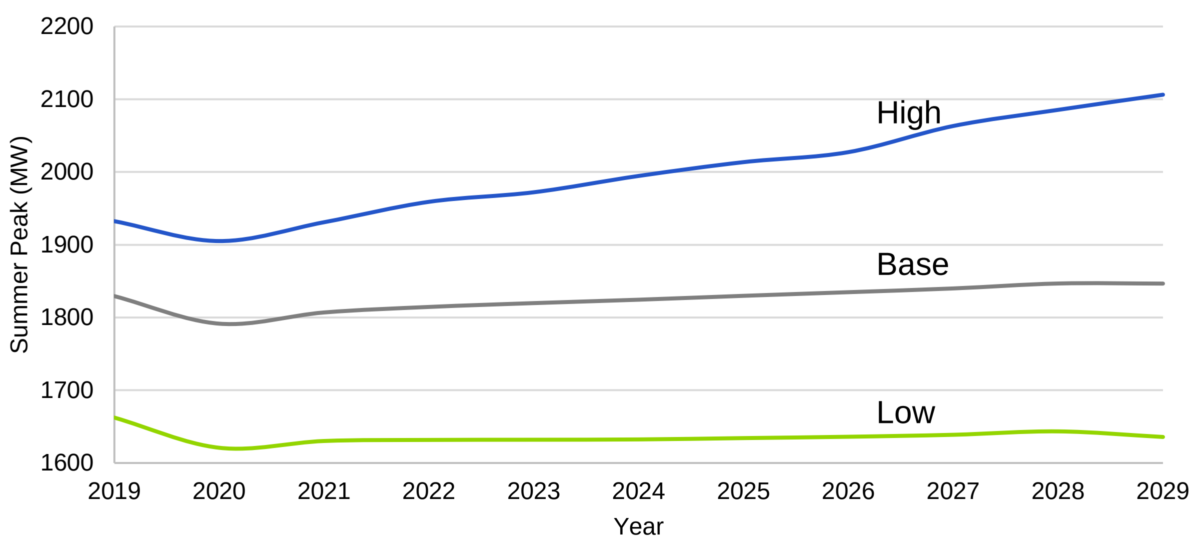
To account for higher than projected EE participation, the average weather forecast for each EDC was decreased by 50% of the forecast of statewide EE peak impacts (Table 4) divided by forecasted total state summer peak load excluding EE and PV impacts.

2.2.5 Load Forecasts by EDC

The base, low, and high forecasts vary across the three EDCs. The base load forecast compound annual growth rates (CAGR) from 2020 to 2029 were 0.38%, 0.24%, 1.01%, and 1.18% for Eversource, Liberty, the Unitil-Seacoast region, and the Unitil-Capital region, respectively. The low forecast CAGRs developed for this study from 2020 to 2029 were 0.1%, -0.02%, -0.21%, and -0.76% for Eversource, Liberty, the Unitil-Seacoast region, and the Unitil-Capital region, respectively. The high forecast CAGRs developed from 2020 to 2029 were 1.12%, 0.83%, 1.78%, and 1.18% for Eversource, Liberty, the Unitil-Seacoast region, and the Unitil-Capital region, respectively. These forecast results are shown graphically for each EDC below.

Figure 9 shows the base, high, and low load forecast results for Eversource. The resulting range between the High and Low Case for Eversource is 470 MW by 2029. The initial dip in the year 2020 is caused by the difference between the actual sum of the summer peak coincident loading across the five Eversource regions (Northern, Southern, Western, Central and Eastern) and the forecasted 90/10 system total summer peak forecast for 2020.

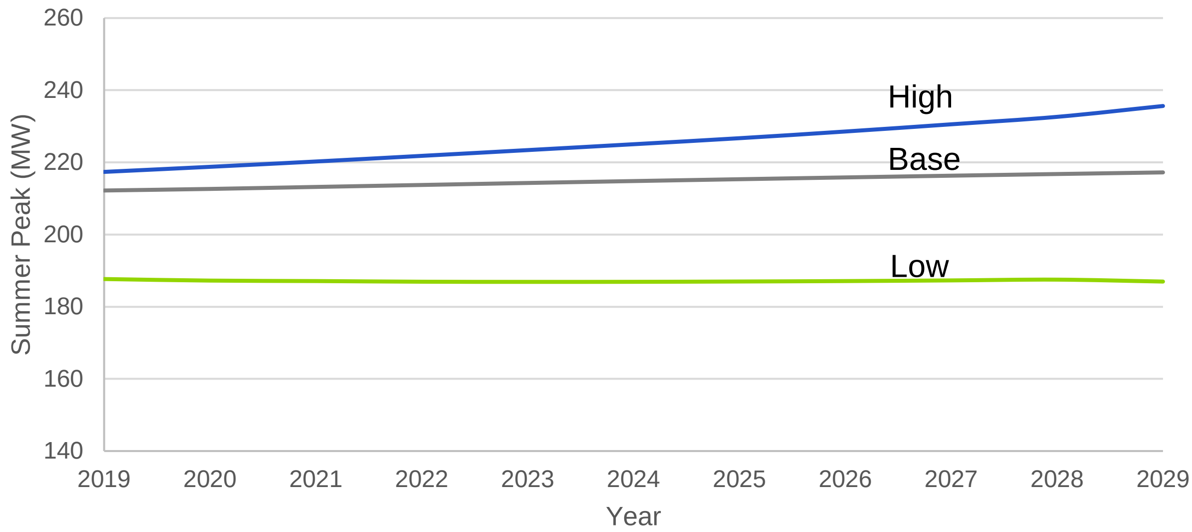
Figure 9. Eversource Load Forecast (Base, Low, High)



Source: Guidehouse, EDC data

Figure 10 shows the base, high, and low load forecast results for Liberty. The resulting range between the high and Low Case for Liberty is 49 MW by 2029. The range between the high and Base Case is smaller compared to Eversource because of Liberty's use of 95/5 extreme weather adjustment factor in its base forecast.[26]

Figure 10. Liberty Load Forecast (Base, Low, High)

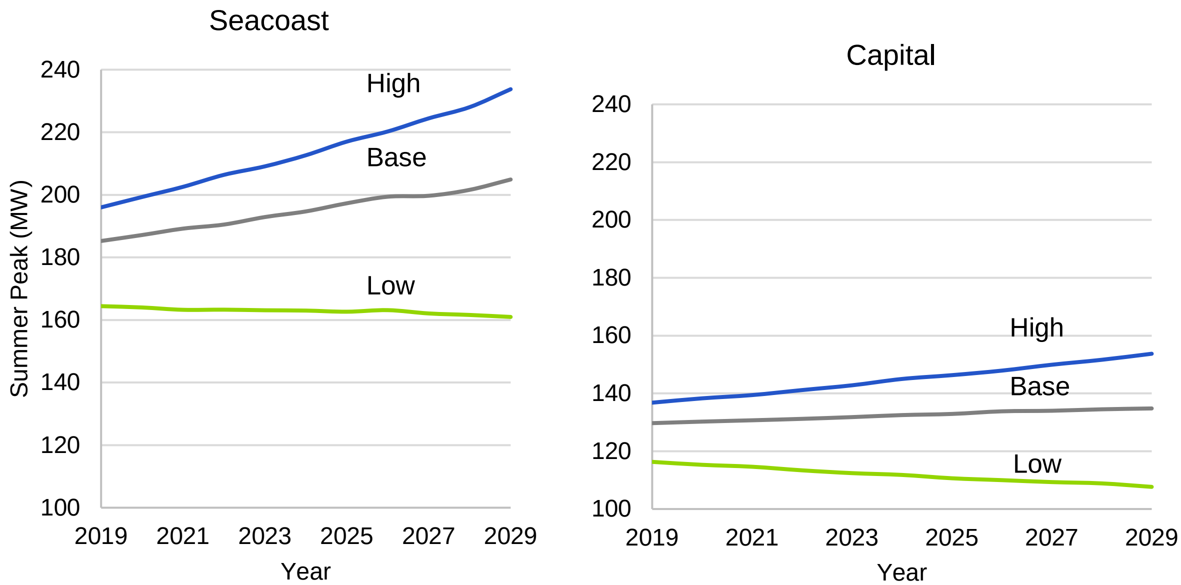


Source: Guidehouse, EDC data

Figure 11 presents the base, high, and low load forecast results for Unitil. The resulting range between the high and Low Case for Unitil is 73 MW for the seacoast region, and 46 MW for the capital region by 2029.

[26] NH PUC. Docket No. 19-064. Liberty Utilities Request for Change in Permanent Rates. Order No. 26, 376 Approving Settlement and Permanent Rates. (June 30, 2020) Available at: https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-064/LETTERS-MEMOS-TARIFFS/19-064_2020-05-26_GSEC_STIPULATION_SETTLEMENT_AGRMT.PDF;
see also, Stipulation and Settlement Agreement (May 26, 2020), Attachment 8. Available at: https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-064/LETTERS-MEMOS-TARIFFS/19-064_2020-05-26_GSEC_ATT_STIPULATION_SETTLEMENT_AGRMT.PDF

Figure 11. Unitil Load Forecast (Base, Low, High for Seacoast and Capital Regions)



Source: Guidehouse, EDC data

2.3 Capacity Deficiency Screening by Location

Based on a screening analysis of historical and forward-looking capacity deficiencies, the study team identified locations for detailed analysis. The screening analysis addressed both normal and contingency capacity deficiencies on distribution lines and substations. The full screening analysis has been provided to the New Hampshire Public Utilities Commission Staff. The study considers other violations at the component level, such as unacceptable steady state voltages, protective relaying limits or miscoordination, or other criteria applied by the EDCs. However, the LVDG analysis focuses on candidate locations with violations of capacity limits. The analysis also excludes minor violations that may be corrected by low cost investments such as installation of capacitors or replacement of distribution line transformers. Based on the screening analysis, the amount of capacity needed to address violations at each location was determined, with reference to load levels exceeding normal or emergency capacity limits.

The study relied on EDC data and planning criteria to conduct the screening analysis, including loading limits for substation transformers or individual circuits to support the findings. The study team also reviewed each EDC’s 5 and 10-year planning studies, capital budgets, and cost data to support the derivation of future and historical capacity deficiencies. Forward-looking capacity deficiencies are based on current EDC planning criteria, whereas planning criteria for prior investments are based on criteria and forecasts that were in effect at the time the decision was made to proceed with the distribution capacity investment. Table 8 presents the prior (historical investments) and current (forward-looking investments) planning criteria used to determine capacity deficiencies for each EDC.

Table 8. EDC Planning Criteria[27]

Condition	Distribution Circuit (Prior)	Distribution Circuit (Current)	Substation Transformer (Prior)	Substation Transformer (Current)
(1) Eversource[28]				
Normal (N-0)	• 100% of normal rating	• 100% of normal rating	• 100% of normal rating	• Bulk: 75% of normal rating • Non-Bulk: 100% TFRAT
N-1 Contingency	• 100% of LTE rating	• 100% of LTE rating	• Non-Bulk: 100% of LTE rating • Bulk: 100% of LTE rating with allowable 720 MWhr unserved load (30MW for 24 hours)	• Non-Bulk: 100% of LTE rating • Bulk: 100% of emergency rating with no allowable loading violations[29]
(2) Liberty				
Normal (N-0)	• 75% of normal rating	• 100% of normal rating	• 75% of normal rating	• 100% of normal rating
N-1 Contingency	• Load transfer to nearby feeders within LTE rating • 24-hour repair	• Load transfer to nearby feeders within LTE rating • 24-hour repair	• Load transfer to nearby transformer with 24 hours within LTE rating • Repair or installation of mobile w/in 24 hours	• Load transfer to nearby transformer with 24 hours within LTE rating • Repair or installation of mobile w/in 24 hours
(3) Unitil				
Normal (N-0)	• 90% of normal seasonal rating	• 90% of normal seasonal rating	• 90% of normal seasonal rating	• 90% of normal seasonal rating
N-1 Contingency	• Load transfer to nearby feeders within seasonal rating	• Load transfer to nearby feeders within seasonal rating	• Load transfer to spare or mobile transformer within 24 hours to within seasonal rating • Repair or installation of spare or mobile w/in 24 hours	• Load transfer to spare or mobile transformer within 24 hours to within seasonal rating • Repair or installation of spare or mobile w/in 24 hours

Source: EDC Planning Criteria

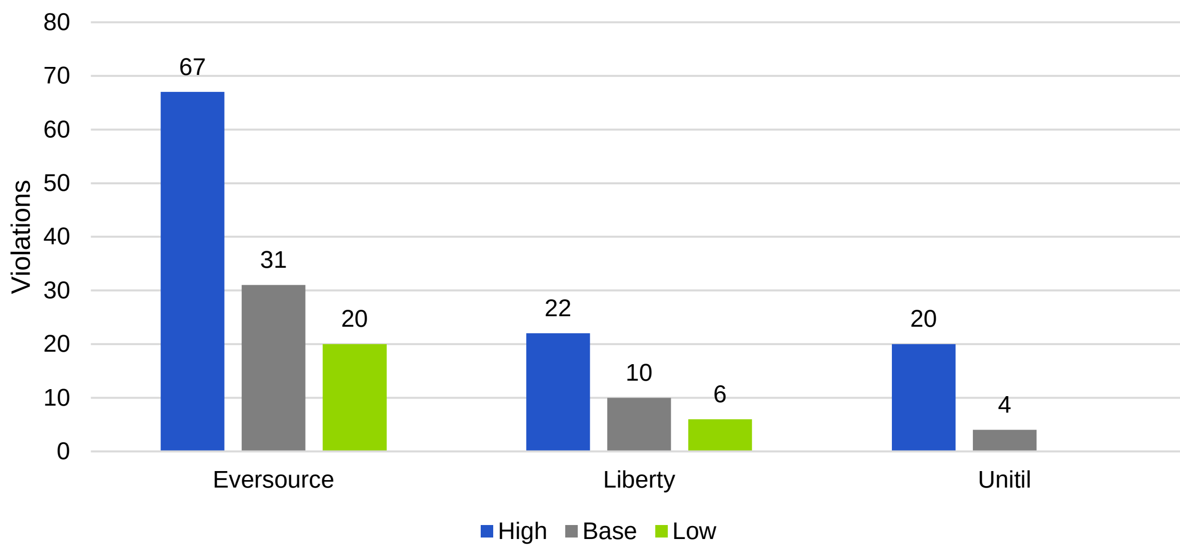
The project team performed the screening analysis for base, low, and high 10-year forward-looking scenarios and 15-year load forecasts for historical distribution capacity

[27] As of June 2020.
[28] Eversource recently revised its planning criteria and disagreement exists between Eversource, Commission Staff, and the Office of the Consumer Advocate (OCA) regarding the need for those revisions. *See* Order No. 26,362 at 5 (June 3, 2020); *see* also Docket No. DE 19-139, Settlement of the Parties, Attachment A (March 11, 2020) (describing recent changes to SYSPLAN-008, which changes the way Eversource calculates bulk transformer preload, and SYSPLAN-010, which previously allowed for a loss of up to 30 MW for up to 24 hours, but no longer allows for any loss of load after initial restoration).
[29] Back up capacity can be provided by feeder ties provided the transformer is loaded to its long-term emergency ratings. The in-service transformer following a contingency may be loaded to its short-term emergency rating if transfers, up to three, can be made within 15 minutes and reduce the in-service transformer loading to below its long-term emergency rating.

investments. The study team consulted with the EDCs to confirm all capacity deficiencies identified at the substation and distribution circuit levels.

Figure 12 presents the number of distribution substations and distribution circuit capacity deficiencies, collectively, for each EDC under the high load forecast scenario. It includes both normal and contingency capacity deficiencies for lines and substations for each EDC. Of the 696 locations reviewed, there are 109 total capacity deficiencies in the high forecast scenario. There are 45 total capacity deficiencies in the base load forecast scenario, with many of the deficiencies occurring further into the study period compared to the high scenario, where many deficiencies occur in 2020 or shortly thereafter. There are 26 total deficiencies in the low forecast scenario, with many of these occurring later in the study period. There are 64 deficiencies that only occur due to the high load forecast.

Figure 12. Forward-Looking Capacity Deficiencies by EDC



Source: Guidehouse, EDC data

Table 9 presents the 45 Base Case capacity deficiencies for each EDC, listed by type of asset upgrade, region, first year the deficiencies occurs and the violation type (i.e., normal or contingency, or both). Appendix B shows all the 109 forward-looking capacity deficiencies across the three EDCs. It also includes the load forecast (low, base, or high) triggering the violation, the first year the violation occurs for that forecast, and the violation type that triggered the capacity deficiency.

The projected violations as measured by capacity deficiencies for the three EDC beginning in 2020 is approximately 107 MW and increases to 147 MW by 2029 for the base load forecast. Total capacity deficiencies in 2029 for the low forecast is 63 MW and 316 MW for the high load forecast. A substantial number of capacity deficiencies occur in 2020, the first year of the forward-looking segment of the study, in large part due to recent changes in planning criteria by Eversource.

Table 9. Base Case Violations (Capacity Deficiencies)

No.	EDC	Asset Type	Asset Name[30]	Substation	Region	Voltage	Forecast	First Violation Year	Violation Type
1	Eversource	Bulk Substation	Ashland		Northern	34.5	Base	2020	N-1, 75% Tx Capacity
2	Eversource	Bulk Substation	Beebe River		Northern	34.5	Base	2020	N-1,
3	Eversource	Bulk Substation	Bridge St. 4kv		Southern	4.16	Base	2020	N-1, 75% Tx Capacity
4	Eversource	Bulk Substation	Chestnut Hill		Western	34.5	Base	2020	N-1, 75% Tx Capacity
5	Eversource	Bulk Substation	Dover		Eastern	34.5	Base	2020	N-1, 75% Tx Capacity
6	Eversource	Bulk Substation	Eddy		Central	34.5	Base	2020	75% Tx Capacity
7	Eversource	Bulk Substation	Great Bay		Eastern	34.5	Base	2020	N-1, 75% Tx Capacity
8	Eversource	Bulk Substation	Huse Road		Central	34.5	Base	2020	N-1, 75% Tx Capacity
9	Eversource	Bulk Substation	Laconia		Northern	34.5	Base	2020	N-1, 75% Tx Capacity
10	Eversource	Bulk Substation	Lawrence Road		Southern	34.5	Base	2020	N-1,
11	Eversource	Bulk Substation	Long Hill		Southern	34.5	Base	2020	75% Tx Capacity
12	Eversource	Bulk Substation	Madbury		Eastern	34.5	Base	2020	75% Tx Capacity
13	Eversource	Bulk Substation	Mill Pond		Eastern	12.47	Base	2020	N-1,
14	Eversource	Bulk Substation	Monadnock		Western	34.5	Base	2020	N-1, 75% Tx Capacity
15	Eversource	Bulk Substation	North Woodstock		Northern	34.5	Base	2020	N-1,
16	Eversource	Bulk Substation	Pemigewasset		Northern	34.5	Base	2020	N-1, 75% Tx Capacity
17	Eversource	Bulk Substation	Portsmouth		Eastern	34.5	Base	2020	N-1, 75% Tx Capacity
18	Eversource	Bulk Substation	Reeds Ferry		Central	34.5	Base	2020	N-1, 75% Tx Capacity
19	Eversource	Bulk Substation	Resistance		Eastern	34.5	Base	2020	N-1,
20	Eversource	Bulk Substation	Rimmon		Central	34.5	Base	2020	75% Tx Capacity
21	Eversource	Bulk Substation	Saco Valley		Northern	34.5	Base	2020	N-1,
22	Eversource	Bulk Substation	South Milford		Southern	34.5	Base	2020	N-1, 75% Tx Capacity

[30] The inclusion of a substation in the list of candidate locations does not represent a determination regarding the continued operation of that substation, which instead would be addressed in a utility rate case or other future proceeding before the Commission. The assumption that any listed substation will continue in operation is solely for purposes of the LVDG study; in view of the current lack of certainty regarding future substation status, that study assumption will not be controlling in any such future case or proceeding.

Table 9. Base Case Violations (Capacity Deficiencies)

No.	EDC	Asset Type	Asset Name[30]	Substation	Region	Voltage	Forecast	First Violation Year	Violation Type
23	Eversource	Bulk Substation	White Lake		Northern	34.5	Base	2020	N-1, 75% Tx Capacity
24	Eversource	Bulk Substation	Whitefield		Northern	34.5	Base	2020	N-1,
25	Eversource	34.5 kV Circuits	380_65	Madbury	Eastern	34.5	Base	2020	Normal
26	Eversource	Non-34.5 kV distribution circuits	2W2_41	Lochmere	Northern	12.47	Base	2020	Normal
27	Eversource	Non-34.5 kV distribution circuits	18H1_21	Millyard	Southern	4.16	Base	2020	Normal
28	Eversource	Non-34.5 kV distribution circuits	41H2_61	North Dover	Eastern	4.16	Base	2020	Normal
29	Eversource	Non-34.5 kV distribution circuits	76W1_31	North Keene	Western	12.47	Base	2020	Normal
30	Eversource	Non-34.5 kV distribution circuits	37H1_42	Tilton	Northern	4.16	Base	2020	Normal
31	Eversource	Non-34.5 kV distribution circuits	37H2_42	Tilton	Northern	4.16	Base	2020	Normal
32	Liberty	Transformer	L4	Olde Trolley 18	Salem NH	13.2	Base	2022	>100% Normal
33	Liberty	Transformer	L1	Salem Depot 9	Salem NH	13.2	Base	2020	>100% Normal
34	Liberty	Transformer	L2	Salem Depot 9	Salem NH	13.2	Base	2020	>100% of Emergency Rating
35	Liberty	Transformer	T1	Vilas Bridge 34	Bellows Falls	13.2	Base	2020	>100% of Emergency Rating
36	Liberty	Feeders	18L4	Olde Trolley 18	Salem NH	13.2	Base	2022	>100% Normal
37	Liberty	Feeders	9L1	Salem Depot 9	Salem NH	13.2	Base	2020	>100% Normal
38	Liberty	Feeders	15H1	Monroe 15	Monroe	2.4	Base	2020	>100% Normal
39	Liberty	Feeders	11L1	Craft Hill 11	Lebanon	13.2	Base	2022	>100% Normal
40	Liberty	Feeders	16L1	Mount Support 16	Lebanon	13.2	Base	2022	>100% Normal
41	Liberty	Feeders	16L4	Mount Support 16	Lebanon	13.2	Base	2021	>100% Normal
42	Unitil	Transformer	Bow Junction 7T2 Xfmr	Bow Junction	Capital	13.8	Base	2022	>90% Normal
43	Unitil	Transformer	Bow Bog 18T2 Xfmr	Bow Bog	Capital	13.8	Base	2024	>90% Normal
44	Unitil	Transformer	Dow's Hill 20T1	Dow's Hill	Seacoast	4.16	Base	2021	>90% Normal
45	Unitil	Circuit	18W2	Bow Bog	Capital	13.8	Base	2025	>90% Normal

Source: Guidehouse, EDC data

Following the review of EDC historical capacity violations, 13 historical capacity deficiencies projects should also be considered for inclusion in the subset of locations for detailed evaluation.

Table 10 summarizes the historical projects by EDC and year in service. Some of these show a year in service of 2020 but the projects had already begun in prior years, such as 2018 or 2019.

Table 10. Summary of Historical Projects

No.	EDC	Project	Year in Service
1	Eversource	Mill Pond Substation	2017
2	Eversource	Rimmon Substation	2020
3	Eversource	Bristol Substation	2015
4	Eversource	White Lake Substation	2020
5	Eversource	Pemi Substation	2020
6	Eversource	West Rd Overloaded Steps	2020
7	Eversource	388 Line Overload	2020
8	Eversource	34.5kV lines Rimmon Substation	2016
9	Eversource	Londonderry	2015
10	Liberty	Mount Support	2017
11	Liberty	Golden Rock Substation	2019
12	Unitil	New Sub-transmission Lines – Broken Ground to Hollis	2020
13	Unitil	Kingston Substation	2017

Source: Guidehouse, EDC data

The following sections describe the selection criteria and how it is applied to derive a subset of locations with capacity deficiencies for further analysis. The objective of the selection process is to ensure a sufficient number of locations, from the 109 forward-looking and 13 historical projects, 122 potential sites, to accurately analyze the indicative value of avoiding capacity investments.

2.3.1 Location Selection Criteria

The study team developed guidelines to select a subset of locations for in-depth analysis. Selection criteria were designed to ensure that the subset of locations represents different types of future and historical capacity investments, and various locations throughout the state. The study team specified that the subset of locations for detailed analysis should include the following:

- A proportional share of locations based on EDC load and service territories served
- Each major region served by each EDC, if possible[31]
- Winter and summer peaking locations
- Midday and late-day peaking locations
- Bulk and non-bulk substations
- Small and large capacity deficiencies
- Normal and contingency overloads or performance violations
- Historical and forward-looking capacity investments

[31] Some regions had few, or no, capacity deficiencies under the Base Case analysis.

The study team determined that a subset of 16 locations (of the 122 capacity deficiencies identified) is sufficient to meet the specified selection criteria. Section 2.3.2 presents the selected subset of locations.

2.3.2 Locations Selected for In-Depth Analysis

Table 11 presents the final list of locations representing each of the EDCs, based on the selection criteria described in Section 2.3.1. To satisfy the selection criteria, the study team includes locations with capacity deficiencies for a range of low, base, and high load growth forecasts. For example, for Eversource, the only non-bulk substation violation occurred for the high growth scenario (Location Numbers 5 and 6 in Table 11).

Table 11. Locations Selected for In-Depth Analysis

No.	EDC	Description	Region	First Year of Capacity Deficiency[32]	First Year Cap. Deficit (MW)[33]	Selection Criteria
1	Eversource	Pemigewassett (Pemi) Substation (Bulk)	Northern	2020	8	Base case transformer normal violation
2	Eversource	Portsmouth Substation (Bulk)	Eastern	2020	12	Base case transformer normal violation
3	Eversource	South Milford Substation (Bulk)	Southern	2020	23	Base case contingency violation
4	Eversource	Monadnock Substation (Bulk)	Western	2020	2	Base case transformer normal violation
5	Eversource	East Northwood Substation (Non-Bulk)	Eastern	2021- High	0.06 – High	High forecast LTE violation
6	Eversource	Rye Substation (Non-Bulk)	Eastern	2022- High	0.07 – High	High forecast LTE violation
7	Eversource	Bristol Substation (Non-Bulk)	Northern	2015	0.04	Base case LTE violation
8	Eversource	Madbury ROW Circuit (34.5 kV)	Eastern	2020	3	Base case normal capacity violation
9	Eversource	North Keene Circuit (12.47 kV)	Northern	2028- High	0.1- High	High forecast normal capacity violation
10	Eversource	Londonderry Circuit (34.5 kV)	Southern	prior to 2014	0.6	Base case normal capacity overload
11	Liberty	Vilas Bridge Substation (Non-Bulk)	Walpole	2020	1	Base case LTE violation
12	Liberty	Mount Support Substation (Bulk)	Lebanon	2014	0.4	Base case normal capacity violation
13	Liberty	Golden Rock Substation (Bulk)	Salem	2019	10	Base case normal capacity violation
14	Unitil	Bow Bog Substation (Non-Bulk)	Capital	2024- High	0.1- High	Base case violation
15	Unitil	Dow’s Hill Substation (Bulk)	Seacoast	2020- High	0.04 – High	Base case violation
16	Unitil	Kingston Substation (Bulk)	Seacoast	prior to 2014	6	Base case violation

Source: Guidehouse, EDC data

[32] For historical investments, the first year of capacity deficiency is the year the investment went into service; for forward-looking investments, the first year of capacity deficiency is the in-service year.
[33] Base case unless otherwise noted; for example, “High” is indicated if no violations occurred for the Base Case load forecast.

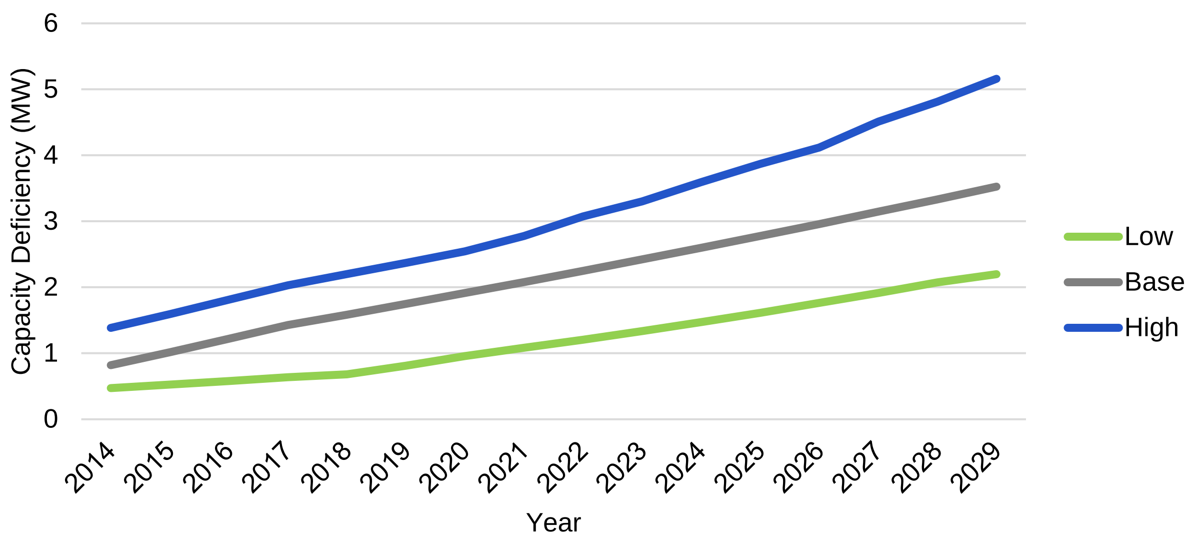
The cost of traditional distribution capacity investments to address deficiencies for each of the 16 locations and the potential value of avoidance via DG is presented in Section 3.0.

2.3.3 Distribution Capacity Deficiency Forecasts for Selected Locations

This section summarizes the results of the screening analysis at each of the 16 locations selected for detailed analysis. For each EDC, capacity deficiency forecasts are presented under the base, low, and high forecasts for the 16 selected locations. It includes illustrations of annual capacity deficiencies for each EDC.

Figure 13 and Figure 14 present historical and forward-looking capacity deficiencies for Eversource. The magnitude of the deficiencies is lower in prior years compared to forward-looking deficiencies, largely due to the change in system planning criteria. That change results in an increase in the number and magnitude of deficiencies, many of which occur in 2020, or in years shortly thereafter.

Figure 13. Historical Location Capacity Deficiencies – Eversource[34]

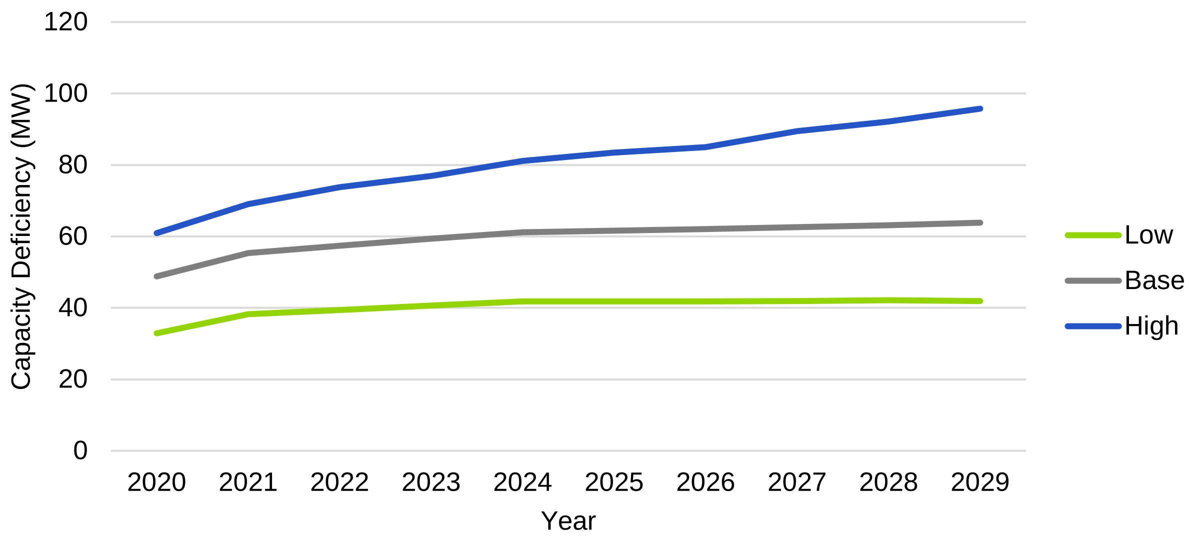


Source: Guidehouse, EDC data

Capacity deficiencies are projected to increase relatively sharply in 2020 and 2021, but taper off beyond these years for the low and base load forecasts for the selected Eversource locations.

[34] Projected capacity deficiencies based on load forecast prepared at the time a decision was made to invest in the project.

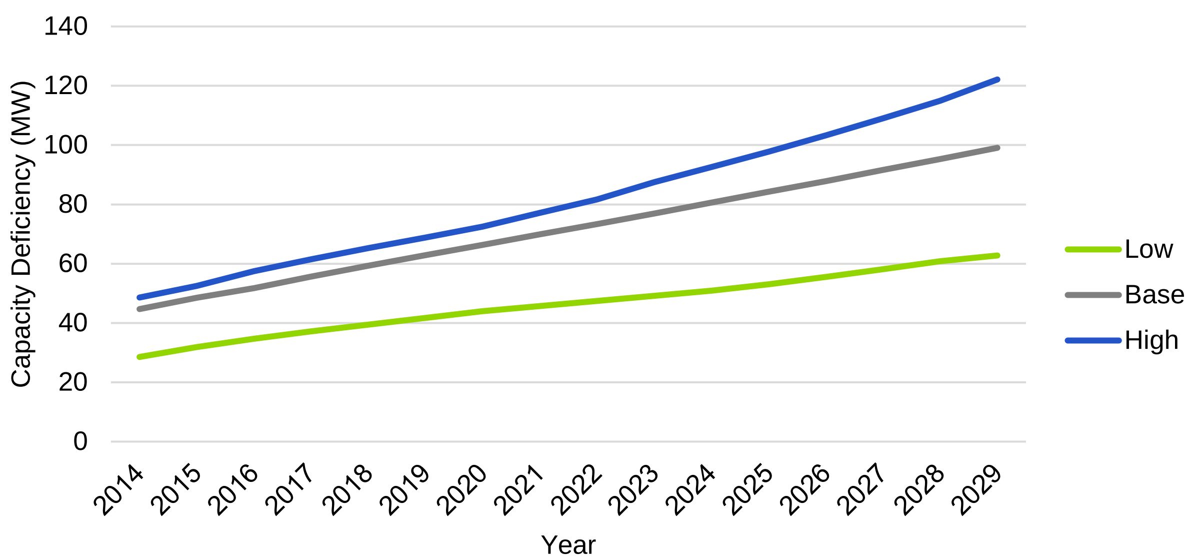
Figure 14. Forward-Looking Location Capacity Deficiencies – Eversource



Source: Guidehouse, EDC data

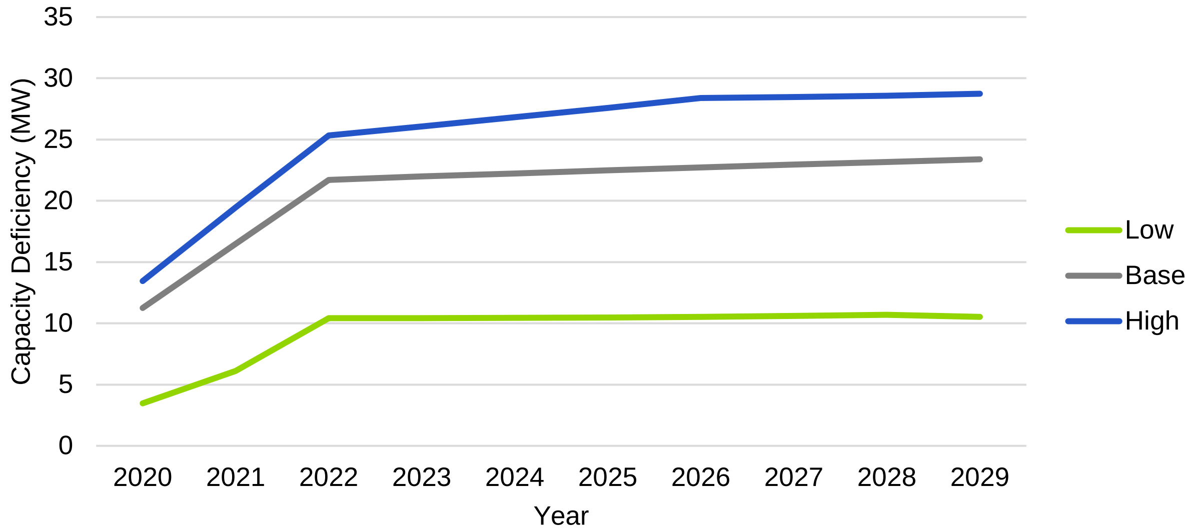
Figure 15 presents capacity deficiencies by year for Liberty. Large capacity deficiencies occur in prior years, as a major project is a previously completed project. Figure 16 presents the forward-looking capacity deficiencies by year for Liberty.

Figure 15. Historical Location Capacity Deficiencies – Liberty



Source: Guidehouse, EDC data

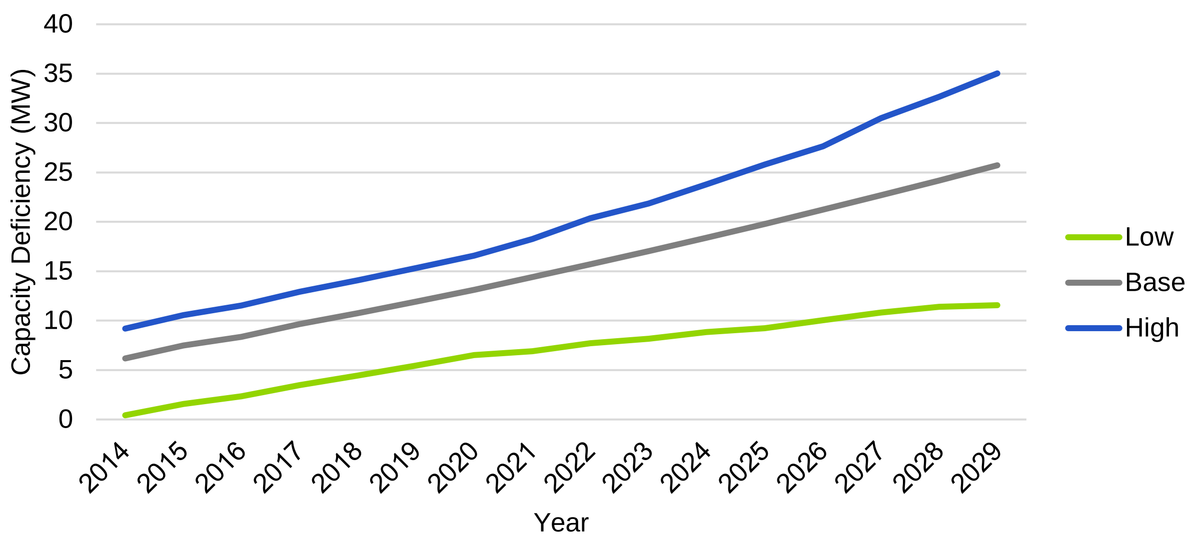
Figure 16. Forward-Looking Location Capacity Deficiencies – Liberty



Source: Guidehouse, EDC Data

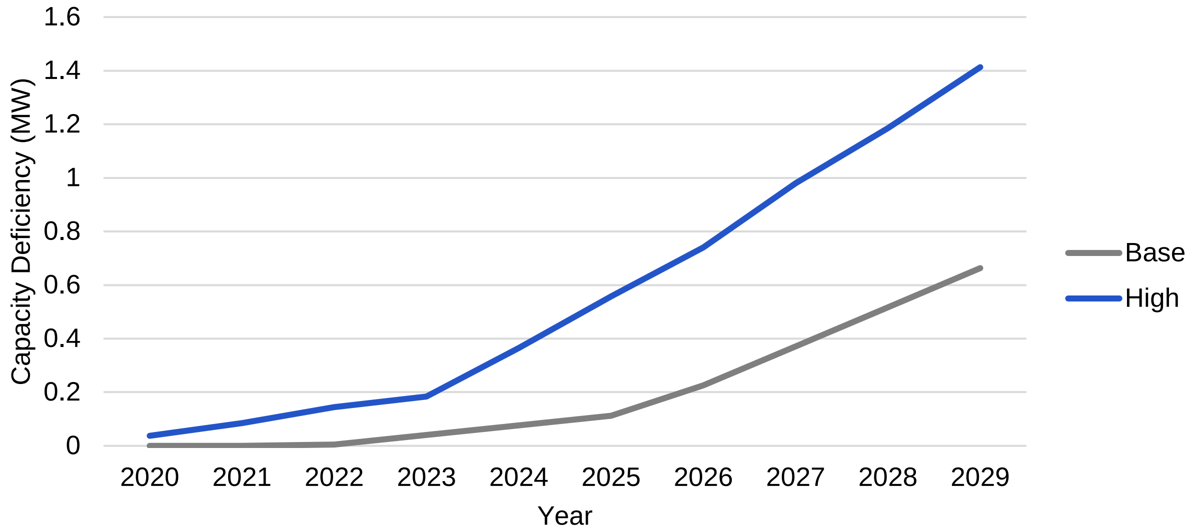
Figure 17 and Figure 18 present historical and forward-looking capacity deficiencies by year for Unitil. As shown in Figure 17, similar to Liberty, a major project completed in prior years caused large capacity deficiencies to occur in early years and increase steadily throughout the study timeframe as the magnitude of deficiencies was projected to increase at a high rate due to load growth. Figure 18 shows the two forward-looking Unitil projects that are minor non-bulk substations overloads with the deficiencies first occurring in later years (there are no capacity deficiencies for the low forecast).

Figure 17. Historical Location Capacity Deficiencies – Unitil



Source: Guidehouse, EDC data

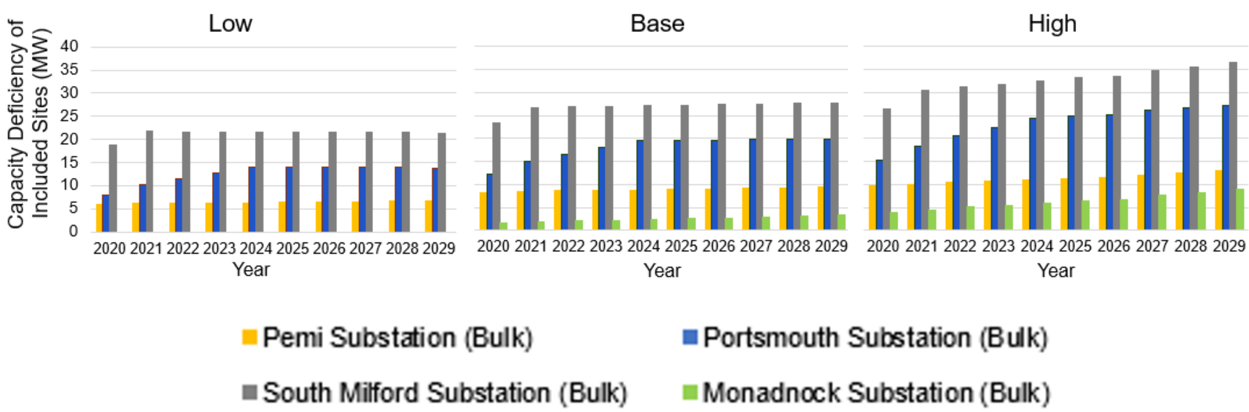
Figure 18. Forward-Looking Location Capacity Deficiencies – Unitil



Source: Guidehouse, EDC Data

Figure 19 presents selected bulk substation capacity planning criteria violations for Eversource under the low, base, and high load forecasts. Both the magnitude of the capacity deficiency and the number of locations with violations varies by the load forecast scenario. However, capacity deficiencies are highest for bulk substations due to the amount of load served and a recent change in Eversource's capacity planning criteria for bulk substations.

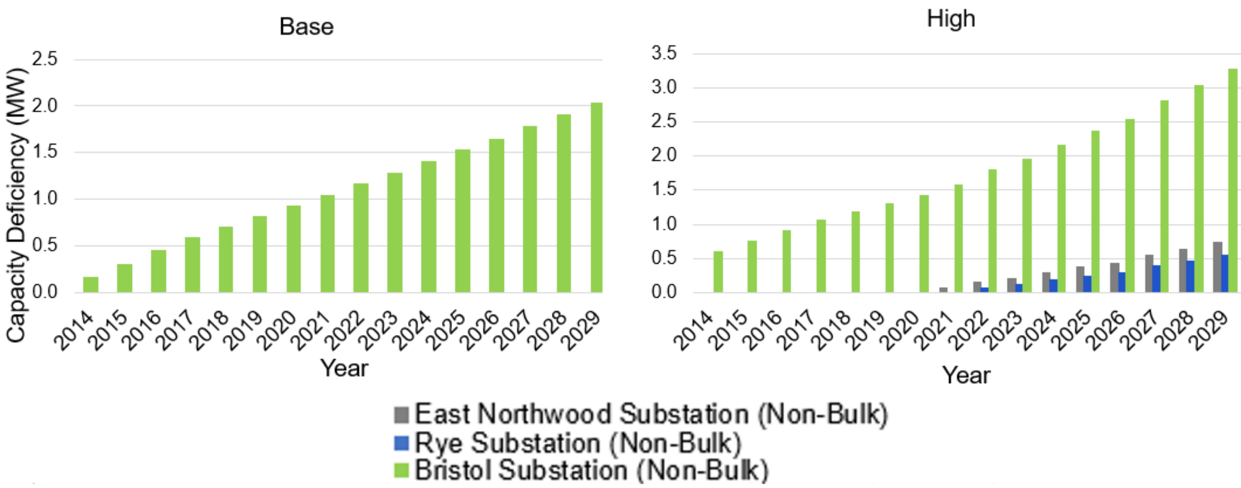
Figure 19. Bulk Substation Capacity Deficiencies – Eversource



Source: Guidehouse, EDC data

Figure 20 presents selected non-bulk substation capacity planning criteria violations for Eversource. Non-bulk substations typically have lower capacity ratings and serve fewer customers compared to bulk substations; hence, the magnitude of capacity deficiencies is lower than bulk substations. There are no non-bulk substation future capacity deficiencies during the Low Case.

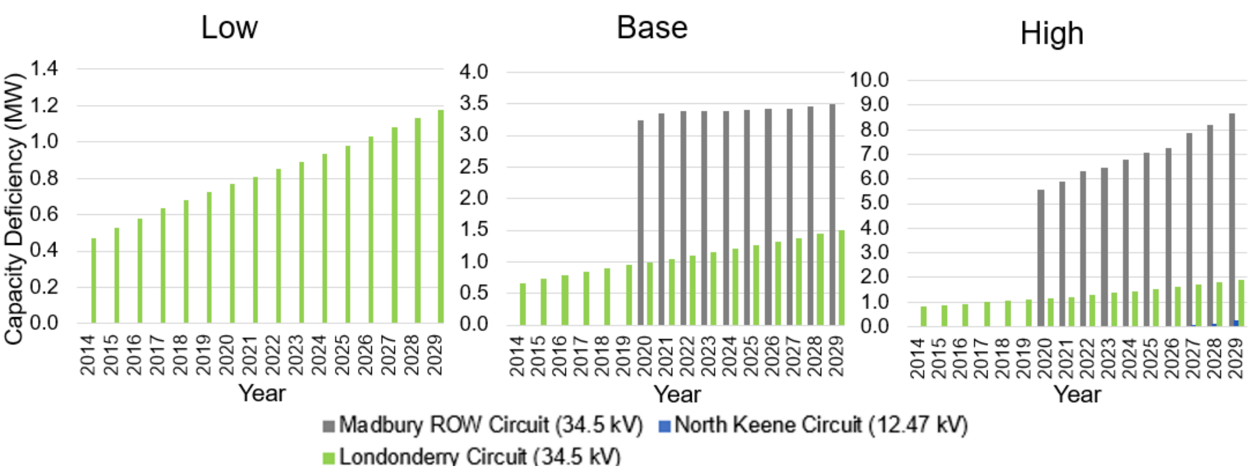
Figure 20. Non-Bulk Substation Capacity Deficiencies – Eversource



Source: Guidehouse, EDC data

Figure 21 presents selected distribution line capacity planning criteria violations for Eversource. Most distribution lines (circuits) typically have lower capacity ratings and serve fewer customers compared to bulk substations; hence, the magnitude of capacity deficiencies is lower than bulk substations, but are comparable to non-bulk substations.

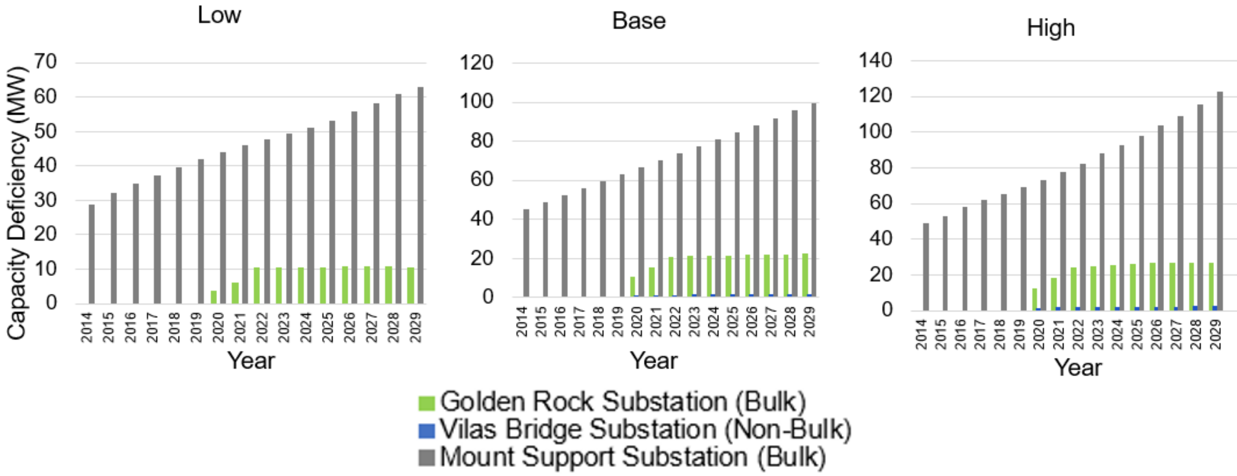
Figure 21. Circuit Capacity Deficiencies – Eversource



Source: Guidehouse, EDC data

Figure 22 presents selected capacity planning criteria violations for Liberty. Two of the three selected locations are historical projects completed between 2015 and 2020. Two of the three Liberty locations also have high capacity deficiencies; one of these, Mount Support, a historical project location, has very high deficiencies due to large number of violations addressed by the project. Due to high load growth projections assumed at the time the project was completed, future deficiencies increase at a higher rate compared to other locations.

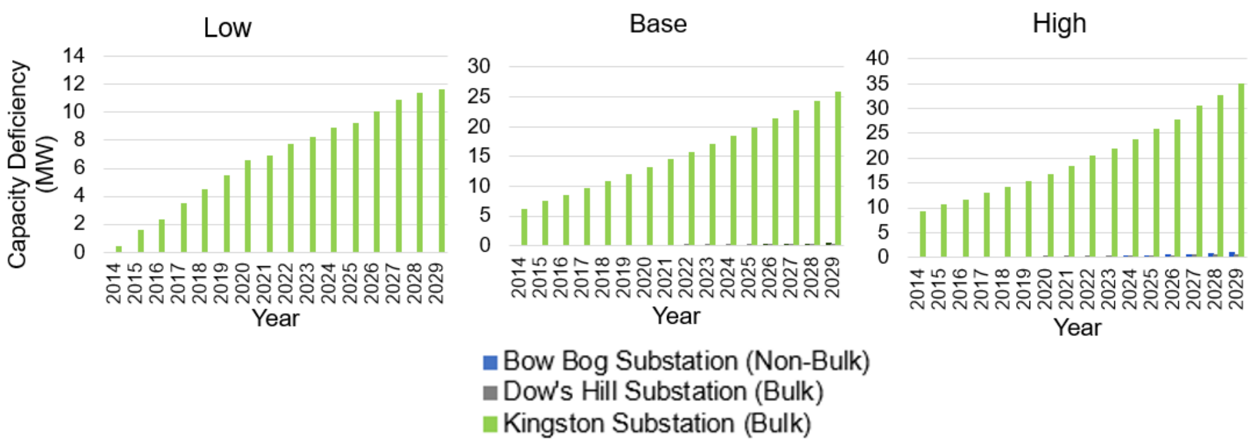
Figure 22. Selected Locations Capacity Deficiencies – Liberty



Source: Guidehouse, EDC data

Figure 23 presents selected locations' capacity planning criteria violations for Unitil. Kingston Substation, the one location with large capacity deficiencies, is a historical location with bulk substation capacity deficiencies. Few locations were available for selection in the forward-looking timeframe due to the prior completion of capacity projects and lack of significant load growth. The two forward-looking locations selected for in-depth review are non-bulk substations.

Figure 23. Selected Locations Capacity Deficiencies – Unitil



Source: Guidehouse, EDC data

3.0 Estimation of Investment Costs for Determining Avoidance Values (Step 2)

Step 2 of the study estimates the cost of capacity investments that potentially could be avoided for the 16 locations selected for in-depth review. The objective is to use these capital costs as one of the primary inputs to an economic model to then derive annual avoided costs over the 15-year study timeframe to inform the development of future

NEM tariffs.[35] The use of the capital costs to derive the avoided value is outlined in Section 4.0. The study determines the cost of traditional capacity investments for each of the 16 locations by:

- Developing avoidable investment capital cost estimates based on utility investments and historical spending for each selected location, including sub-transmission lines, substations, and distribution lines.
- Confirming capacity upgrade options and unit costs with the EDCs.
- Identifying potential capacity avoidance using scenarios (base, high, and low forecasts).
- Establishing cost avoidance associated with capacity avoidance opportunities by feeder type, voltage, location, length, and load diversity.

The analysis included derivation of historical spending versus forward-looking planned spend for traditional investments. However, only the capacity component of prior actual investments was used to determine theoretically avoidable costs for projects that have already been completed.[36]

3.1 Investment Costs Associated with Capacity Needs

This section identifies the cost of traditional investments required to address capacity deficiencies at the 16 locations derived in Section 2.3.2. It includes only those costs required to address capacity deficiencies, excluding any historical or forward-looking costs that may be needed to address reliability or performance issues. It also excludes the cost of minor investments such as capacitor banks, line transformers, and secondary line upgrades, unless those costs are included in major projects where minor upgrades are included in project totals, such as new distribution feeders that are constructed as part of a new substation or substation upgrade.

3.1.1 Derivation of Distribution Capacity Costs

Capacity costs for traditional investments that the EDCs would otherwise make to address capacity deficiencies, absent DG, or other load reduction measures were developed. The cost of traditional distribution capacity projects is used in Section 4.0 to determine the potential value of investment avoidances. Actual distribution capacity investments were reviewed and used for historical project locations, whereas forward-looking investments were estimated for study purposes.

The approach and assumptions applied to derive traditional capacity investments are summarized as follows:

[35] As noted previously, the analysis is intended to be theoretical and should not be construed as an NWS analysis for avoiding traditional capacity investments at specific locations.
[36] The derivation and application of costs associated with completed projects is intended as a counter-factual analysis to evaluate avoided costs based on a combination of actual and forecast costs of conventional capacity investments.

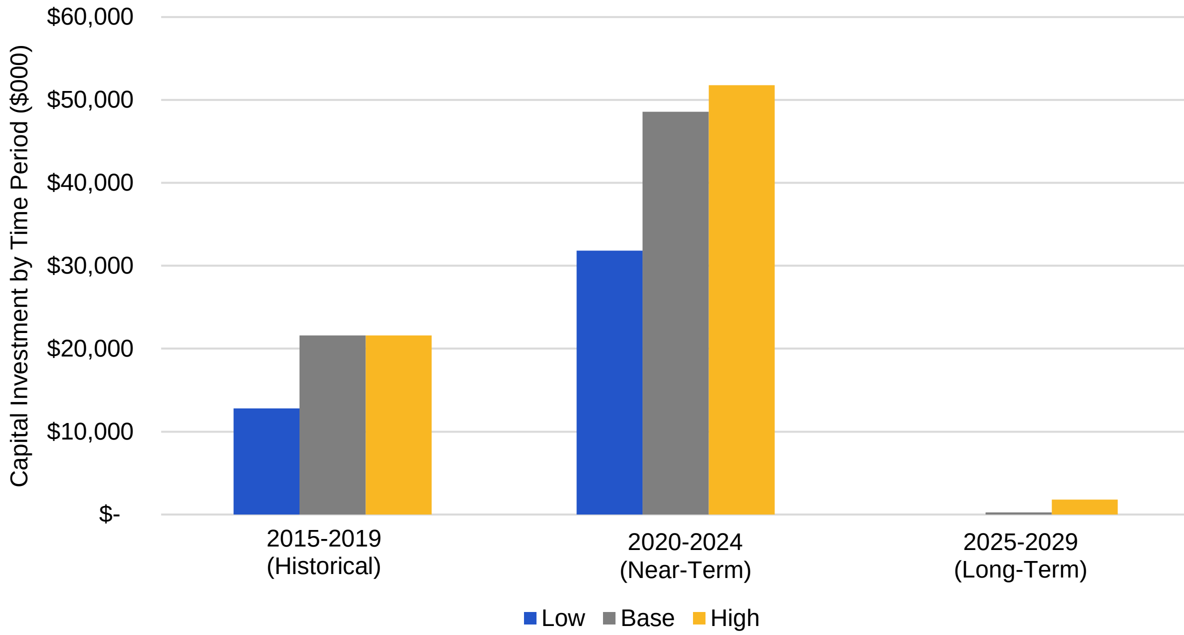
1. Capacity additions or upgrades are structured to address deficiencies over the entire study timeframe, up to year 2029
2. Mitigation options to address capacity deficiencies are based on EDC planning criteria that existed or exist at the date of the first year of capacity deficiency
3. Load growth is based on the growth projections that were prepared at the time the decision was made by an EDC for historical investments; for forward-looking investments, load growth projections are outlined in Section 2.2
4. The first year of the capacity investment is assumed to occur in the first year a capacity deficiency occurs. EDCs expect to complete some of the near-term projects after the first year a capacity deficiency is expected to occur.[37]
5. Only the capacity investment component of a project is included in project totals, some completed or proposed projects have a reliability cost component that is not reflected in the investment costs used in the LVDG analysis[38]
6. Actual EDC investment costs are used for historical project locations
7. EDC budget values are used to support derivation of forward-looking investments, where available
8. EDC per unit costs are applied for project locations where cost estimates are not available, typically for projects beyond the first 5 years

3.1.2 EDC Locational Capacity Investments

Figure 24 presents the composite capital investment value by EDC over the study timeframe for the 16 locations over three intervals: historical (2015-2019), near-term (2020–2024), and long-term (2025–2029). As prior sections note, the majority of capacity investments are needed in the near-term due to recent changes to planning criteria, with minimal investment needed thereafter to address capacity deficiencies. Further, long-term investments shown in Figure 24 are only required under the high load growth forecast.

[37] For example, several large capacity investments in the analysis are assumed to be undertaken in 2020 although the project may not yet actually be underway and may in fact not occur for several years. This is largely the result of Eversource’s recently revised planning criteria.
[38] The EDCs provided data that indicated the amount of project costs associated with capacity versus reliability. The portion of the project cost needed for reliability was removed from total project costs.

Figure 24. Capital Investment Over Time for Selected Locations Across all EDCs



Note: 2015-2019 based on historical values (for capacity additions only)
Source: Guidehouse, EDC data

Table 12 summarizes the capital investment cost by location for the 16 selected locations. The investment costs by location range from a low of $200,000 for the East Northwood Substation in the Eversource service territory to a high of $14,300,000 for the Monadnock Substation in the Eversource service territory.

Table 12. Capital Investment by Location

EDC	Location	Traditional Investment Estimated Capital Costs for Capacity Additions
Eversource	Pemi Substation (Bulk)	$7,469,000
	Portsmouth Substation (Bulk)	$2,500,000
	South Milford Substation (Bulk)	$13,150,000
	Monadnock Substation (Bulk)	$14,300,000
	East Northwood Substation (Non-Bulk)	$200,000
	Rye Substation (Non-Bulk)	$3,000,000
	Bristol Substation (Non-Bulk)	$1,200,000
	Madbury ROW Circuit (34.5 kV)	$2,000,000
	North Keene Circuit (12.47 kV)	$1,530,000
	Londonderry Circuit (34.5 kV)	$615,000
Liberty	Vilas Bridge Substation (Non-Bulk)	$2,300,000
	Mount Support Substation (Bulk)	$7,608,000
	Golden Rock Substation (Bulk)	$6,400,000
Unitil	Bow Bog Substation (Non-Bulk)	$254,000
	Dow’s Hill Substation (Bulk)	$446,000
	Kingston Substation (Bulk)	$12,193,000

Source: Guidehouse, EDC data

When reviewing the capacity violations for the 16 selected locations, some capacity deficiencies are only triggered under certain load growth forecasts, while others are present in all load forecast scenarios. This is indicated per site in Table 13.

Table 13. Summary of Selected Locations Load Forecast Scenarios

EDC	Description	Low	Base	High
Eversource	Pemi Substation (Bulk)	✓	✓	✓
	Portsmouth Substation (Bulk)	✓	✓	✓
	South Milford Substation (Bulk)	✓	✓	✓
	Monadnock Substation (Bulk)		✓	✓
	East Northwood Substation (Non-Bulk)			✓
	Rye Substation (Non-Bulk)			✓
	Bristol Substation (Non-Bulk)	✓	✓	✓
	Madbury ROW Circuit (34.5 kV)		✓	✓
	North Keene Circuit (12.47 kV)			✓
	Londonderry Circuit (34.5 kV)	✓	✓	✓
Liberty	Vilas Bridge Substation (Non-Bulk)		✓	✓
	Mount Support Substation (Bulk)	✓	✓	✓
	Golden Rock Substation (Bulk)	✓	✓	✓
Unitil	Bow Bog Substation (Non-Bulk)		✓	✓
	Dow's Hill Substation (Bulk)		✓	✓
	Kingston Substation (Bulk)	✓	✓	✓
	Total	**8**	**13**	**16**

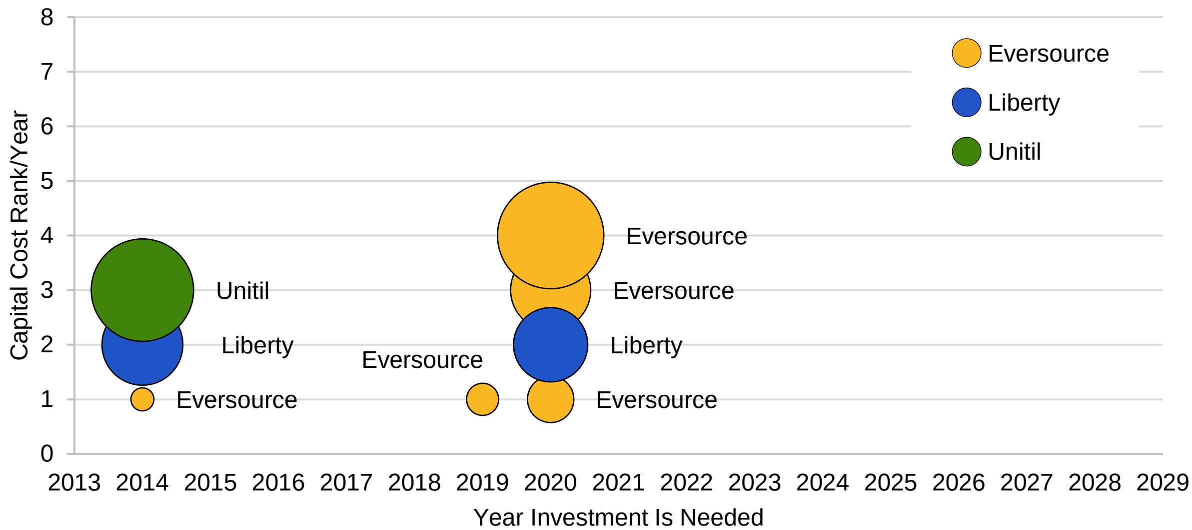
Source: Guidehouse, EDC data

The following section summarizes the capital investment cost for the three load forecast scenarios: low, base, and high.

3.2 Capital Cost Results by Load Forecast Scenario

Figures 25 through 27 present the capital costs of the selected locations by year of investment for each load growth forecast. In these figures, yellow represents an Eversource location, blue represents a Liberty location, and green represents a Unitil location. The size of the bubble equates to the amount of capital investment cost (see Table 12), i.e., larger bubble means higher capital cost. The locations are also ranked in each year by the amount of investment cost per location for that year with the highest investment cost in that year having the highest rank (i.e., highest bubble on the figure for that year). Figure 25 presents the low load forecast's capital costs by year of investment need for each of the EDCs. Figure 25 shows the eight locations of the selected 16 that would require an investment in the low load forecast scenario.

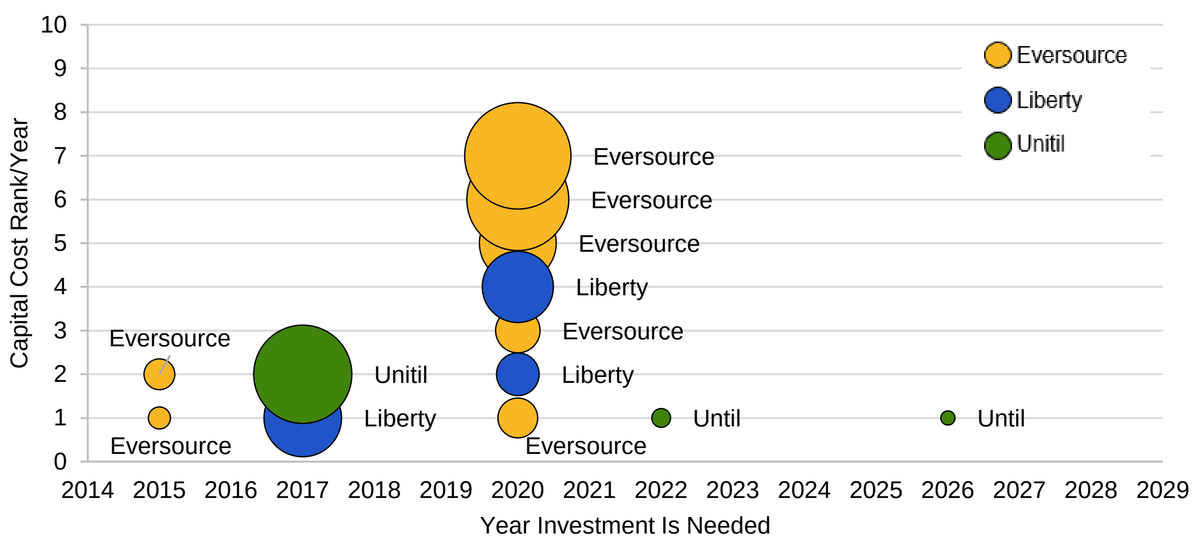
Figure 25. Low Load Forecast Capital Costs by Year of Investment Need



Source: Guidehouse, EDC data

Figure 26 shows results for the base load forecast's avoided costs by year of capital investment need for each of the EDCs. More location capital investments are required under the base load forecast scenario than the low load forecast scenario. Figure 26 includes 13 of the selected 16 locations.

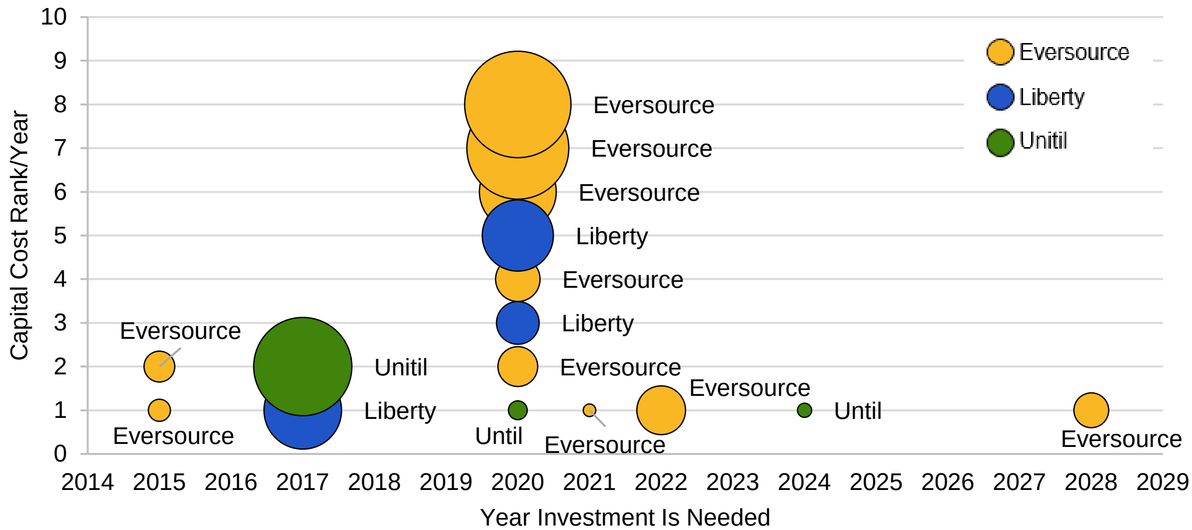
Figure 26. Base Load Forecast Capital Costs by Year of Investment Need



Source: Guidehouse, EDC data

Figure 27 presents the high load forecast's avoided costs by year of investment need for each of the EDCs. The high forecast includes all of the 16 selected locations and investments out to year 2028.

Figure 27. High Load Forecast Capital Costs by Year of Investment Need



Source: Guidehouse, EDC data

4.0 Economic Analysis and Mapping of DG Output Profiles with Distribution Capacity Needs (Step 3)

Step 3 includes an economic analysis to estimate values of investment avoidance at the 16 selected locations and the mapping of representative DG output profiles with the distribution capacity needs. The analysis to develop an economic value of avoiding investments starts with calculating the investment revenue requirement. The team annualizes this value to determine an annual total dollar value and uses the maximum demand reduction needed to avoid the investment in each year to determine an annual value per kW. Finally, to determine an indicative hourly value per kW per year, the team distributes the annual total value either for 2020 or for the first year of need if later than 2020 over the hours of need in that year. Sections 4.1 and 4.2 summarize the economic analysis.

The second part of Step 3 includes a comparison of hourly load profiles for all 16 locations and representative DG production profiles to illustrate the coincidence in terms of hours of the day between location-specific capacity deficits and DG production profiles. This is summarized in Sections 4.3.1 and 4.3.2. Section 4.3.3 includes a description of this methodology.

4.1 Annual Avoidance Benefits Estimation Methodology

Completing the economic analysis first requires development of an annualized value of local avoided costs. Based on an industry literature scan, the study identifies various methods to estimate the capacity avoidance benefits:

- Annualization of difference in net present value (NPV) of revenue requirement
- Real Economic Carrying Charge (RECC) methodologies

- Flat annualization of a capital cost to estimate the annual cost of that investment
- Stochastic methodologies[39]

Appendix C presents the four methodologies considered for forecasting the economic value of distribution capacity avoidance, including the pros and cons of each approach. As a result of this comparison, the team determined that the RECC methodology without a set deferral period, or Method C, is the most appropriate method of those considered to estimate the locational value of avoidance and can be used to inform future studies and NEM tariffs. Avoidance in all further references is defined as the yearly deferral of the estimated capital investment cost associated with capacity that is quantified from the year of the investment need through the end of the study period. The decision to use the RECC methodology was driven by the flexibility of the RECC methodology to be leveraged throughout the study period without assuming specific avoidance durations such as 5 or 10 years, as described above.

4.1.1 RECC Methodology Detailed Summary

The RECC method leads to the development of a RECC rate that yields the same present value of the investment revenue requirement when adjusted for inflation over the life of the asset. This is basically a reshaping of the costs to develop a stream of costs that increase with inflation. In other words, this is the amount of dollars in the first year the investment is needed that, when increased at a fixed rate of inflation every year, results in the same present value at the end of the life of the investment as the present value of the revenue requirements. The inputs to determine the RECC rate are the same as the inputs for developing the revenue requirement (Table 14).

[39] While the study considered stochastic methodologies, the scope of the study did not include a full stochastic analysis, so this approach was excluded from further study.

Table 14. Revenue Requirement and RECC Inputs

Input	Eversource[40]	Liberty (as of April 30, 2020)[41]	Unitil[42]
Long Term Debt Rate	4.11%	5.97%	7.15%
Equity Rate	9.67%	9.40%	9.50%
% Debt in Capital Structure	48.08%	50.00%	49.03%
% Equity in Capital Structure	51.92%	50%	50.97%
Return on Rate Base	8.70%	9.45%	10.15%
Nominal Discount Rate or After Tax WACC (%/year)	6.82%	7.69%	8.32%
Inflation Rate[43]	1.90%	1.90%	1.90%

Source: Guidehouse, EDC data

In addition to developing a stream of costs, the RECC value also reflects the value (including inflation) associated with avoiding an investment in any specific year and moving that investment to the next year. This method of developing the RECC rate was first established in the late 1970s.[44]

Key inputs to the RECC method to determine the annual avoidance value are the revenue requirement, inflation rate, weighted average cost of capital (WACC) for each EDC, and asset lifetime. The asset lifetime is assumed to be 30 years for all assets evaluated.

The specific equation used to calculate the RECC rate (%/year) is:

$$RECC\left(\frac{\%}{year}\right) = (WACC - inflation\ rate) * \left(\frac{(1+WACC)^{asset\ lifetime}}{(1+WACC)^{asset\ lifetime} - (1+inflation\ rate)^{asset\ lifetime}}\right)$$

Once the RECC rate is determined, the avoidance value for a single year is calculated using the equation below:

[40] Docket No. 18-177. Eversource Petition for Continuation of Reliability Enhancement Program. Purington and Goulding Technical Statement Attachment. Available at: https://www.puc.nh.gov/regulatory/Docketbk/2018/18-177/INITIAL%20FILING%20-%20PETITION/18-177_2018-11-16_EVERSOURCE_ATT_TECH_STATEMENT_ALLEN_PURINGTON_GOULDING.PDF
[41] Docket No. DE 17-189. Petition for Approval of Battery Storage Program. Settlement of the Parties, Attachment 1. (November 19, 2018) Available at: https://puc.nh.gov/Regulatory/Docketbk/2017/17-189/LETTERS-MEMOS-TARIFFS/17-189_2018-11-19_GSEC_ATT_SETTLEMENT.PDF This Study does not incorporate the updated values as a result of Order No. 26,377 (June 30, 2020), which approved Liberty's request for an increase in permanent rates. However, the project team reviewed the updated numbers and concluded that the changes had a de minimis impact on study results and did not change the study conclusions.
[42] Docket No. DE 19-043. Unitil 2019 Step Adjustment. Direct Testimony of Todd R. Diggins. Schedule TRD-1 2019. Available at: https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-043/INITIAL%20FILING%20-%20PETITION/19-043_2019-02-28_UES_ATT_DTESTIMONY_DIGGINS.PDF
[43]Gross Domestic Product: Implicit Price Deflator https://fred.stlouisfed.org/data/GDPDEF.txt
[44] Lazar, J., Chernick, P., Marcus, W., and LeBel, M. (Ed.). (2020, January). Electric cost allocation for a new era: A manual. Montpelier, VT: Regulatory Assistance Project.

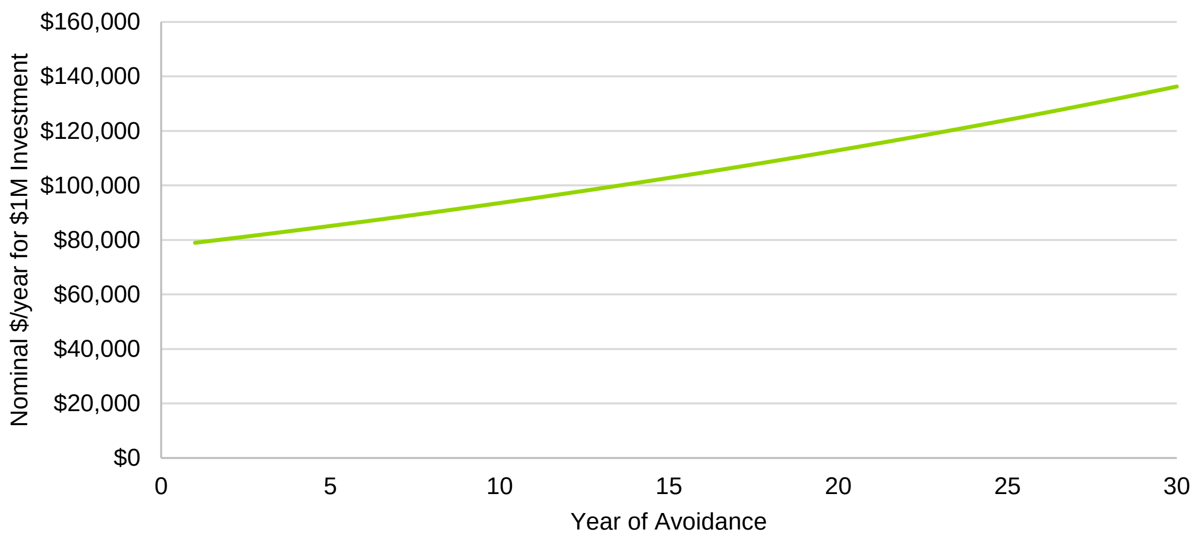
$$Single\ year\ avoidance\ benefit\ (\$) = Revenue\ Requirement * \frac{RECC}{(1 + inflation\ rate)}$$

The avoidance value in any given year can then be calculated as:

$$Avoidance\ benefit\ in\ year\ x\ (\$) = Single\ year\ avoidance\ benefit * (1 + infalation\ rate)^x$$

Figure 28 provides an example of the calculated RECC avoidance benefit for an investment of $1 million with a 30-year asset lifetime. The yearly avoidance benefit increases from approximately $80,000 up to close to $140,000 over the 30-year period. For this study, avoided costs per kW were only calculated to the end of the study period because capacity deficiency is unknown beyond the study period.

Figure 28. RECC Avoidance Value



Source: Guidehouse, EDC data

First, the RECC annual value was used to develop the yearly $/kW. As described in the next section, the RECC annual value is also used to develop the $/kW/hr value. The key input to the calculation of those values is the revenue requirement of the estimated traditional capacity investment (development of the estimate of capital cost associated with capacity is summarized in Section 3.0). Table 15 lists the revenue requirement for the 16 locations considered for in-depth review. The revenue requirement ranges from a low of $242,995 for the East Northwood Substation (Non-Bulk) in the Eversource service territory to a high of $17,374,146 for the Monadnock Substation (Bulk), also in the Eversource service territory.

Table 15. Revenue Requirement by Location

EDC	Location	Estimated Revenue Requirement for Traditional Investment Capacity Additions
Eversource	Pemi Substation (Bulk)	$9,074,650
	Portsmouth Substation (Bulk)	$3,037,438
	South Milford Substation (Bulk)	$15,976,924
	Monadnock Substation (Bulk)	$17,374,146
	East Northwood Substation (Non-Bulk)	$242,995
	Rye Substation (Non-Bulk)	$3,644,926
	Bristol Substation (Non-Bulk)	$1,457,970
	Madbury ROW Circuit (34.5 kV)	$2,429,950
	North Keene Circuit (12.47 kV)	$1,858,912
	Londonderry Circuit (34.5 kV)	$747,210
Liberty	Vilas Bridge Substation (Non-Bulk)	$2,715,803
	Mount Support Substation (Bulk)	$7,557,017
	Golden Rock Substation (Bulk)	$8,983,404
Unitil	Bow Bog Substation (Non-Bulk)	$299,375
	Dow's Hill Substation (Bulk)	$525,674
	Kingston Substation (Bulk)	$14,371,184

Source: Guidehouse, EDC data

4.1.2 Annual Avoidance Value Results

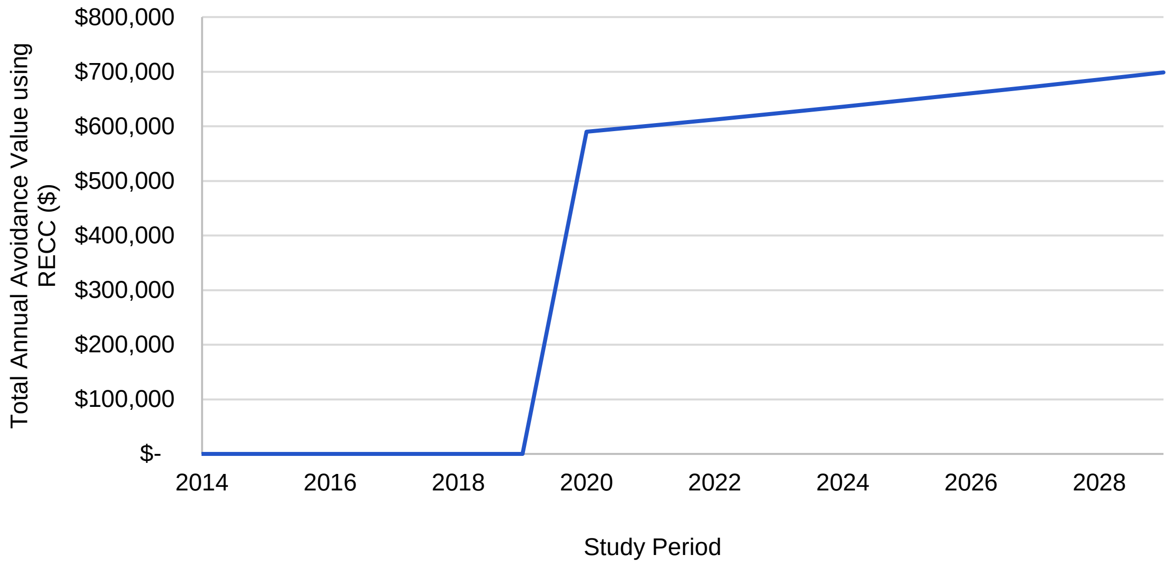
The calculation of the annual economic value from the revenue requirement is shown in detail for two example locations: Pemi Substation in the Eversource service territory and Dow's Hill Substation in the Unitil service territory. The results of the annual economic analysis for all locations are presented in tabular form following the two detailed examples. Additional graphical examples of annual value for avoidance of investment are found in Appendix D.

Example #1- Pemi Substation (Bulk) Yearly Economic Analysis (EDC: Eversource)

The RECC annual avoidance value begins in 2020, the first year of the capacity deficit (Figure 29).[45] The annual value is the same for all cases (low, base, and high) since the first year of the capacity deficit does not change due to load forecast scenario. The value increases from approximately $600,000 in year 2020 to close to $700,000 by 2029, the end of the study period.

[45] Note: this deficit is driven by a change in planning criteria.

Figure 29. Total Annual Avoidance Value – Pemi Substation (Bulk)



Source: Guidehouse, EDC data

Once the annual dollar value is calculated using the RECC method, the next step is to calculate the yearly value for all three load growth scenarios on a $/kW basis. Table 16 provides examples of calculations for the Pemi Substation. Column (A) is the yearly value from the RECC analysis and is shown in Figure 29 as well. Columns (B) through (D) are the estimated maximum capacity deficit for Pemi from 2020 through to 2029, the first year of need through the end of the study period. The final three columns, (E) through (G) are the calculated local avoided annual value for the three load forecast scenarios. The scenario with the lowest capacity deficit, the Low Case for the Pemi example, results in the highest value per kW reduced.

Table 16. Pemi Substation (Bulk) Yearly Economic Analysis- Example Calculations

Year with Capacity Deficiency	Yearly Value from RECC Analysis ($)	Estimated Capacity Deficit (MW)			Local Avoided Annual Value ($/kW)		
		Low	Base	High	Low	Base	High
Column	(A)	(B)	(C)	(D)	(E)=(A)/(B)	(F)=(A)/(C)	(G)=(A)/(D)
2020	$589,811	6.07	8.3	9.77	$97	$71	$60
2021	$601,017	6.16	8.5	10.07	$98	$71	$60
2022	$612,436	6.21	8.6	10.47	$99	$71	$58
2023	$624,073	6.25	8.7	10.68	$100	$72	$58
2024	$635,930	6.29	8.8	11.01	$101	$72	$58
2025	$648,013	6.35	8.9	11.31	$102	$73	$57
2026	$660,325	6.42	9.0	11.54	$103	$73	$57
2027	$672,871	6.50	9.1	12.07	$104	$74	$56
2028	$685,656	6.61	9.3	12.42	$104	$74	$55
2029	$698,683	6.65	9.44	12.88	$105	$74	$54

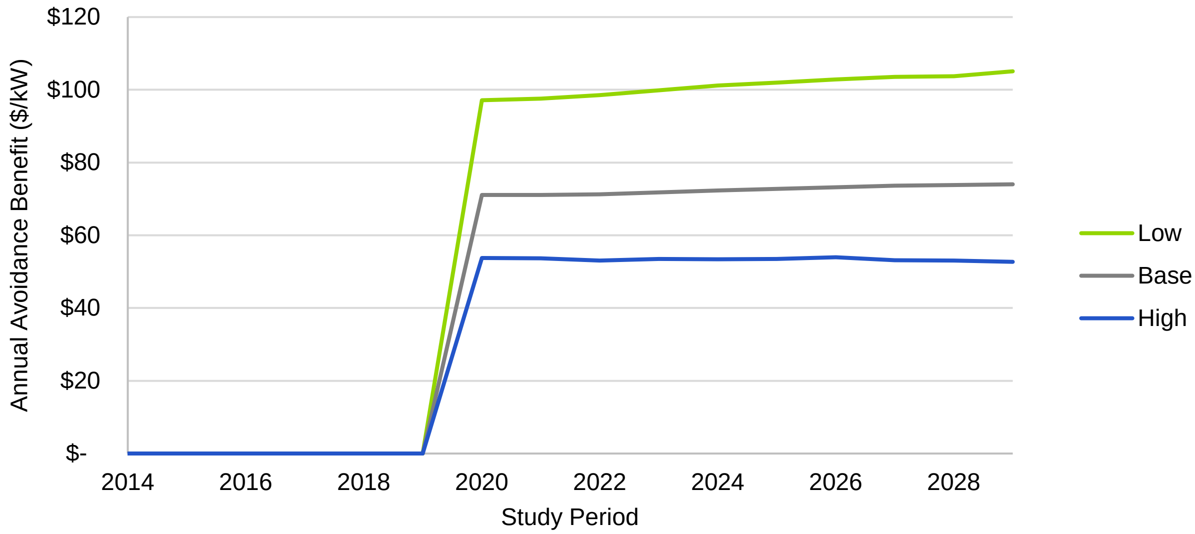
Table 16. Pemi Substation (Bulk) Yearly Economic Analysis- Example Calculations

Year with Capacity Deficiency	Yearly Value from RECC Analysis ($)	Estimated Capacity Deficit (MW)			Local Avoided Annual Value ($/kW)		
		Low	Base	High	Low	Base	High
Column	(A)	(B)	(C)	(D)	(E)=(A)/(B)	(F)=(A)/(C)	(G)=(A)/(D)
2030	$711,958	Because the values for capacity deficiency are unknown past the end of the study period, a $/kW value cannot be calculated past the end of the study period even though there is still avoided annual value. The avoided annual value continues until an investment is made. In this example, that is assumed to be at least 30 years or the lifetime of the asset. This study examines avoided cost values through the end of the study period; 2029.					
2031	$725,485						
2032	$739,270						
2033	$753,316						
2034	$767,629						
2035	$782,214						
2036	$797,076						
2037	$812,220						
2038	$827,652						
2039	$843,378						
2040	$859,402						
2041	$875,730						
2042	$892,369						
2043	$909,324						
2044	$926,602						
2045	$944,207						
2046	$962,147						
2047	$980,428						
2048	$999,056						
2049	$1,018,038						

Source: Guidehouse, EDC data

Columns (E) through (G) are also shown in Figure 30.

Figure 30. Annual Avoidance Benefit – Pemi Substation (Bulk)

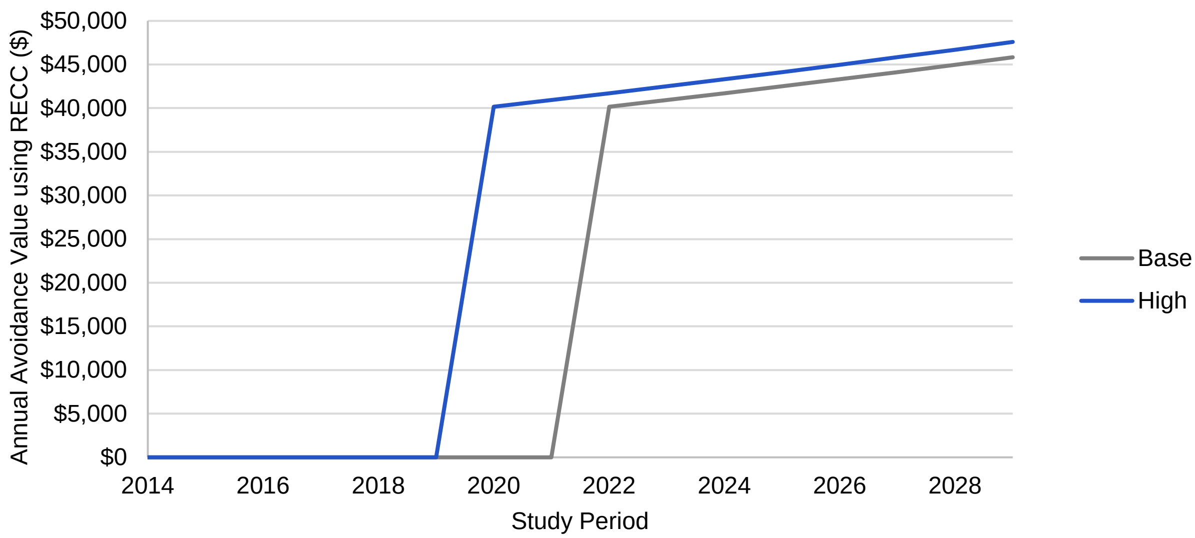


Source: Guidehouse, EDC data

Example #2- Dow's Hill Substation (Bulk) Yearly Economic Analysis (EDC: Unitil)

Dow's Hill Substation is used as the second example since the first year of capacity deficit varies between the load forecast scenarios. For the High Case, the annual avoidance value begins in 2020 and for the Base Case it begins in 2022 (Figure 31). These are the first year of capacity deficit for each load forecast scenario.

Figure 31. Total Annual Avoidance Value – Dow's Hill Substation (Bulk)

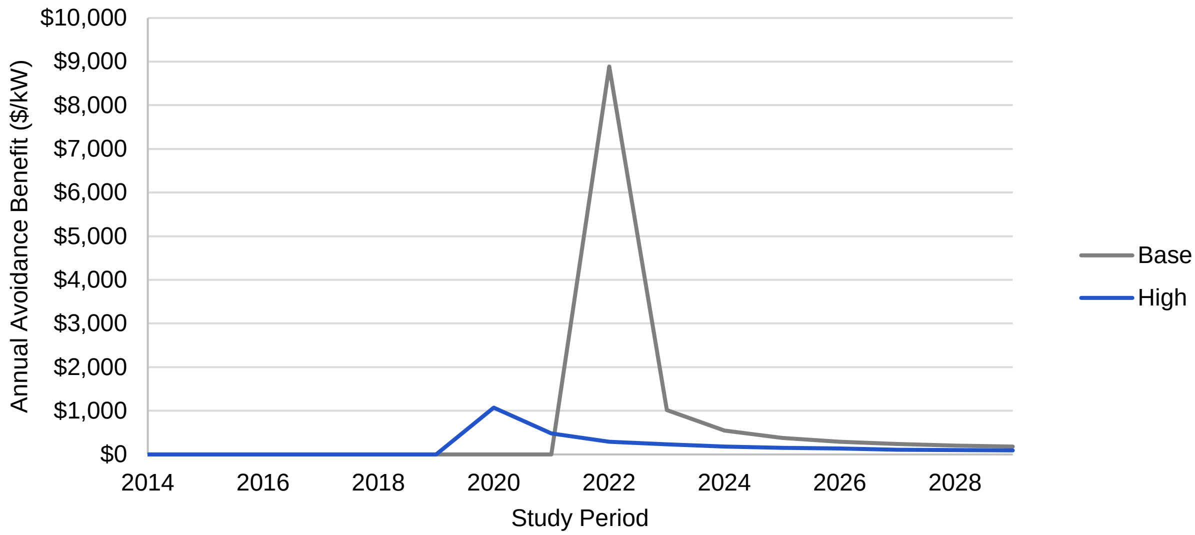


Source: Guidehouse, EDC data

The local annual avoidance benefit for Dow's Hill can be determined (Figure 32) using the same process as the Pemi Substation (Table 16). The first-year avoidance value for

Dow's Hill for the Base Case for 2022 is high since the capacity deficit is less than 5 kW. As the capacity deficit increases, the annual avoidance value per kW decreases drastically. The difference between the base and High Case is pronounced for Dow's Hill for two reasons. First, the High Case leads to a capacity deficit in an earlier year than the Base Case. Second, the high forecast leads to a much flatter and larger capacity deficit over time compared to the Base Case, which leads to a more consistent $/kW per year value.

Figure 32. Annual Avoidance Value– Dow's Hill Substation (Bulk)



Source: Guidehouse, EDC data

For locations such as Pemi where the load forecast does not influence the investment year, the yearly value from the RECC analysis provides the same annual value for each load forecast. The load forecast does not change the investment needed or the cost of that investment. Given this, the forecast with the lowest capacity deficiency results in the highest $/kW value in that year. For locations where the load forecast does change the initial year of capacity deficit, such as Dow's Hill, the case with an earlier capacity deficit may lead to a non-zero annual avoidance value that is higher than cases with lower load forecasts.

Table 17 shows the results of the total annual avoidance value using the RECC method for all 16 locations and all load forecast scenarios. Table 18 shows the results of the annual avoidance value per kW for all 16 locations and all load forecast scenarios.

Table 17. Total Annual Avoidance Value by Location and Load Forecast

EDC	Site	Forecast	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Eversource	Pemi Substation (Bulk)	All							$589,811	$601,017	$612,436	$624,073	$635,930	$648,013	$660,325	$672,871	$685,656	$698,683
	Portsmouth Substation (Bulk)	All							$197,420	$201,171	$204,993	$208,888	$212,856	$216,901	$221,022	$225,221	$229,500	$233,861
	South Milford Substation (Bulk)	All							$1,038,427	$1,058,157	$1,078,262	$1,098,749	$1,119,625	$1,140,898	$1,162,575	$1,184,664	$1,207,173	$1,230,109
	Monadnock Substation (Bulk)	Base & High							$1,129,240	$1,150,695	$1,172,559	$1,194,837	$1,217,539	$1,240,672	$1,264,245	$1,288,266	$1,312,743	$1,337,685
	East Northwood Substation (Non-Bulk)	High								$15,794	$16,094	$16,399	$16,711	$17,029	$17,352	$17,682	$18,018	$18,360
	Rye Substation (Non-Bulk)	High									$236,903	$241,405	$245,991	$250,665	$255,428	$260,281	$265,226	$270,266
	North Keen Circuit (34.5kV)	High														$120,821	$123,116	$125,456
	Bristol Substation (Non-Bulk)	All		$94,761	$96,562	$98,397	$100,266	$102,171	$104,112	$106,090	$108,106	$110,160	$112,253	$114,386	$116,559	$118,774	$121,031	$123,330
	Madbury ROW Circuit (34.5 kV)	Base & High							$157,936	$160,936	$163,994	$167,110	$170,285	$173,521	$176,817	$180,177	$183,600	$187,089
	Londonderry Circuit (34.5 kV)	All		$48,565	$49,488	$50,428	$51,386	$52,363	$53,358	$54,371	$55,404	$56,457	$57,530	$58,623	$59,737	$60,872	$62,028	$63,207
Liberty	Golden Rock Substation (Bulk)	All							$642,568	$654,777	$667,217	$679,894	$692,812	$705,976	$719,389	$733,058	$746,986	$761,179
	Vilas Bridge Substation (Non-Bulk)	Base & High							$194,257	$197,948	$201,709	$205,541	$209,446	$213,426	$217,481	$221,613	$225,824	$230,114
	Mount Support Substation (Bulk)	All				$540,541	$550,811	$561,276	$571,941	$582,807	$593,881	$605,165	$616,663	$628,379	$640,318	$652,485	$664,882	$677,515
Unitil	Bow Bog Substation (Non-Bulk)	Base													$22,879	$23,314	$23,757	$24,208
		High											$22,879	$23,314	$23,757	$24,208	$24,668	$25,137
	Dow's Hill Substation (Bulk)	Base									$40,174	$40,937	$41,715	$42,508	$43,315	$44,138	$44,977	$45,831
		High							$40,174	$40,937	$41,715	$42,508	$43,315	$44,138	$44,977	$45,831	$46,702	$47,589
	Kingston Substation (Bulk)	All				$1,098,295	$1,119,163	$1,140,427	$1,162,095	$1,184,175	$1,206,674	$1,229,601	$1,252,963	$1,276,769	$1,301,028	$1,325,747	$1,350,937	$1,376,604

Source: Guidehouse, EDC data

Table 18. Annual Avoidance Value per kW by Location and Load Forecast

EDC	Location	Forecast	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Eversource	Pemi Substation (Bulk)	Low							$97	$98	$99	$100	$101	$102	$103	$104	$104	$105
		Base							$71	$71	$71	$72	$72	$73	$73	$74	$74	$74
		High							$60	$60	$58	$58	$58	$57	$57	$56	$55	$54
	Portsmouth Substation (Bulk)	Low							$25	$20	$18	$16	$15	$15	$16	$16	$16	$17
		Base							$16	$13	$12	$12	$11	$11	$11	$11	$12	$12
		High							$13	$11	$10	$9	$9	$9	$9	$9	$9	$9
	South Milford Substation (Bulk)	Low							$55	$49	$50	$51	$52	$53	$54	$55	$56	$57
		Base							$44	$40	$40	$41	$41	$42	$43	$43	$44	$44
		High							$39	$35	$34	$35	$34	$34	$35	$34	$34	$34
	Monadnock Substation (Bulk)	Base							$730	$639	$584	$552	$528	$499	$476	$455	$430	$407
		High							$288	$262	$233	$223	$207	$195	$188	$171	$162	$152
	East Northwood Substation (Non-Bulk)	High								$260	$105	$79	$57	$46	$41	$32	$28	$25
	Rye Substation (Non-Bulk)	High									$3,641	$2,168	$1,346	$1,027	$870	$653	$570	$493
	North Keen Circuit (34.5kV)	High														$860,465	$1,128	$511
	Bristol Substation (Non-Bulk)	Low						$1,187	$550	$387	$303	$248	$209	$181	$159	$142	$128	$120
		Base		$315	$218	$167	$144	$126	$113	$102	$93	$86	$80	$75	$71	$67	$64	$61
		High		$126	$107	$93	$85	$79	$74	$67	$60	$56	$52	$49	$46	$42	$40	$38
	Madbury ROW Circuit (34.5 kV)	Base							$49	$48	$49	$49	$50	$51	$52	$53	$53	$54
		High							$29	$28	$26	$26	$25	$25	$24	$23	$22	$22
	Londonderry Circuit (34.5 kV)	Low		$92	$85	$79	$76	$72	$69	$67	$65	$63	$61	$60	$58	$56	$55	$54
		Base		$68	$64	$60	$58	$56	$54	$52	$51	$49	$48	$47	$46	$44	$43	$42
		High		$58	$54	$52	$50	$49	$47	$45	$43	$42	$40	$39	$38	$36	$35	$34
Liberty	Golden Rock Substation (Bulk)	Low							$185	$107	$64	$65	$66	$67	$68	$69	$70	$72
		Base							$63	$43	$32	$33	$33	$33	$33	$34	$34	$34
		High							$53	$36	$28	$28	$28	$27	$27	$28	$28	$29
	Vilas Bridge Substation (Non-Bulk)	Base							$180	$179	$178	$176	$175	$175	$174	$174	$174	$174
		High							$140	$136	$131	$127	$123	$119	$115	$111	$108	$102
	Mount Support Substation (Bulk)	Low				$18	$17	$16	$15	$15	$15	$14	$14	$14	$14	$13	$13	$13
		Base				$11	$11	$11	$10	$10	$10	$10	$9	$9	$9	$9	$9	$9
		High				$11	$10	$10	$10	$9	$9	$9	$8	$8	$8	$8	$7	$7
Unitil	Bow Bog Substation (Non-Bulk)	Base													$291	$124	$80	$59
		High											$179	$87	$59	$43	$34	$28
	Dow's Hill Substation (Bulk)	Base									$8,888	$1,017	$549	$381	$294	$241	$206	$180
		High							$1,072	$483	$289	$231	$183	$152	$133	$111	$100	$90
	Kingston Substation (Bulk)	Low				$316	$251	$209	$178	$172	$157	$150	$142	$138	$130	$122	$119	$119
		Base				$114	$104	$96	$89	$82	$77	$72	$68	$64	$61	$58	$56	$54
		High				$85	$79	$74	$70	$65	$59	$56	$53	$49	$47	$43	$41	$39

Source: Guidehouse, EDC data

4.2 Hourly Avoidance Value Estimation Methodology

After calculating the annual avoidance value, the next step is to develop an indicative value of avoidance value for each hour. This step also leverages the yearly total annual avoidance value from the RECC analysis. The year of annual value used is either 2020 or the first year of the capacity deficit if that is after 2020. Therefore, the hourly value demonstrated here is not based on the highest or average annual value, but for many cases it is based on the lowest value when the year of investment need is 2020. However, the capacity deficiency is also the lowest for many of the cases since it is in the earlier year of need.

These $/kW/hr may be lower for later years if the capacity deficiency and number of hours of need increase at a rate higher than the rate that the annual value is increasing (which is the inflation rate of 1.9%). Even though all of the annual growth rates are lower than 1.9%, since these annual growth rates are applied to the entire load and not just the capacity deficiency (defined as the difference between the growing load and a fixed capacity threshold), the capacity deficiency can increase at rates greater than the load growth rates. The analytical method used to develop this indicative value is presented for two examples, the Pemi Substation and the Portsmouth Substation, both in the Eversource service territory. Appendix D provides three additional examples.

4.2.1 Examples of Analytical Approach to Calculate Hourly Value

Example #1- Pemi Substation (Bulk) – Hourly Analysis for 2020 (EDC: Eversource)

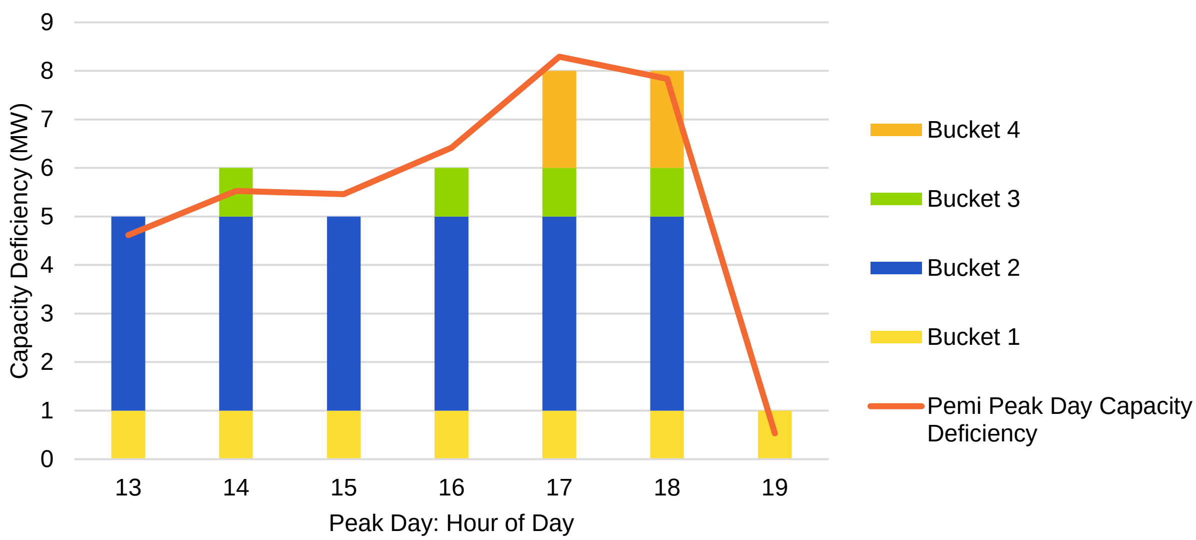
To simplify the explanation of the analytical process, the results that follow are for the peak day for the Pemi Substation. A three-step methodology was developed to assign an avoidance value to each hour. The first step is outlined as follows:

- **Step 1:** Segment peak day load excess into load capacity deficiency buckets
  - Round hourly capacity deficiency to nearest MW to generalize capacity deficiency load curve
  - Rank all hours with capacity deficiency from lowest capacity deficiency to highest capacity deficiency. For example, hour 19 has the lowest capacity deficiency, hours 13 and 15 have the second lowest capacity, hours 14 and 16 have the third lowest capacity deficiency, and hours 17 and 18 have the highest capacity deficiency.
  - Determine the capacity deficiency needs. This defines the number of buckets. For example, there are four levels of capacity deficiency needs for Pemi on the peak day: 1 MW (hour 19), 5 MW (hours 13 and 15), 6 MW (hours 14 and 16), and 8 MW (hours 17 and 18).
  - The first bucket is the heights of the lowest capacity deficiency need. This is 1 MW for hour 19.
  - The difference in capacity deficiency between each unique capacity deficiency level defines the height of the subsequent bucket. For example, the height of the second bucket is 5 MW minus 1 MW or 4 MW. This process is continued until all levels are met.

Based on the process outlined in the first step, four load buckets are required for Pemi's peak day to go from lowest capacity deficiency to highest capacity deficiency (see Figure 33).

- Bucket 1 height is 1 MW
- Bucket 2 height is 4 MW
- Bucket 3 height is 1 MW
- Bucket 4 height is 2 MW

Figure 33. Marginal Load Buckets (MW) – Pemi Substation (Bulk)



Source: Guidehouse, EDC data

The second step calculates the weight of each hour. Hours with more capacity deficiency have higher weights.

- **Step 2:** Determine a total relative weight for each hour
  - Weight for each bucket in each hour equals load excess per bucket per hour divided by total MWh of excess load in that bucket across all hours.
  - Weight for each bucket is the height of the bucket divided by the sum of the heights of all buckets.
  - Total relative weight is the sum product of the bucket hourly weight and weight for each bucket. Results of this step are shown in Table 19.

Table 19. Hour of Day Weighting Example Calculation – Pemi Substation (Bulk)

Relative Weight by Hour of Day ↓	Bucket 1	Bucket 2	Bucket 3	Bucket 4	Total Relative Weight
13	14%	17%	0%	0%	10%
14	14%	17%	25%	0%	13%
15	14%	17%	0%	0%	10%
16	14%	17%	25%	0%	13%

Table 19. Hour of Day Weighting Example Calculation – Pemi Substation (Bulk)

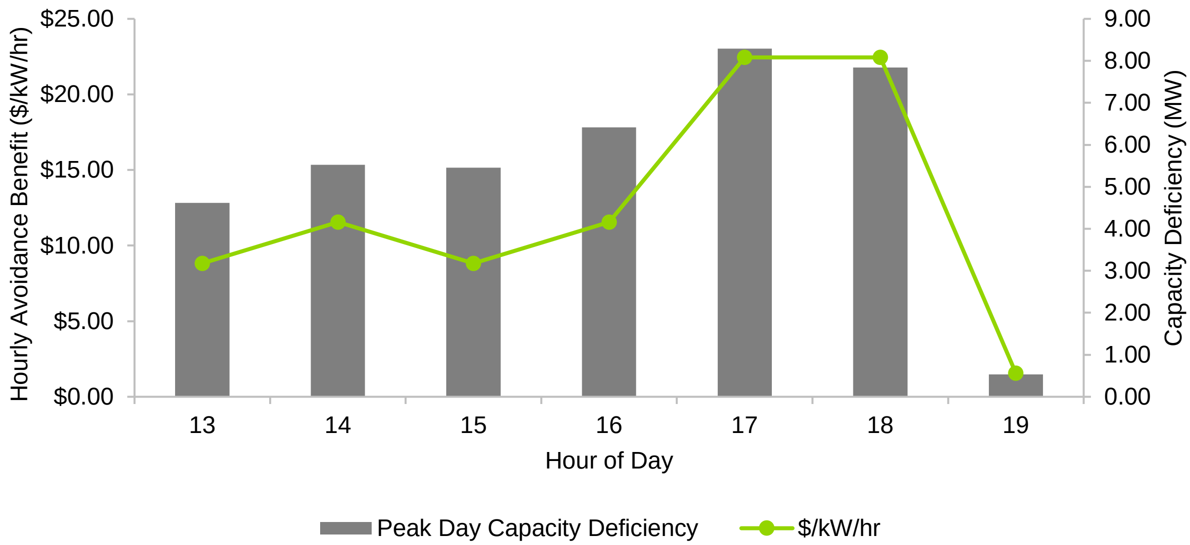
Relative Weight by Hour of Day ↓	Bucket 1	Bucket 2	Bucket 3	Bucket 4	Total Relative Weight
17	14%	17%	25%	50%	26%
18	14%	17%	25%	50%	26%
19	14%	0%	0%	0%	2%
Weight Across Buckets	13%	50%	13%	25%	100%

Source: Guidehouse, EDC data

The third step uses the total annual avoidance value ($) to calculate the hourly avoidance value.

- **Step 3**: Solve for the $/kW value that gets multiplied by the total relative weight such that the $/kW/hr for each hour times the amount of kW capacity deficit in each hour is equal to the total annual avoidance value for 2020. The results of Step 3 are presented in Figure 34.

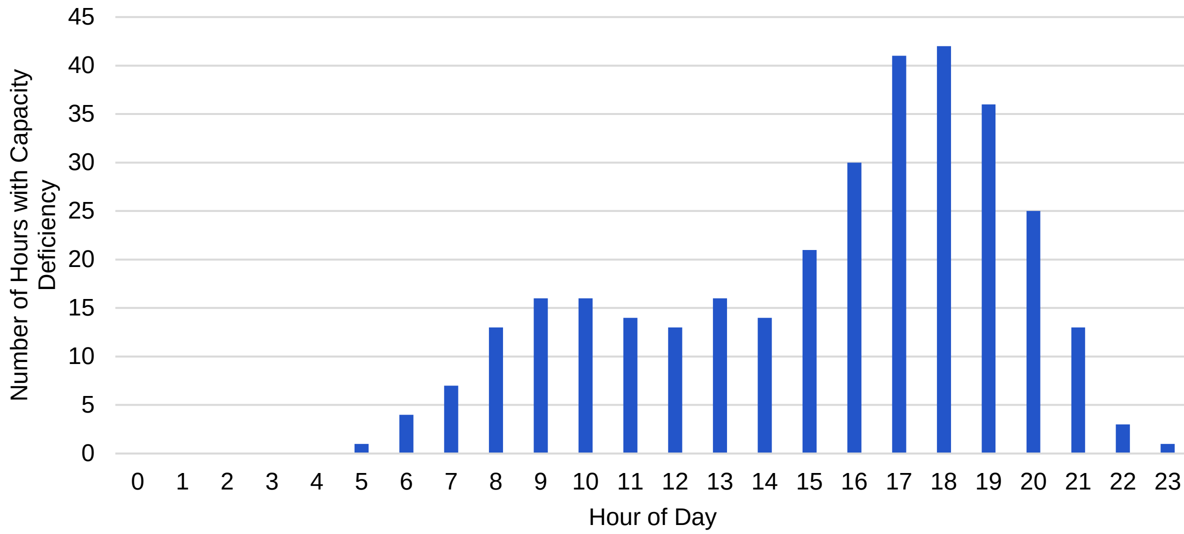
Figure 34. Hourly Avoidance Value and Capacity Deficiency – Pemi Substation (Bulk)



Source: Guidehouse, EDC data

While the results for the peak day provide a simple example, to accurately represent the $/kW/hr, all hours of the year when there is a capacity deficiency need to be considered in the analysis. Figure 35 presents the number of times there is a capacity deficiency for each hour. As reflected in the figure, capacity deficiency frequently occurs during hours 16 through 20. However, there are some instances of capacity deficiency for hours between hour 5 and hour 23.

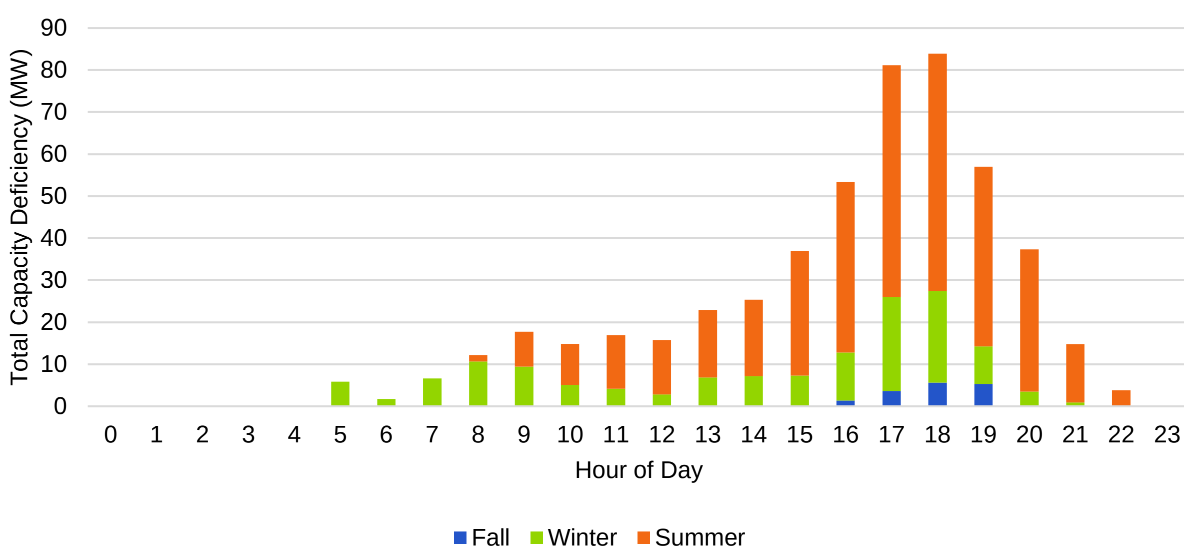
Figure 35. Number of Hours with Capacity Deficiency – Pemi Substation (Bulk)



Source: Guidehouse, EDC data

Figure 36 presents the seasonal distribution of total capacity deficits at Pemi for 2020 for each hour of the day. Winter is defined as November through February, spring is March through May, summer is June through September, and fall is October. The majority of capacity deficits occur in the summer and winter periods at Pemi. There are no capacity deficits that occur in the spring period and few that occur in the fall.

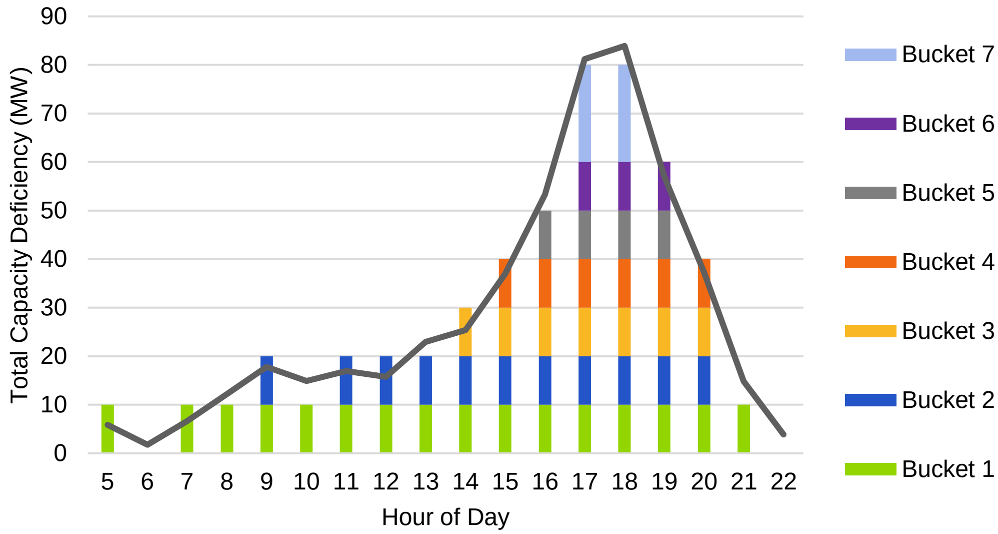
Figure 36. Seasonal Deficit Analysis – Pemi Substation (Bulk)



Source: Guidehouse, EDC data

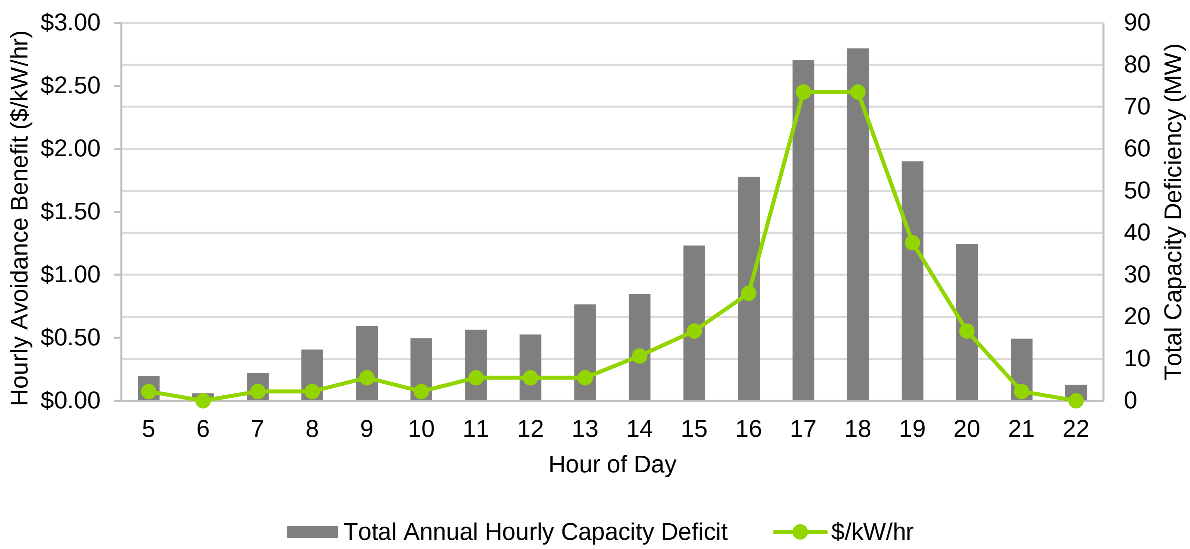
The same three step methodology used for the Pemi peak day can be used to assign a value given the total capacity deficit per hour over a whole year. Figure 37 shows the seven buckets needed to generalize the annual capacity deficit curve. Figure 38 shows the total annual capacity deficit and the $/kW/hr considering all hours of the year. Similar to the peak day analysis, the sum over all hours equals the annual avoidance value. The $/kW/hr during the peak time period of hours 17 and 18 is close to $23 for the peak day, but drops to about $2.50 when all hours of the year are considered.

Figure 37. Marginal Load Buckets (MW) – Pemi Substation (Bulk)



Source: Guidehouse, EDC data

Figure 38. Pemi Hourly Analysis for All Hours of Year

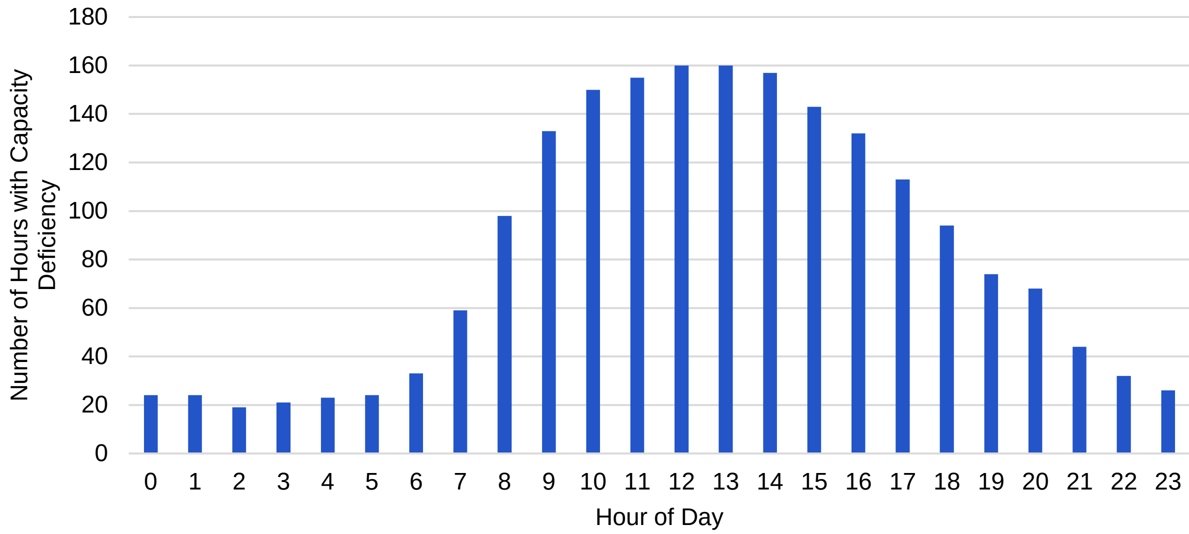


Source: Guidehouse, EDC data

Example #2- Hourly Local Value Calculation for Portsmouth Substation

This same annual analysis is repeated for Portsmouth, which had at least 19 hours of capacity deficiency for each hour of the day when considering all hours across an entire year (Figure 39). In contrast with the Pemi Substation, which had peaks in the afternoon and early evening, the majority of the hours with capacity deficiency at Portsmouth are for hours 12 and 13.

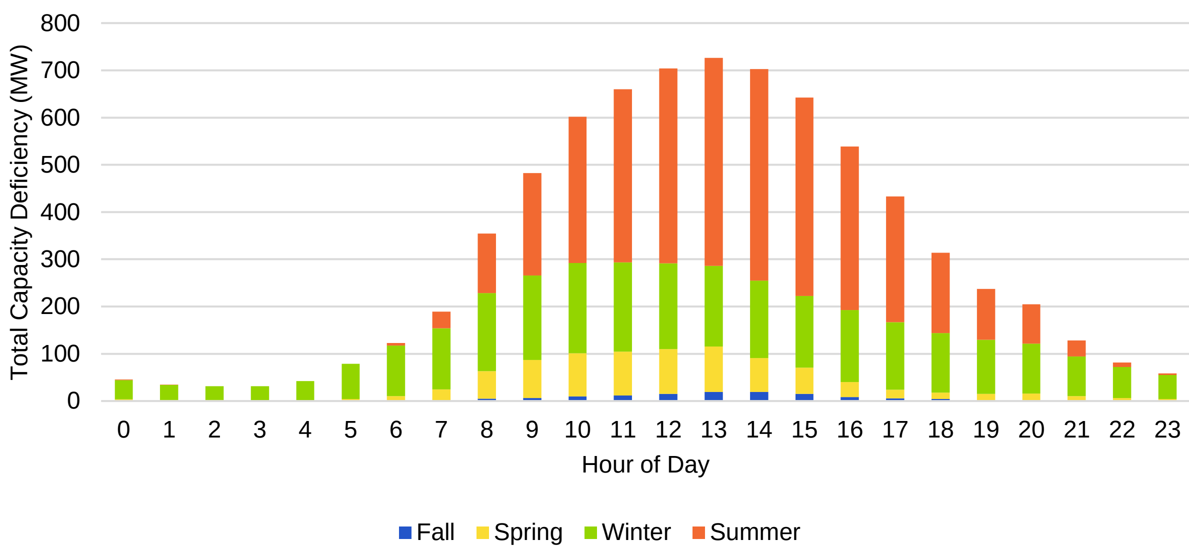
Figure 39. Number of Hours with Capacity Deficiency – Portsmouth Substation (Bulk)



Source: Guidehouse, EDC data

Similar to the Pemi Substation, the majority of the capacity deficit occurred in the summer and winter periods, with some in the spring and fall periods as well (Figure 40).

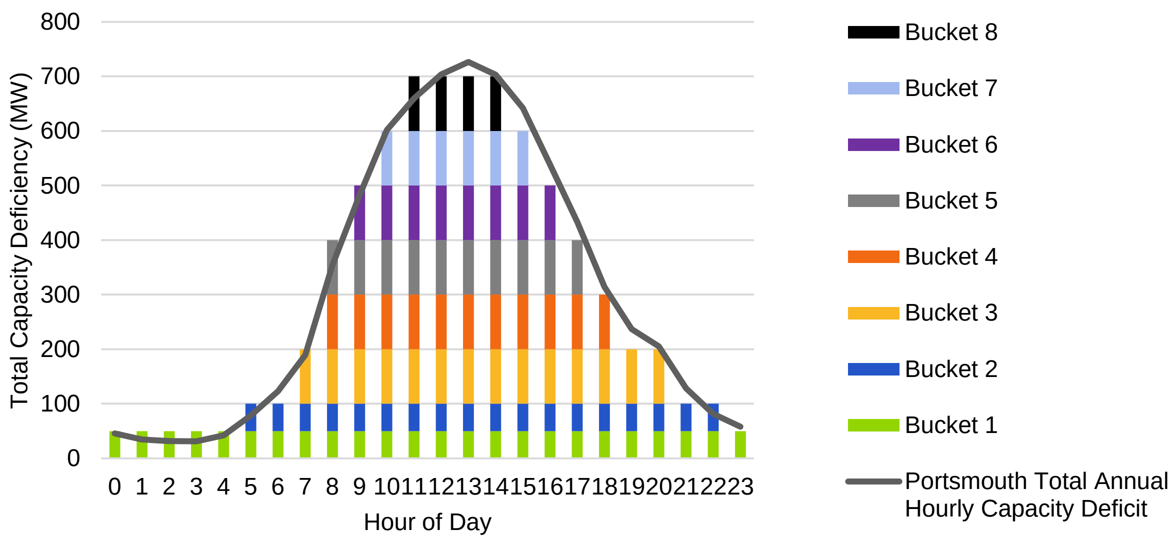
Figure 40. Seasonal Deficit Analysis – Portsmouth Substation (Bulk)



Source: Guidehouse, EDC data

Due to the capacity deficiency variation by hour, Portsmouth required eight capacity deficiency buckets over all hours to generalize the yearly annual hourly capacity deficit (Figure 41).

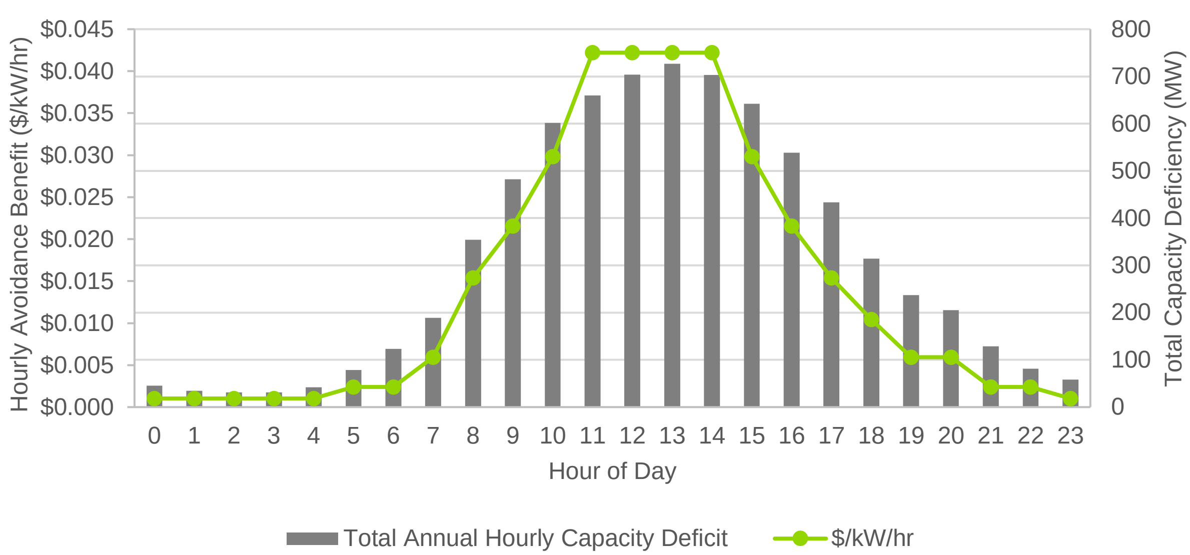
Figure 41. Marginal Load Buckets (MW) – Portsmouth Substation (Bulk)



Source: Guidehouse, EDC data

The hourly value is small per kW, as Figure 42 shows.

Figure 42. Portsmouth Hourly Analysis for All Hours of the Year



Source: Guidehouse, EDC data

4.2.2 Hourly Avoided Cost Analysis Summary and Results

The 16 locations considered for detailed review in this study provide different outputs for hourly value per kilowatt per hour. Table 20 summarizes the results for all 16 locations and provides a rank of the value.[46] The maximum hourly value ranges from $0.04/kW/hr (for Mount Support and Portsmouth substations) up to $4,483/kW/hr (for the Dow's Hill Substation). Overall, the study found that the largest factor in determining the hourly value is the total annual megawatt-hours of capacity deficiency based on the utility planning criteria.

Table 20. Hourly Avoided Cost Analysis Summary

Location	Year Considered	Revenue Requirement	Total Hours of Capacity Deficiency	Total Annual MWh of Capacity Deficiency	Maximum $/kW/hr	Relative $/kW/hr Value Ranking
Pemi Substation (Bulk)	2020	$9,074,650	326	509	$2.45	11
Portsmouth Substation (Bulk)	2020	$3,037,438	1,966	7,446	$0.04	16
South Milford Substation (Bulk)	2020	$15,976,924	6,696	41,928	$0.05	14
Monadnock Substation (Bulk)	2020	$17,374,146	15	10.53	$203.68	6
East Northwood Substation (Non-Bulk)	2021	$242,995	3	0.07	$256.77	5
Rye Substation (Non-Bulk)	2022	$3,644,926	2	0.10	$3,185.54	2
Bristol Substation (Non-Bulk)	2020	$1,457,970	5	0.43	$301.37	4
Madbury ROW Circuit (34.5 kV)	2020	$2,429,950	7	14	$17.03	8
North Keene Circuit (12.47 kV)	2028	$1,858,912	1	0.11	$1,128.25	3
Londonderry Circuit (34.5 kV)	2020	$747,210	467	115.81	$1.01	13
Vilas Bridge Substation (Non-Bulk)	2020	$2,715,803	909	247.68	$2.91	10
Mount Support Substation (Bulk)	2020	$7,557,017	1,329	21,484	$0.04	15
Golden Rock Substation (Bulk)	2020	$8,983,404	164	434	$3.14	9
Bow Bog Substation (Non-Bulk)	2026	$299,375	5	0.27	$128.17	7
Dow's Hill Substation (Bulk)	2022	$525,674	2	0.008	$4,483.12	1
Kingston Substation (Bulk)	2020	$14,371,184	203	789	$2.00	12

Source: Guidehouse

The results for each hour for the 16 selected locations is presented in Table 21. The first row for each location is the maximum deficiency seen across the whole year in each hour. The second row is the sum of the deficiency per hour for 1 year. The third row is the count of the hours with capacity deficiency across 1 year. The fourth row is the resulting hourly avoided cost value in terms of $/kW/hr.

[46] This hourly analysis was completed for 2020 for all locations where there was a capacity deficit in 2020 or for the first year of capacity deficit if that occurred after 2020. For some locations, the capacity deficit was so low in the first year, that the second year of capacity deficit was used for the hourly analysis.

Table 21. Hourly Avoided Cost Detailed Results by Location (Selected Locations 1-8 on 1st page and 9-16 on 2nd page)

EDC	Substation	Parameter	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Eversource	Pemi Substation (Bulk)	Max Deficiency per Hour (MW)						6	1	2	3	2	3	3	3	5	6	5	6	8	8	5	5	4	2	0
		Sum of Deficiency per Hour for One Year (MW)						6	2	7	12	18	15	17	16	23	25	37	53	81	84	57	37	15	4	0
		Count of Hours with Deficiency for One Year						1	4	7	13	16	16	14	13	16	14	21	30	41	42	36	25	13	3	1
		Hourly Avoidance Value ($/kW/hr)						$ 0.07		$ 0.07	$ 0.07	$ 0.18	$ 0.07	$ 0.18	$ 0.18	$ 0.18	$ 0.36	$ 0.55	$ 0.85	$ 2.45	$ 2.45	$ 1.25	$ 0.55	$ 0.07		
	Portsmouth Substation (Bulk)	Max Deficiency per Hour (MW)	4	3	3	3	4	5	7	8	9	10	10	11	12	12	12	12	11	10	8	7	7	6	6	4
		Sum of Deficiency per Hour for One Year (MW)	46	35	31	31	42	79	123	189	354	482	602	660	704	727	703	642	538	433	314	237	205	129	81	58
		Count of Hours with Deficiency for One Year	24	24	19	21	23	24	33	59	98	133	150	155	160	160	157	143	132	113	94	74	68	44	32	26
		Hourly Avoidance Value ($/kW/hr)	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.01	$ 0.02	$ 0.02	$ 0.03	$ 0.04	$ 0.04	$ 0.04	$ 0.04	$ 0.03	$ 0.02	$ 0.02	$ 0.01	$ 0.01	$ 0.01	$ 0.00	$ 0.00	$ 0.00
	South Milford Substation (Bulk)	Max Deficiency per Hour (MW)	10	8	7	7	7	9	12	14	14	15	17	19	20	21	22	22	23	23	22	21	19	17	15	12
		Sum of Deficiency per Hour for One Year (MW)	474	318	239	248	345	704	1432	1879	2114	2171	2208	2193	2216	2232	2199	2236	2566	3007	3100	2956	2739	2149	1410	793
		Count of Hours with Deficiency for One Year	194	164	144	146	166	242	280	296	314	312	313	317	317	316	312	317	320	326	330	331	332	332	318	257
		Hourly Avoidance Value ($/kW/hr)							$ 0.01	$ 0.01	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.03	$ 0.05	$ 0.05	$ 0.05	$ 0.03	$ 0.02	$ 0.01	$ 0.01
	Monadnock Substation (Bulk)	Max Deficiency per Hour (MW)															0.1	0.6	0.8	1.4	1.5	0.8	0.4			
		Sum of Deficiency per Hour for One Year (MW)															0.1	0.6	1.9	3.5	2.6	1.4	0.5			
		Count of Hours with Deficiency for One Year															1	1	3	3	3	2	2			
		Hourly Avoidance Value ($/kW/hr)															$ 2	$ 12	$ 55	$ 204	$ 97	$ 36	$ 10			
	East Northwood Substation (Non-Bulk)	Max Deficiency per Hour (MW)																			0.061	0.004				
		Sum of Deficiency per Hour for One Year (MW)																			0.061	0.004				
		Count of Hours with Deficiency for One Year																			2	1				
		Hourly Avoidance Value ($/kW/hr)																			$ 257	$ 11				
	Rye Substation (Non-Bulk)	Max Deficiency per Hour (MW)																0.03	0.07							
		Sum of Deficiency per Hour for One Year (MW)																0.03	0.07							
		Count of Hours with Deficiency for One Year																1	1							
		Hourly Avoidance Value ($/kW/hr)																$ 956	$3,186							
	Bristol Substation (Non-Bulk)	Max Deficiency per Hour (MW)																			0.09	0.16	0.11	0.01		
		Sum of Deficiency per Hour for One Year (MW)																			0.15	0.16	0.11	0.01		
		Count of Hours with Deficiency for One Year																			2	1	1	1		
		Hourly Avoidance Value ($/kW/hr)																			$ 256	$ 301	$ 155	$ 6		
	Madbury ROW Circuit (34.5 kV)	Max Deficiency per Hour (MW)											1	2	2	3	2			0	3					
		Sum of Deficiency per Hour for One Year (MW)											1	2	2	3	2			0	3					
		Count of Hours with Deficiency for One Year											1	1	1	1	1			1	1					
		Hourly Avoidance Value ($/kW/hr)											$ 3.2	$ 7.2	$ 7.2	$ 17.0	$ 7.2			$ 0.3	$ 17.0					

Legend
Lowest value → Highest value

EDC	Substation	Parameter	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
			Hour of Day																							
	North Keene Circuit (12.47 kV)	Max Deficiency per Hour (MW)												0.11												
	North Keene Circuit (12.47 kV)	Sum of Deficiency per Hour for One Year (MW)												0.11												
	North Keene Circuit (12.47 kV)	Count of Hours with Deficiency for One Year												1												
	North Keene Circuit (12.47 kV)	Hourly Avoidance Value ($/kW/hr)												$ 1,128												
	Londonderry Circuit (34.5 kV)	Max Deficiency per Hour (MW)	0.2	0.1			2.4			2.8	5.2	0.3	0.5	0.6	0.7	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.7	0.5	0.3
	Londonderry Circuit (34.5 kV)	Sum of Deficiency per Hour for One Year (MW)	0.2	0.1			2.4			2.8	5.4	0.7	1.2	2.7	4.2	5.9	7.6	9.1	11.2	15.3	16.2	12.2	9.9	6.0	2.1	0.6
	Londonderry Circuit (34.5 kV)	Count of Hours with Deficiency for One Year	2	1			1			1	3	3	7	13	15	23	28	34	38	69	82	54	46	30	13	4
	Londonderry Circuit (34.5 kV)	Hourly Avoidance Value ($/kW/hr)					$ 0.03			$ 0.03	$ 0.14		$ 0.03	$ 0.03	$ 0.09	$ 0.14	$ 0.22	$ 0.31	$ 0.45	$ 1.01	$ 1.01	$ 0.45	$ 0.31	$ 0.14	$ 0.03	$ 0.01
Liberty	Vilas Bridge Substation (Non-Bulk)	Max Deficiency per Hour (MW)	0.3				0.4	0.3	0.8	0.9	2.5	2.4	2.2	2.0	1.7	1.4	1.3	1.9	1.4	1.4	0.9	0.8	0.7	0.5	0.3	
Liberty	Vilas Bridge Substation (Non-Bulk)	Sum of Deficiency per Hour for One Year (MW)	0.3				0.4	0.6	13.1	20.1	19.1	14.8	15.3	12.8	9.1	10.7	12.2	13.9	16.9	26.4	28.3	19.8	10.2	3.1	0.7	
Liberty	Vilas Bridge Substation (Non-Bulk)	Count of Hours with Deficiency for One Year	1				1	6	50	69	70	64	63	57	36	42	41	52	61	74	77	75	49	16	5	
Liberty	Vilas Bridge Substation (Non-Bulk)	Hourly Avoidance Value ($/kW/hr)	$ 0.01				$ 0.01	$ 0.01	$ 0.33	$ 0.64	$ 0.64	$ 0.33	$ 0.33	$ 0.33	$ 0.19	$ 0.19	$ 0.19	$ 0.33	$ 0.33	$ 1.40	$ 2.91	$ 0.64	$ 0.19	$ 0.09	$ 0.01	
Liberty	Mount Support Substation (Bulk)	Max Deficiency per Hour (MW)	11	7					5	18	34	38	45	52	57	61	63	56	48	44	39	36	31	34	27	17
Liberty	Mount Support Substation (Bulk)	Sum of Deficiency per Hour for One Year (MW)	21	11					8	153	557	1051	1525	1828	1995	2257	2458	2265	2034	1697	1292	907	685	475	203	63
Liberty	Mount Support Substation (Bulk)	Count of Hours with Deficiency for One Year	4	2					4	28	49	69	86	92	108	114	120	114	113	103	91	77	65	51	28	11
Liberty	Mount Support Substation (Bulk)	Hourly Avoidance Value ($/kW/hr)								$ 0.00	$ 0.00	$ 0.01	$ 0.02	$ 0.02	$ 0.02	$ 0.04	$ 0.04	$ 0.04	$ 0.02	$ 0.02	$ 0.02	$ 0.01	$ 0.00	$ 0.00	$ 0.00	
Liberty	Golden Rock Substation (Bulk)	Max Deficiency per Hour (MW)											2	5	7	8	9	10	10	9	7	5	3	2	0	0
Liberty	Golden Rock Substation (Bulk)	Sum of Deficiency per Hour for One Year (MW)											3	14	31	56	75	84	65	53	29	13	6	3	0	0
Liberty	Golden Rock Substation (Bulk)	Count of Hours with Deficiency for One Year											2	6	14	21	24	24	23	19	15	7	4	3	1	1
Liberty	Golden Rock Substation (Bulk)	Hourly Avoidance Value ($/kW/hr)											$ 0.05	$ 0.18	$ 0.43	$ 1.01	$ 1.98	$ 3.14	$ 1.40	$ 1.01	$ 0.43	$ 0.18	$ 0.05	$ 0.05		
Unitil	Bow Bog Substation (Non-Bulk)	Max Deficiency per Hour (MW)														0.02	0.07	0.08	0.06	0.04						
Unitil	Bow Bog Substation (Non-Bulk)	Sum of Deficiency per Hour for One Year (MW)														0.02	0.07	0.08	0.06	0.04						
Unitil	Bow Bog Substation (Non-Bulk)	Count of Hours with Deficiency for One Year														1	1	1	1	1						
Unitil	Bow Bog Substation (Non-Bulk)	Hourly Avoidance Value ($/kW/hr)														$ 17	$ 85	$ 128	$ 74	$ 39						
Unitil	Dow's Hill Substation (Bulk)	Max Deficiency per Hour (MW)																	0.004	0.005						
Unitil	Dow's Hill Substation (Bulk)	Sum of Deficiency per Hour for One Year (MW)																	0.004	0.005						
Unitil	Dow's Hill Substation (Bulk)	Count of Hours with Deficiency for One Year																	1	1						
Unitil	Dow's Hill Substation (Bulk)	Hourly Avoidance Value ($/kW/hr)																	$ 4,483	$ 4,483						
Unitil	Kingston Substation (Bulk)	Max Deficiency per Hour (MW)												3	5	8	10	10	11	11	10	9	8	6	3	
Unitil	Kingston Substation (Bulk)	Sum of Deficiency per Hour for One Year (MW)												8	33	57	84	101	107	109	106	84	57	33	10	
Unitil	Kingston Substation (Bulk)	Count of Hours with Deficiency for One Year												6	14	18	21	23	23	24	23	22	15	9	5	
Unitil	Kingston Substation (Bulk)	Hourly Avoidance Value ($/kW/hr)												$ 0.09	$ 0.31	$ 0.72	$ 1.09	$ 1.64	$ 2.00	$ 2.00	$ 2.00	$ 1.09	$ 0.72	$ 0.31	$ 0.09	

Source: Guidehouse

Legend
Lowest value → Highest value

4.3 Mapping of DG Production Profiles with Distribution Capacity Need

This section maps NEM-eligible DG production profiles with hours of distribution capacity need at each of the 16 selected locations. It assesses whether solar PV output aligns with hours of distribution capacity need, and where and when energy storage is required in conjunction with solar PV to provide energy for all hours during which capacity deficits occur. It is structured to illustrate when DG production profiles align with hours of capacity need, but not to quantify the amount of DG or storage needed to avoid distribution capacity investments.

The comparison of load versus DG production profiles should be viewed as a high level illustration of the alignment of DG production profiles on days where the number of hours and magnitude of capacity deficiency is highest for each of the 16 locations. The LVDG study determines the potential value of distribution capacity avoidance and should not be construed as a locational non-wires solution (NWS) assessment.

An NWS study typically includes a detailed analysis of all hours of the year where capacity deficiencies exist, with an economic analysis of trade-offs of different mixes of DG and other demand reduction resources (e.g., standalone solar versus solar paired with energy storage, demand response, or targeted energy efficiency), including the amount of effective load reduction required over each year of the study. Equally important, an NWS would include a determination of the amount of DG or load reduction measures—or a portfolio including both—needed to reliably avoid a traditional distribution capacity investment.[47] Other considerations include the value of load reductions and associated reduced energy costs on a time-differentiated basis over all hours of the years. Similarly, an NWS considers transmission impacts for both pool (ISO-NE Regional Network Service) and non-pooled transmission assets (Local Network Service) for each EDC within New Hampshire. The LVDG study only considers the value of capacity avoidance for distribution assets and does not consider the ability of a specific solution to fully achieve avoidance values. Any NWS assessment would need to evaluate all of these considerations and should be conducted on a case by cases basis.

The illustrative mapping analysis includes the following steps:

1. Determine distribution capacity deficits for seasonal peaks for the most recent year that hourly data is available from the EDC
2. Generate 24-hour seasonal peak day load profiles for each location
3. Develop 24-hour average solar PV production profiles using NREL's PVWatts Calculator (fixed and two-axis tracking)

[47] For example, locational Equivalent Load Carrying Capability (ELCC) studies of distribution level assets.

4. Select appropriate average profile from among fixed variants, one- and two-axis tracking
5. Compare normalized hourly solar PV production profile and load profiles for seasonal peak days
6. Illustrate the coincidence of solar PV production during hours of distribution capacity needs[48]
7. Compare solar PV paired with energy storage charge/discharge profiles at locations where solar PV production does not fully align with hours of need
8. Add the production profile for representative run-of-river hydro unit at each location to further evaluate DG coincidence with peak

4.3.1 Load and DG Production Profiles

This section presents detailed solar PV, solar PV paired with energy storage, and hydro production profiles on representative days with distribution capacity deficiencies. Two locations, Pemi and Portsmouth, are highlighted in this section. Detailed production profiles for three additional locations, Madbury, Kingston, and Mount Support, appear in Appendix E. A complete, abbreviated set of 16 locational analyses and production profiles is presented in tabular form at the end of Section 4.3.2.

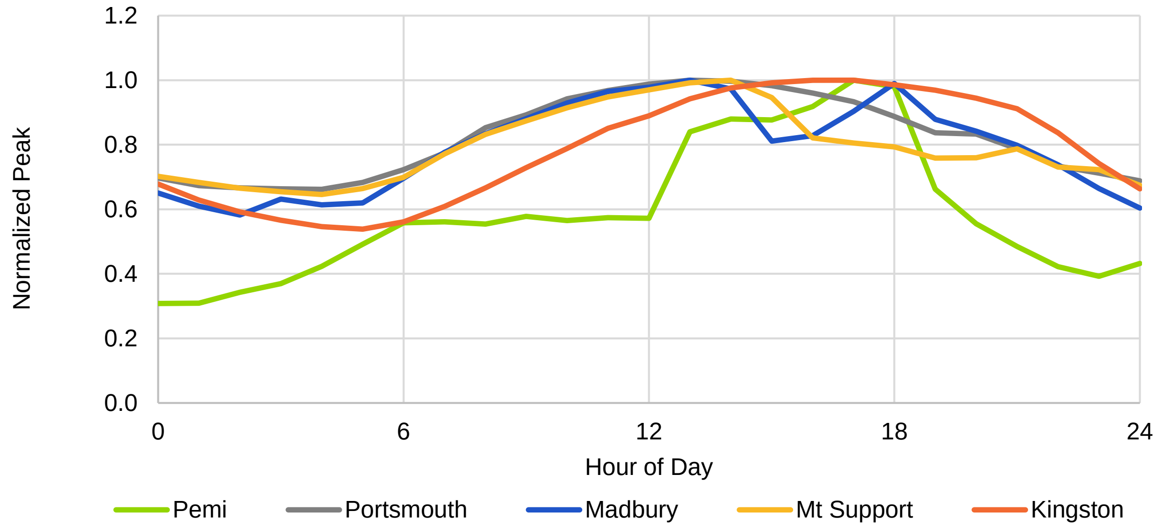
The first step in the study's mapping process includes development of hourly average monthly and peak load profiles for each of the 16 selected locations. Figure 43 presents peak day hourly load profiles for the two locations in this section, and the three additional locations that appear in Appendix E. The profiles include, at minimum, the following characteristics and attributes:

- At least one location for each EDC
- Distribution line and substation capacity deficiencies
- Normal (N-0) and contingency (N-1) capacity deficiencies
- Bulk and non-bulk substations
- Load data for each location for the first year where a full years' hourly data is available (2018 or 2019)

The mapping of DG profiles (solar PV, solar PV paired with storage, and hydro) to peak day load profiles is presented in next section. Hourly profiles for the five locations with peak day load are presented in Figure 43, Table 22 indicates that four of the five locations are summer peaking.

[48] Coincidence is defined as hours when there is a capacity deficiency during which hours solar PV production is non-zero

Figure 43. Peak Day Load for Five Example Locations



Source: Guidehouse, EDC data

Table 22. Summary of Locational Peak Load at 16 Selected Locations

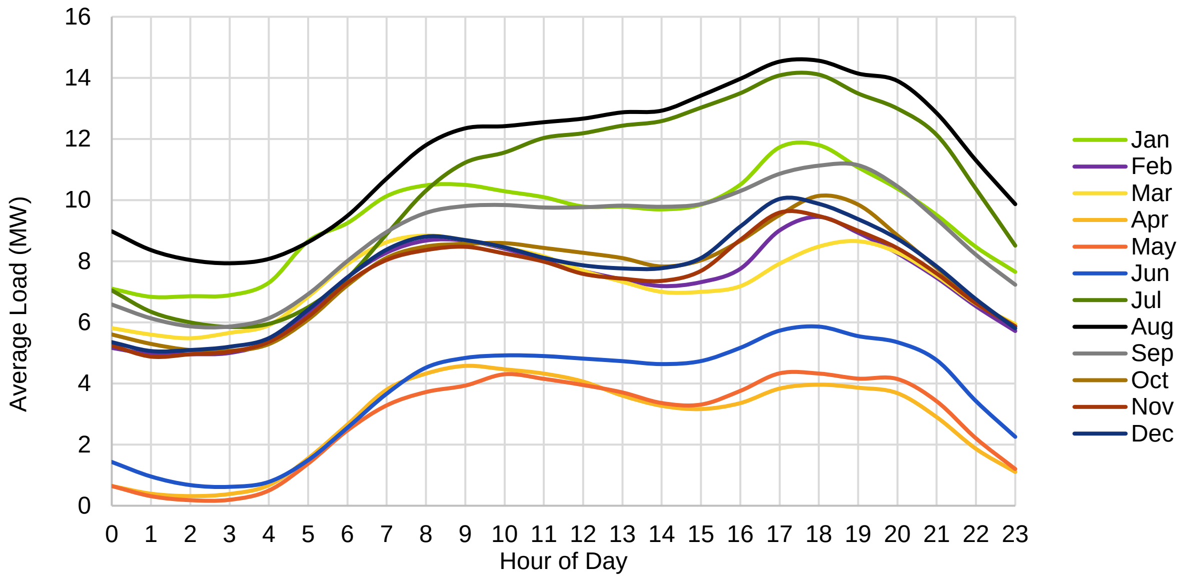
EDC	Location	Region	Winter (Peak and Date Time)	Summer (Peak and Date Time)
Eversource	Pemi Substation (Bulk)	Northern	23 MW 1/7/19 17:00	
Eversource	Portsmouth Substation (Bulk)	Eastern		40 MW 7/30/19 13:00
Eversource	South Milford Substation (Bulk)	Southern	36.9 MW 1/21/19 17:00	41.4 MW 7/30/19 17:00
Eversource	Monadnock Substation (Bulk)	Western	34.4 MW 1/16/19 17:00	34.9 MW 7/19/19 18:00
Eversource	East Northwood Substation (Non-Bulk)	Eastern		5.7 MW 7/21/19 18:00
Eversource	Rye Substation (Non-Bulk)	Eastern		4.2 MW 7/21/19 16:00
Eversource	Bristol Substation (Non-Bulk)	Northern		6.3 MW 7/20/19 19:00
Eversource	Madbury ROW Circuit (34.5 kV)	Eastern		32.58 MW 7/20/19 13:00
Eversource	North Keene Circuit (12.47 kV)	Northern		10.9 MW 6/28/19 11:00
Eversource	Londonderry Circuit (34.5 kV)	Southern		2.63 MW 6/24/19
Liberty	Vilas Bridge Substation (Non-Bulk)	Walpole	4.39 MW 2/24/19 16:00	4.21MW 8/19/19 15:00
Liberty	Mount Support Substation (Bulk)	Lebanon		40.9 MW 7/30/19 14:00
Liberty	Golden Rock Substation (Bulk)	Salem		49.27 MW 7/30/19 15:00
Unitil	Bow Bog Substation (Non-Bulk)	Capital		3077 kW 7/30/19 15:00
Unitil	Dow's Hill Substation (Bulk)	Seacoast		1679 kW 8/29/2018 17:00
Unitil	Kingston Substation (Bulk)	Seacoast		51 MW 8/29/18 17:00

Source: Guidehouse, EDC data

Figure 44 and Figure 45 present average hourly monthly load profiles for two locations, Pemi and Portsmouth. Each figure is derived using 2018 or 2019 EDC hourly data obtained from substation SCADA readings. Details for these two locations are listed below:

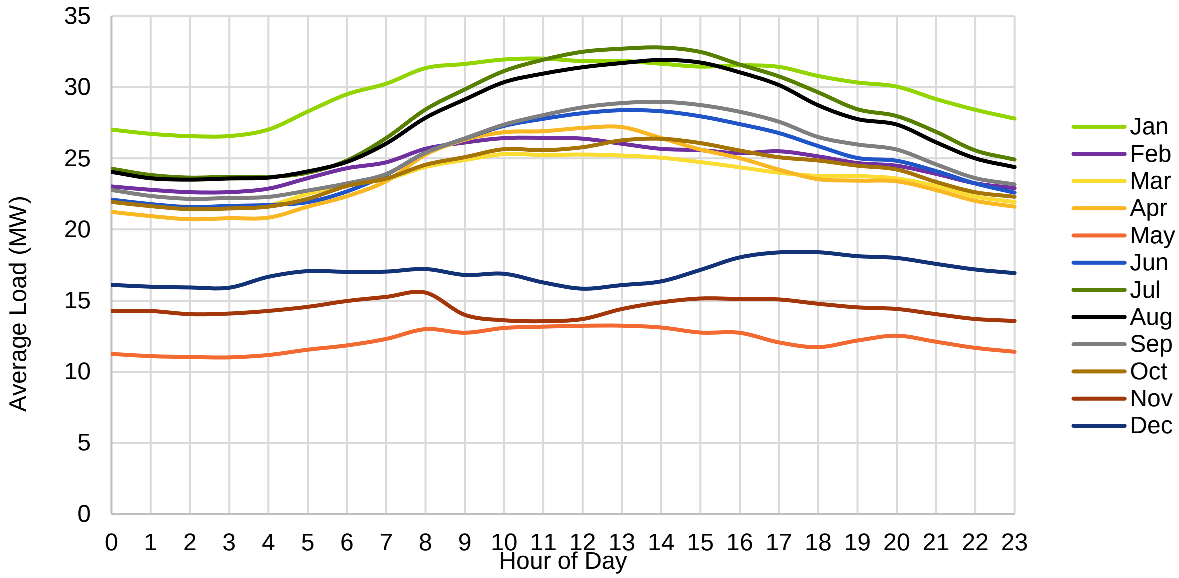
- Pemi Substation (Bulk):
  - Winter peaking with a daily average peak in the early evening
  - Annual Peak Day: 1/7/2019 17:00, 23 MW
- Portsmouth Substation (Bulk)
  - Summer midday peaking substation
  - Annual Peak Day: 7/30/2019 13:00, 40 MW

Figure 44. Average Hourly Profile by Month – Pemi Substation (Bulk)



Note: Although the peak day occurs in January, average January load is much lower than that of the summer months.
Source: Guidehouse, EDC data

Figure 45. Average Hourly Profile by Month – Portsmouth Substation (Bulk)



Source: Guidehouse, EDC data

Solar PV Configurations Considered

Multiple solar PV configurations are considered, ranging from fixed-axis to single and dual-axis tracking, outlined in Table 23.

Table 23. Solar PV Configurations Considered

Solar PV Configurations Considered	Orientation
Fixed – 135	SE
Fixed – 180	S
Fixed – 225	SW
Fixed – 270	W
Single Axis Tracking	NA
Dual Axis Tracking	NA

Source: Guidehouse

A central New Hampshire location (Figure 46) was selected after the examination of various locations confirmed that differences in solar PV production were minimal and would not materially affect the analysis.

Figure 46. Location Selected for Solar PV Configurations

Source: National Renewable Energy Laboratory, Google Maps

Solar PV Configuration Comparison

Using PVWatts data, average and peak day summer (June-September) and average and peak day winter (November-February) 24-hour solar PV production profiles were created to align with seasonal peak capacity needs for a 1 kW (1,000 Watt) nameplate system (see Figure 47 and Figure 48, and Figure 49 and Figure 50, respectively). Average profiles were created for six orientations and peak day profiles for three orientations. The dual-axis tracking has the highest overall average production (W AC/W DC) while the fixed axis, with an azimuth angle of 180°,[49] has the highest overall production of the fixed array configurations.

[49] The azimuth angle is the angle clockwise from true north describing the direction that the array faces. An azimuth angle of 180° is for a south-facing array, and an azimuth angle of zero degrees is for a north-facing array.

Figure 47. Average Summer Production by Solar Array Configuration Type

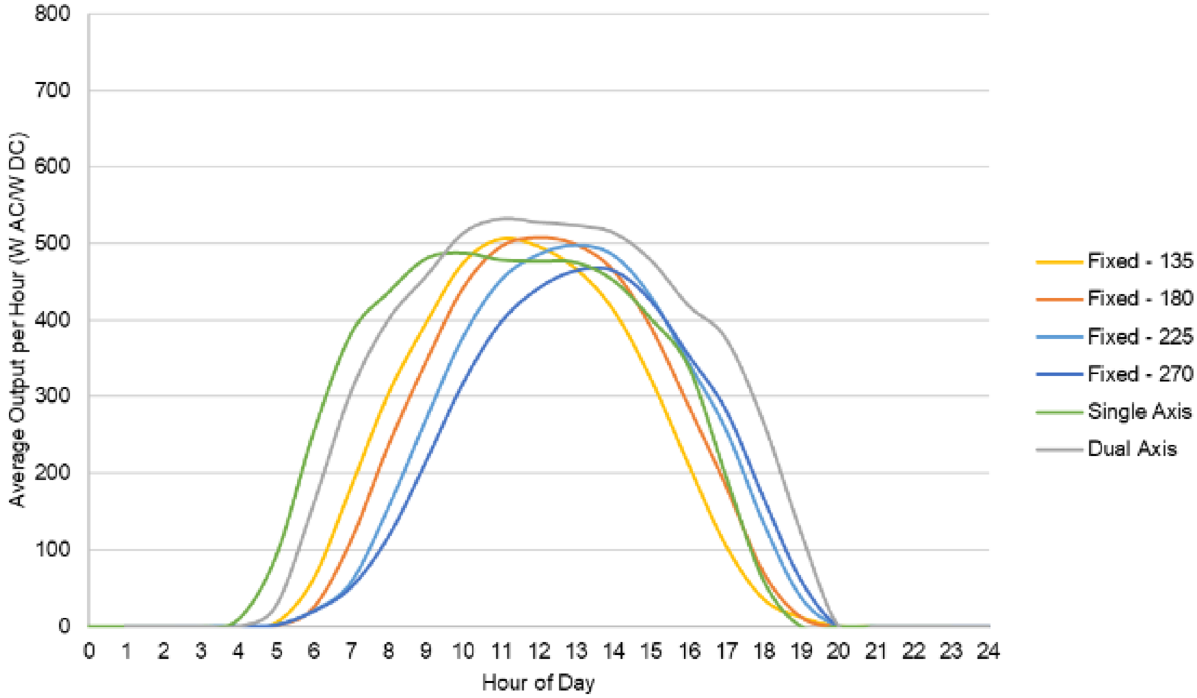
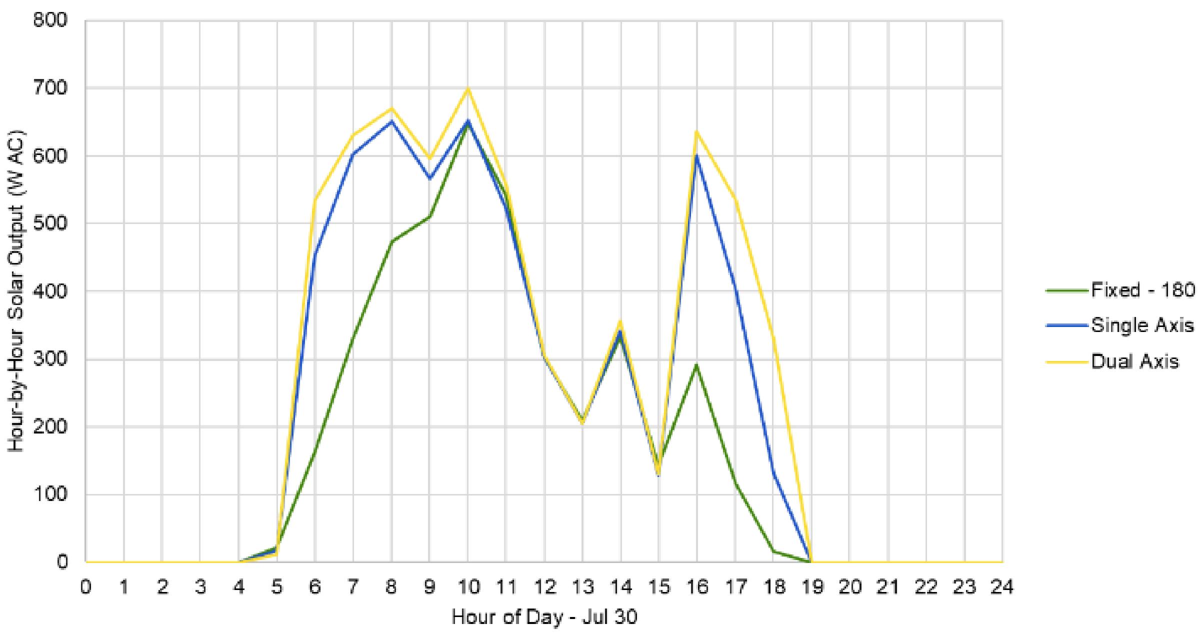


Figure 48. Peak Day Summer Production by Solar Array Configuration Type



Source: Guidehouse

Figure 49. Average Winter Production by Solar Array Configuration Type

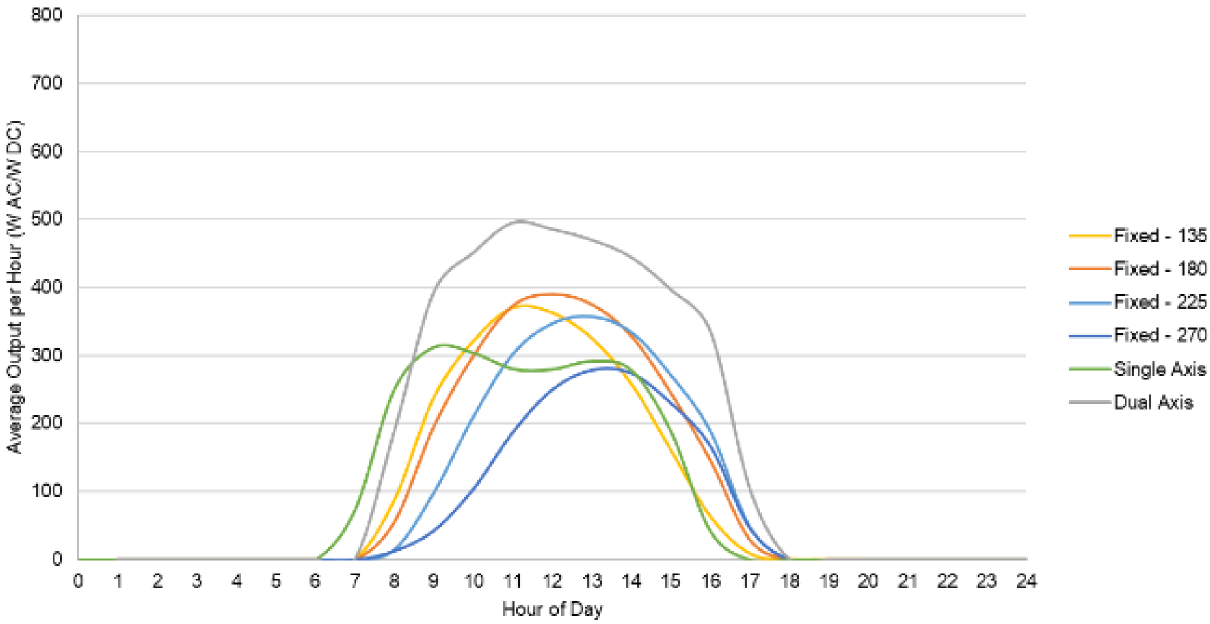
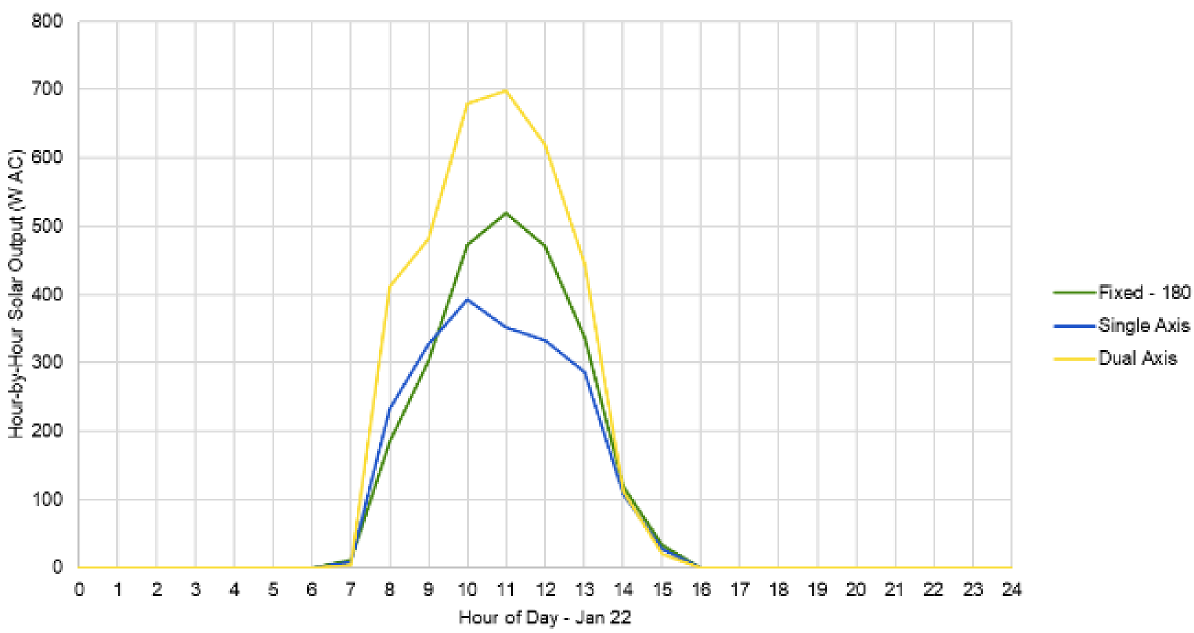


Figure 50. Peak Day Winter Production by Solar Array Configuration Type



Source: Guidehouse

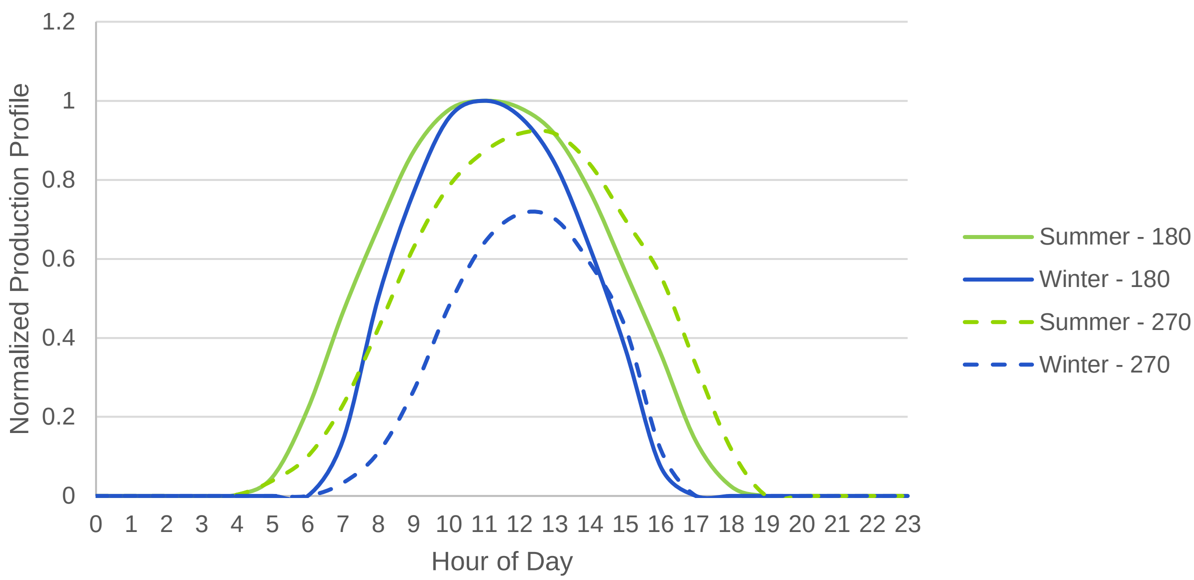
Selection of Representative Solar PV Production Profile

A fixed-180° solar PV production profile was selected to align with the hours of capacity deficiency for each of the selected locations. That decision is supported by the following considerations:

- The dual-axis tracking produces the highest amount of electricity; however, there are limitations with installation of dual-axis tracking. The costs (capital and O&M) are generally higher than fixed systems.
- Single-axis tracking provides a wider peak performance period, on average, at a lower capital cost than dual-axis tracking. However, the additional hours of production are earlier in the day and are generally not coincident with hours of peak electric demand.
- Of the fixed array options, the 180°-azimuth angle provides the highest total annual production and the highest seasonal average energy production. The higher overall production provides additional energy to charge storage when considering solar paired with storage.

Figure 51 illustrates the production profiles for solar PV with a fixed-180° orientation compared to a western facing device (i.e., fixed-270°), which show some differences such as a 1-hour shift in production during the summer for the fixed-270° orientation. However, the higher energy production from the fixed-180° suggests it is a better choice for comparing solar production profiles to the capacity deficiencies at all 16 locations.

Figure 51. Representative Solar PV Production Profiles – Normalized Fixed

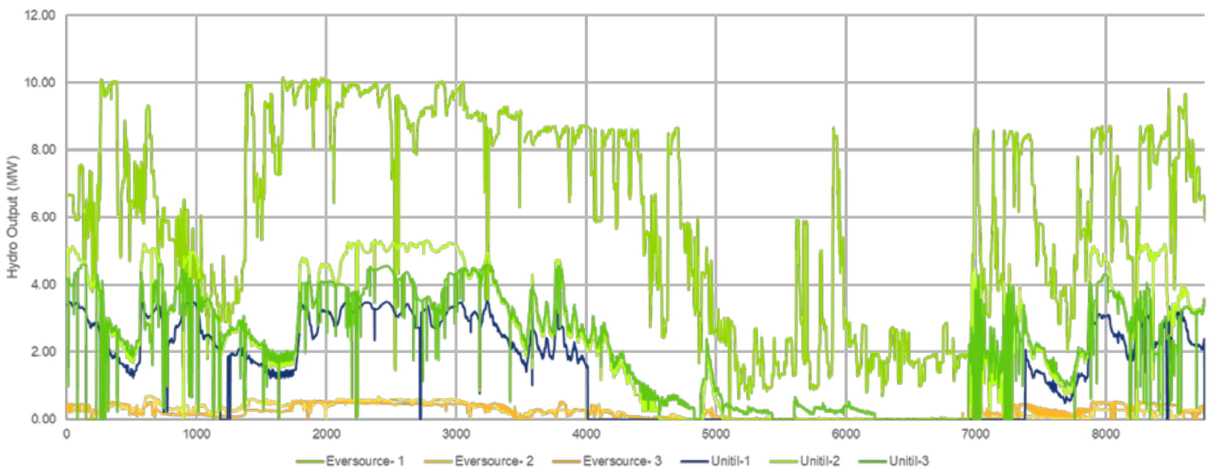


Note: Normalized to max for each season for the Fixed-180° case.
Source: Guidehouse

Hydro Production Analysis

The study reviewed recent hydro production profiles for six locations in Eversource's and Unitil's service territories as a proxy to determine seasonal and hourly variations at undeveloped sites.[50] Figure 52 through Figure 54 present the results of the analysis of the six hydro production profiles and their alignment with hours of capacity deficiency. Figure 52 presents actual hourly data for the entire year (8,760 hours). Figure 53 and Figure 54 present normalized 24-hour daily profiles for summer and winter months, respectively, where normalized values are equal to the average hourly output, expressed as a percent of maximum hydro output for each season.

Figure 52. Hydroelectric Production Analysis



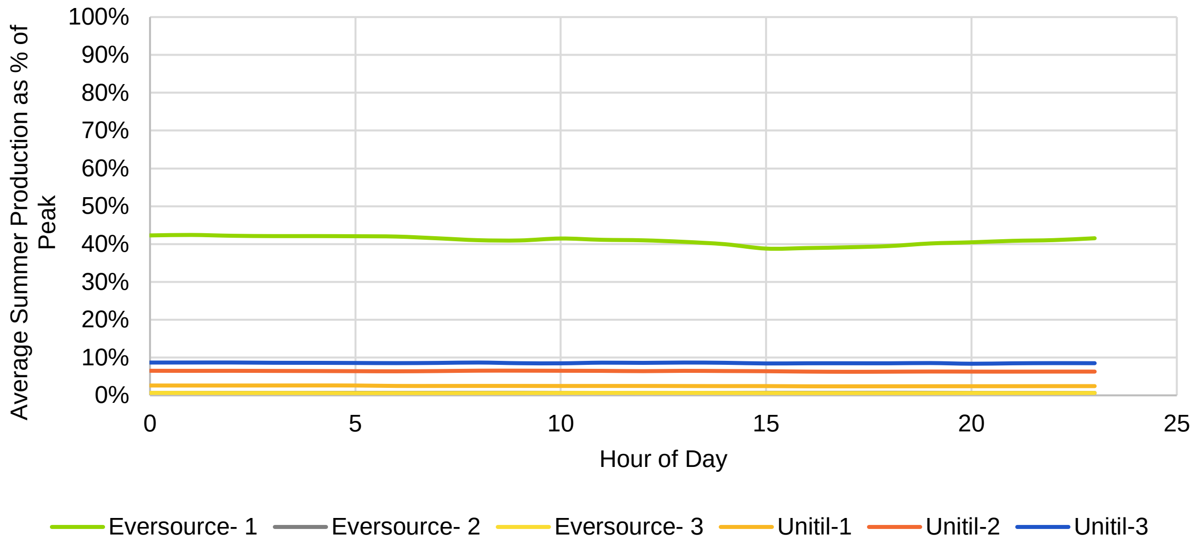
Source: Guidehouse, EDC data

Seasonal Average Hydro Production Profiles

Figure 53 and Figure 54 present the summer and winter average hydro generation production profiles. Winter production is generally higher than summer production as a percent of annual peak production.

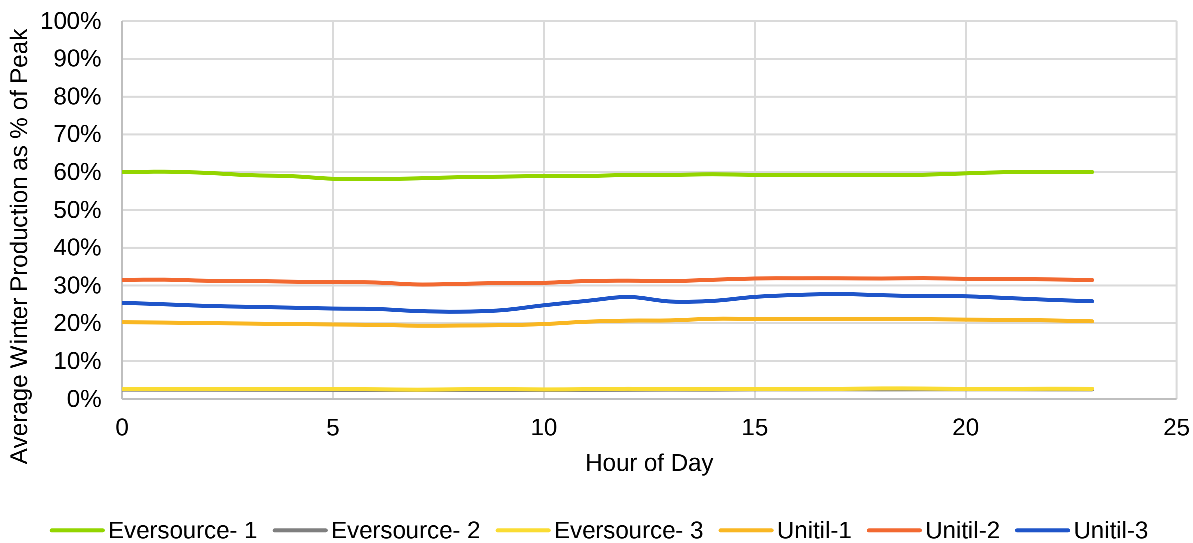
[50] The study did not include investigation of hydrological conditions at any potential sites near or adjacent to the 16 locations to develop representative production profiles.

Figure 53. Summer Average Hydro Production Profiles



Source: Guidehouse, EDC data

Figure 54. Winter Average Hydro Production Profiles



Source: Guidehouse, EDC data

4.3.2 Mapping of DG Production Profile with Capacity Deficiency Profile

This section compares the DG production profiles developed in Section 4.3.1 to the hours of capacity deficiencies for each of the 16 locations. Two locations, Eversource's Pemi and Portsmouth substations, are analyzed in detail for the first year when capacity deficiencies occur. Appendix E presents detailed analyses of three other locations and the final graphical result for the remaining 11 sites.

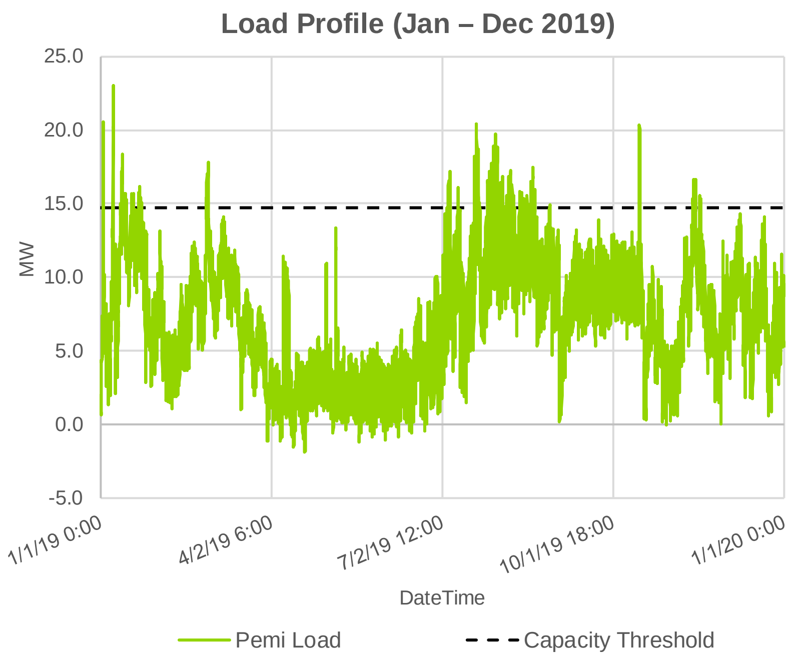
Pemi Substation (Bulk) Analysis

Figure 55 presents historical hourly loads for the Pemi substation, a late day winter peaking location with normal overloads, with the distribution capacity threshold superimposed. The figure indicates capacity limits are exceeded at the Pemi station during winter and summer months.

The duration and energy deficiencies at Pemi follows:

- Hours of capacity deficiency: 326
- Energy deficiency: 508.7 MWh (Approximately, 0.8% of total energy (63,137 MWh)

Figure 55. Annual Hourly Profile – Pemi Substation (Bulk)



Source: Guidehouse, EDC data

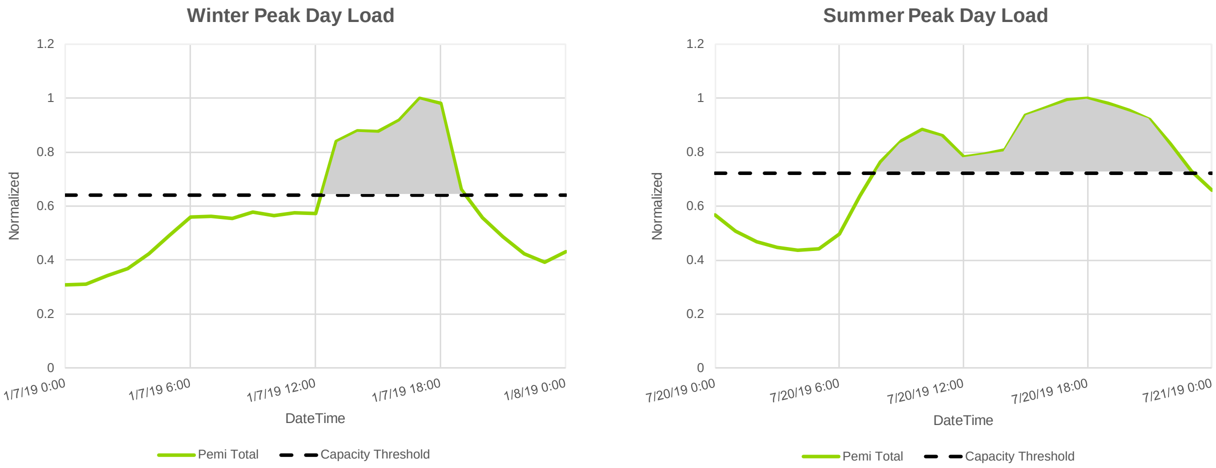
Table 24. Annual Load Profile and Capacity Threshold – Pemi Substation (Bulk)

Location	Region	Peak (MW)	Time of Peak	First Year Deficit (MW)
Pemi Substation (Bulk)	Northern	23	1/7/19 17:00	8.29

Source: Guidehouse, EDC data

Figure 56 presents winter and summer peak day capacity deficiencies at the Pemi substation, normalized to values on a common, per unit scale. The figure indicates that the duration of the winter peak is narrower than summer and occurs later in the day.

Figure 56. Seasonal Capacity Deficiencies – Pemi Substation (Bulk)

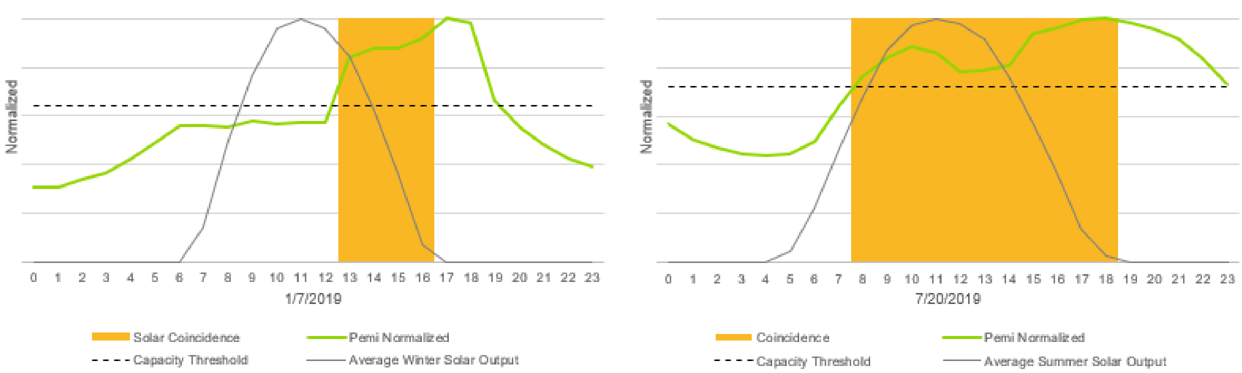


Source: Guidehouse, EDC data

Figure 57 presents normalized single-axis solar PV output versus hourly loads for the Pemi substation for the winter and summer peaks. The figure indicates that solar coincidence is greater during summer months. However, solar PV alone is unable to meet capacity deficits during early evening hours when solar PV output is low, as follows:

- Hours of capacity need: 7 hours (winter) vs. 16 hours (summer)
- Winter solar coincidence: 4 out of 7 hours
- Summer solar coincidence: 11 out of 16 hours

Figure 57. Solar Mapping – Pemi Substation

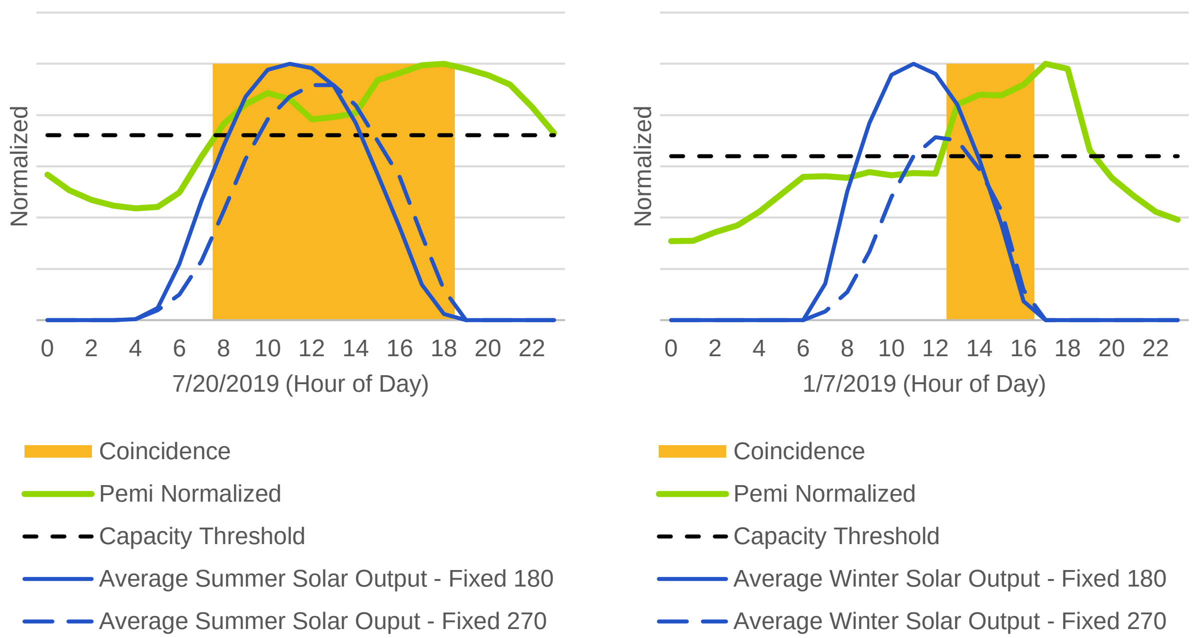


Source: Guidehouse, EDC data

Pemi Substation (Bulk) – Solar Coincidence Analysis – Fixed Axis: 180 and 270

Figure 58 shows the difference between the solar PV production based on different azimuth angles (south at 180° and west at 270° angle). While the fixed-270° has a later peak than the fixed-180° orientation, the height of the peak is much lower, and the coincidence hours are equivalent.

Figure 58. Solar Coincidence Analysis – Fixed Axis: 180° and 270° – Pemi Substation



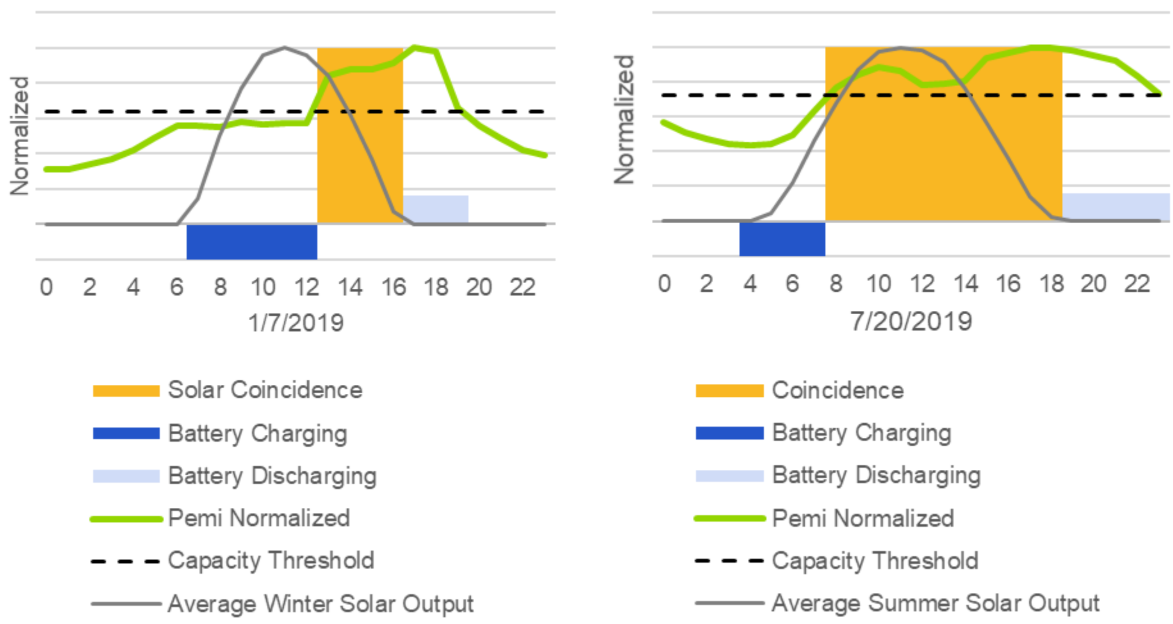
Source: Guidehouse, EDC data

Pemi Substation (Bulk) – Solar and Supplemental Storage

Figure 59 illustrates the hours when supplemental energy storage is needed for DG output to fully align with hours of capacity deficiencies. While these figures are illustrative, the pairing of solar with energy storage confirms the combination is better suited to address capacity deficiencies at Pemi. The figure indicates that the available number of charging hours are greater in the winter and required number of charging and discharging hours are greater in summer, summarized as follows:

- Winter charging interval: 6 hours, 3 hours discharge
- Summer charging interval: 4 hours, 5 hours discharge

Figure 59. Solar plus Storage Charging Analysis – Pemi Substation (Bulk)

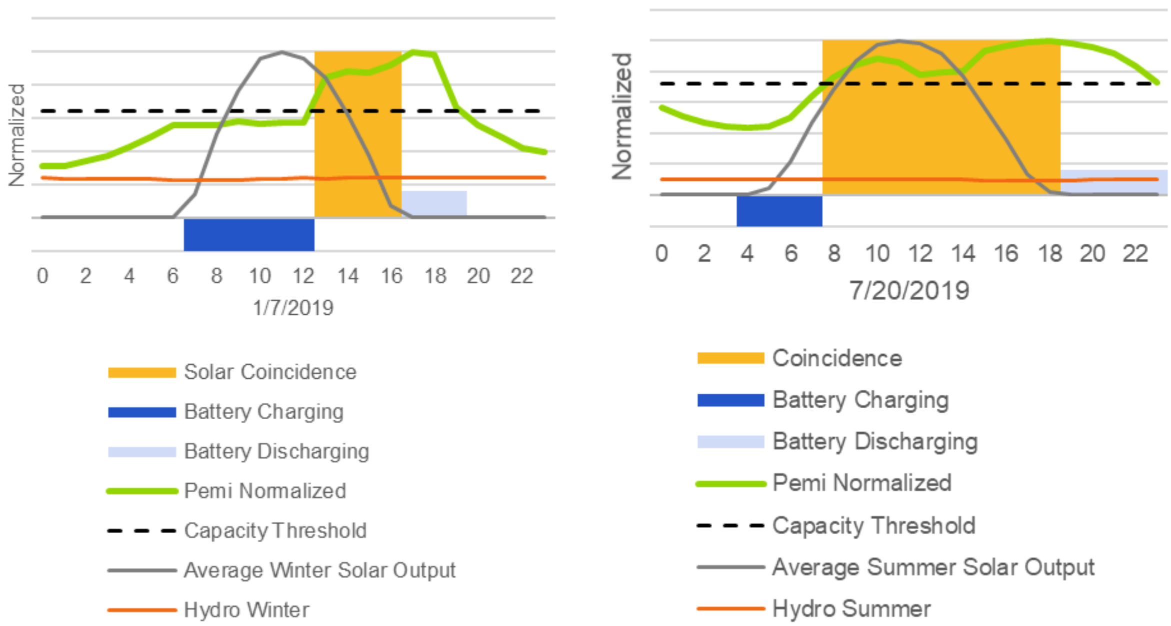


Source: Guidehouse, EDC data

Pemi Substation (Bulk) – Solar, Storage, and Hydro Coincidence Analysis

In Figure 60, summer and winter hydro production profiles are added to illustrate the coincidence of hydro production and the offset to solar and battery production requirements.

Figure 60. Solar, Storage, Hydro Coincidence Analysis – Pemi Substation



Source: Guidehouse, EDC data

Portsmouth Substation (Bulk) Analysis

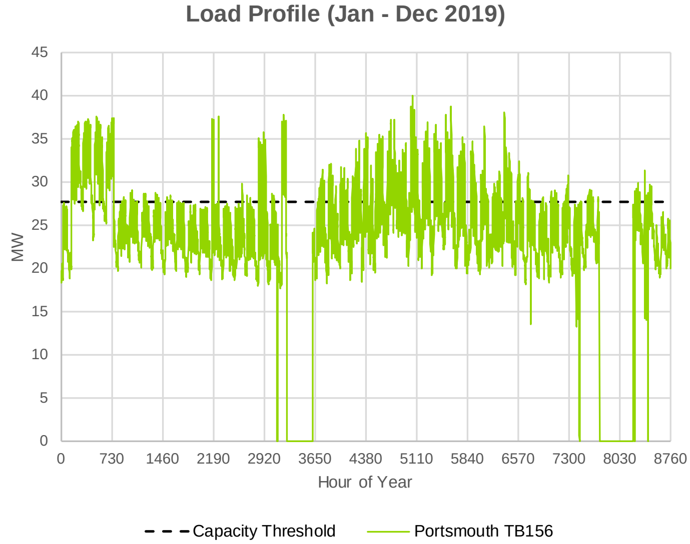
Figure 61 presents hourly profiles for the Portsmouth substation, a midday peaking bulk substation, where capacity deficiencies occur many hours during the year. These deficiencies occur during winter and summer months and are caused by insufficient transformation capacity to back up the contingency loss of one of two transformers at Portsmouth.[51]

The duration and energy deficiencies at Portsmouth are as follows:

- Hours of capacity deficiency: 1,966
- Energy deficiency: 7,446 MWh (Approximately, 3.7% of total energy (200,560 MWh)

[51] Portsmouth is an example of a bulk substation where the recently-modified system planning criteria affected the potential violation analysis, as a result of an increased number of hours of exposure for contingency overloads.

Figure 61. Annual Hourly Profile – Portsmouth Substation (Bulk)



Source: Guidehouse, EDC data

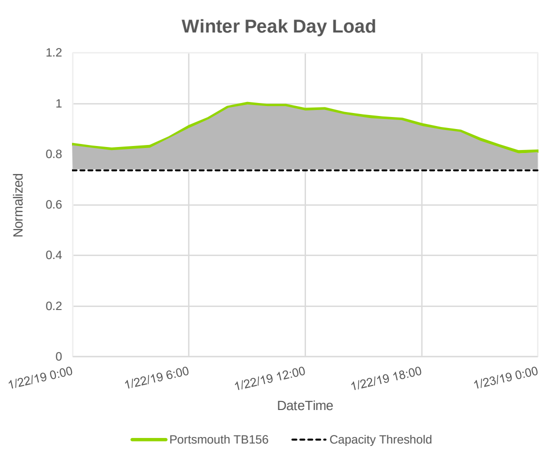
Table 25. Annual Load Profile and Capacity Threshold – Portsmouth Substation

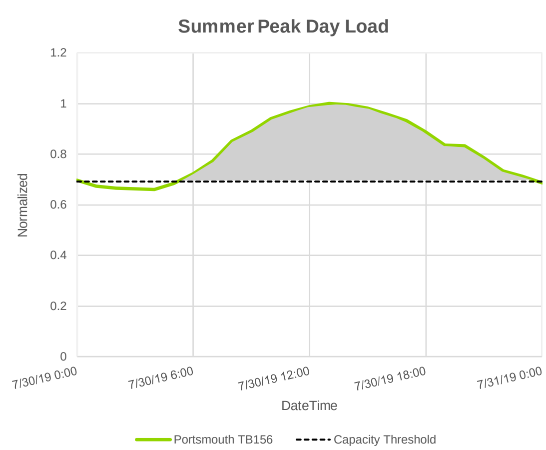
Location	Region	Peak (MW)	Time of Peak	First Year Deficit (MW)
Portsmouth Substation (Bulk)	**Eastern**	**40**	**7/30/19 13:00**	**12.3**

Source: Guidehouse, EDC data

Figure 62 illustrates the duration of capacity deficiencies at Portsmouth during winter and summer conditions. The figure indicates a significant number of hours of exposure for potential contingency overloads. It also indicates that significant solar PV production coupled with energy storage would better align with hours of capacity deficiencies during summer months, as there are fewer hours when energy storage discharge is needed to meet capacity deficiencies when solar production is zero.

Figure 62. Seasonal Capacity Deficiencies – Portsmouth Substation





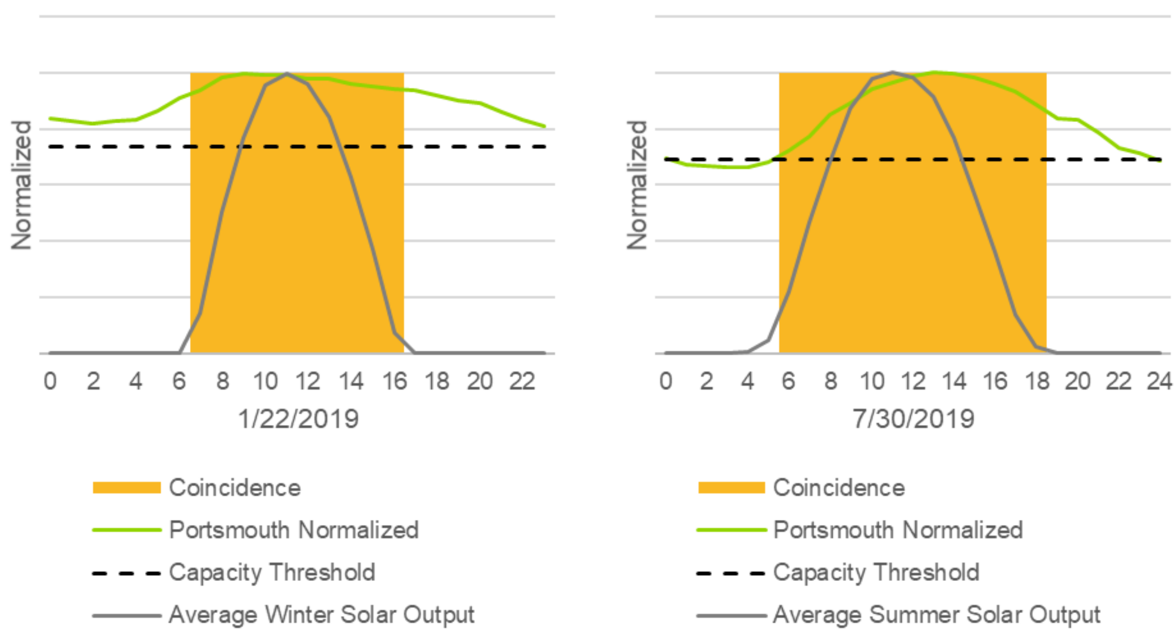
Source: Guidehouse, EDC data

Portsmouth Substation (Bulk) – Solar Coincidence Analysis

Figure 63 indicates there is a greater number of hours in the summer where solar production coincides with hours of capacity deficiency. There is a large number of hours in winter where solar production is zero during hours of capacity deficiency.

- Winter coincidence interval: 10 out of 24 hours
- Summer coincidence interval: 13 out of 18 hours

Figure 63. Solar Coincidence Analysis – Portsmouth Substation (Bulk)



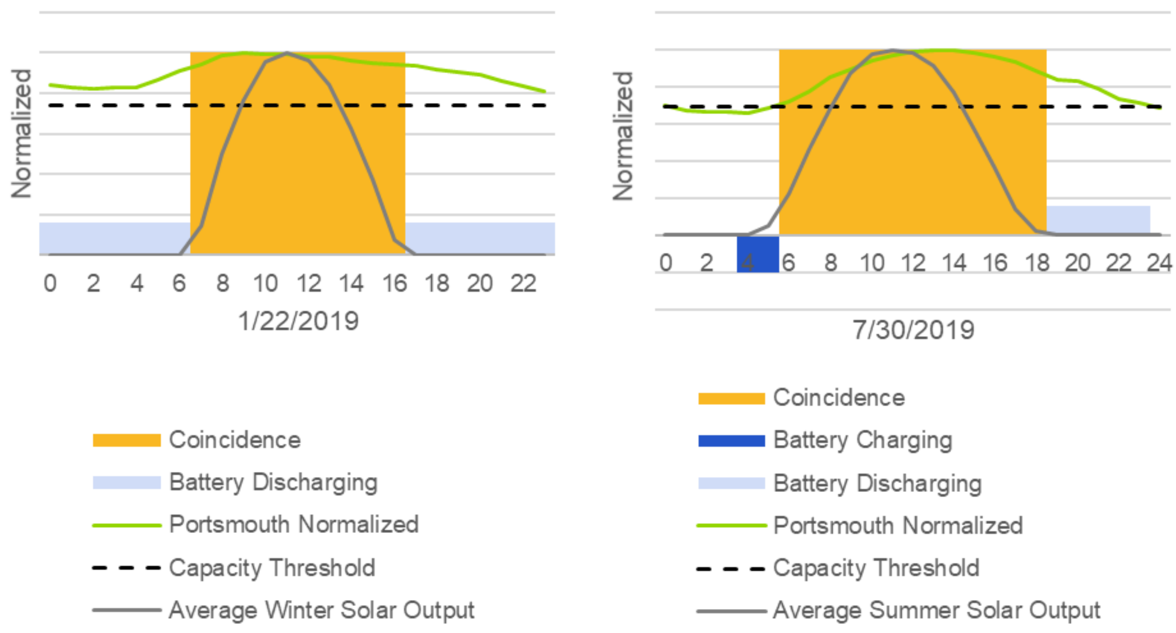
Source: Guidehouse, EDC data

Portsmouth Substation (Bulk) – Solar and Supplement Storage Charging Analysis

Figure 64 indicates that the lengthy capacity deficiency interval constrains the availability of solar to charge battery storage, summarized as follows:

- Winter: No hours available for charging via solar, 12-hour discharge interval
- Summer 2-hour charging interval, 5-hour discharge interval

Figure 64. Solar plus Storage Charging Analysis – Portsmouth Substation (Bulk)

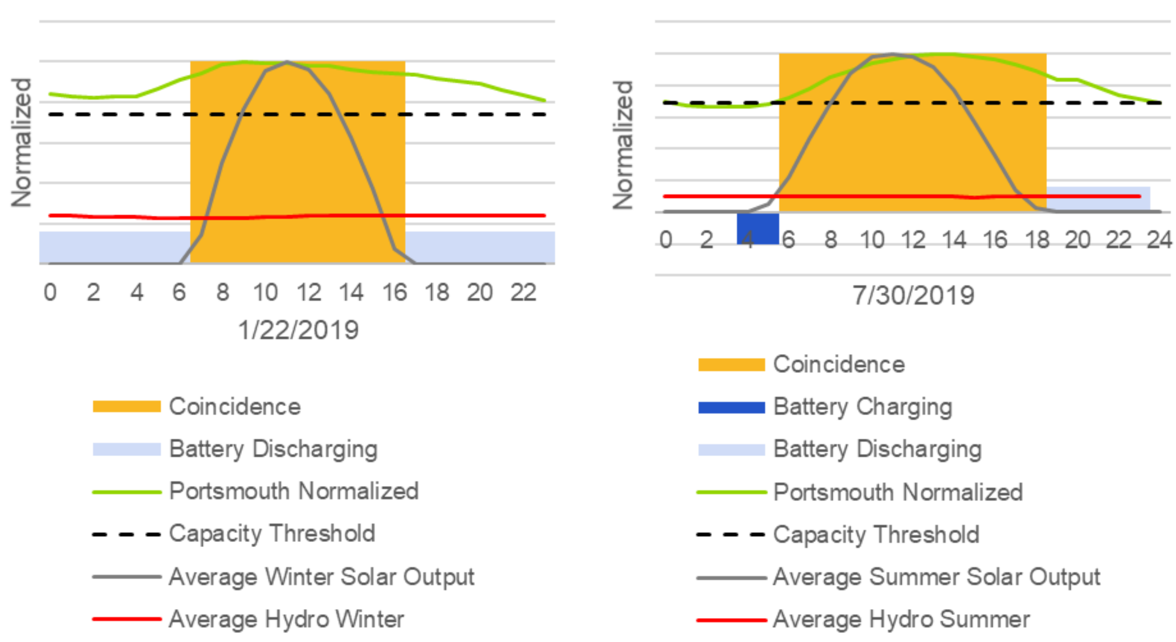


Source: Guidehouse, EDC data

Portsmouth Substation (Bulk) – Solar, Storage, and Hydro Coincidence Analysis

Figure 65 indicates that hydroelectric production in the winter is higher, which could offer greater support to address capacity deficiencies at Portsmouth.

Figure 65. Solar, Storage, and Hydro Coincidence Analysis – Portsmouth



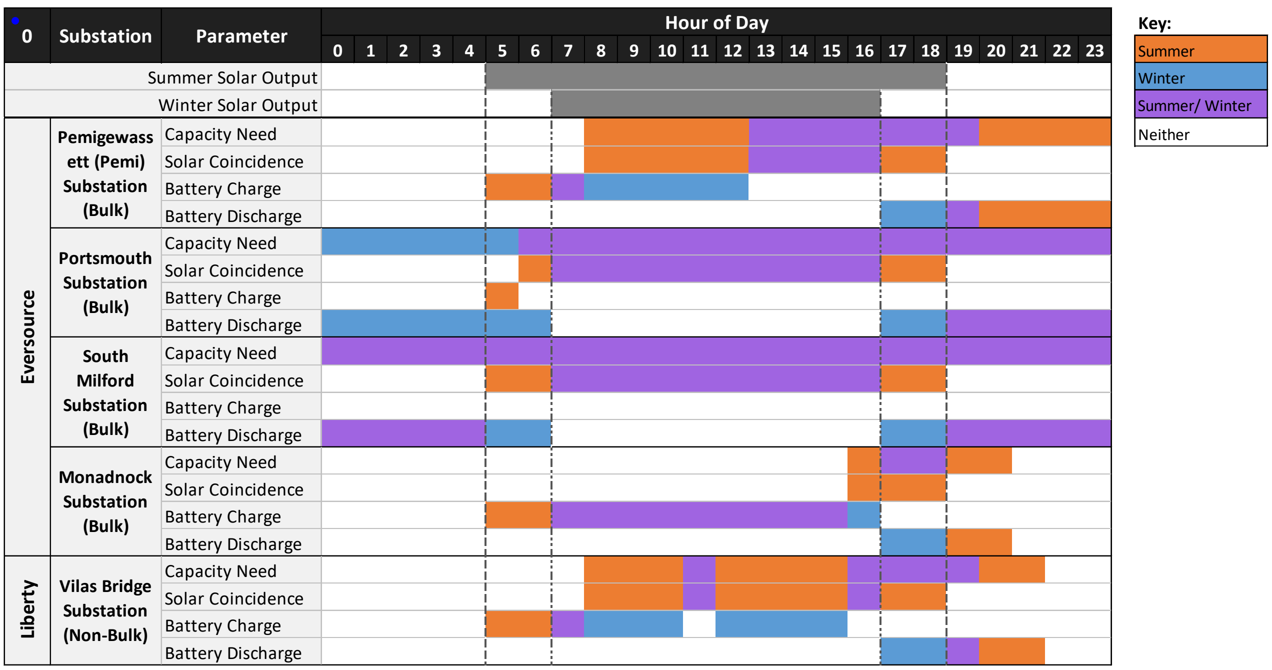
Source: Guidehouse, EDC data

High Level Mapping of DG and Capacity Deficiency Profiles

The load and DG profile analysis presented in the prior set of diagrams are simplified in Figure 66, which illustrates the hours during which solar PV production coincides with hours of capacity deficiency on peak days for the five locations where first year deficiencies occur during both summer and winter months. It also illustrates the hours during which solar PV production is available to charge battery storage devices and hours during which discharge of battery storage would enable alignment with more hours of capacity deficiency at times when solar production is zero.[52]

For example, the Pemi location has a summer peak day capacity deficiency between the hours of 7:00 a.m. and 11:00 p.m., and a winter peak day capacity deficiency between the hours of 12:00 p.m. and 7:00 p.m. Battery storage charging with solar energy production is available between 5:00 a.m. to 7:00 a.m. during summer and 6:00 a.m. through 12:00 p.m. in the winter.

Figure 66. Locations with Summer and Winter Peaks



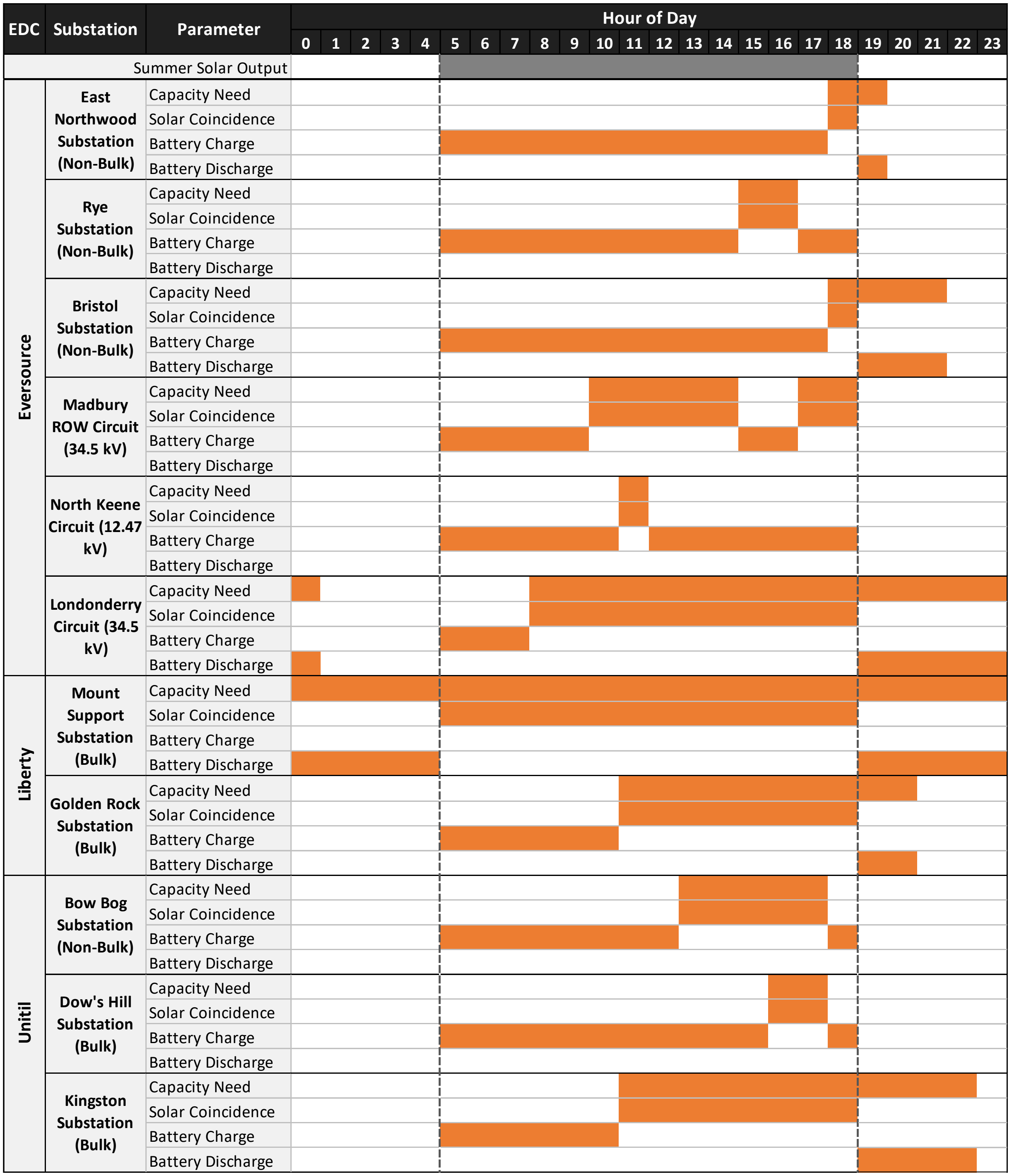
Source: Guidehouse, EDC data

Figure 67 is similar to Figure 66, but is less visually complex as it displays the remaining 11 locations, each of which are summer peaking only. Figure 67 indicates that several locations experience late afternoon or early evening peaks, such as the East Northwood and Bristol non-bulk substations. However, the duration of capacity deficiency is narrow

[52] Figure 64 excludes hydro production profiles as energy is produced for 24 hours, continuously throughout the days, for each season. Inclusion of hydro profiles would render the illustration unnecessarily complex.

at those two locations, along with other locations such as Dow Hill, leaving several hours of battery charging available from solar PV production.

Figure 67. Locations with Summer Peaks Only



Source: Guidehouse, EDC data

4.3.3 Methodology to Map Capacity Deficiency and DG Production Profiles (Example)

The methodology the study team applied to map and compare hourly capacity deficiencies to DG production profiles is described in the following steps. These steps describe how the normalized values that appear in Section 4.3.2 are derived and how actual values for a specific location (Pemi Bulk Substation) are derived and can be developed for other locations, including site-specific values for solar for different orientations.

1. The hourly capacity deficiencies measured in MW are derived for the summer and winter peak day during which the maximum capacity deficiency occurs. If there are no capacity deficiencies during the winter or summer season, only the season during which a capacity deficiency occurs is evaluated.
2. The hourly capacity deficiencies identified in Step 1 are normalized by converting the hourly load, measured in MW, to per unit values, where the hourly load during which the maximum capacity deficiency is equal to one, and all other hours are equal to the MW value during each hour divided by the maximum daily load measured in MW. Referring to Figure 55 and Table 24, per unit values are derived by subtracting the firm capacity represented by the dashed line (approximately 15 MW) from the actual hourly loads on peak days.[53] The maximum first-year capacity deficit in this instance is just above 8 MW.
3. The solar production values predicted to occur on the day of the summer and winter peak is derived via NREL's PVWatts solar model. The hourly solar production values are converted to per unit values using the approach described in Step 2 for hourly loads. The solar production profiles were derived based on the location listed in Figure 46 and that appear in Figure 51. The actual peak solar production during the summer using PVWatts is approximately 700 watts for a device with a rated output of 1,000 watts. However, location-specific profiles could be used in place of the single location presented in Figure 46. Similarly, different solar panel orientations and fixed versus rotating axis could be applied. The duration of the coincidence of solar production with hours of capacity deficiency in Figure 57 are 4 hours during the winter peak day, 11 during the summer.
4. The per-unit solar production profiles are superimposed on the per-unit hourly load profiles. The hours during which solar production coincides with hours of capacity deficiency are shaded (orange in the examples provided above). Figure 58 shows how the level and hours of coincidence change when a different orientation of a fixed axis solar array is chosen.

[53] Firm capacity is the lower of the seasonal normal (N-0) or contingency (N-1) rating of the line or substation.

5. For hours during which solar production is zero and where capacity deficiencies occur, energy storage is evaluated to determine the number of hours during which energy storage devices would need to be discharged to address capacity deficiencies. An assumption is made that energy storage charging must occur during hours when there are no capacity deficiencies. But solar production is greater than zero. Charging (dark blue) and discharge (light blue) hours are superimposed on the hourly chart. Figure 59 displays the number of available energy storage charge and discharge hours for winter and summer peak days.
6. The last step shows the alignment of hourly hydroelectric output, measured in per unit, over the entire day (Figure 60). The normalized hourly per-unit values for hydroelectric are based on site-specific actual production data instead of the proxy hourly values that are used for solar and solar paired with energy storage.

4.4 Summary: DG Production Profile Analysis

The potential for DG production to align with hours of capacity deficiency varies based on the selected location and duration of need.

- Solar PV production alone typically does not fully align with hours of capacity deficiencies in several locations analyzed, as a result of capacity deficiencies that occur during evening peak hours.
- Some of the locations analyzed have both summer and winter capacity deficiencies; the hours of need are not the same due to seasonal variations in load.
- Storage capacity, when paired with solar, improves the overall alignment of DG production with hours of locational capacity need.
- Hydroelectric production on average aligns with hours of capacity deficiencies, but at reduced production levels during the summer months when water flow is lower.

5.0 Conclusions

The study’s findings are intended to inform the Commission of the potential value of locational capacity avoidance to better inform development of future NEM tariffs and related compensation rates for eligible DG technologies. The amount of DG and energy storage required to avoid capacity investments at specific locations, as typically performed in an NWS analysis, was not included as a part of this study. Instead, the study focuses on determination of the time-differentiated value of avoiding traditional capacity investments at selected locations through technology-agnostic load reduction. A related objective was to analyze the alignment of DG production profiles with locational load profiles and capacity deficiency hours for specific NEM-eligible DG technologies. Those technologies include solar PV, solar PV paired with energy storage, and hydroelectric generation, all with capacities rated up to 1 MW.

Based on the analysis in Sections 2.0 through 4.0, the study supports the following findings and conclusions:

- Out of 696 total potential locations, 122 distribution system substations or lines were identified as candidate locations for detailed analysis of capacity investment avoidance opportunities under base, low, and high load growth forecast scenarios. Of the 122 locations considered, 13 are historical and 109 are future, with 77 triggered only in the High Case during the study time horizon.
- The projected capacity deficiencies for the three EDCs beginning in 2020 total approximately 107 MW, increasing to 147 MW by 2029, under the base load forecast. Total capacity deficiencies in 2029 for the low load growth forecast are 63 MW and for the high load growth forecast are 317 MW. A substantial number of capacity deficiencies occur in 2020, the first year of the forward-looking period covered by the study, in large part due to recent changes in planning criteria implemented by Eversource.
- Of the 16 locations selected for detailed analysis, five are historical investments. Five of the 16 locations have first year capacity deficiencies that occur during both winter and summer months; the remaining 11 are summer peaking only.
- The cost of traditional distribution system investments to address capacity deficiencies at the selected locations, expressed in terms of a revenue requirement, ranges from less than $1 million to over $14 million. The total value of traditional capacity investments at the 16 selected locations is approximately $75 million.
- The economic value of capacity investment avoidance varies significantly among the 16 locations based on a theoretical analysis of capacity avoidance using the RECC approach. The maximum hourly economic value of capacity investment avoidance ranges from under $1 per kilowatt (kW) per hour to over $4,000 per kW per hour. The greatest driver for that variance is the total number of hours over which capacity deficiencies occur at a specific location. A lower value is generally indicative of a capacity deficiency that occurs over a large number of hours, while a higher value is generally indicative of a capacity deficiency that occurs during fewer hours.
- Related findings from the capacity deficiency analysis and evaluation of DG production profiles are summarized as follows:
    - The number of hours of capacity deficiency varies significantly by location, with some locations with fewer than 15 hours of deficiency per year, while other locations are capacity deficient for several thousand hours per year.
    - Most locations have capacity deficiencies during late afternoon or early evening hours. Solar PV production profiles do not fully align with those hours of capacity deficiency. Solar PV paired with energy storage typically can produce electricity during most or all hours during which there are locational capacity deficiencies.
    - Hydro production profiles typically align with hours of capacity deficiency, but with lower production during summer months as compared to winter months.

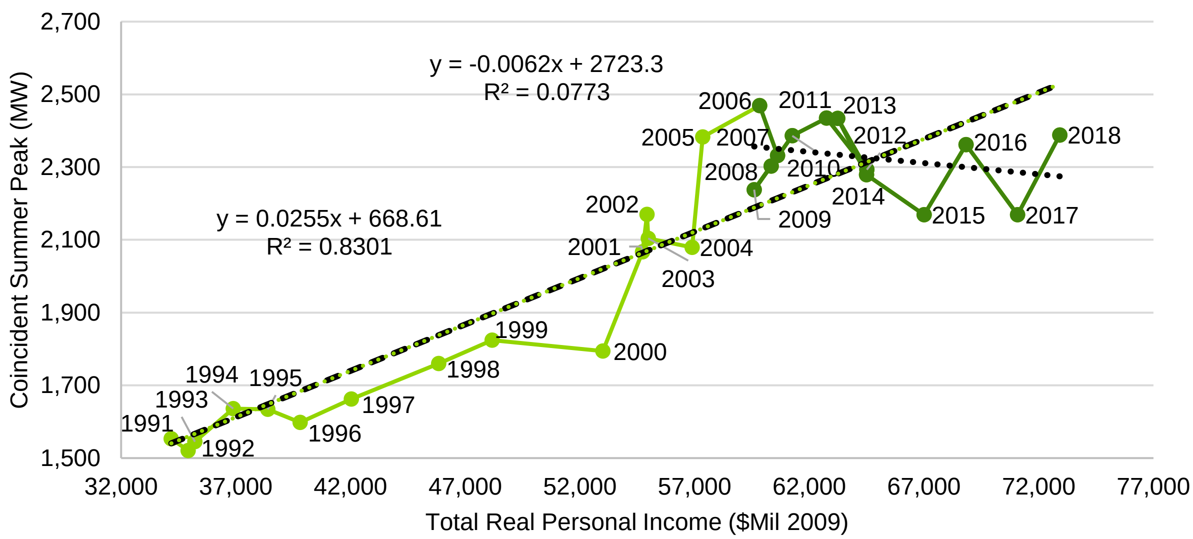
Appendix A. Detailed Methodology and Assumptions

A.1 Analysis of Economic Variables Impact on Load

Details of Analysis of Economic Factors on Peak Load:

Figure A-1 shows the New Hampshire summer peak in MW coincident with the ISO-NE peak compared with the total real personal income of New Hampshire from 1991 to 2018.[54] Given the inflection point in the coincident summer peak load in the 2006 where the increasing load no longer correlates with increasing total real personal income, the figure shows two trend lines. The first shows the trend line from 1991 to 2018 and the second shows the trend from 2006 to 2018.

Figure A-1. Coincident Summer Peak (MW) vs. Total Real Peal Income (1991-2018)

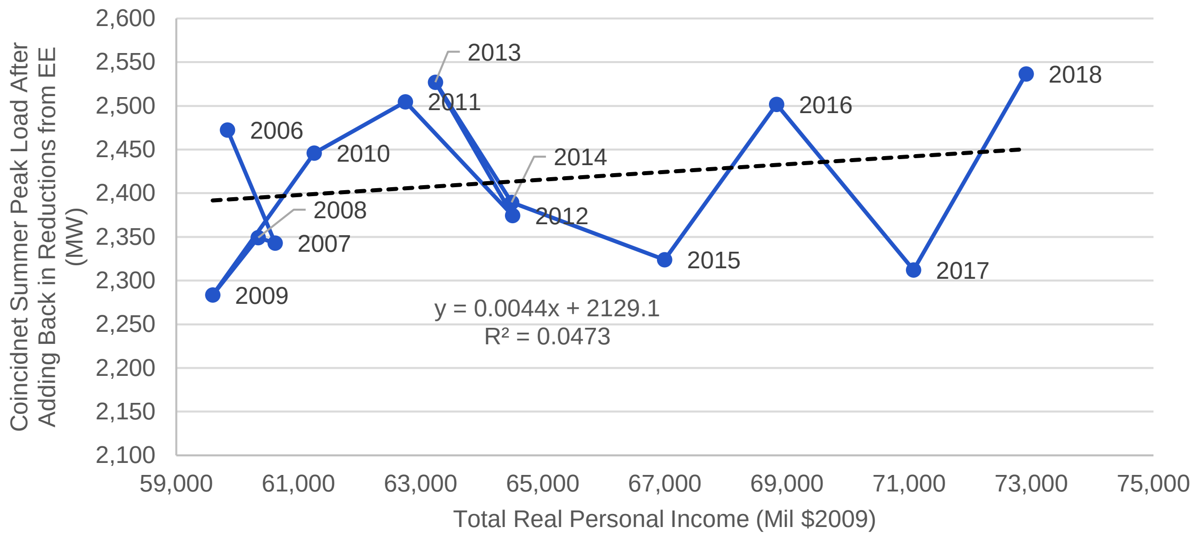


Source: ISO-NE, https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/

Given the inflection point in the coincident summer peak load in 2006 where the increasing load no longer correlates with increasing total real personal income, the study reviews the more recent summer peaks and added back in the EE impacts that have reduced peak load. This analysis of summer peaks from 2006 to 2018, which removes the EE impacts on load reduction, is shown in Figure A-2. This figure shows a slightly upward trend as opposed to a minor downward trend in loading as relates to total real personal income, but the correlation is still poor.

[54] This analysis looked at the historic ISO-NE NH coincident summer peak since that is the value that is forecasted by ISO-NE forward for 10 years. The non-coincident summer peak did not vary significantly from the coincident peak for the historic period.

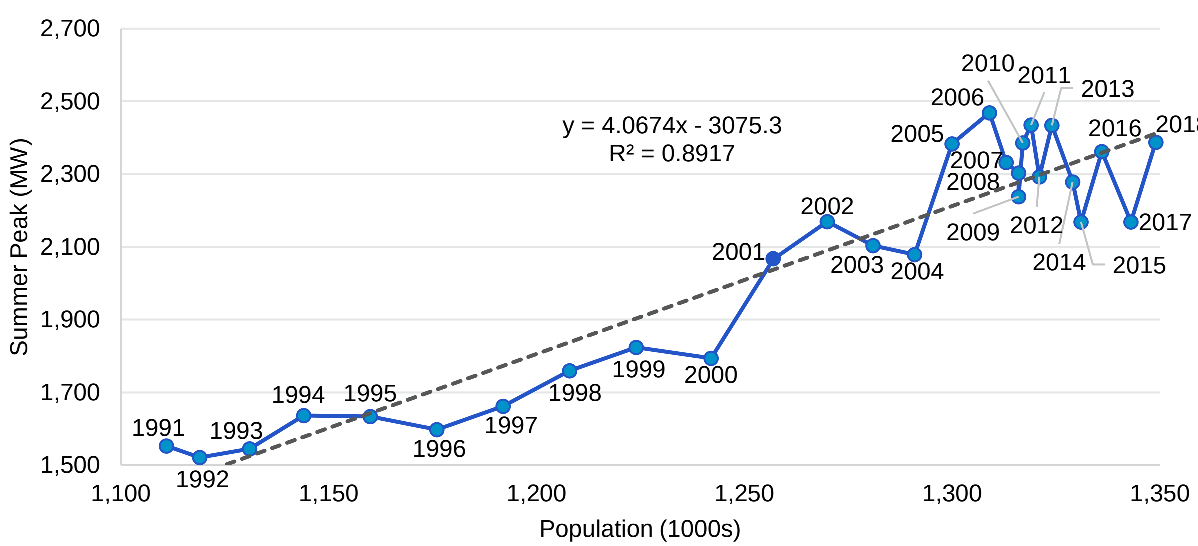
Figure A-2. Coincident Summer Peak After Adding Back in Peak Load Reductions from EE vs. Total Real Personal Income (2006-2018)



Source: ISO-NE, https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/

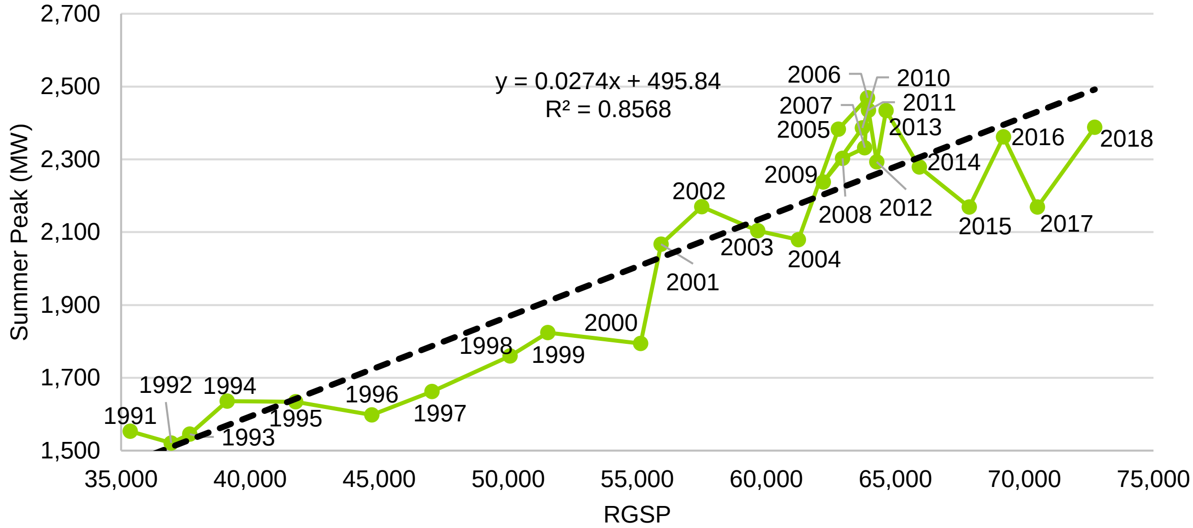
In addition to looking at the past 30 years and the past 12 years of summer peak as compared to total real personal income, the study also compared loading with total statewide population and real gross state product. The analysis revealed similar trends when considering total population and real gross state product as those seen with total real personal income. Additional metrics used for comparing coincident summer peak and economic factors are shown in Figure A-3 and Figure A-4.

Figure A-3. Coincident Summer Peak (MW) vs. Statewide Population (1991-2018)



Source: ISO-NE, https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/

Figure A-4. Coincident Summer Peak (MW) vs. Real Gross State Product (1991-2018)



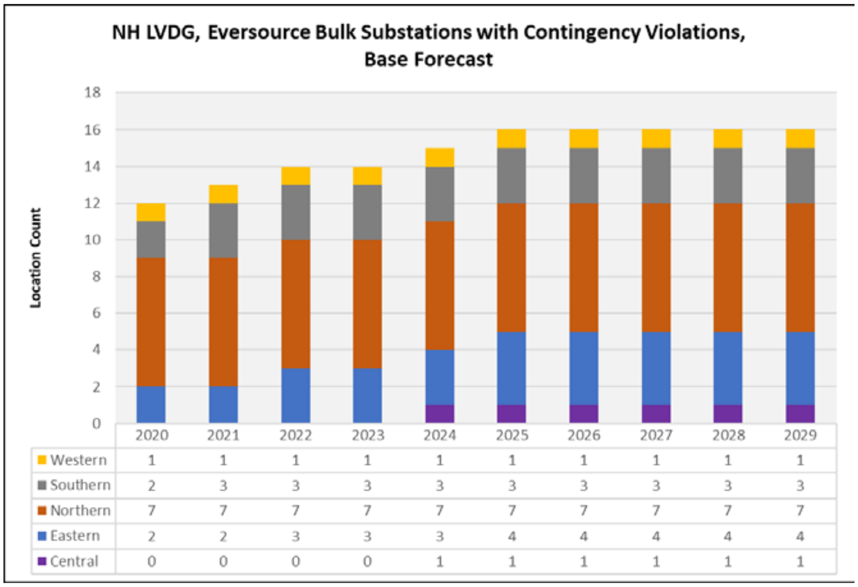
Source: ISO-NE, https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/

A.2 Forward-Looking Violation Screening

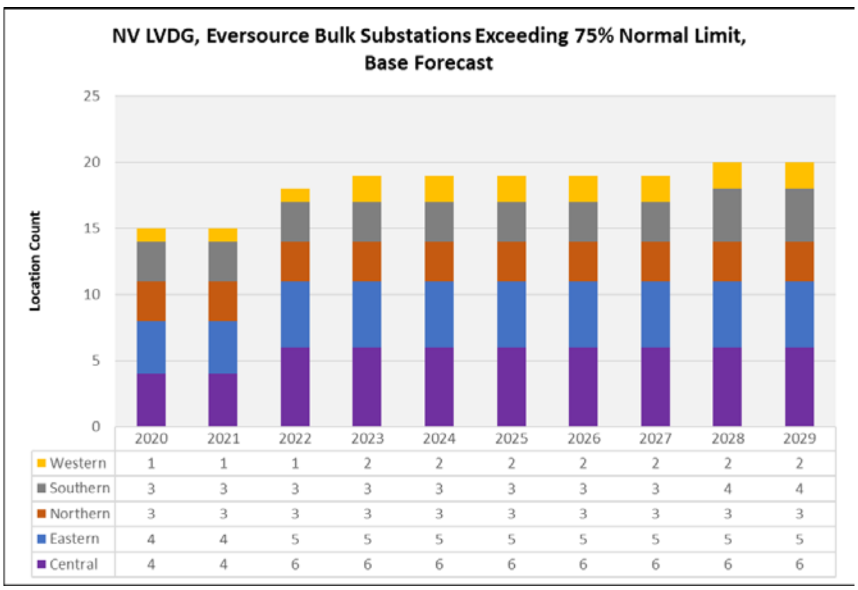
Capacity Deficiency Analysis: Eversource- Base Forecast

- In the base forecast Year 1, 12 substations do not meet Eversource's capacity planning criteria for contingencies (i.e., N-1 violations) and 15 bulk substations exceed 75% transformer normal limit rating[55]
- Six bulk substations have both normal and contingency violations during the 10-year forecast
- No violations occur on non-bulk substations
- Several near-term violations due to change in planning criteria for bulk substations

[55] Eversource recently changed their capacity planning criteria for bulk substations, which caused numerous near-term violations. Eversource's current capacity planning criteria is under review by the Commission.

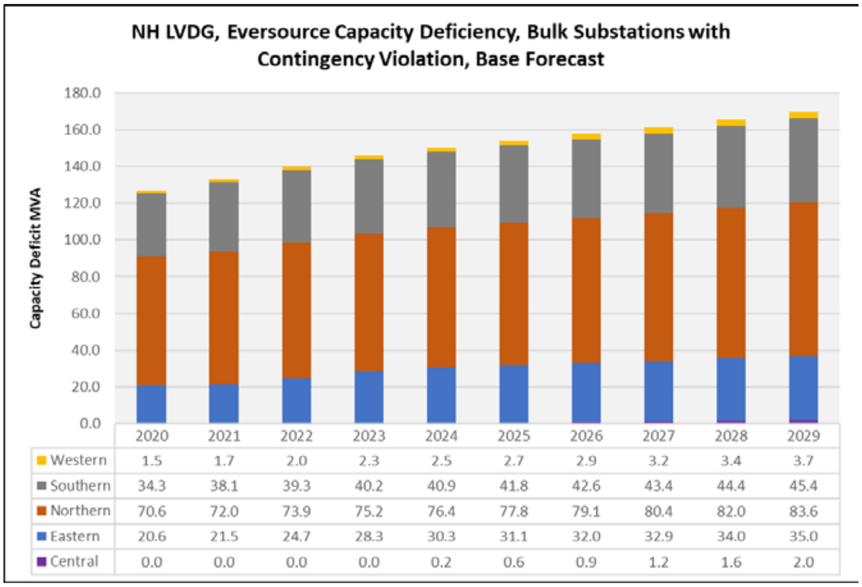


Source: Guidehouse, EDC data



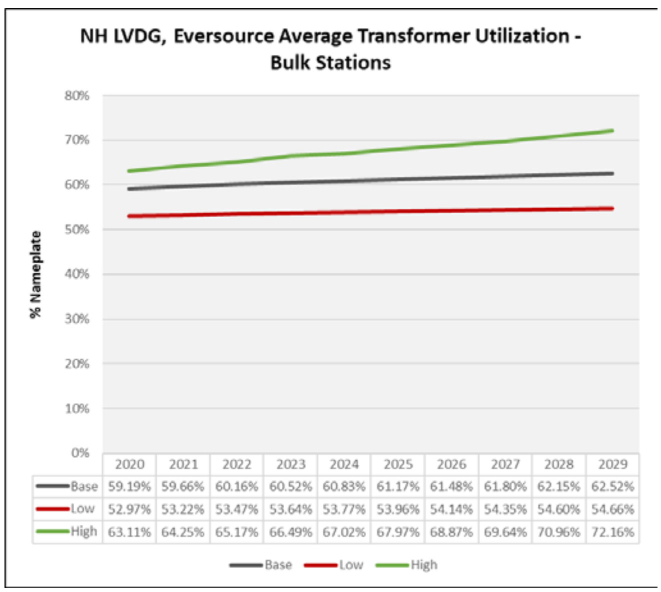
Source: Guidehouse, EDC data

- Approximately half of the total bulk substation capacity deficiencies are located in the northern region
- Capacity deficiencies are driven by bulk substations not meeting contingency (N-1) planning criteria rather than normal overloads caused by load growth
- Average bulk substations capacity utilization is 60% for the 10-year base load forecast



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Western	1.5	1.7	2.0	2.3	2.5	2.7	2.9	3.2	3.4	3.7
Southern	34.3	38.1	39.3	40.2	40.9	41.8	42.6	43.4	44.4	45.4
Northern	70.6	72.0	73.9	75.2	76.4	77.8	79.1	80.4	82.0	83.6
Eastern	20.6	21.5	24.7	28.3	30.3	31.1	32.0	32.9	34.0	35.0
Central	0.0	0.0	0.0	0.0	0.2	0.6	0.9	1.2	1.6	2.0

Source: Guidehouse, EDC data

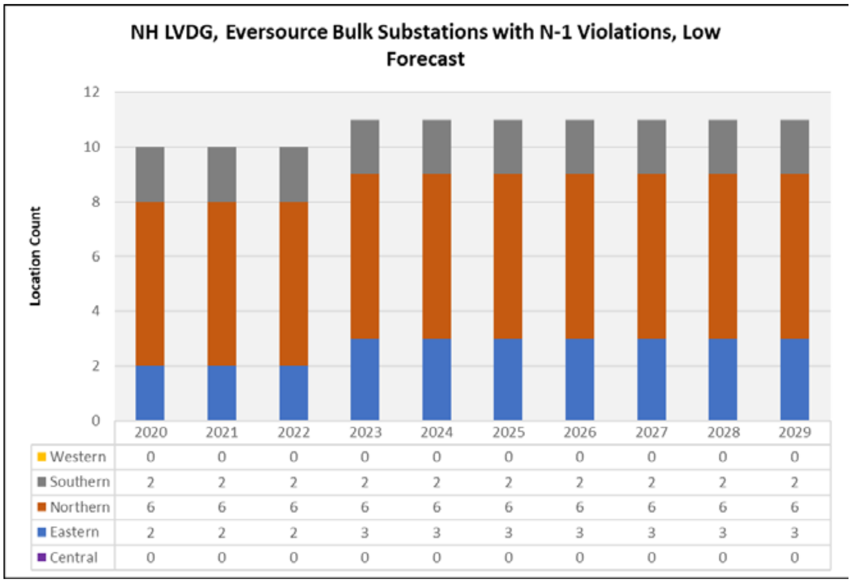


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Base	59.19%	59.66%	60.16%	60.52%	60.83%	61.17%	61.48%	61.80%	62.15%	62.52%
Low	52.97%	53.22%	53.47%	53.64%	53.77%	53.96%	54.14%	54.35%	54.60%	54.66%
High	63.11%	64.25%	65.17%	66.49%	67.02%	67.97%	68.87%	69.64%	70.96%	72.16%

Source: Guidehouse, EDC data

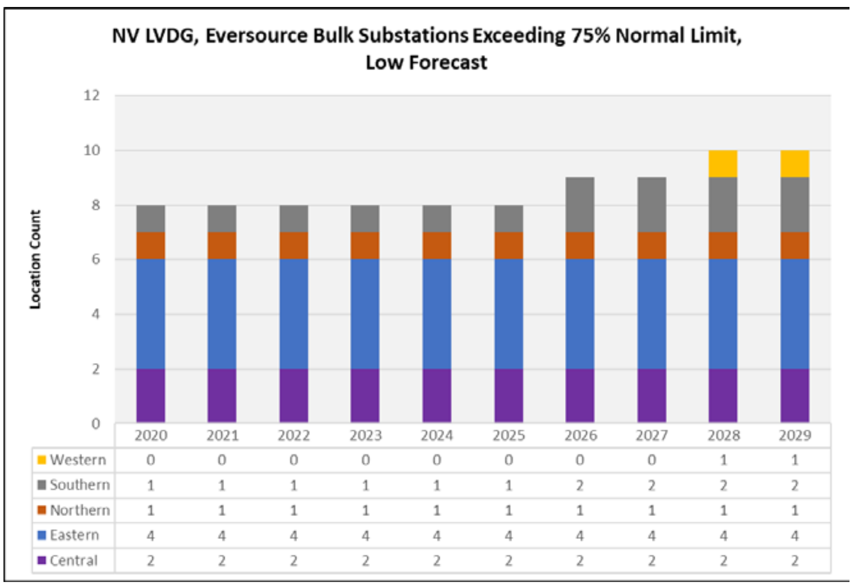
Capacity Deficiency Analysis: Eversource- Low Forecast

- Based on a low load forecast, the number of identified locations with N-1 contingency violations and normal limit violations drops to 10 and 8, respectively
- Number of bulk substations with both normal and contingency violations is two through 2022 and increases to three thereafter
- No violations occur on non-bulk substations



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Western	0	0	0	0	0	0	0	0	0	0
Southern	2	2	2	2	2	2	2	2	2	2
Northern	6	6	6	6	6	6	6	6	6	6
Eastern	2	2	2	3	3	3	3	3	3	3
Central	0	0	0	0	0	0	0	0	0	0

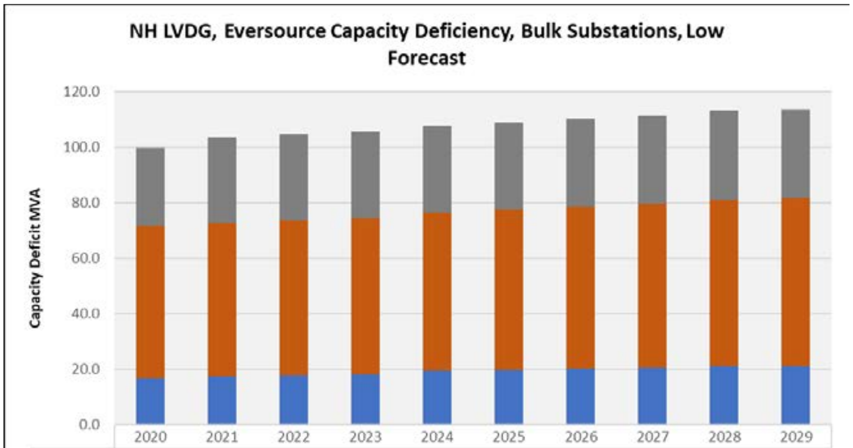
Source: Guidehouse, EDC data



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Western	0	0	0	0	0	0	0	0	1	1
Southern	1	1	1	1	1	1	2	2	2	2
Northern	1	1	1	1	1	1	1	1	1	1
Eastern	4	4	4	4	4	4	4	4	4	4
Central	2	2	2	2	2	2	2	2	2	2

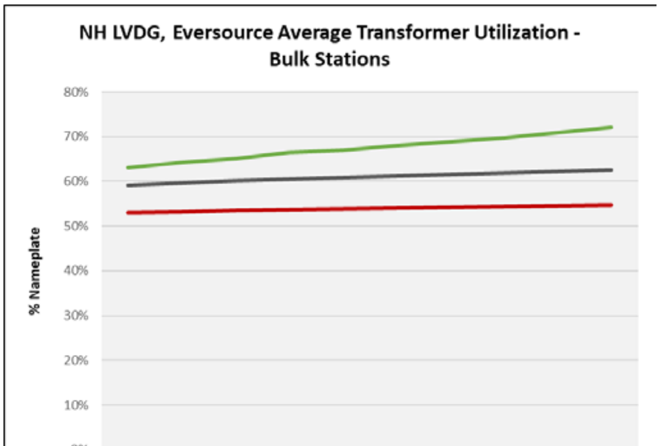
Source: Guidehouse, EDC data

- The low load forecast does not materially decrease the number of bulk substations with contingency violations
- Approximately 14 MVA of capacity deficiency growth in the 10-year period
- In Year 10, 10-year capacity deficiencies drop from about 170 MVA to 110 MVA
- Average substation capacity utilization drops from 60% to 54% for the 10-year low forecast



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Western	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southern	28.0	30.9	31.1	31.2	31.3	31.4	31.6	31.8	32.1	32.1
Northern	54.8	55.3	56.1	56.6	57.0	57.7	58.3	59.0	60.0	60.3
Eastern	16.7	17.4	17.6	17.9	19.4	19.7	20.1	20.5	21.1	21.1
Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Source: Guidehouse, EDC data

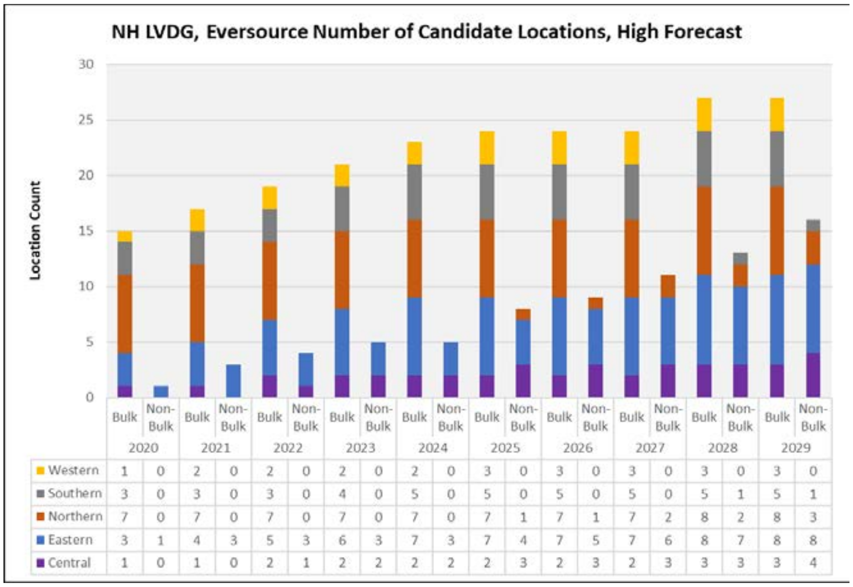


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Base	59.19%	59.66%	60.16%	60.52%	60.83%	61.17%	61.48%	61.80%	62.15%	62.52%
Low	52.97%	53.22%	53.47%	53.64%	53.77%	53.96%	54.14%	54.35%	54.60%	54.66%
High	63.11%	64.25%	65.17%	66.49%	67.02%	67.97%	68.87%	69.64%	70.96%	72.16%

Source: Guidehouse, EDC data

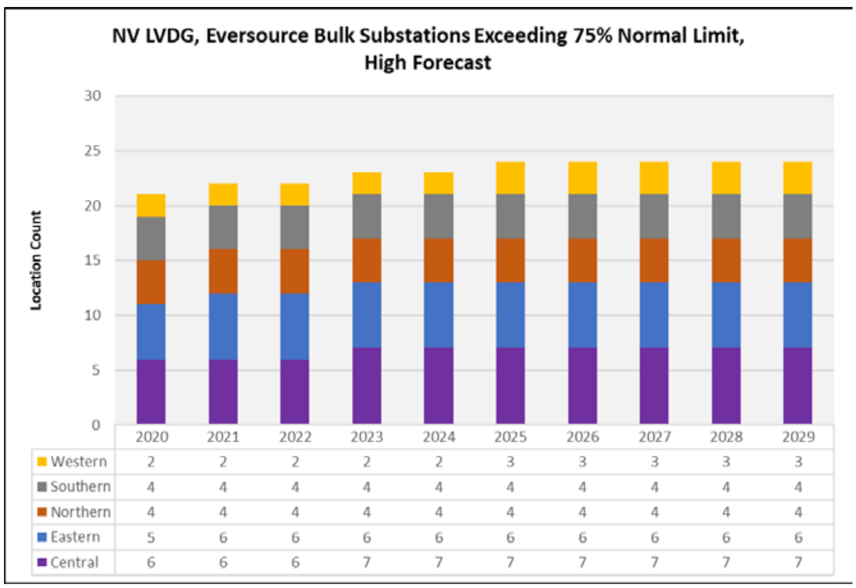
Capacity Deficiency Analysis: Eversource- High Forecast

- Identified locations with capacity deficiencies include bulk and non-bulk substations for the high load forecast case
- By Year 10, approximately 50% of bulk substations and 20% of non-bulk substations experience violations (e.g., potential candidate substations for capacity investment avoidance)
- Eastern region non-bulk substations impacted the most by high forecast



	2020		2021		2022		2023		2024		2025		2026		2027		2028		2029	
	Bulk	Non-Bulk	Bulk	Non-Bulk	Bulk	Non-Bulk	Bulk	Non-Bulk	Bulk	Non-Bulk	Bulk	Non-Bulk	Bulk	Non-Bulk	Bulk	Non-Bulk	Bulk	Non-Bulk	Bulk	Non-Bulk
Western	1	0	2	0	2	0	2	0	2	0	3	0	3	0	3	0	3	0	3	0
Southern	3	0	3	0	3	0	4	0	5	0	5	0	5	0	5	0	5	1	5	1
Northern	7	0	7	0	7	0	7	0	7	0	7	1	7	1	7	2	8	2	8	3
Eastern	3	1	4	3	5	3	6	3	7	3	7	4	7	5	7	6	8	7	8	8
Central	1	0	1	0	2	1	2	2	2	2	2	3	2	3	2	3	3	3	3	4

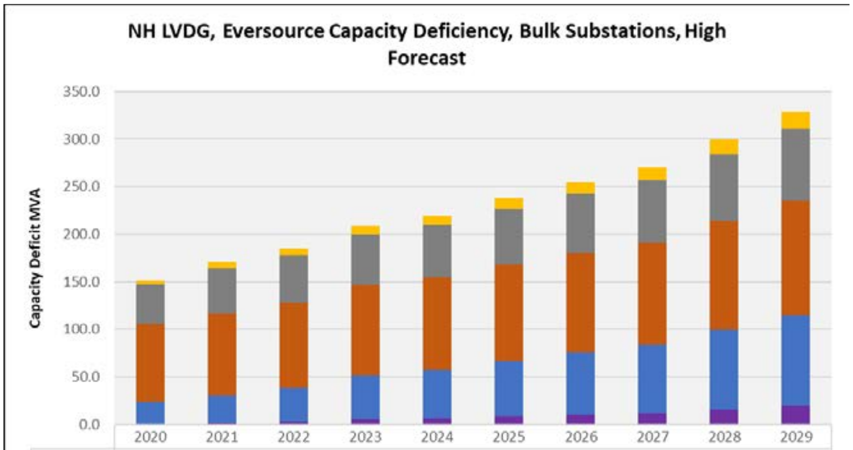
Source: Guidehouse, EDC data



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Western	2	2	2	2	2	3	3	3	3	3
Southern	4	4	4	4	4	4	4	4	4	4
Northern	4	4	4	4	4	4	4	4	4	4
Eastern	5	6	6	6	6	6	6	6	6	6
Central	6	6	6	7	7	7	7	7	7	7

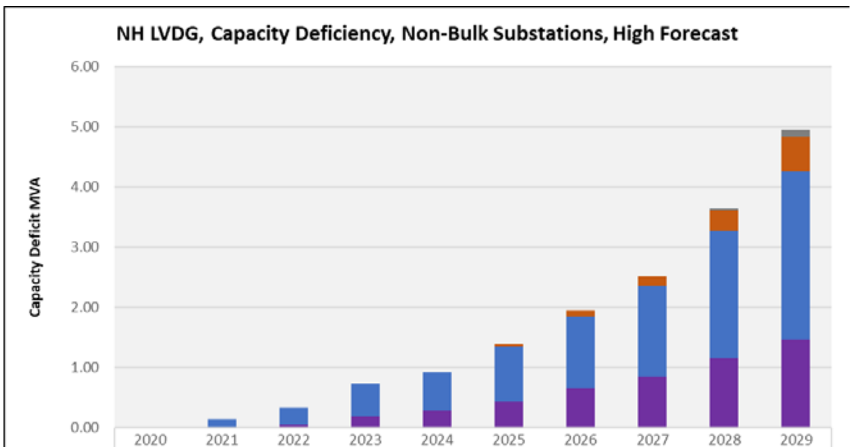
Source: Guidehouse, EDC data

- The number of and magnitude of substation capacity deficiencies increase significantly for the high load forecast case
- Total capacity deficiency doubles in the 10-year period (over 300 MVA in 2029)
- Highest capacity deficiency growth rates in western and eastern regions bulk substations



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Western	4.1	6.9	7.8	9.1	9.6	10.8	12.4	13.7	16.1	18.2
Southern	41.3	47.3	49.7	53.5	55.2	58.9	62.4	65.3	70.4	74.9
Northern	82.1	86.2	89.7	94.9	96.9	100.7	104.3	107.3	114.3	120.6
Eastern	23.5	29.0	35.5	46.1	51.1	58.8	65.7	71.9	83.3	94.8
Central	0.6	1.5	2.8	5.5	6.5	8.5	10.3	11.8	15.8	20.3

Source: Guidehouse, EDC data

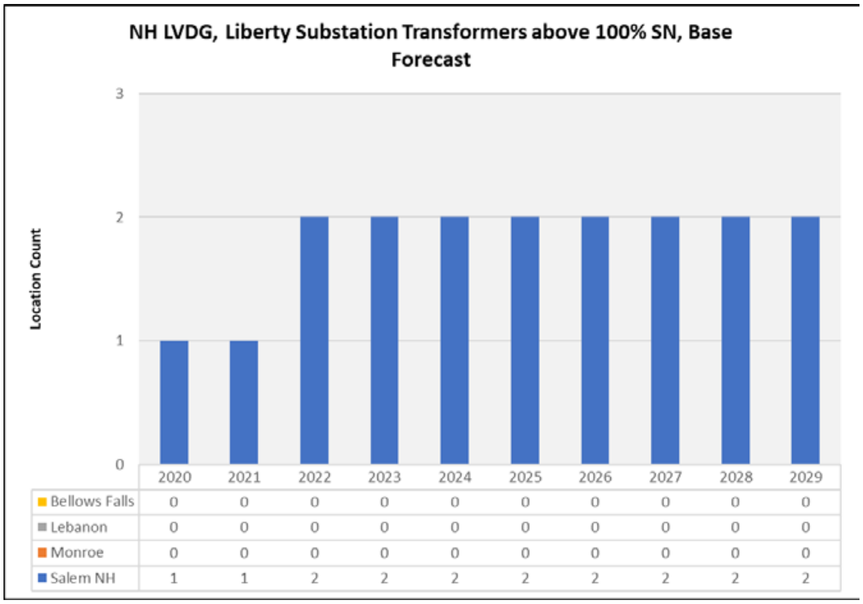


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Western	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Southern	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.12
Northern	0.00	0.00	0.00	0.00	0.00	0.05	0.10	0.15	0.35	0.58
Eastern	0.02	0.14	0.28	0.53	0.65	0.91	1.20	1.51	2.12	2.79
Central	0.00	0.00	0.05	0.19	0.27	0.43	0.65	0.84	1.15	1.46

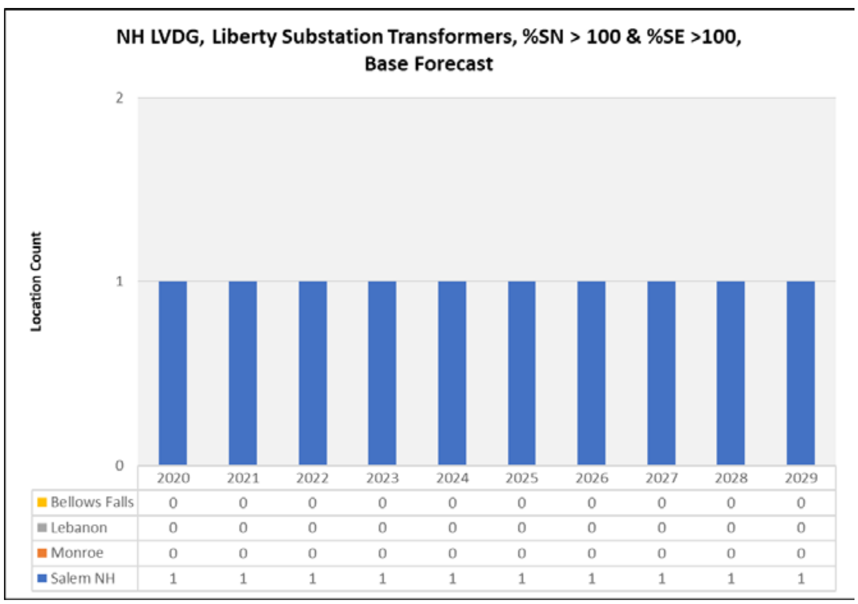
Source: Guidehouse, EDC data

Capacity Deficiency Analysis: Liberty- Base Forecast

- Over the 10-year period, one transformer exceeds 100% normal rating in the first 2 years and an additional transformer starting in 2022
- One substation transformer exceeds 100% normal and 100% emergency ratings through 2029

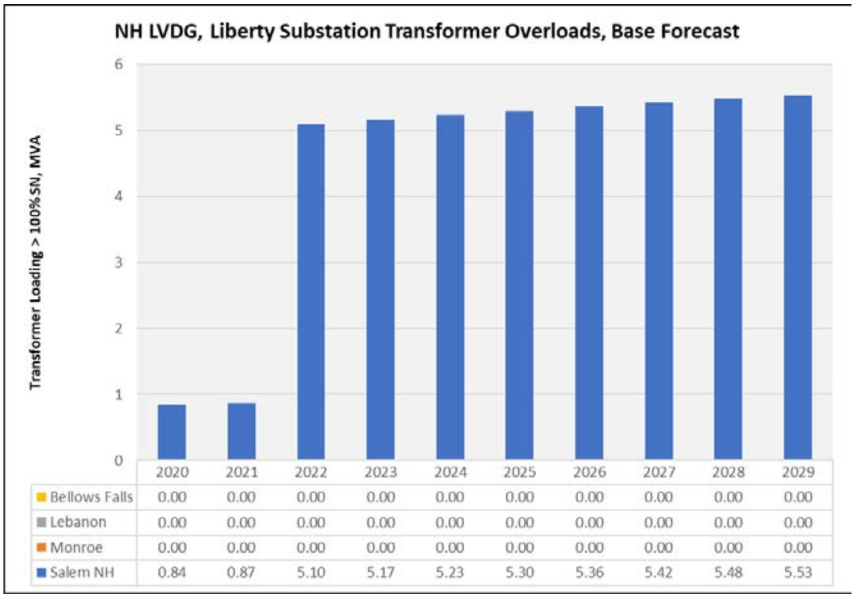


Source: Guidehouse, EDC data



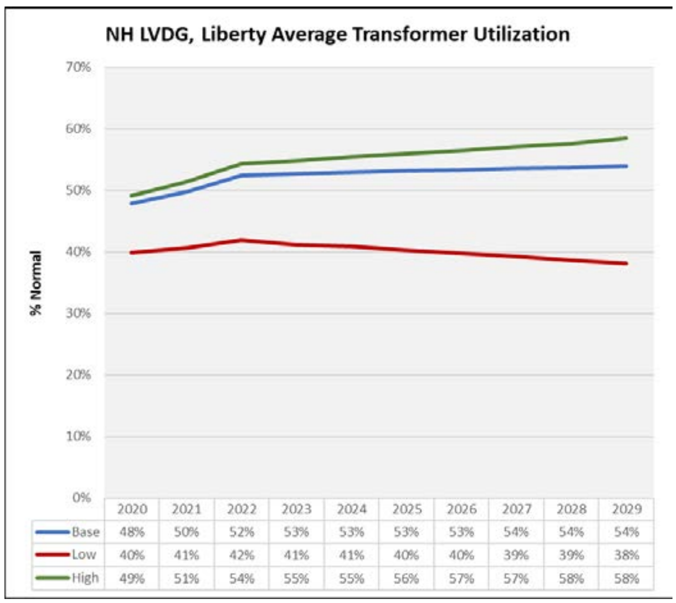
Source: Guidehouse, EDC data

- For the base load forecast, capacity deficiency growth in the 10-year period is approximately 5 MVA
- Capacity deficiency growth in the 10-year period only observed in the Salem area
- Average substations capacity utilization is 52% for the 10-year base load forecast



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Bellows Falls	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lebanon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Monroe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Salem NH	0.84	0.87	5.10	5.17	5.23	5.30	5.36	5.42	5.48	5.53

Source: Guidehouse, EDC data

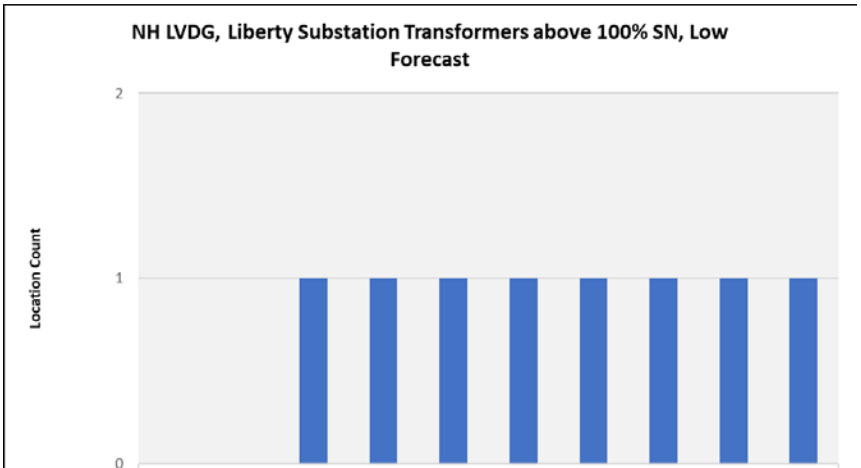


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Base	48%	50%	52%	53%	53%	53%	53%	54%	54%	54%
Low	40%	41%	42%	41%	41%	40%	40%	39%	39%	38%
High	49%	51%	54%	55%	55%	56%	57%	57%	58%	58%

Source: Guidehouse, EDC data

Capacity Deficiency Analysis: Liberty - Low Forecast

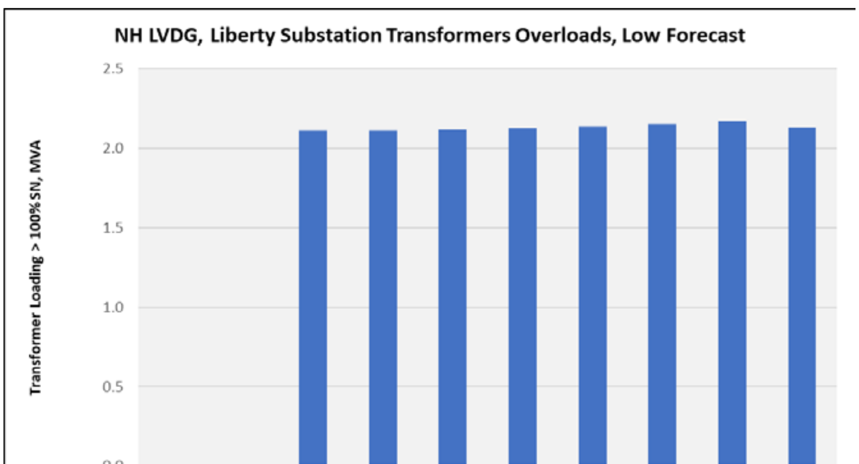
- For the low load forecast, one substation transformer exceeds 100% normal ratings starting in 2022
- None of the substation transformers exceed both 100% normal and 100% emergency ratings



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Bellows Falls	0	0	0	0	0	0	0	0	0	0
Lebanon	0	0	0	0	0	0	0	0	0	0
Monroe	0	0	0	0	0	0	0	0	0	0
Salem NH	0	0	1	1	1	1	1	1	1	1

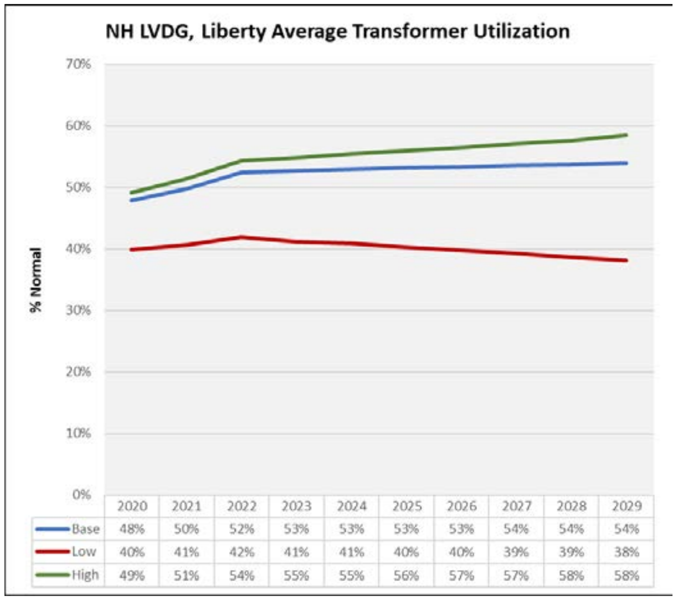
Source: Guidehouse, EDC data

- For the low forecast, the projected capacity deficiency growth remains constant for last eight years
- Approximately 2 MVA of capacity deficiency per year from 2022 to 2029
- Average substation capacity utilization drops from 52% to 40% for the 10-year low forecast



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Bellows Falls	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lebanon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Monroe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Salem NH	0.00	0.00	2.11	2.11	2.12	2.13	2.14	2.15	2.17	2.13

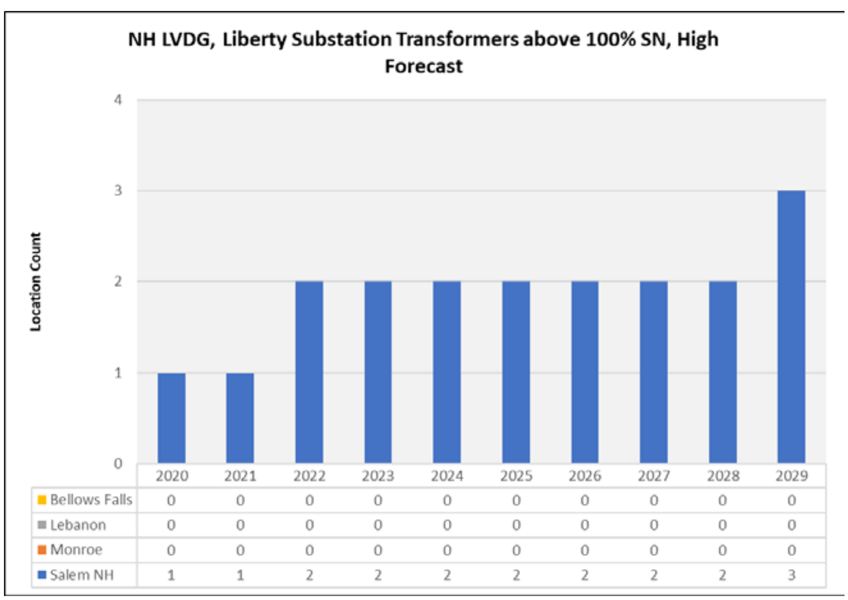
Source: Guidehouse, EDC data



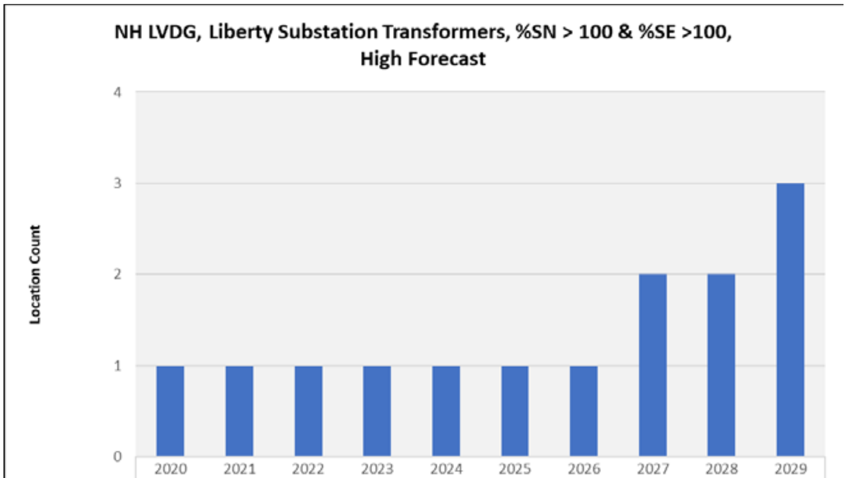
Source: Guidehouse, EDC data

Capacity Deficiency Analysis: Liberty- High Forecast

- For the high forecast, two substations exceed 100% normal ratings and two substations exceed both 100% normal and 100% emergency ratings
- For the 10-year period, one transformer exceeds 100% normal ratings in the first 2 years, an additional transformer in 2022, and a third transformer in 2029
- For the 10-year period, one transformer exceeds 100% normal and 100% emergency ratings in the first 7 years, an additional transformer in 2027, and a third transformer in 2029



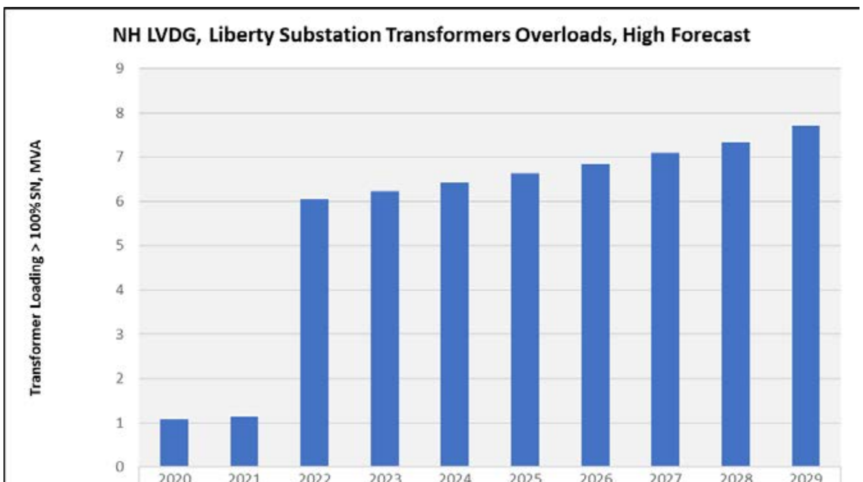
Source: Guidehouse, EDC data



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Bellows Falls	0	0	0	0	0	0	0	0	0	0
Lebanon	0	0	0	0	0	0	0	0	0	0
Monroe	0	0	0	0	0	0	0	0	0	0
Salem NH	1	1	1	1	1	1	1	2	2	3

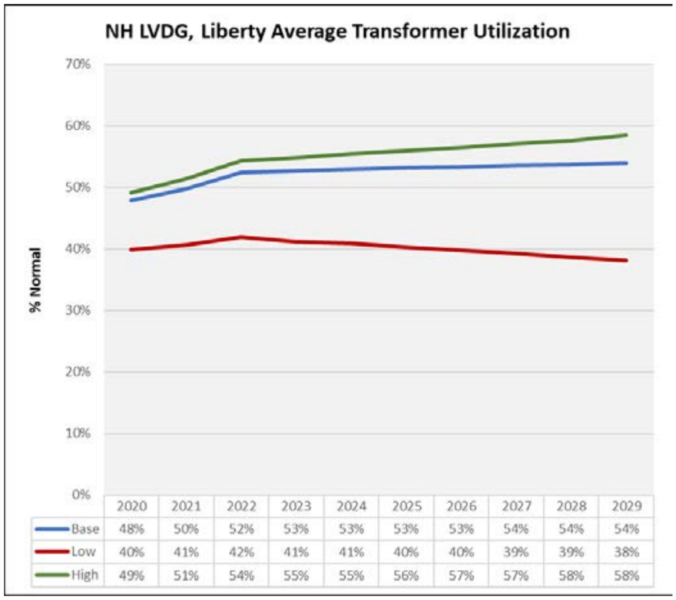
Source: Guidehouse, EDC data

- For the high load forecast, capacity deficiency growth in the 10-year period increases to approximately 7 MVA
- Approximately a 10% increase in average transformer utilization in the 10-year period



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Bellows Falls	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lebanon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Monroe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Salem NH	1.08	1.14	6.04	6.23	6.43	6.63	6.85	7.08	7.33	7.71

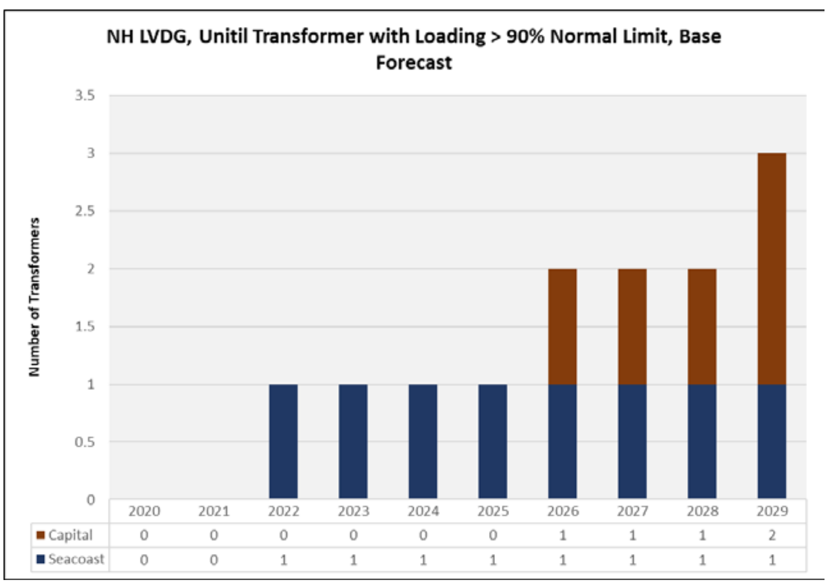
Source: Guidehouse, EDC data



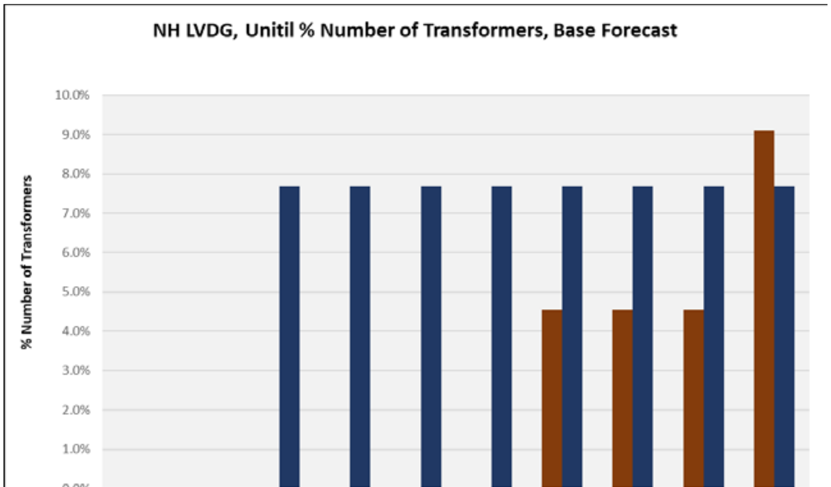
Source: Guidehouse, EDC data

Capacity Deficiency Analysis: Unitil - Base Forecast

- For the base load forecast, three substation transformers in the capital and seacoast regions exceed Unitil's 90% normal loading criteria by 2029
- Seacoast and capital regions have a single substation transformer above 90% normal limit starting in 2022 and 2026, respectively
- Capital region has one additional transformer above the 90% normal limit in 2029



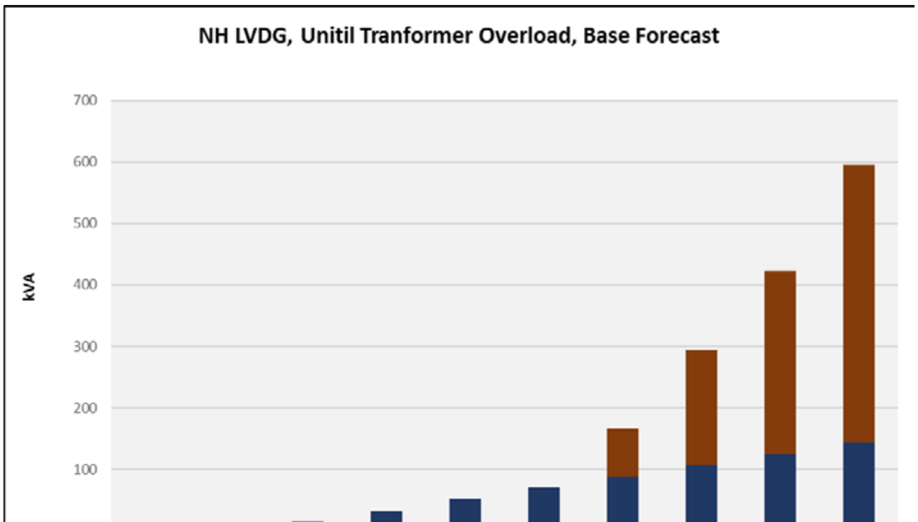
Source: Guidehouse, EDC data



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.5%	4.5%	4.5%	9.1%
Seacoast	0.0%	0.0%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%

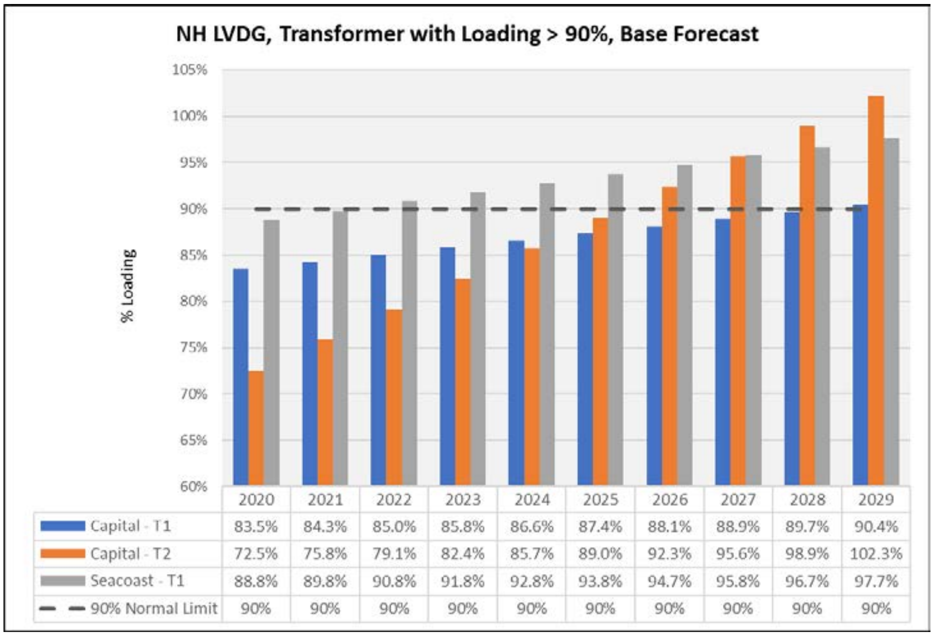
Source: Guidehouse, EDC data

- Three substation transformers exceed Unitil's 90% criteria for normal loading limit for the 10-year base load forecast
- Two transformers in the capital region
- One transformer in the seacoast region



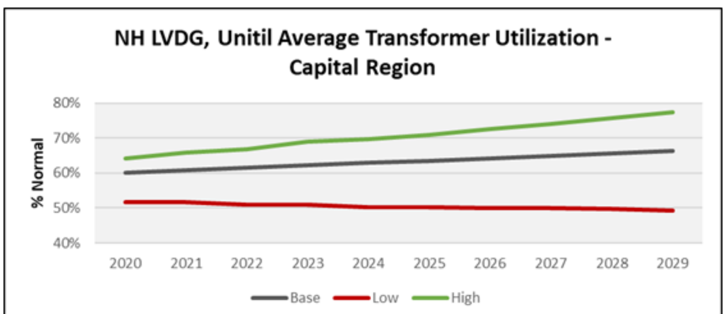
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital	0	0	0	0	0	0	78	188	298	453
Seacoast	0	0	15	33	52	70	88	107	125	143

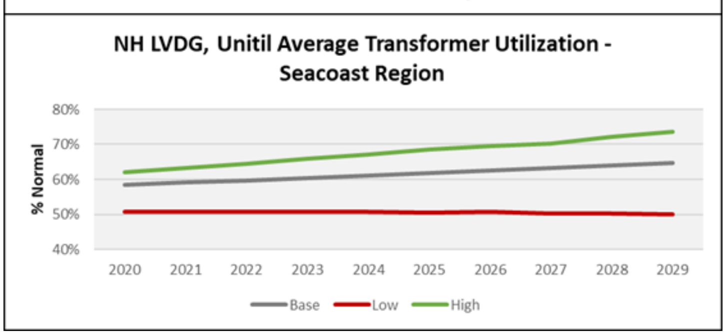
Source: Guidehouse, EDC data



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital - T1	83.5%	84.3%	85.0%	85.8%	86.6%	87.4%	88.1%	88.9%	89.7%	90.4%
Capital - T2	72.5%	75.8%	79.1%	82.4%	85.7%	89.0%	92.3%	95.6%	98.9%	102.3%
Seacoast - T1	88.8%	89.8%	90.8%	91.8%	92.8%	93.8%	94.7%	95.8%	96.7%	97.7%
90% Normal Limit	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%

Source: Guidehouse, EDC data

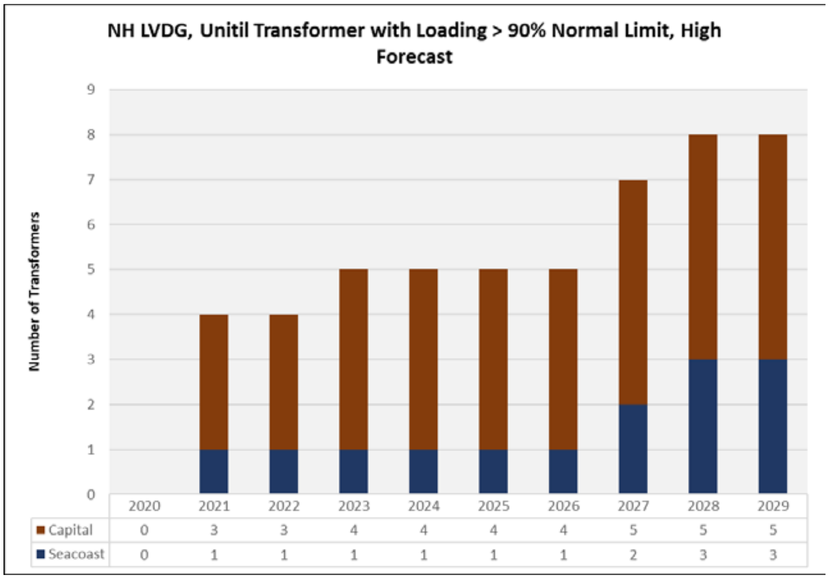




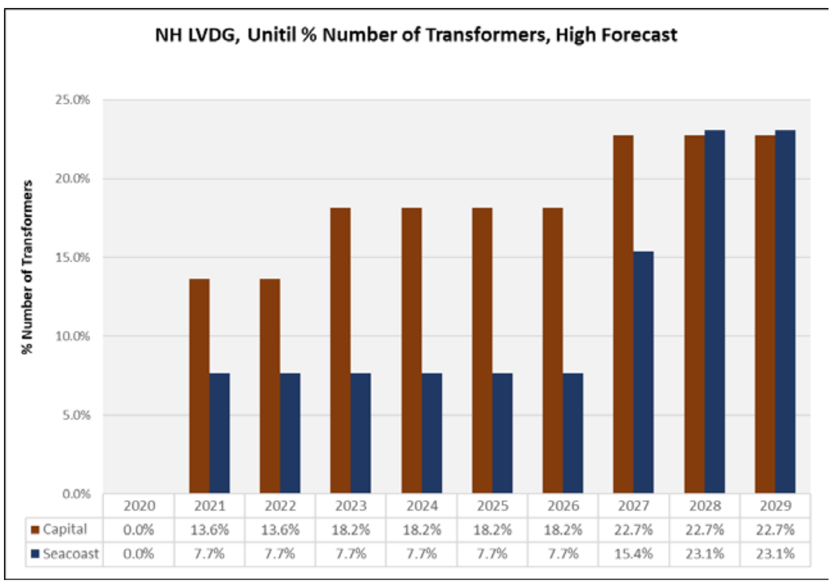
Source: Guidehouse, EDC data

Capacity Deficiency Analysis: Unitil- High Forecast

- There are no violations on substation transformers for the low forecast case; however, five violations occur for the high forecast case
- Most additional violations occur in later years

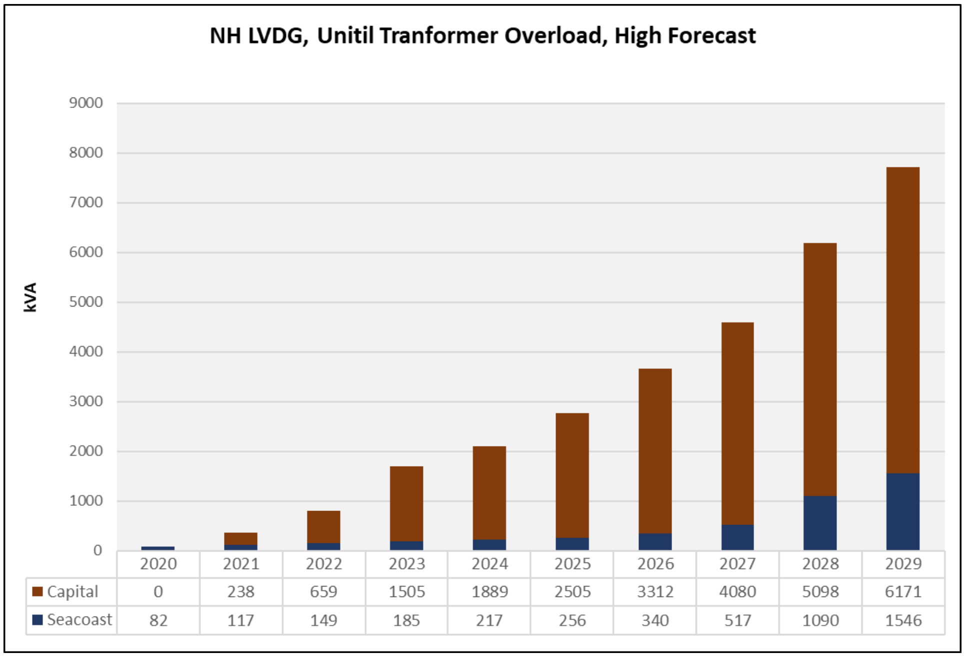


Source: Guidehouse, EDC data

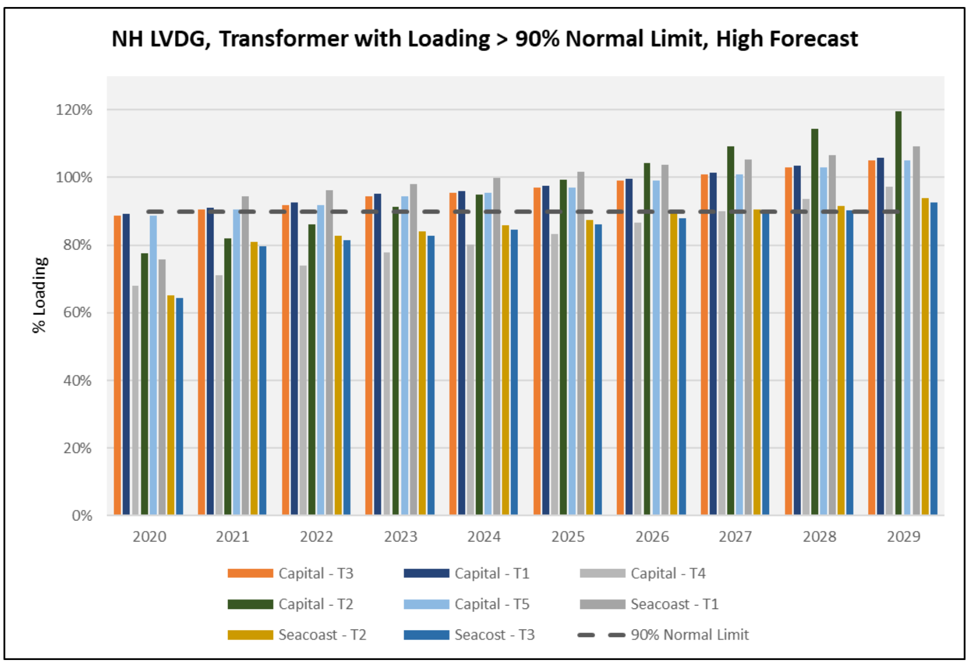


Source: Guidehouse, EDC data

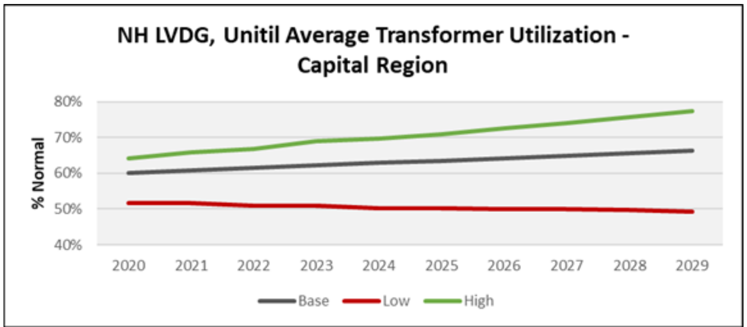
- Eight substation transformers exceed Unitil’s 90% normal loading limit for the 10-year high forecast case
- Transformer loadings increase significantly for High Case

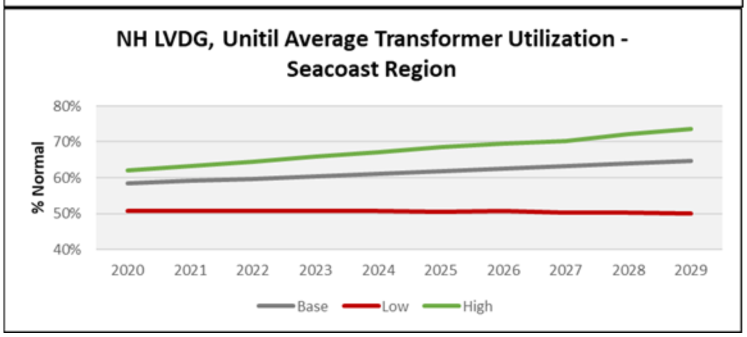


Source: Guidehouse, EDC data



Source: Guidehouse, EDC data





Source: Guidehouse, EDC data

Appendix B. Forward-Looking Capacity Deficiencies by Location

Table B-1. Complete List of Capacity Deficiencies by Location

No.	EDC	Asset Type	Asset Name	Substation	Region	Voltage	Forecast that Triggers Violation	First Violation Year	Violation Type
1	Eversource	Bulk Substation	Ashland		Northern	34.5	Low	2020	N-1, 75% Tx Capacity
2	Eversource	Bulk Substation	Bedford		Central	34.5	High	2020	75% Tx Capacity
3	Eversource	Bulk Substation	Beebe River		Northern	34.5	Low	2020	N-1
4	Eversource	Bulk Substation	Brentwood		Eastern	34.5	High	2022	N-1
5	Eversource	Bulk Substation	Bridge St. 34.5kv		Southern	34.5	High	2021	75% Tx Capacity
6	Eversource	Bulk Substation	Bridge St. 4kv		Southern	4.16	Low	2020	N-1, 75% Tx Capacity
7	Eversource	Bulk Substation	Chestnut Hill		Western	34.5	Base	2020	N-1, 75% Tx Capacity
8	Eversource	Bulk Substation	Dover		Eastern	34.5	Low	2020	N-1, 75% Tx Capacity
9	Eversource	Bulk Substation	Eddy		Central	34.5	Base	2020	75% Tx Capacity
10	Eversource	Bulk Substation	Great Bay		Eastern	34.5	Low	2020	N-1, 75% Tx Capacity
11	Eversource	Bulk Substation	Huse Road		Central	34.5	Low	2020	N-1, 75% Tx Capacity
12	Eversource	Bulk Substation	Laconia		Northern	34.5	Base	2020	N-1, 75% Tx Capacity
13	Eversource	Bulk Substation	Lawrence Road		Southern	34.5	Base	2020	N-1
14	Eversource	Bulk Substation	Long Hill		Southern	34.5	Base	2020	75% Tx Capacity
15	Eversource	Bulk Substation	Madbury		Eastern	34.5	Low	2020	75% Tx Capacity
16	Eversource	Bulk Substation	Mill Pond		Eastern	12.47	Low	2020	N-1
17	Eversource	Bulk Substation	Monadnock		Western	34.5	Base	2020	N-1, 75% Tx Capacity
18	Eversource	Bulk Substation	North Woodstock		Northern	34.5	Low	2020	N-1
19	Eversource	Bulk Substation	North Keene		Western	12.47	High	2022	N-1, 75% Tx Capacity
20	Eversource	Bulk Substation	Oak Hill		Central	34.5	High	2020	75% Tx Capacity

No.	EDC	Asset Type	Asset Name	Substation	Region	Voltage	Forecast that Triggers Violation	First Violation Year	Violation Type
21	Eversource	Bulk Substation	Pemigewasset		Northern	34.5	Low	2020	N-1, 75% Tx Capacity
22	Eversource	Bulk Substation	Pine Hill		Central	34.5	High	2026	75% Tx Capacity
23	Eversource	Bulk Substation	Portsmouth		Eastern	34.5	Low	2020	N-1, 75% Tx Capacity
24	Eversource	Bulk Substation	Reeds Ferry		Central	34.5	Low	2020	N-1, 75% Tx Capacity
25	Eversource	Bulk Substation	Resistance		Eastern	34.5	Low	2020	N-1
26	Eversource	Bulk Substation	Rimmon		Central	34.5	Base	2020	75% Tx Capacity
27	Eversource	Bulk Substation	Rochester		Eastern	34.5	High	2020	75% Tx Capacity
28	Eversource	Bulk Substation	Saco Valley		Northern	34.5	Low	2020	N-1
29	Eversource	Bulk Substation	South Milford		Southern	34.5	Low	2020	N-1, 75% Tx Capacity
30	Eversource	Bulk Substation	Tasker Farm		Eastern	34.5	High	2027	N-1, 75% Tx Capacity
31	Eversource	Bulk Substation	Thornton		Southern	34.5	High	2029	N-1
32	Eversource	Bulk Substation	Weare		Central	34.5	High	2021	N-1
33	Eversource	Bulk Substation	White Lake		Northern	34.5	Low	2020	N-1, 75% Tx Capacity
34	Eversource	Bulk Substation	Whitefield		Northern	34.5	Base	2020	N-1
35	Eversource	Non-Bulk Substation	Cutts Street		Eastern	12.47	High	2027	LTE
36	Eversource	Non-Bulk Substation	East Northwood		Eastern	12.47	High	2021	LTE
37	Eversource	Non-Bulk Substation	Hanover Street		Central	12.47	High	2024	LTE
38	Eversource	Non-Bulk Substation	Long Hill		Southern	12.47	High	2029	LTE
39	Eversource	Non-Bulk Substation	Loudon		Northern	12.47	High	2028	LTE
40	Eversource	Non-Bulk Substation	Loudon		Northern	12.47	High	2025	LTE
41	Eversource	Non-Bulk Substation	Meetinghouse Road		Central	12.47	High	2022	LTE
42	Eversource	Non-Bulk Substation	North Hampton		Eastern	4.16	High	2028	LTE
43	Eversource	Non-Bulk Substation	Portland Street		Eastern	12.47	High	2025	LTE
44	Eversource	Non-Bulk Substation	Portland Street		Eastern	12.47	High	2029	LTE
45	Eversource	Non-Bulk Substation	Rye		Eastern	4.16	High	2022	LTE

No.	EDC	Asset Type	Asset Name	Substation	Region	Voltage	Forecast that Triggers Violation	First Violation Year	Violation Type
46	Eversource	Non-Bulk Substation	Salmon Falls		Eastern	4.16	High	2022	LTE
47	Eversource	Non-Bulk Substation	Stark Avenue		Eastern	4.16	High	2027	LTE
48	Eversource	Non-Bulk Substation	Suncook		Central	12.47	High	2026	LTE
49	Eversource	Non-Bulk Substation	Warner		Central	4.16	High	2029	LTE
50	Eversource	34.5 kV Circuits	371_62	Cocheco Street	Eastern	34.5	High	2025	Normal
51	Eversource	34.5 kV Circuits	3137X_65	Madbury	Eastern	34.5	High	2020	Normal
52	Eversource	34.5 kV Circuits	380_65	Madbury	Eastern	34.5	Base	2020	Normal
53	Eversource	34.5 kV Circuits	314_22	South Milford	Southern	34.5	High	2028	Normal
54	Eversource	Non-34.5 kV distribution circuits	15W4_63	Cutts Street	Eastern	12.47	High	2028	Normal
55	Eversource	Non-34.5 kV distribution circuits	16H3_21	Edgeville	Southern	4.16	High	2026	Normal
56	Eversource	Non-34.5 kV distribution circuits	2W2_41	Lochmere	Northern	12.47	Low	2020	Normal
57	Eversource	Non-34.5 kV distribution circuits	40W1_21	Long Hill	Southern	12.47	High	2022	Normal
58	Eversource	Non-34.5 kV distribution circuits	18H1_21	Millyard	Southern	4.16	Low	2020	Normal
59	Eversource	Non-34.5 kV distribution circuits	41H2_61	North Dover	Eastern	4.16	Low	2020	Normal
60	Eversource	Non-34.5 kV distribution circuits	76W1_31	North Keene	Western	12.47	Low	2020	Normal
61	Eversource	Non-34.5 kV distribution circuits	3H1_21	Nowell Street	Southern	4.16	High	2022	Normal
62	Eversource	Non-34.5 kV distribution circuits	90H2_64	Pittsfield	Northern	4.16	High	2023	Normal
63	Eversource	Non-34.5 kV distribution circuits	48H1_63	Rye	Eastern	4.16	High	2025	Normal

No.	EDC	Asset Type	Asset Name	Substation	Region	Voltage	Forecast that Triggers Violation	First Violation Year	Violation Type
64	Eversource	Non-34.5 kV distribution circuits	51H1_61	Salmon Falls	Eastern	4.16	High	2020	Normal
65	Eversource	Non-34.5 kV distribution circuits	4W2_31	Swanzey	Western	12.47	High	2023	Normal
66	Eversource	Non-34.5 kV distribution circuits	37H1_42	Tilton	Northern	4.16	Base	2020	Normal
67	Eversource	Non-34.5 kV distribution circuits	37H2_42	Tilton	Northern	4.16	Base	2020	Normal
68	Liberty	Transformer	L1	Olde Trolley 18	Salem NH	13.2	High	2026	>100% of Emergency Rating
69	Liberty	Transformer	L2	Olde Trolley 18	Salem NH	13.2	High	2026	>100% of Emergency Rating
70	Liberty	Transformer	L3	Olde Trolley 18	Salem NH	13.2	High	2027	>100% of Emergency Rating
71	Liberty	Transformer	L4	Olde Trolley 18	Salem NH	13.2	Low	2022	>100% Normal
72	Liberty	Transformer	L1	Salem Depot 9	Salem NH	13.2	Base	2020	>100% Normal
73	Liberty	Transformer	L2	Salem Depot 9	Salem NH	13.2	Low	2020	>100% of Emergency Rating
74	Liberty	Transformer	L3	Salem Depot 9	Salem NH	13.2	High	2020	>100% of Emergency Rating
75	Liberty	Transformer	L1	Spicket River 13	Salem NH	13.2	High	2027	>100% of Emergency Rating
76	Liberty	Transformer	L2	Spicket River 13	Salem NH	13.2	High	2027	>100% of Emergency Rating
77	Liberty	Transformer	L3	Spicket River 13	Salem NH	13.2	High	2027	>100% of Emergency Rating
78	Liberty	Transformer	T2	Mount Support 16	Lebanon	13.2	High	2021	>100% of Emergency Rating
79	Liberty	Transformer	T1	Vilas Bridge 34	Bellows Falls	13.2	Base	2020	>100% of Emergency Rating
80	Liberty	Feeders	18L4	Olde Trolley 18	Salem NH	13.2	Low	2022	>100% Normal
81	Liberty	Feeders	14L4	Pelham 14	Salem NH	13.2	High	2021	>100% Normal
82	Liberty	Feeders	9L1	Salem Depot 9	Salem NH	13.2	Base	2020	>100% Normal

No.	EDC	Asset Type	Asset Name	Substation	Region	Voltage	Forecast that Triggers Violation	First Violation Year	Violation Type
83	Liberty	Feeders	9L2	Salem Depot 9	Salem NH	13.2	High	2029	>100% Normal
84	Liberty	Feeders	13L3	Spicket River 13	Salem NH	13.2	High	2026	>100% Normal
85	Liberty	Feeders	15H1	Monroe 15	Monroe	2.4	Low	2020	>100% Normal
86	Liberty	Feeders	11L1	Craft Hill 11	Lebanon	13.2	Low	2022	>100% Normal
87	Liberty	Feeders	16L1	Mount Support 16	Lebanon	13.2	Low	2022	>100% Normal
88	Liberty	Feeders	16L4	Mount Support 16	Lebanon	13.2	Base	2021	>100% Normal
89	Liberty	Feeders	16L5	Mount Support 16	Lebanon	13.2	High	2026	>100% Normal
90	Unitil	Transformer	Penacook 4T3 Xfmr	Penacook	Capital	13.8	High	2022	>90% Normal
91	Unitil	Transformer	Bow Junction 7T2 Xfmr	Bow Junction	Capital	13.8	Base	2022	>90% Normal
92	Unitil	Transformer	Boscawen 13T1 Xfmr	Boscawen	Capital	13.8	High	2028	>90% Normal
93	Unitil	Transformer	Bow Bog 18T2 Xfmr	Bow Bog	Capital	13.8	Base	2024	>90% Normal
94	Unitil	Transformer	Iron Works Road 22T1 Xfmr	Iron Works Road	Capital	13.8	High	2022	>90% Normal
95	Unitil	Transformer	Dow's Hill 20T1	Dow's Hill	Seacoast	4.16	Base	2021	>90% Normal
96	Unitil	Transformer	Hampton Beach 3T3	Hampton Beach	Seacoast	13.8	High	2028	>90% Normal
97	Unitil	Transformer	Seabrook 7T1	Seabrook	Seacoast	13.8	High	2028	>90% Normal
98	Unitil	Transformer	Timberlane 13T1	Timberlane	Seacoast	13.8	High	2025	>90% Normal
99	Unitil	Circuit	1H1	Bridge Street	Capital	4.16	High	2023	>90% Normal
100	Unitil	Circuit	3H2	Gulf Street	Capital	4.16	High	2028	>90% Normal
101	Unitil	Circuit	4W4	Penacook	Capital	13.8	High	2028	>90% Normal
102	Unitil	Circuit	18W2	Bow Bog	Capital	13.8	Base	2025	>90% Normal
103	Unitil	Circuit	22W1	Iron Works Road	Capital	13.8	High	2028	>90% Normal
104	Unitil	Circuit	24H1	Hazen Drive	Capital	4.16	High	2025	>90% Normal
105	Unitil	Circuit	Gilman Lane 19X3	Gilman Lane	Seacoast	34.5	High	2029	>90% Normal
106	Unitil	Circuit	3W4	Hampton Beach	Seacoast	13.8	High	2024	>90% Normal
107	Unitil	Circuit	7W1	Seabrook	Seacoast	13.8	High	2028	>90% Normal
108	Unitil	Circuit	21W2	Westville	Seacoast	13.8	High	2027	>90% Normal
109	Unitil	Circuit	58X1W	Westville Tap	Seacoast	34.5	High	2028	>90% Normal

Source: Guidehouse, EDC data

Appendix C. Selection of Real Economic Carrying Charge

The study considers two options when determining which methodological approach would be the most appropriate given the objectives of the study. The first option, referred to as Option A, includes assuming a specific avoidance duration (e.g., 10 years) to determine the annual dollar value of avoidance. The second option, Option B, considers approaches where no specific avoidance timeframe needs to be assumed. Instead the approach leverages the assumption that the investment is avoided for all years of the investment life (e.g., 30 years) after the initial year of need. Because the scope includes a timeframe of 10 forward-looking years, in this study the avoidance value is quantified from the year of initial investment through the end of the study period.

The study considers two methodological approaches that can be used for Option A, when an avoidance timeframe is assumed. These are referred to as Method A and Method B. The methods, and the pros and cons of each, are summarized below:

- **Method A: Annualization of difference in NPV of revenue requirement.** This approach entails determining the NPV of the revenue requirement with the investment made in year 1 versus the investment made after some fixed avoidance period (i.e., 5 to 10 years). This provides a single total dollar value which then needs to be annualized over the avoidance years.
    - **Pros:** If the investment at the end of the avoidance period and the duration of the avoidance period is known, then this method provides the most accurate representation of the avoided costs for a specific asset.
    - **Cons:** This method is not as appropriate for a generalized study such as the one being undertaken here to develop an indicative set of locational values of distributed generation because a set timeframe for deferral or avoidance is uncertain and may vary across locations.
- **Method B: RECC with avoidance period.** This method captures the difference in NPV of two payment streams: the revenue requirement of an investment made in year 0 compared to the same project avoided to year 1.
    - **Pros:** The RECC method is a flexible method in that it can be used to determine the total value of avoiding an investment for a set period of time. This total value can then be annualized in a similar way as Method A.
    - **Cons:** The RECC method may produce higher or lower results than the results of Method A for the same avoidance timeframe, cost, and asset lifetime. If a specific avoidance timeframe can be determined Method A may be more appropriate.

Given the limitations and the number of assumptions required for either Method A or Method B within Option A, the study turned to Option B which involves formulas that do not require a set assumed deferral or avoidance period. Similar to Option A the study looked at two methodological approaches to support this option. These are referred to as Method C and Method D, and the pros and cons of each method are summarized below:

- **Method C: RECC without an assumed avoidance period.** The RECC method creates a stream of annual values over the lifetime of the investment or asset which can be leveraged directly as the annualized value in that year. (Note, for the purposes of this LVDG study, annual avoidance values would be quantified through the end of the study time period.)
    - **Pros:** This is a flexible approach since it does not require a set avoidance timeframes to calculate annual avoided costs.
    - **Cons:** This method assumes the investment is avoided for the study timeframe; it does not consider that an investment may not be fully avoided within the study timeframe period. It also does not quantify the value of avoided investment beyond the study timeframe.
- **Method D: Flat annualized cost.** This method calculates a flat annualized cost or payment from the revenue requirement such that the present value of all the annual costs is equal to the revenue requirement.
    - **Pros:** This method is the simplest method of the methods considered and provides a constant nominal value over the life of the asset.
    - **Cons:** Since the capacity deficiency increases over time for the majority of the locations and scenarios considered, a flat annualized value would lead to a decreasing value per kW for the majority of cases.

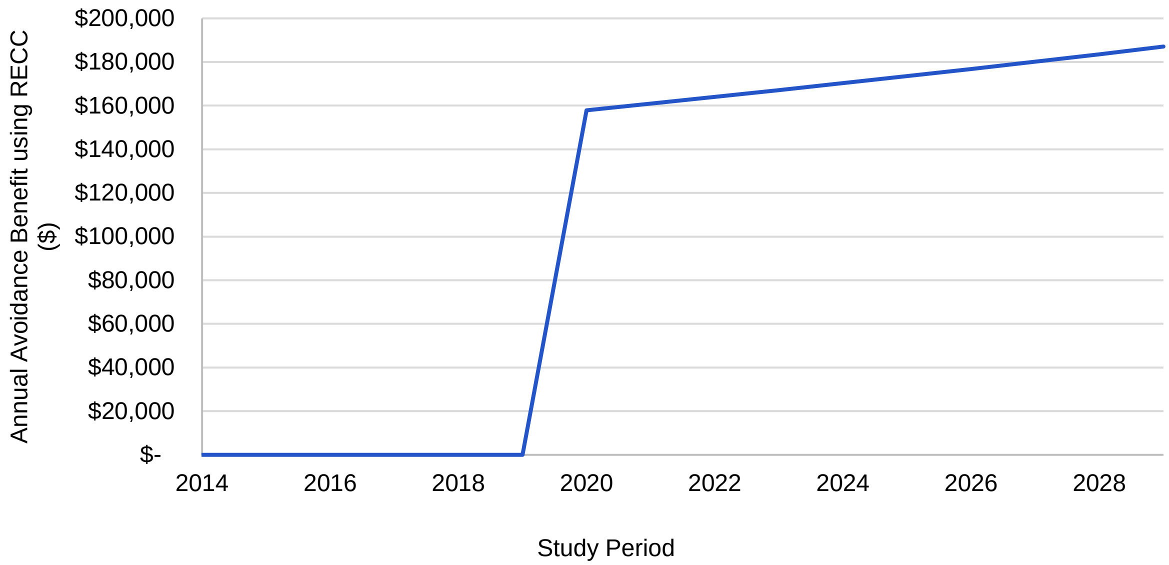
Appendix D. Economic Analysis

D.1 Three Additional Examples of Annual Value for Avoidance of Investment

Additional Example #1 - Madbury ROW Circuit (34.5 kV) Yearly and Hourly Economic Analysis (EDC: Eversource):

Annual avoidance value begins in 2020, the first year of the capacity deficit.[56]

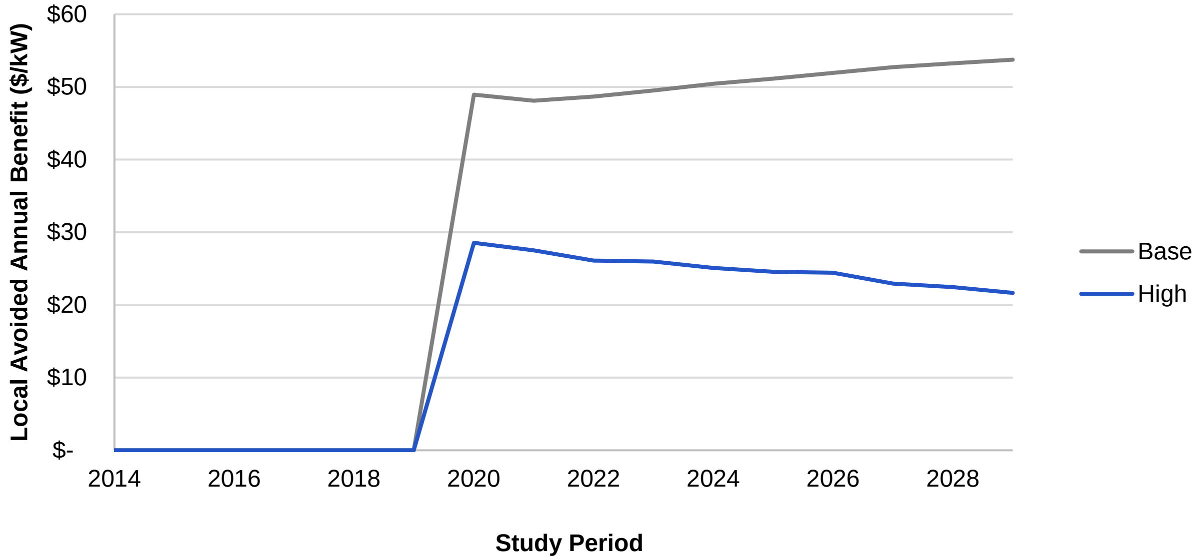
Figure D-1. Annual Avoidance Value – Madbury ROW Circuit (34.5 kV)



Source: Guidehouse, EDC data

[56] Note: this deficit is driven by a change in planning criteria.

Figure D-2. Local Avoided Annual Value – Madbury ROW Circuit (34.5 kV)

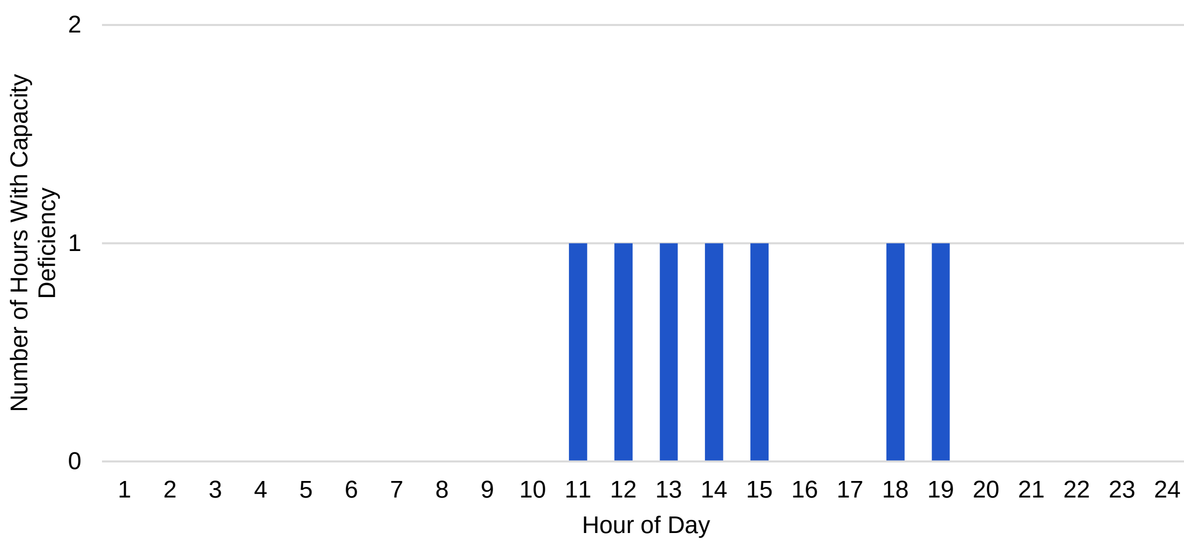


Source: Guidehouse, EDC data

Example Hourly Local Value Calculation for Madbury ROW Circuit (34.5 kV):

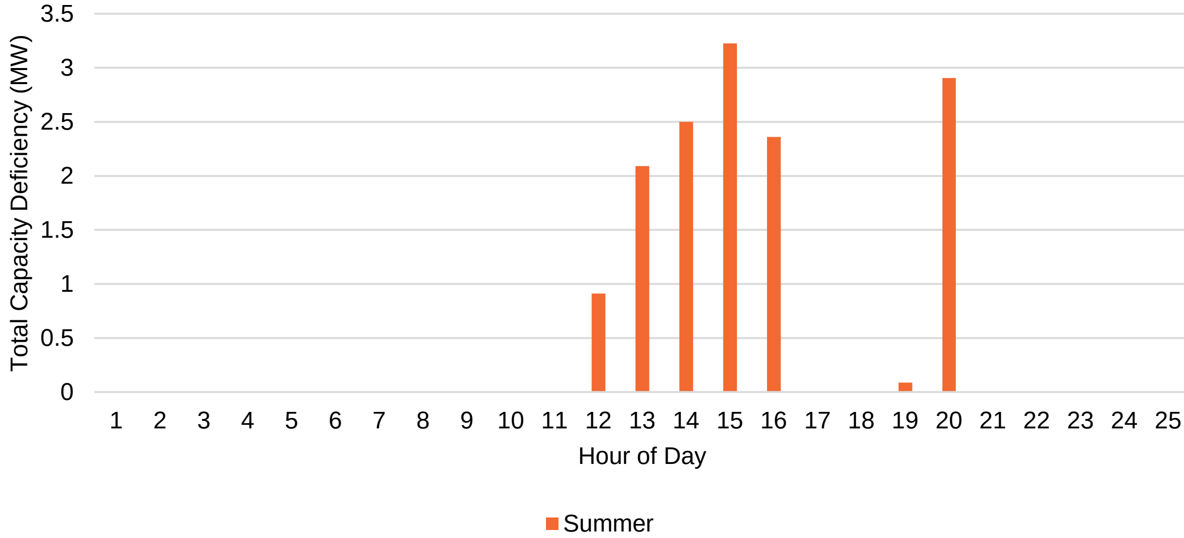
- Since Madbury ROW only has 1 day of capacity deficiency, the hourly and yearly analysis provide the same results.

Figure D-3. Number of Hours with Capacity Deficiency – Madbury ROW Circuit (34.5 kV)



Source: Guidehouse, EDC data

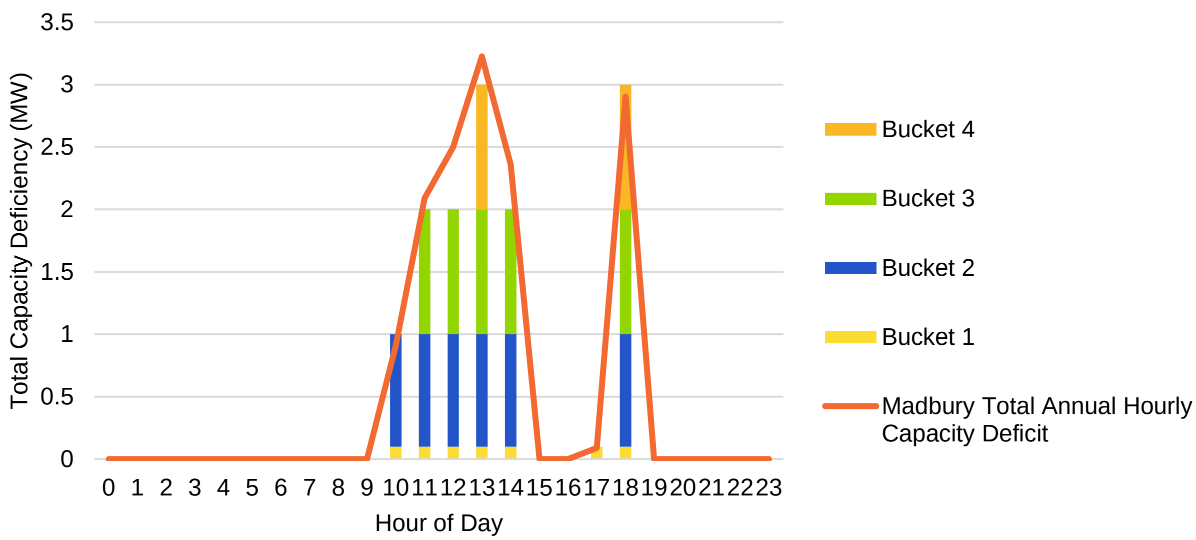
Figure D-4. Seasonal Capacity Deficiency Analysis – Madbury ROW Circuit (34.5 kV)



Source: Guidehouse, EDC data

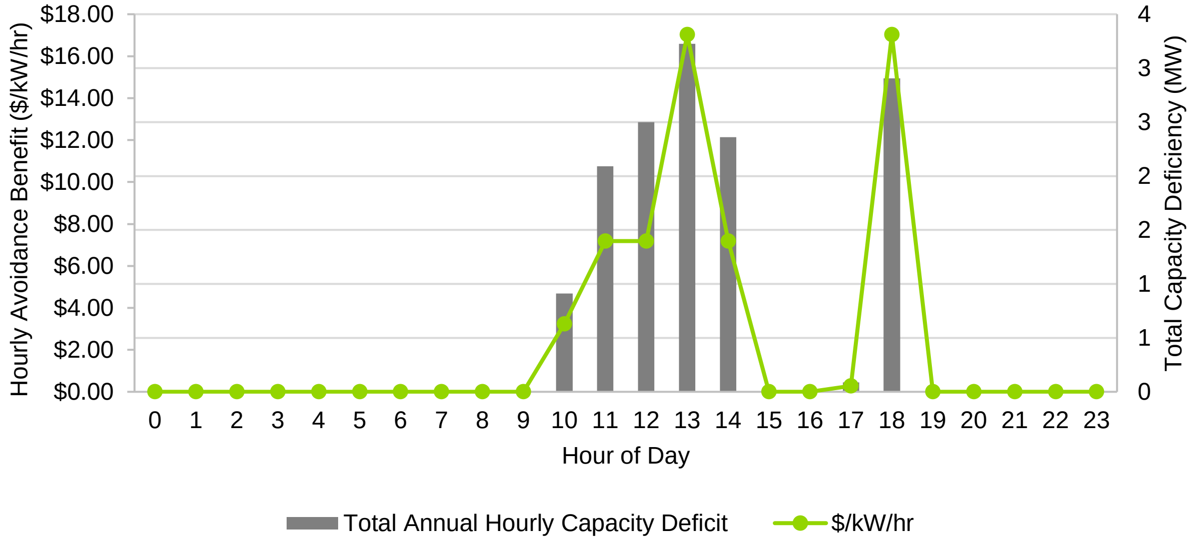
Madbury has two spikes on the peak day, but only four capacity deficiency buckets.

Figure D-5. Marginal Load Buckets (MW) – Madbury ROW Circuit (34.5 kV)



Source: Guidehouse, EDC data

Figure D-6. Hourly Analysis for All Hours of Year – Madbury ROW Circuit (34.5 kV)

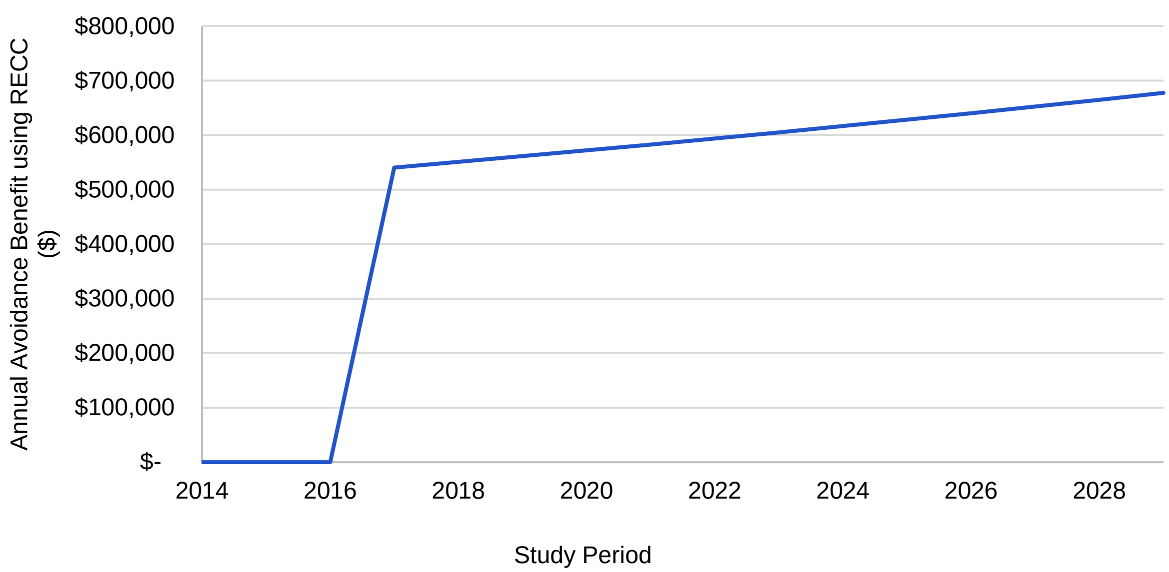


Source: Guidehouse, EDC data

Additional Example #2 - Mount Support Substation Yearly and Hourly Economic Analysis (EDC: Liberty):

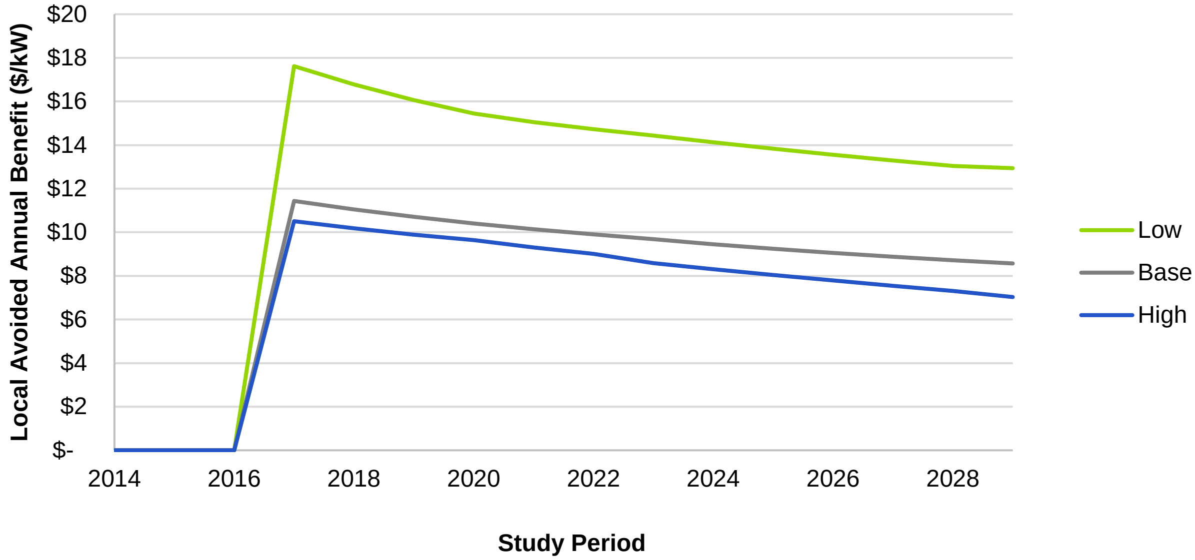
The annual avoidance value begins in 2017 and continues throughout the study period.

Figure D-7. Annual Avoidance Value – Mount Support Substation (Bulk)



Source: Guidehouse, EDC data

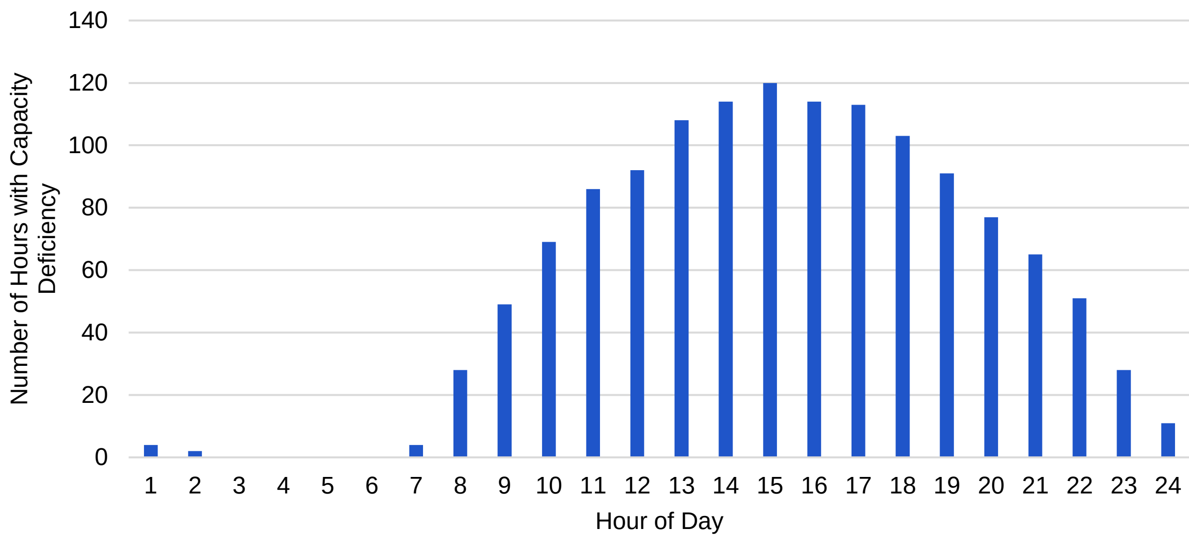
Figure D-8. Local Avoided Annual Value – Mount Support Substation (Bulk)



Source: Guidehouse, EDC data

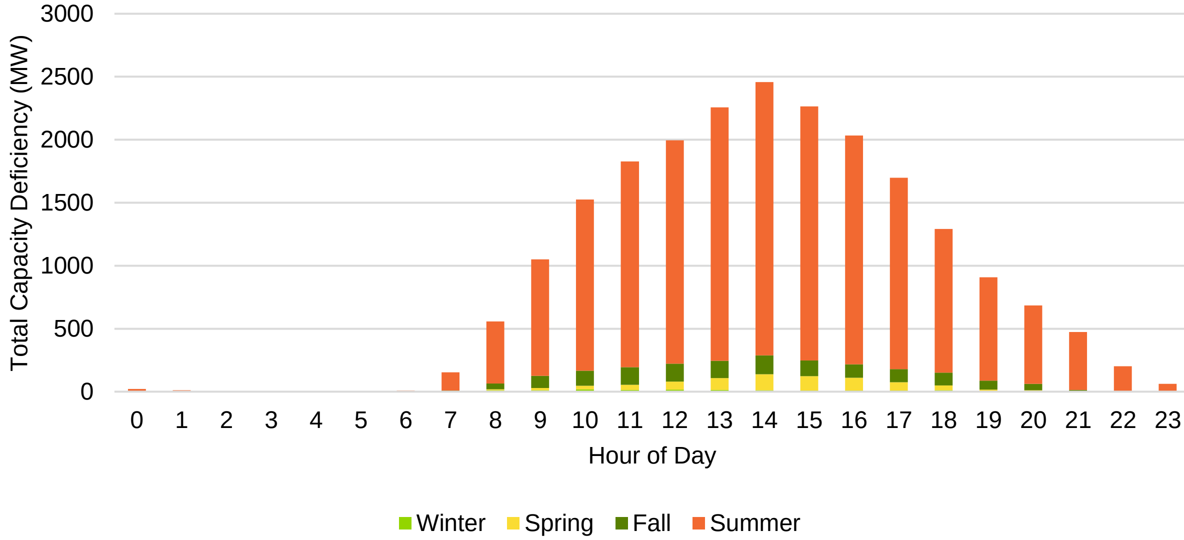
Mount Support is a historical project that had significant capacity deficiency in the region before the upgrade was performed.

Figure D-9. Number of Hours with Capacity Deficiency – Mount Support Substation (Bulk)



Source: Guidehouse, EDC data

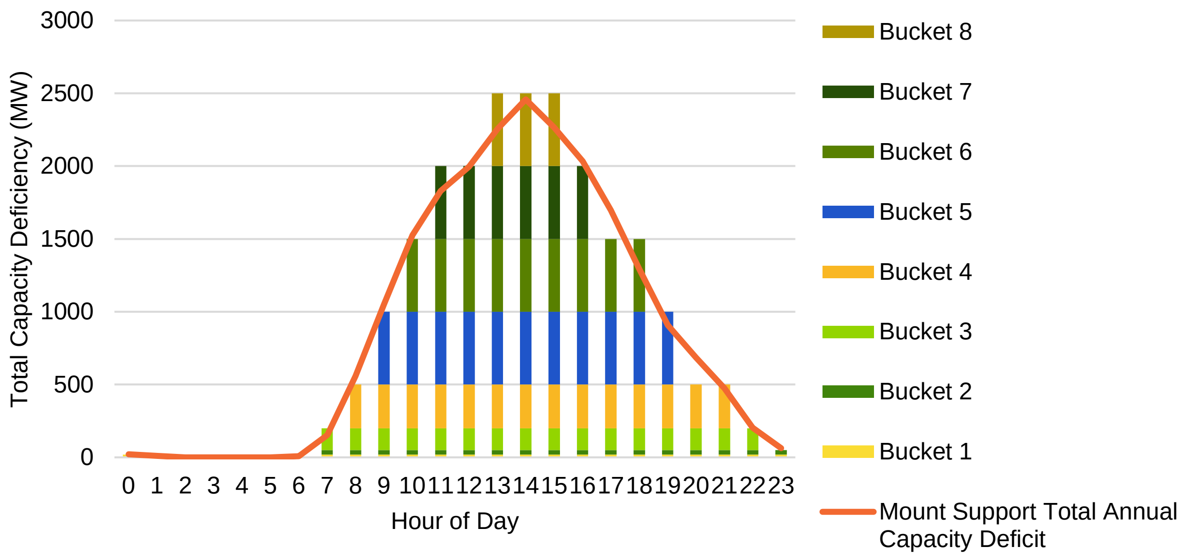
Figure D-10. Seasonal Capacity Analysis – Mount Support Substation (Bulk)



Source: Guidehouse, EDC data

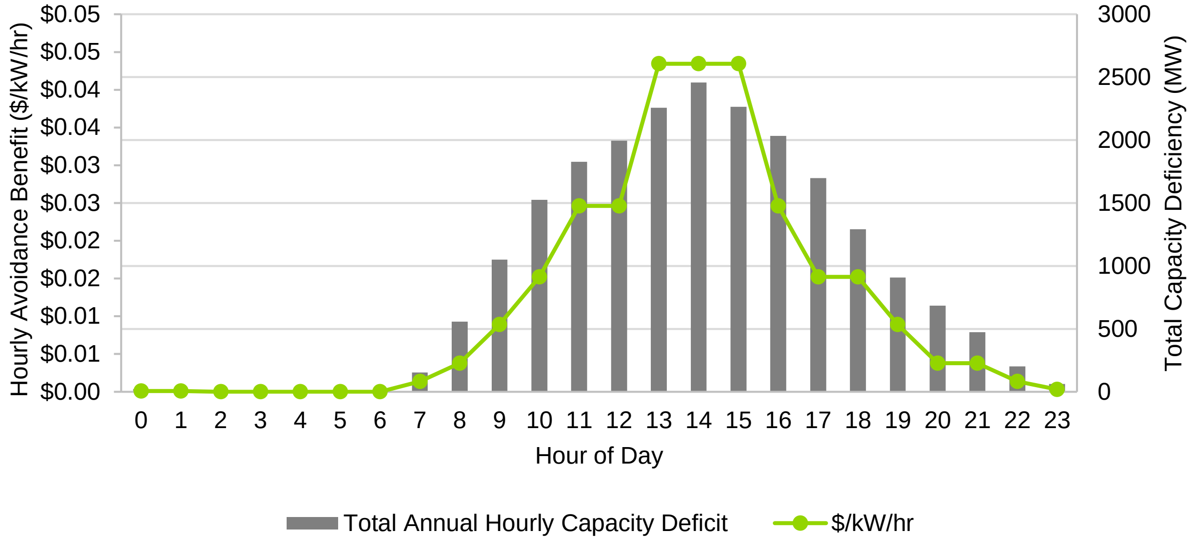
Given the number of hours of need and the large capacity deficiency for some hours, the hourly value of avoidance is small.

Figure D-11. Marginal Load Buckets (MW) – Mount Support Substation (Bulk)



Source: Guidehouse, EDC data

Figure D-12. Hourly Analysis for All Hours of Year – Mount Support Substation (Bulk)

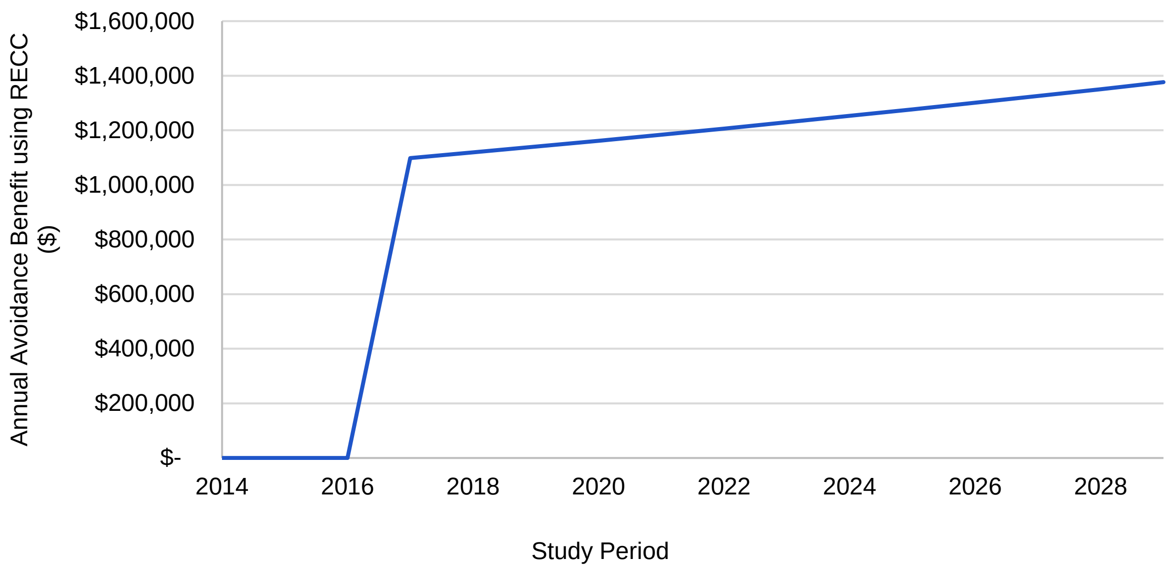


Source: Guidehouse, EDC data

Additional Example #3 - Kingston Substation Yearly and Hourly Economic Analysis (EDC: Unitil):

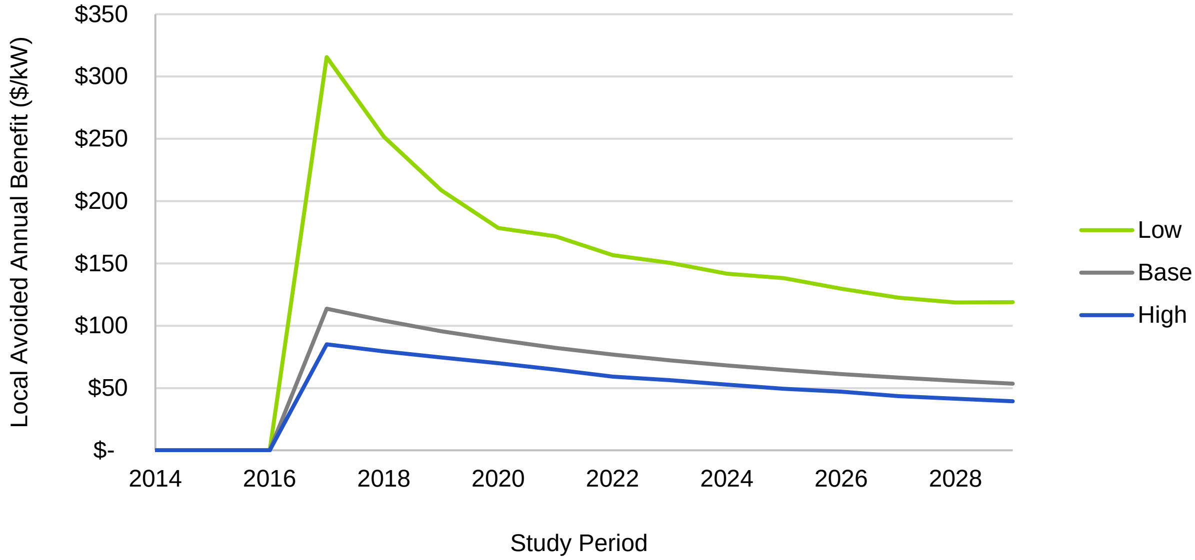
The annual avoidance value begins in 2017 and continues throughout the study period.

Figure D-13. Annual Avoidance Value – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

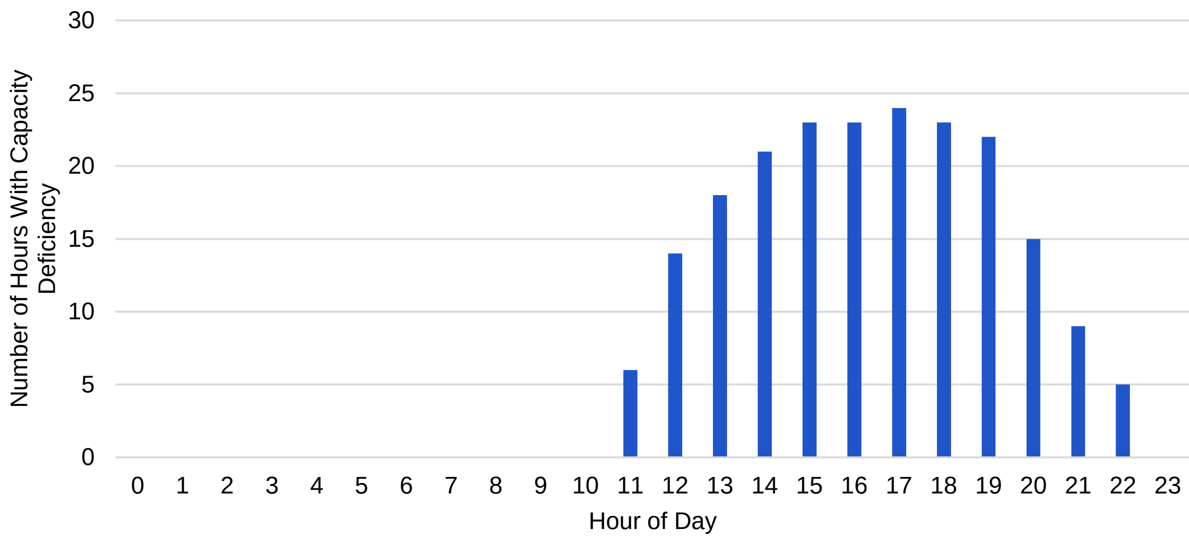
Figure D-14. Local Avoided Annual Value – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

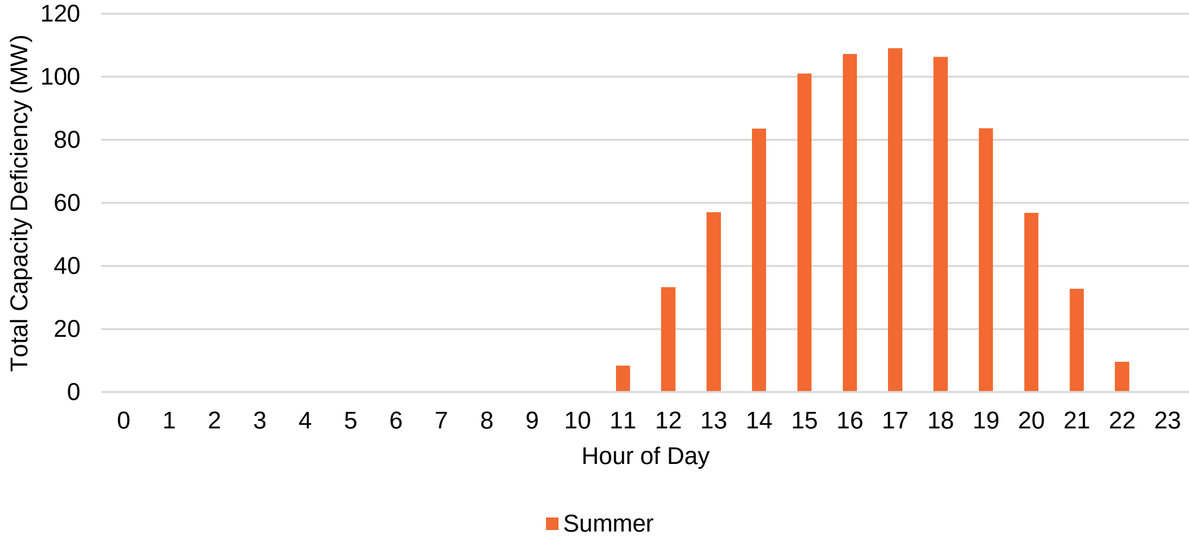
Kingston is a historical project. Based on the seacoast regional hourly load profile, this location only has periods of need during the summer season.

Figure D-15. Number of Hours with Capacity Deficiency – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

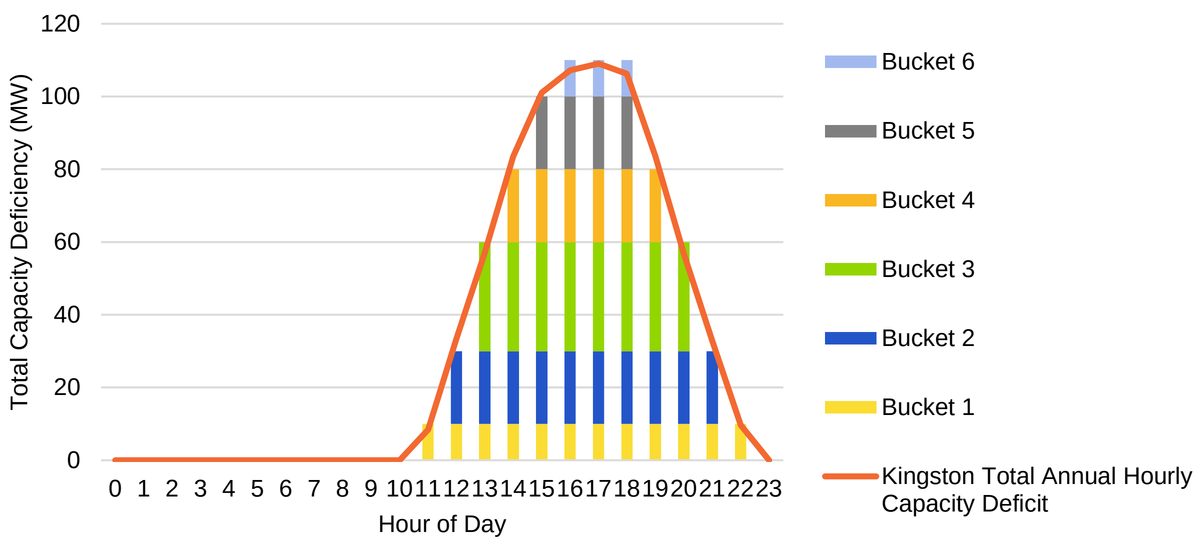
Figure D-16. Seasonal Capacity Deficiency Analysis – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

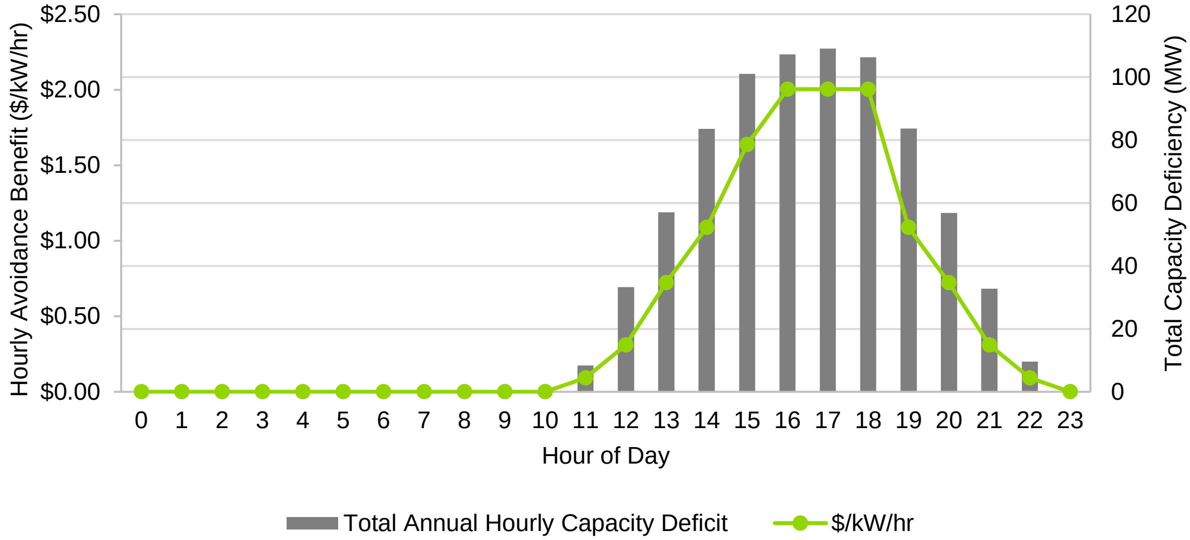
While the revenue requirement for Kingston was the highest of all the examples, the hourly value is lower than Pemi and Madbury because the capacity deficiency in terms of total MWh is higher than for Pemi and Madbury.

Figure D-17. Marginal Load Buckets (MW) – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

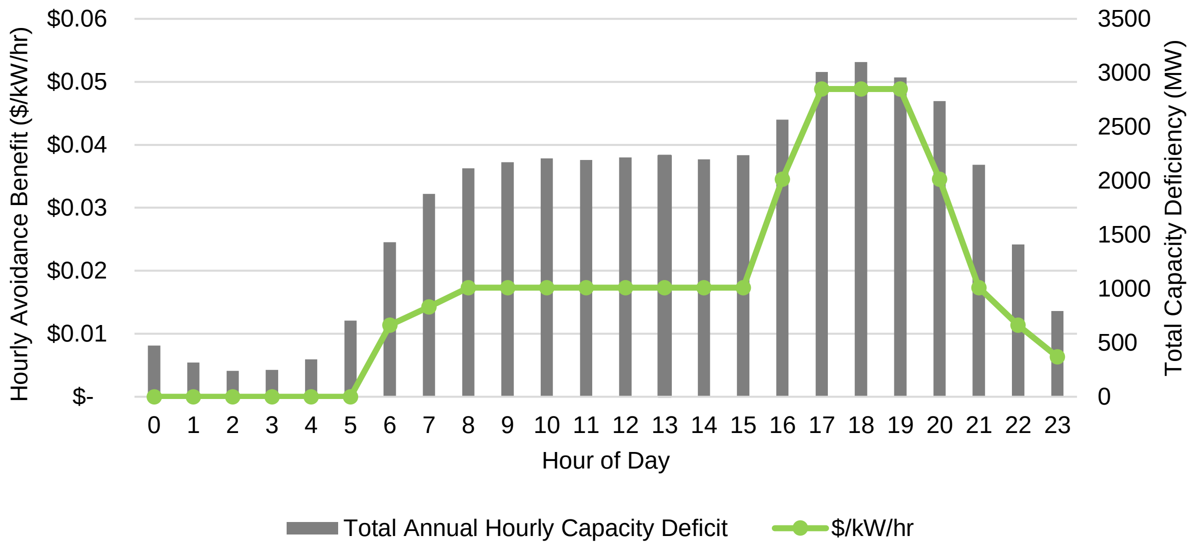
Figure D-18. Hourly Analysis for All Hours of Year – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

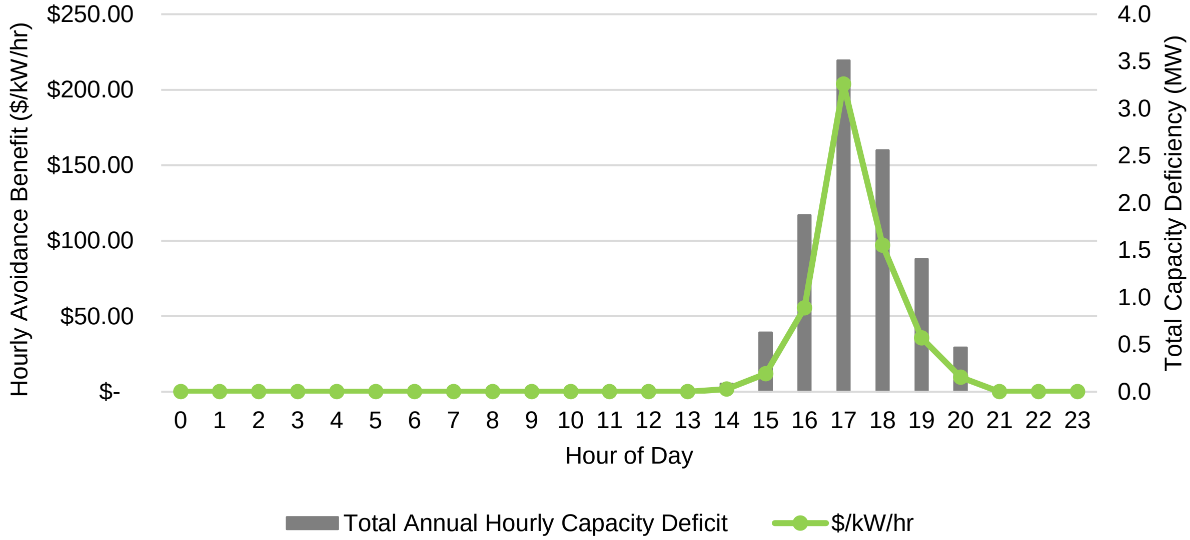
D.2 Hourly Analysis Results for Remaining 11 Sites

Figure C-19. Hourly Analysis for All Hours of Year – South Milford Substation (Bulk)



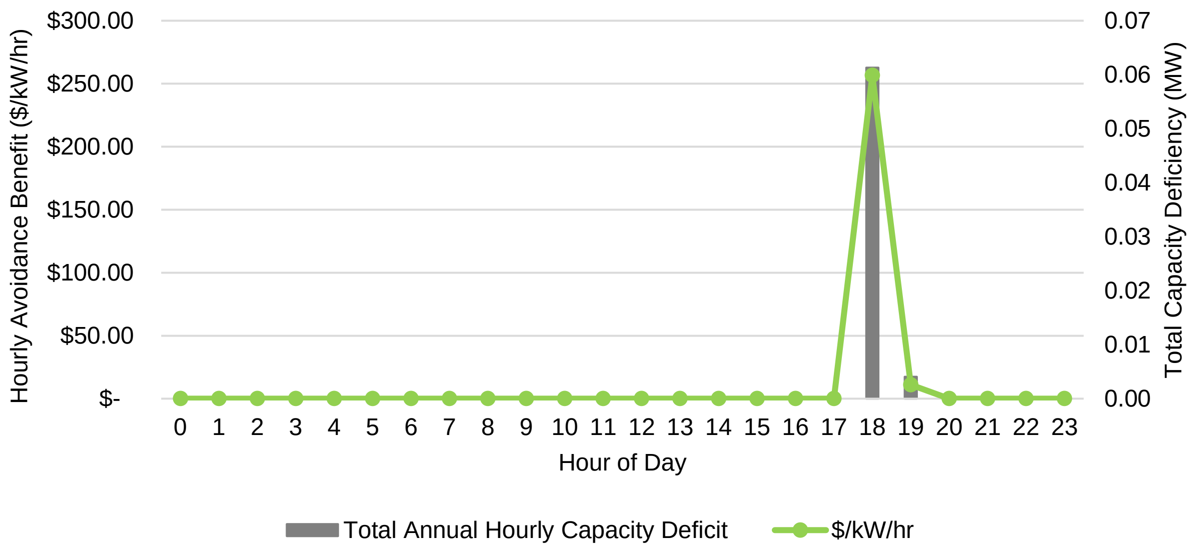
Source: Guidehouse, EDC Data

Figure C-20. Hourly Analysis for All Hours of Year – Monadnock Substation (Bulk)



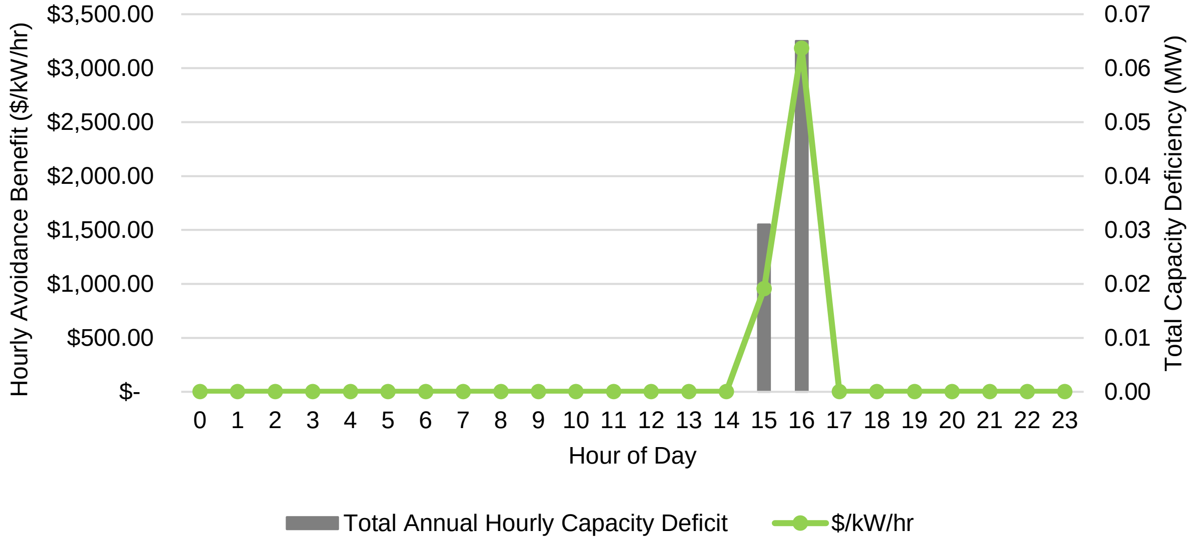
Source: Guidehouse, EDC Data

Figure C-21. Hourly Analysis for All Hours of Year – East Northwood Substation (Bulk)



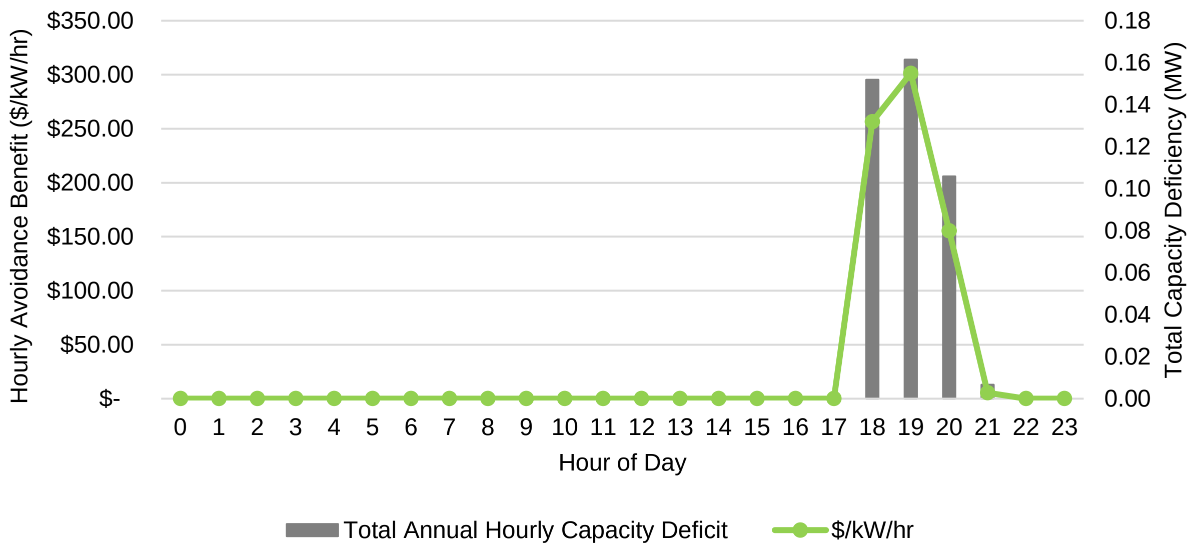
Source: Guidehouse, EDC Data

Figure C-22. Hourly Analysis for All Hours of Year – Rye Substation (Non-Bulk)



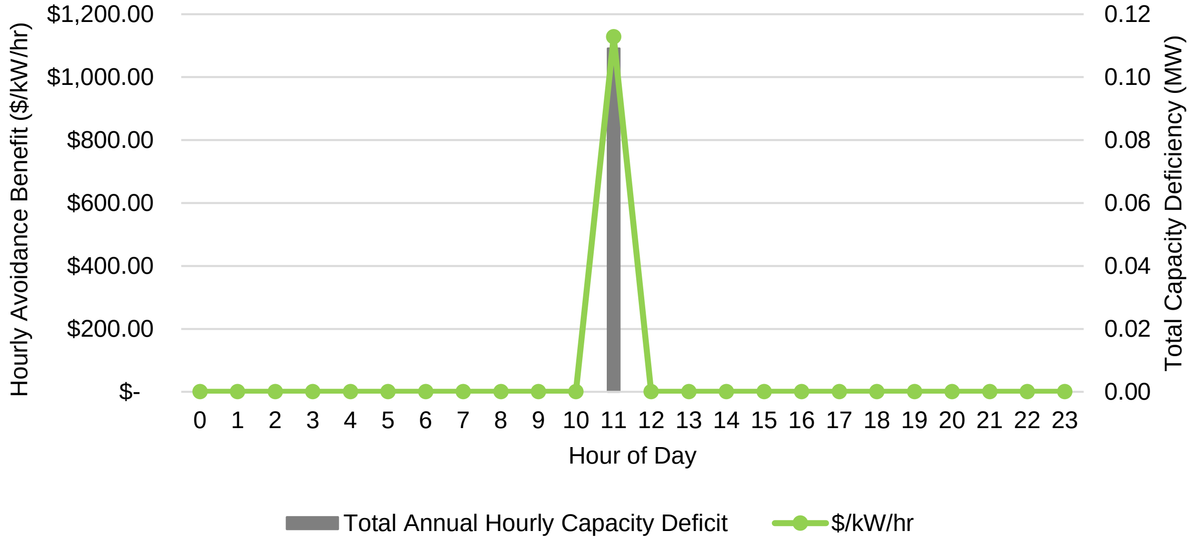
Source: Guidehouse, EDC Data

Figure C-23. Hourly Analysis for All Hours of Year – Bristol Substation (Non-Bulk)



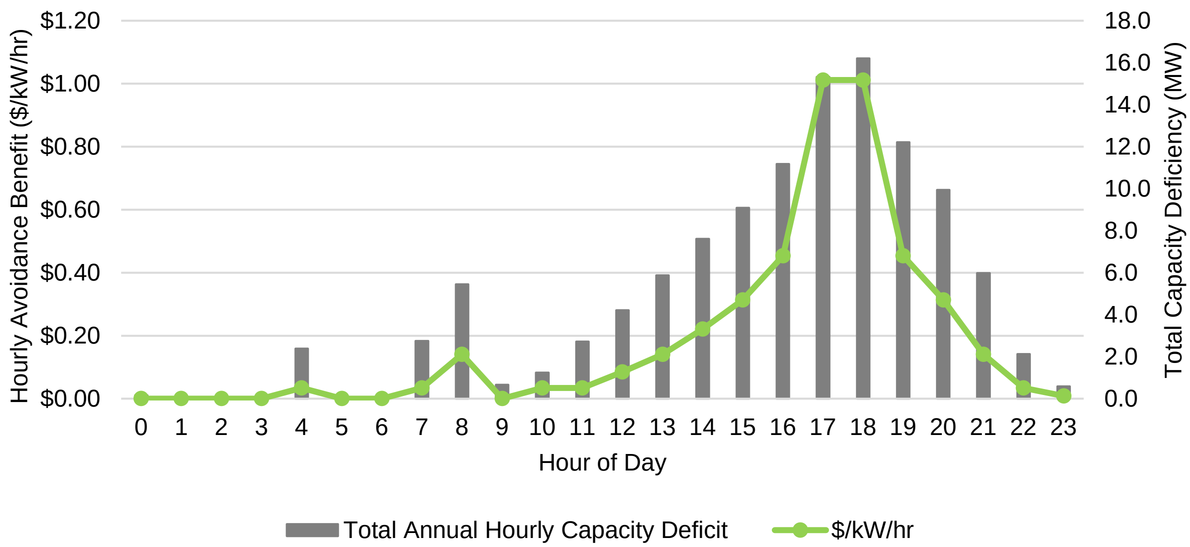
Source: Guidehouse, EDC Data

Figure C-24. Hourly Analysis for All Hours of Year – North Keene Circuit (12.47 kV)



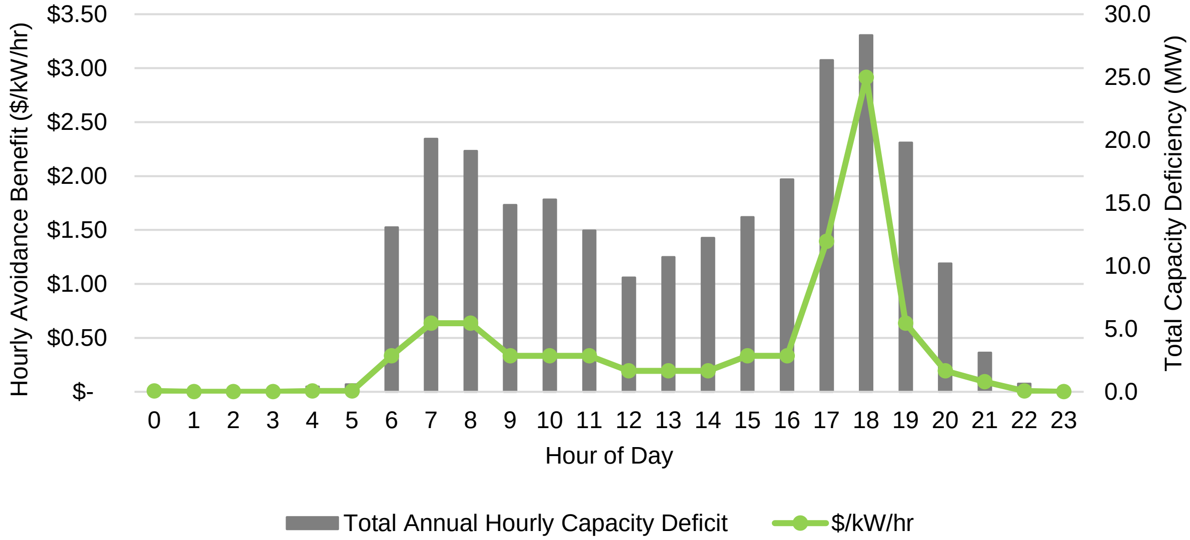
Source: Guidehouse, EDC data

Figure C-25. Hourly Analysis for All Hours of Year – Londonderry Circuit (34.5 kV)



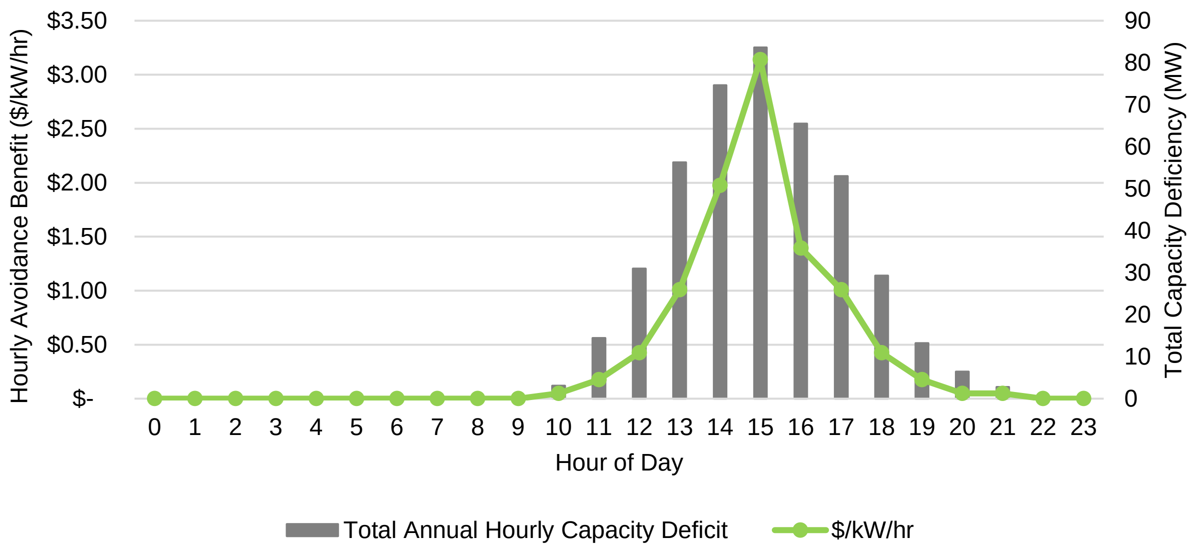
Source: Guidehouse, EDC Data

Figure C-26. Hourly Analysis for All Hours of Year – Vilas Bridge Substation (Non-Bulk)



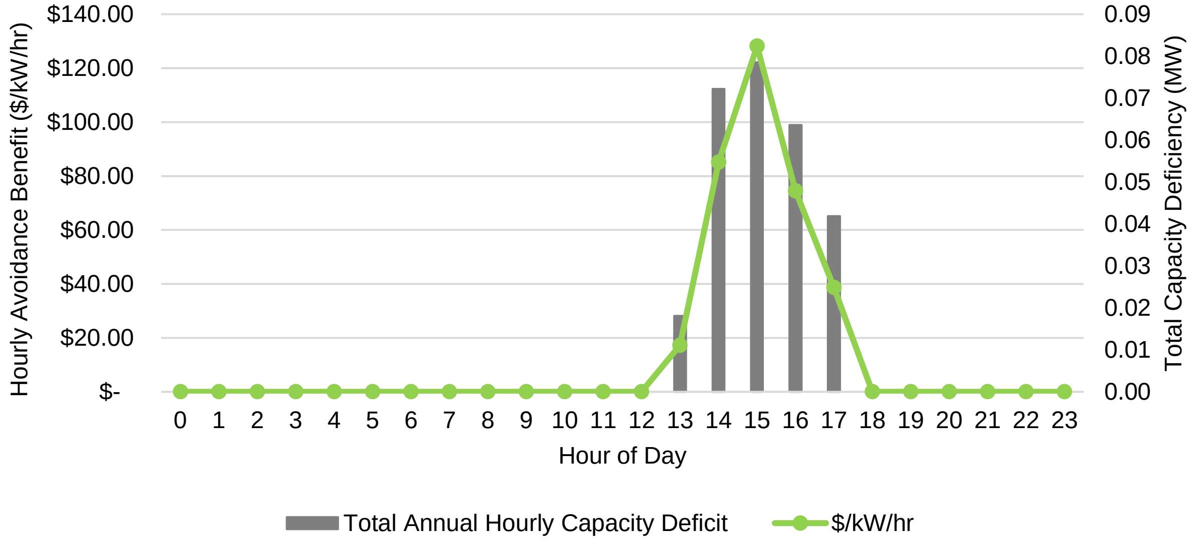
Source: Guidehouse, EDC Data

Figure C-27. Hourly Analysis for All Hours of Year – Golden Rock Substation (Bulk)



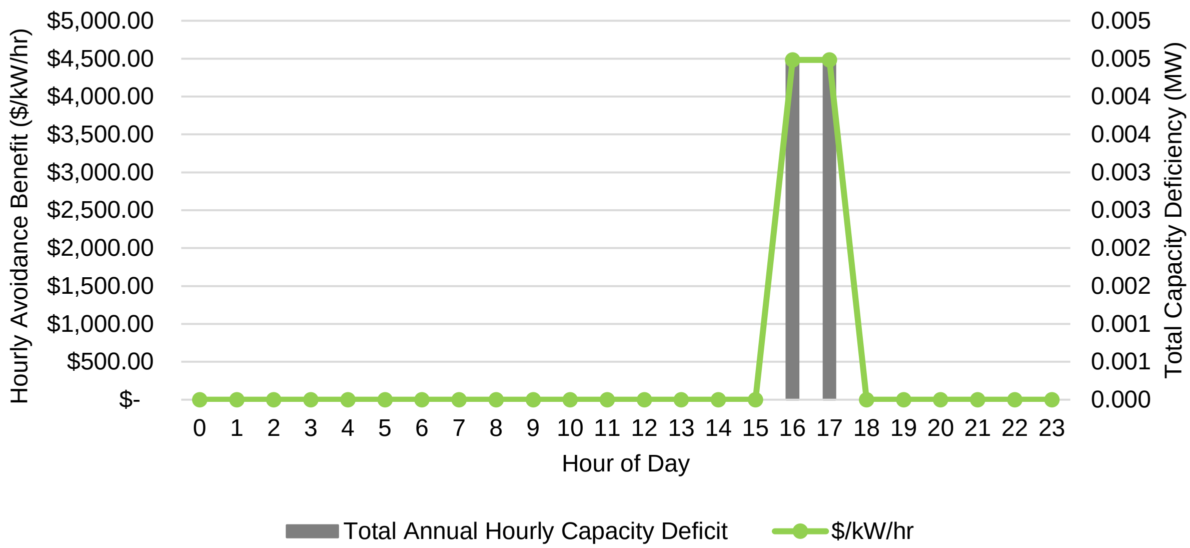
Source: Guidehouse, EDC Data

Figure C-28. Hourly Analysis for All Hours of Year – Bow Bog Substation (Bulk)



Source: Guidehouse, EDC Data

Figure C-29. Hourly Analysis for All Hours of Year – Dow's Hill Substation (Bulk)



Source: Guidehouse, EDC Data

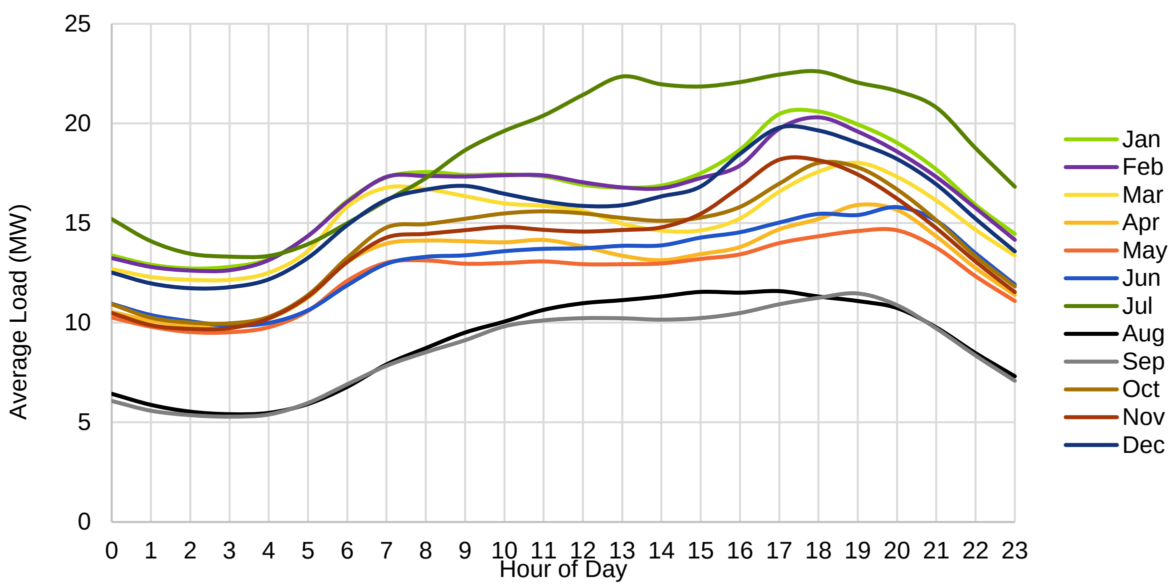
Appendix E. Additional Examples of Load and DG Output Profiles

E.1 Three Additional Examples of Locational Load Profiles

Details of the Eversource location including the following:

- Madbury ROW Circuit (34.5 kV) has reasonably consistent mid-afternoon to evening summer peaks
- Summer midday normal overload on distribution supply line
- Annual Peak Day: 7/20/2019 13:00, 32.58 MW

Figure E-1. Average Hourly Profile by Month – Madbury ROW Circuit (34.5 kV)

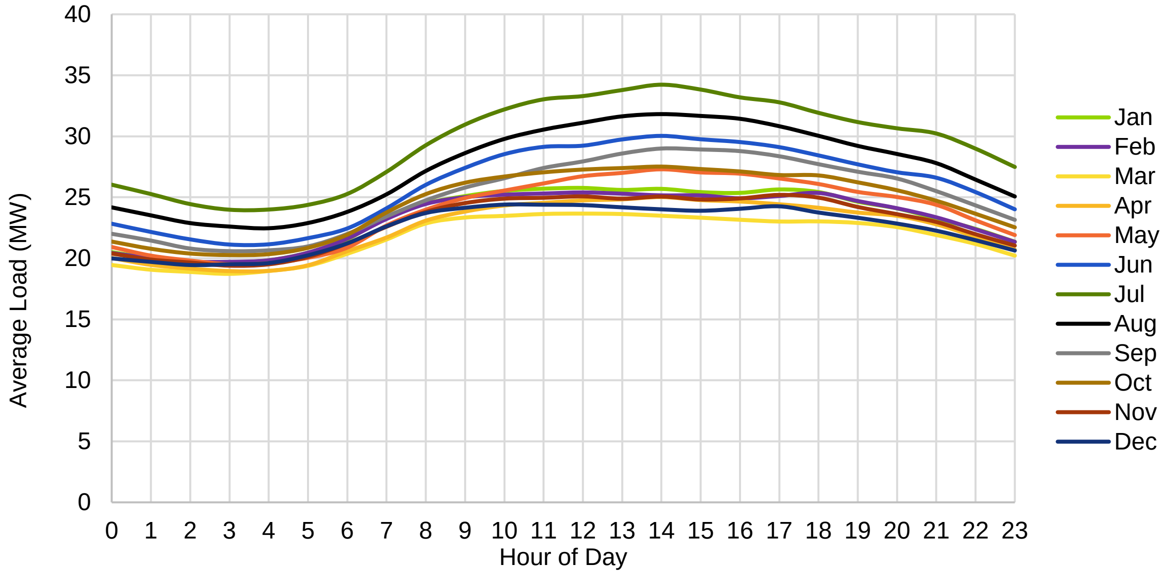


Source: Guidehouse, EDC data

Details of the Liberty location include the following:

- Mount Support Substation (Bulk) is a summer peaking substation with a midday peak
- Annual Peak Day: 7/30/2019 14:00, 40.9 MW

Figure E-2. Average Hourly Profile by Month – Mount Support Substation (Bulk)

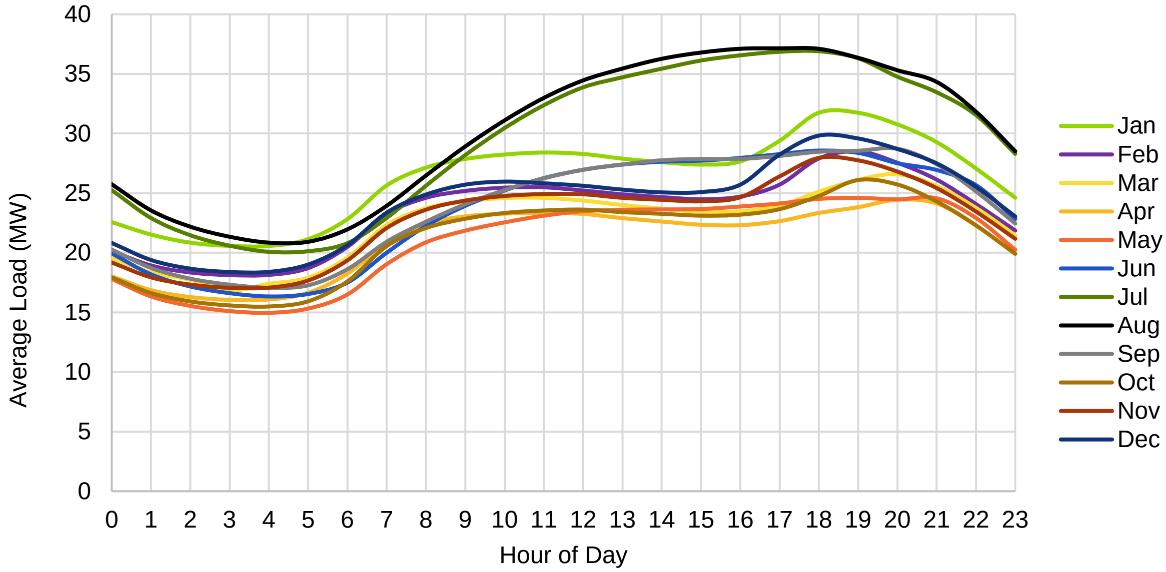


Source: Guidehouse, EDC data

Details on the Unitil location include the following:

- Kingston Substation (Bulk) used the seacoast region 8,760 load data since no hourly level data is available at the substation
- The seacoast region is summer peaking with higher average peaks in July and August
- July and August have the highest average load in the seacoast region
- Kingston Annual Peak Day: 8/29/2018 17:00, 51,000 kW

Figure E-3. Average Hourly Profile by Month – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

E.2 Three Additional Detailed Examples of DG Production Profile Mapping to Load

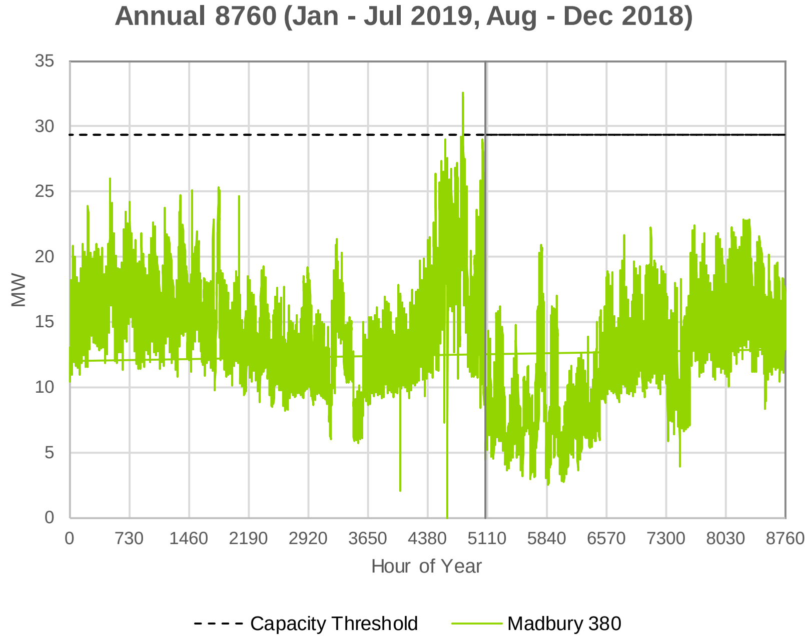
Madbury ROW Circuit (34.5 kV) DG Analysis Results

Madbury ROW Circuit (34.5 kV) – Annual Load Profile and Capacity Threshold:

Figure E-4 is an example of a location where the hours of capacity deficiencies occur during a relatively small number of hours on a major distribution line. All hours of capacity deficiency occur during a single summer day (but increase to several days during later years). This is a summer peaking location with midday normal (N-0) overload.

- Annual hours of capacity deficiency: 7
- Energy deficiency: 14 MWh
    - Approximately, 0.012% of total energy (121,360 MWh)

Figure E-4. Capacity Deficiencies – Madbury ROW Circuit (34.5 kV)



Source: Guidehouse, EDC data

Table E-1. Annual Load Profile and Capacity Threshold – Madbury ROW Circuit (34.5 kV)

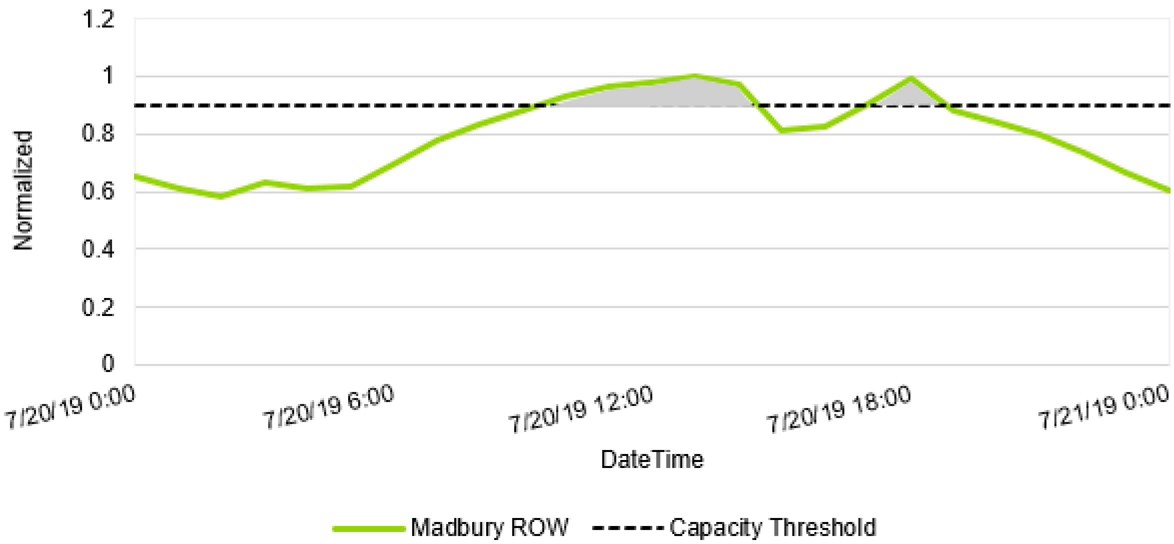
Location	Region	Peak (MW)	Time of Peak	First Year Deficit (MW)
Madbury ROW Circuit (34.5 kV)	Eastern	32.58	7/20/19 13:00	3.23

Source: Guidehouse, EDC data

Madbury ROW Circuit (34.5 kV) – Annual Peak Day and Capacity Threshold:

- Summer peaking with midday and early evening normal overload
- Hours of capacity deficiency only occur for a single summer peak day
- Total of 7 hours of capacity deficiency are split across midday and evening hours
- The number of hours of capacity deficiencies increases over time due to load growth

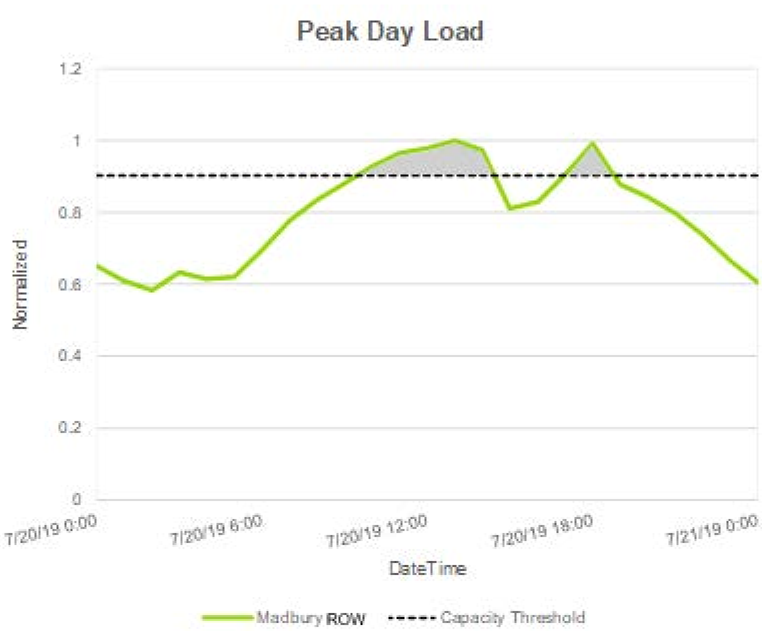
Figure E-5. Summer Peak Day Load – Madbury ROW Circuit (34.5 kV)



Source: Guidehouse, EDC data

Figure E-6 presents the summer peak day for Madbury during which capacity deficiencies occur. Deficiencies occurred on 1 day and the number of hours of capacity deficiencies over the year are low; however, on the peak day the hours when deficiencies occur extend from midday to early evening.

Figure E-6. Capacity Deficiencies – Madbury ROW Circuit (34.5 kV)

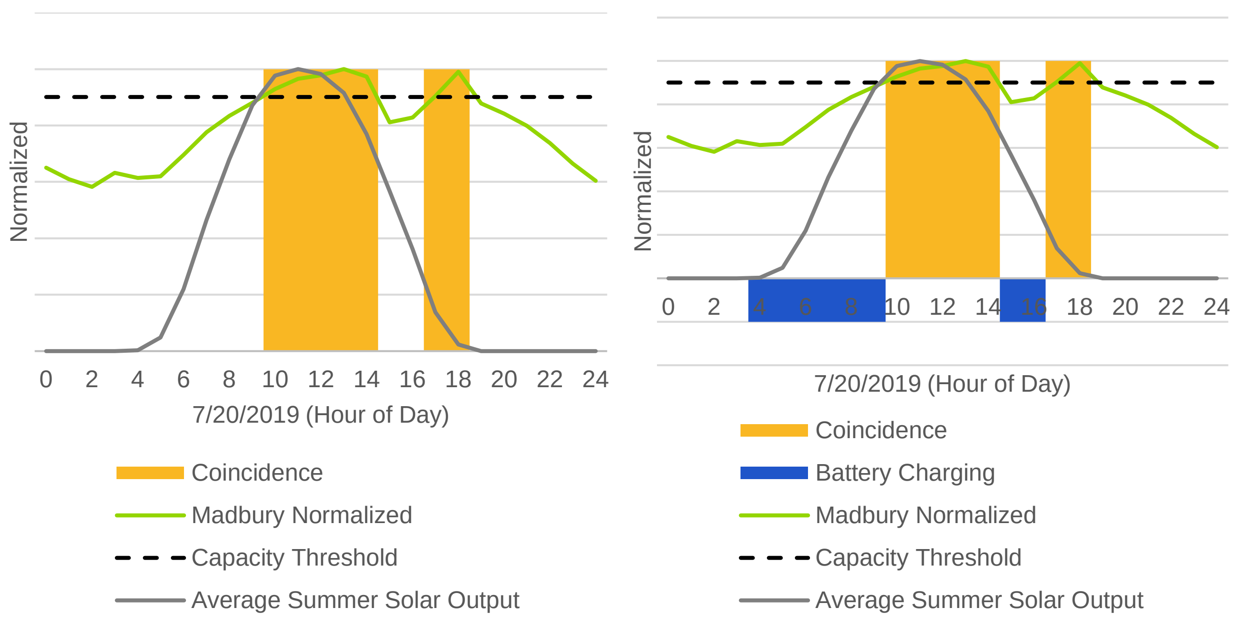


Source: Guidehouse, EDC data

Madbury ROW Circuit (34.5 kV) – Solar Coincidence and Solar plus Storage Charging Analysis:

- Summer coincidence of solar production: 7 out of 7 hours
- Summer: 8-hour charging interval, no hours needed for storage discharge (if enough solar is produced during peak hours)

Figure E-7. Solar Coincidence and Solar plus Storage Charging Analysis – Madbury ROW Circuit (34.5 kV)

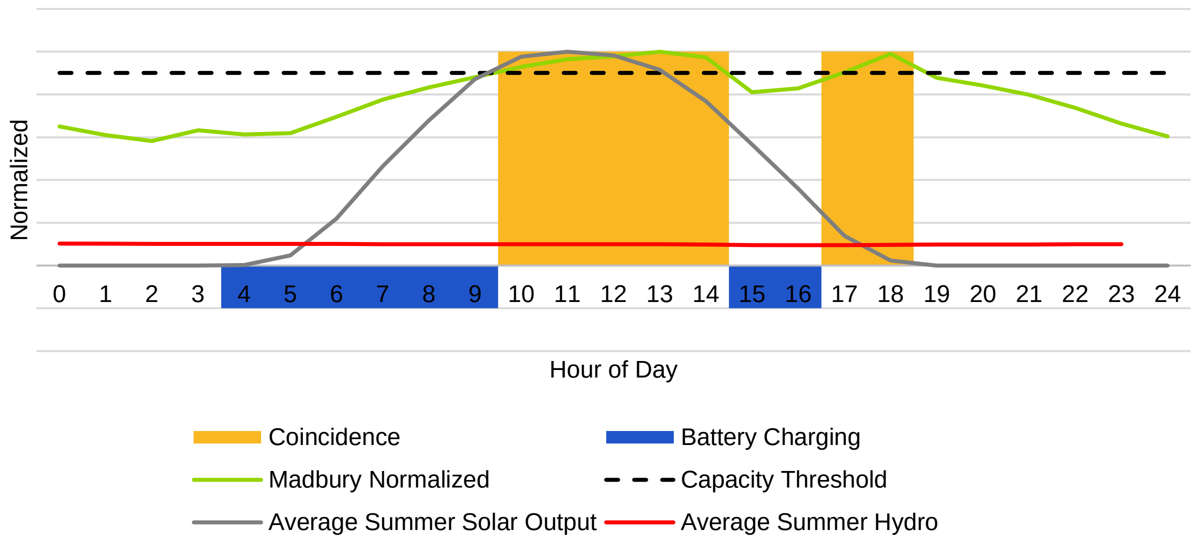


Source: Guidehouse, EDC data

Madbury ROW Circuit (34.5 kV) – Solar plus Storage plus Hydro Coincidence Analysis:

- The addition of hydro does little to further address the main period of need, given that it is highly coincident with solar production hours
- The late hours of need may benefit from solar plus storage and/or the addition of hydropower

Figure E-8. Solar Coincidence and Solar plus Storage plus Hydro Analysis – Madbury Circuit (34.5 kV)



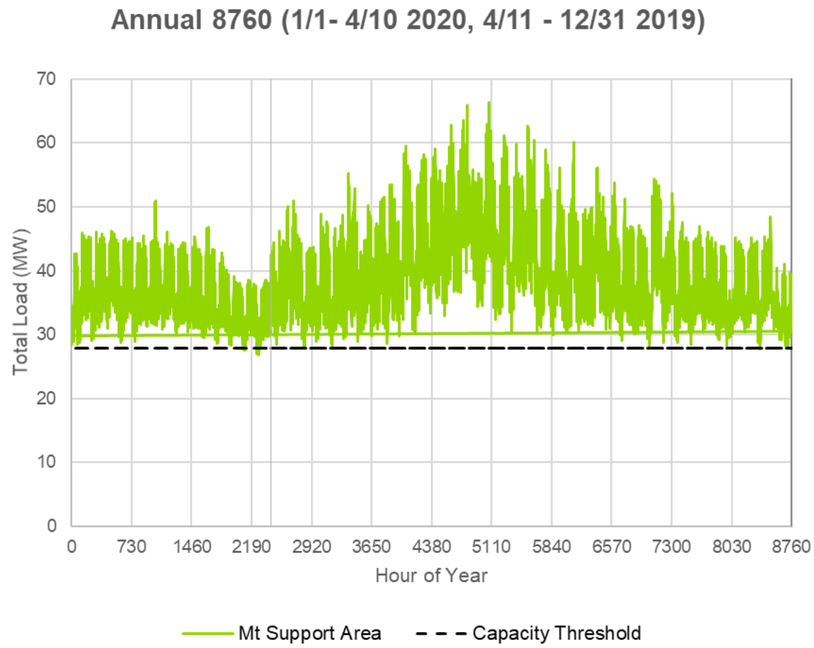
Source: Guidehouse, EDC data

Mount Support Substation (Bulk) DG Analysis Results

Mount Support Substation (Bulk) – Annual Peak Day and Capacity Threshold:

- Summer peaking substation with midday peak
- Historical project with normal and emergency overloads
    - Normal loading in excess of ratings for three feeders, one transformer, and one supply line
    - Emergency loading in excess of ratings for three transformers and four supply lines
- Mount Support load profile used as a proxy for the area in 2019-2020

Figure E-9. Capacity Deficiencies – Mount Support Substation (Bulk)



Source: Guidehouse, EDC data

Table E-2. Annual Load Profile and Capacity Threshold – Mount Support Substation (Bulk)

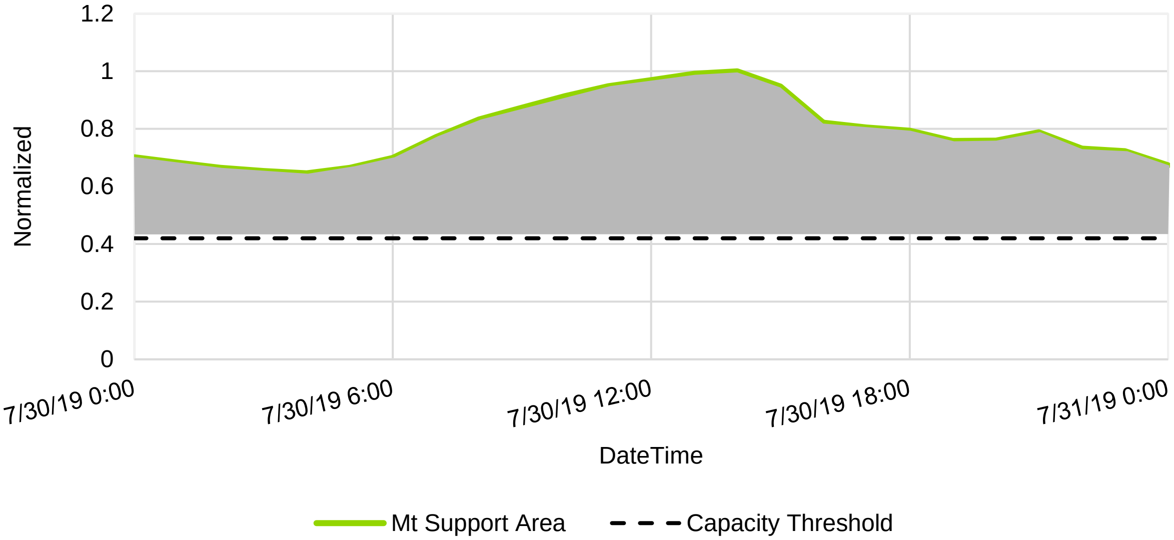
Location	Region	Peak (MW)	Time of Peak	First Year Deficit (MW)
Mount Support Substation (Bulk)	**Lebanon**	**66.4**	**7/30/19 14:00**	**Prior 2014**

Source: Guidehouse, EDC data

Mount Support Substation (Bulk) – Annual Peak Day and Capacity Threshold:

- Summer peaking substation with midday peak
- Deficiencies occur over the entire peak day due to significant (N-1) contingency exposure on substation transformer with low capacity rating
- Hours of capacity deficiency on peak day: 24

Figure E-10. Peak Day Load – Mount Support Substation (Bulk)

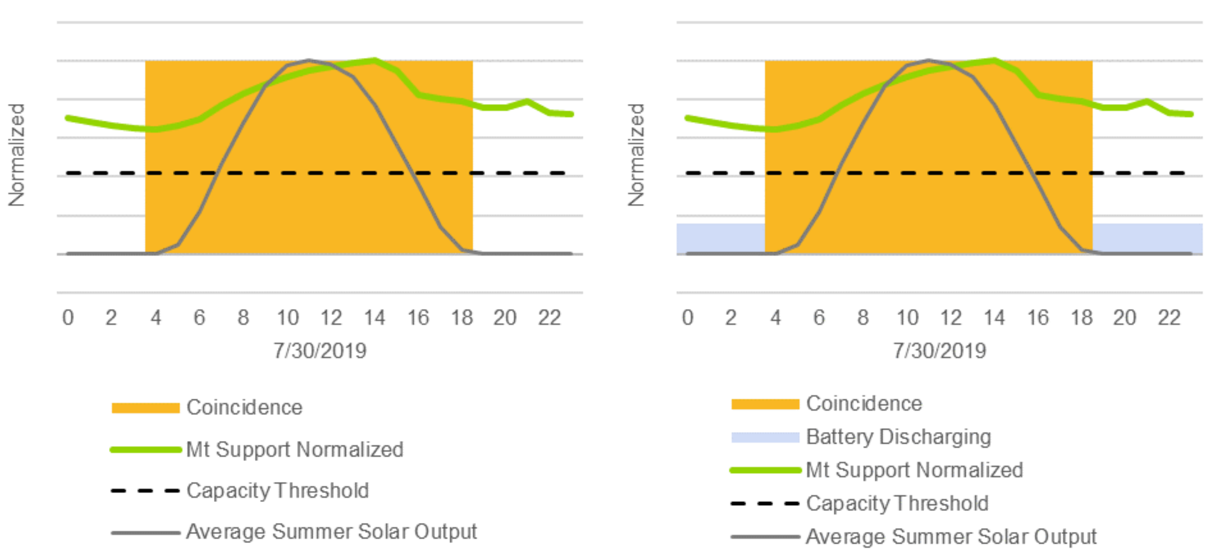


Source: Guidehouse, EDC data

Mount Support Substation (Bulk) – Solar Coincidence and Solar plus Storage Charging Analysis:

- Summer coincidence for 15 out of 24 hours.
- 15 hours of solar production vs. 24 hours of distribution capacity needs
- Limited or no charging opportunity for storage on peak day

Figure E-11. Solar Coincidence and Solar plus Storage Charging Analysis – Mount Support Substation (Bulk)

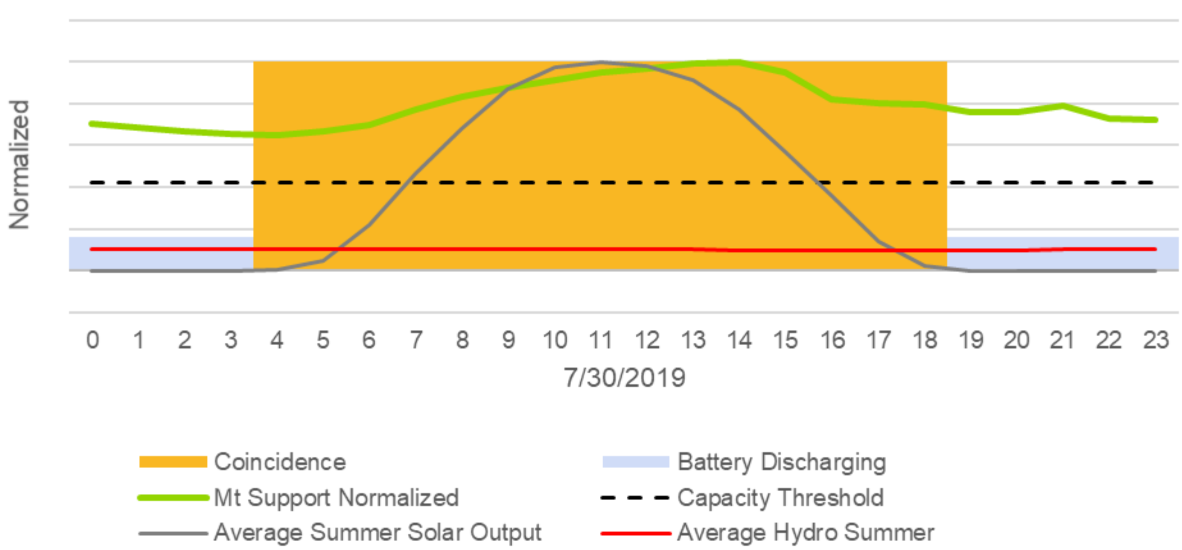


Source: Guidehouse, EDC data

Mount Support Substation (Bulk) – Solar plus Storage plus Hydro:

- Adding hydro could help to meet the hours of need at Mount Support
- On average, even though hydro production is much lower in the summer it is consistent across the entire day on average
- This aligns well with the broad period of need at Mount Support on the summer peak day

Figure E-12. Solar Coincidence and Solar plus Storage plus Hydro – Mount Support Substation (Bulk)



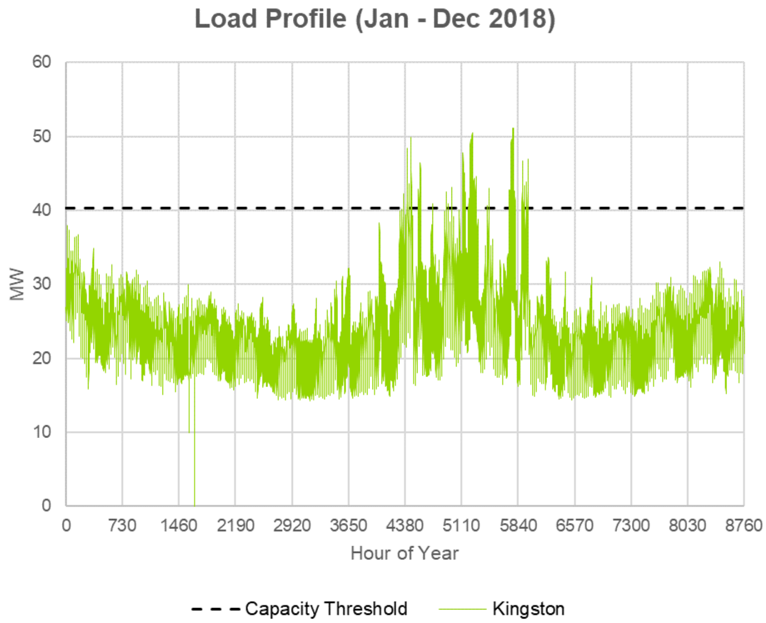
Source: Guidehouse, EDC data

Kingston Substation (Bulk) DG Analysis Results

Kingston Substation (Bulk) – Annual Peak Day and Capacity Threshold:

- Summer peaking location with normal overload
- Historical project with normal overload
- Annual 8,760 for year 2018
    - 2018 deficit: 10.7 MW
- Hours of capacity deficiency: 203
- Energy deficiency: 788 MWh
    - Approximately, 0.4% of total energy (211,733 MWh)

Figure E-13. Capacity Deficiencies – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

Table E-3. Annual Load Profile and Capacity Threshold – Kingston Substation (Bulk)

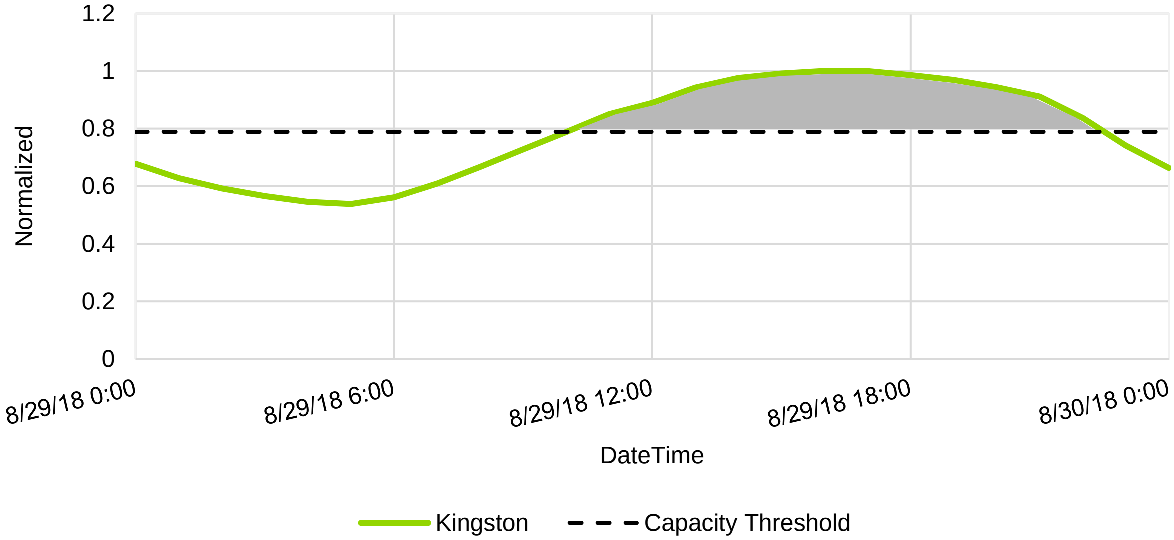
Location	Region	Peak (MW)	Time of Peak	First Year Deficit (MW)
Kingston Substation (Bulk)	Seacoast	51	8/29/18 17:00	Prior 2014

Source: Guidehouse, EDC data

Kingston Substation (Bulk) – Annual Peak Day and Capacity Threshold:

- Kingston is a summer peaking location with normal overload
- The load profile is smooth given that we are using the seacoast region hourly loads
- Hours of capacity deficiency on peak day is relatively high: 12

Figure E-14. Peak Day Load – Kingston Substation (Bulk)

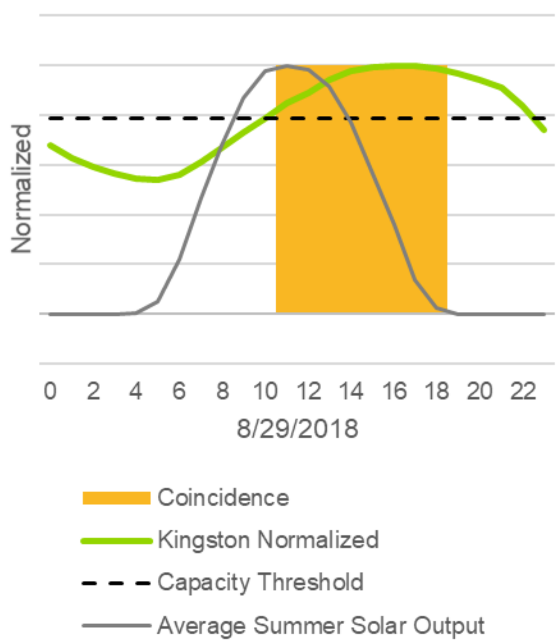


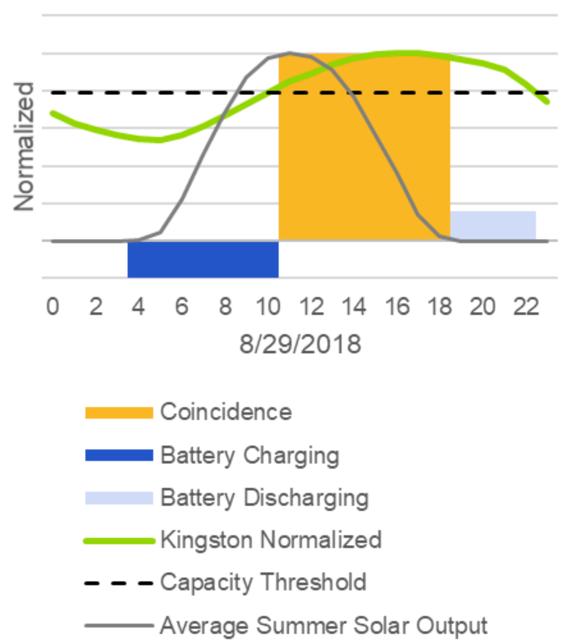
Source: Guidehouse, EDC data

Kingston Substation (Bulk) – Solar Coincidence and Solar plus Storage Charging Analysis:

- Summer coincidence interval: 8 out of 12 hours
- Summer 7-hour charging interval, 4-hour discharge interval

Figure E-15. Solar Coincidence and Solar plus Storage Charging Analysis – Kingston Substation (Bulk)



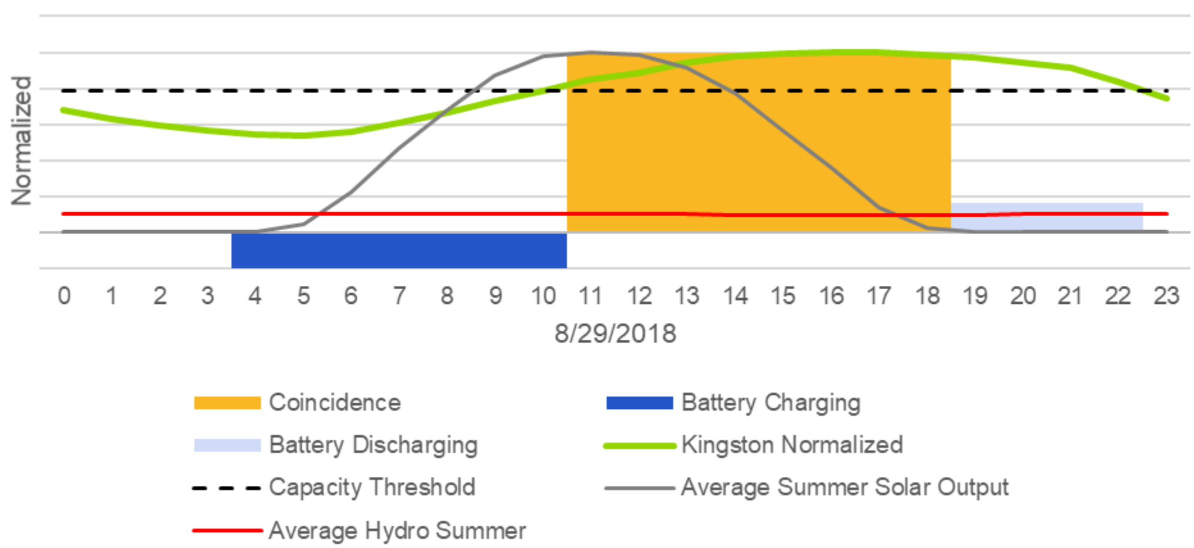


Source: Guidehouse, EDC data

Kingston Substation (Bulk) – Solar plus Storage plus Hydro Analysis:

- The peak hours later in the day could benefit from hydro production and reduce the size of any battery storage
- Based on the seacoast hourly profile, there are many hours of need that have either no coincidence or low solar PV production that could benefit from either battery storage or hydropower production

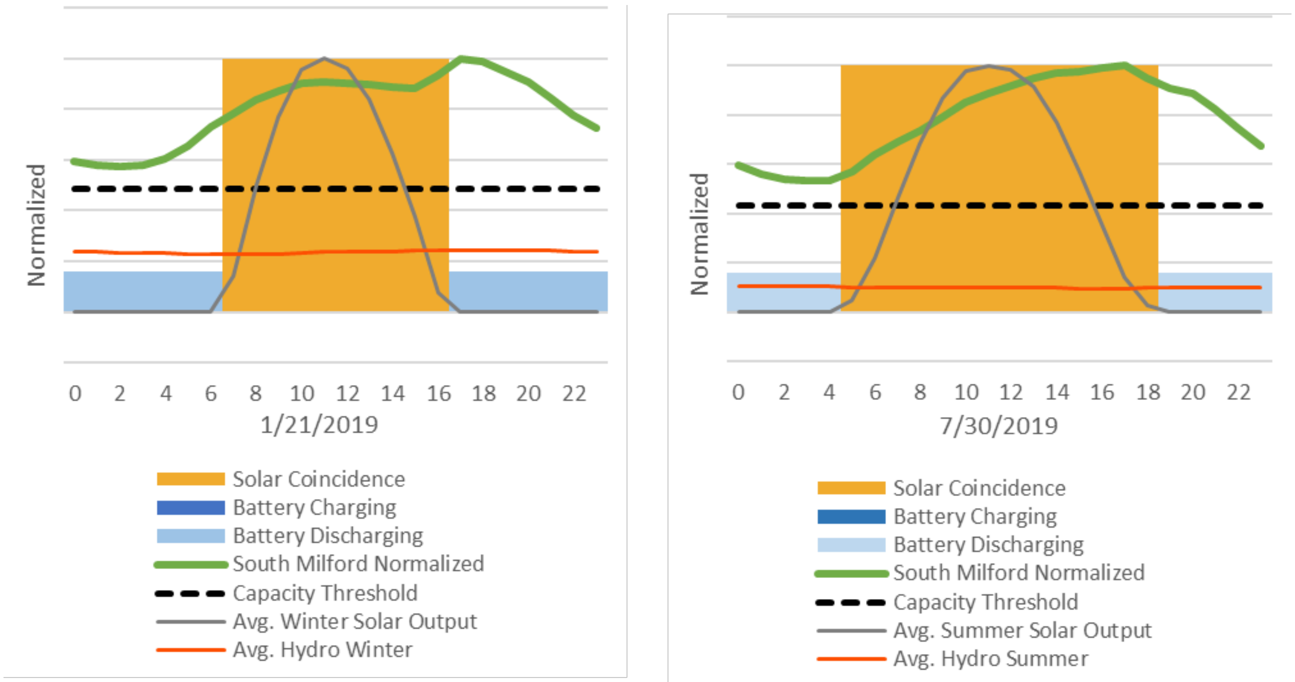
Figure E-16. Solar Coincidence and Solar plus Storage plus Hydro Analysis – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

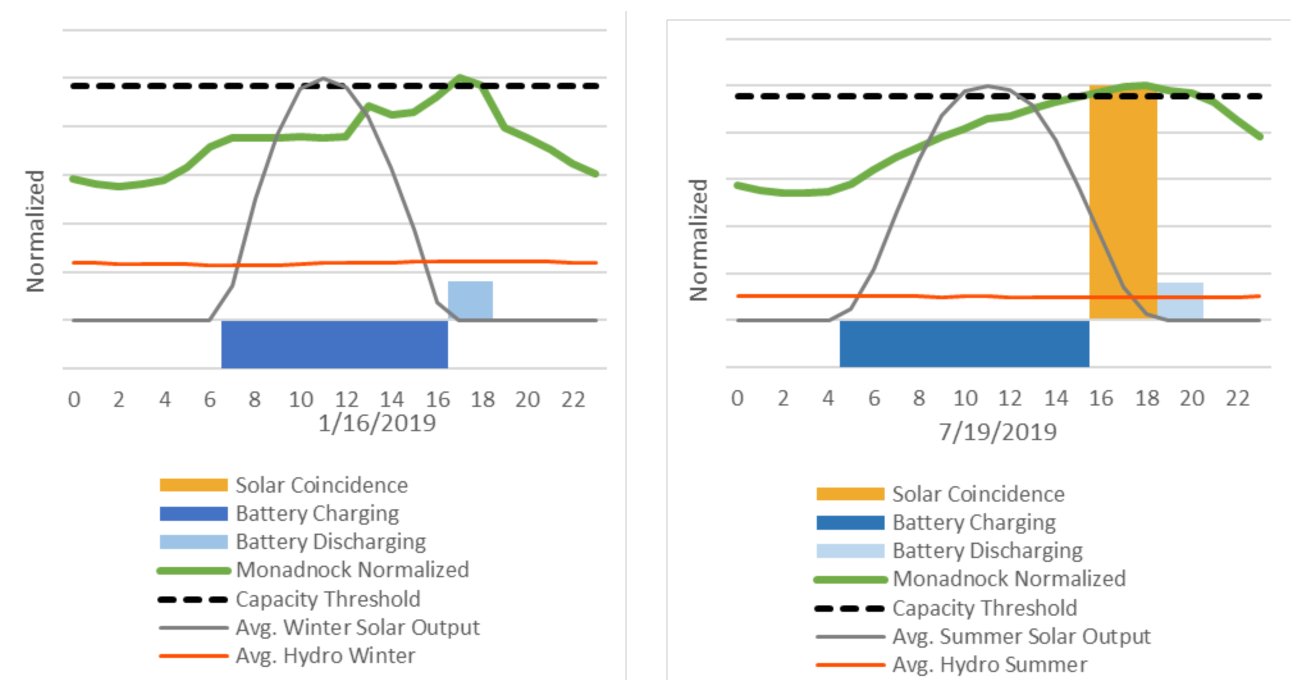
E.3 DG Production Profiles for Remaining 11 Sites

Figure E-17. Solar Coincidence and Solar plus Storage plus Hydro Analysis – South Milford



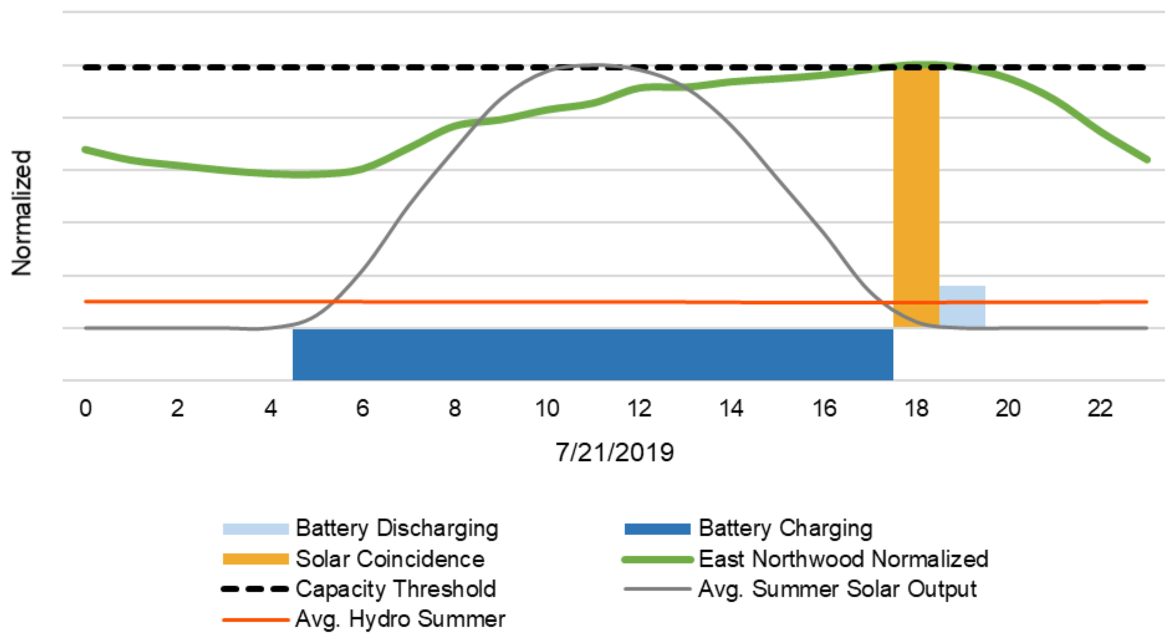
Source: Guidehouse, EDC data

Figure E-18. Solar Coincidence and Solar plus Storage plus Hydro Analysis – Monadnock



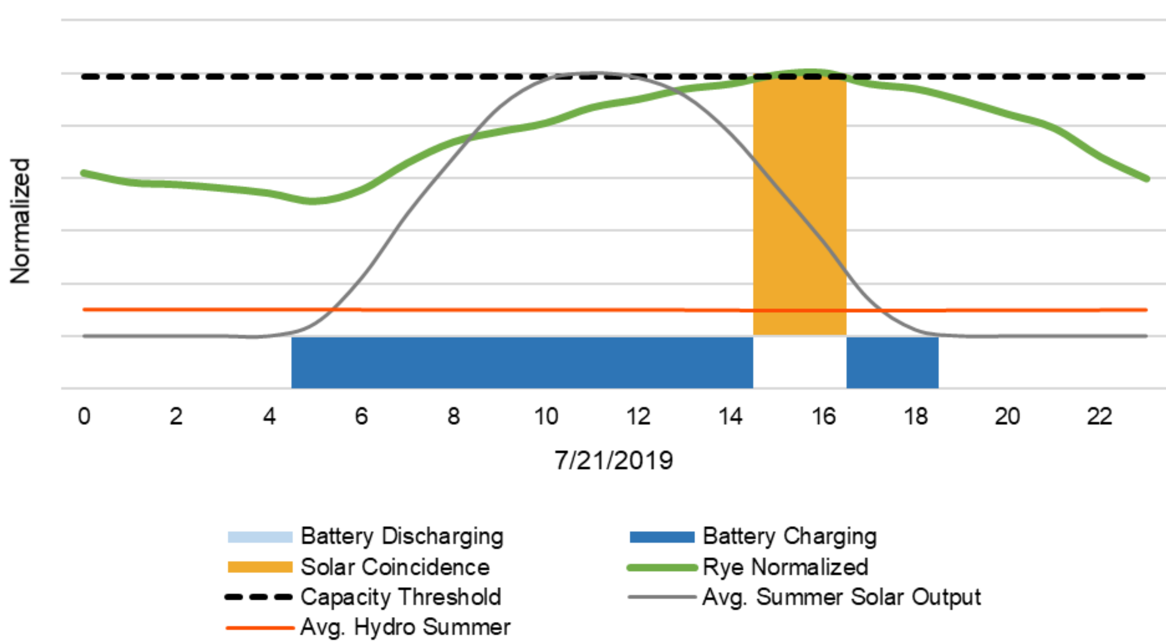
Source: Guidehouse, EDC data

Figure E-19. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – East Northwood (Non-Bulk)



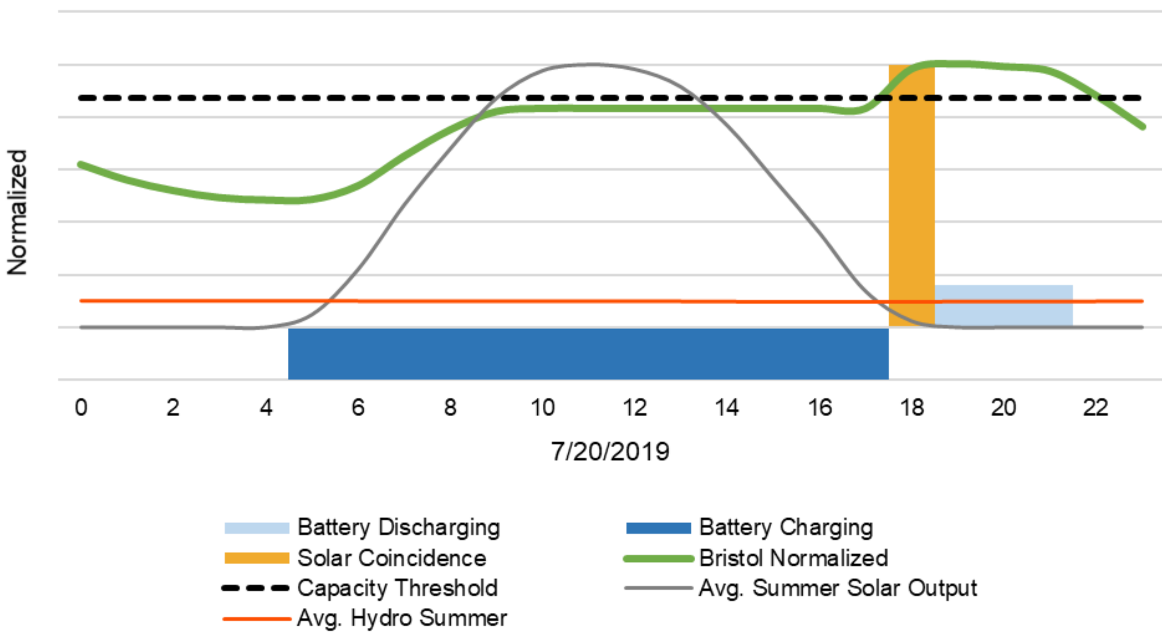
Source: Guidehouse, EDC data

Figure E-20. Solar Coincidence and Solar plus Storage plus Hydro Charging Analysis – Rye (Non-Bulk)



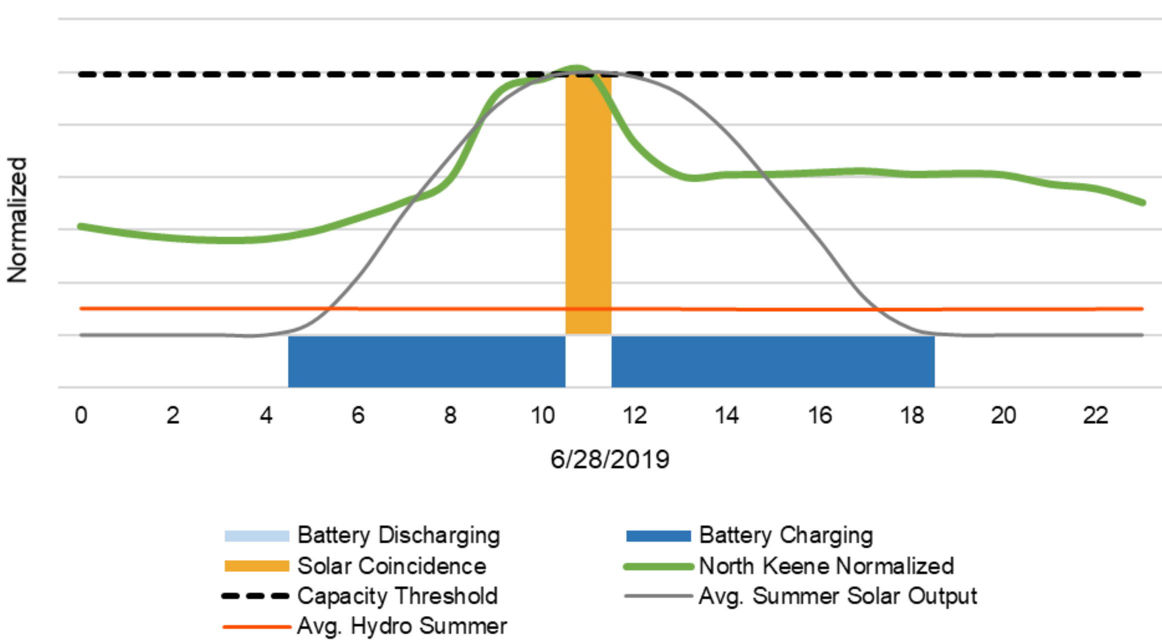
Source: Guidehouse, EDC data

Figure E-21. Solar Coincidence and Solar plus Storage plus Hydro Charging Analysis – Bristol (Non-Bulk)



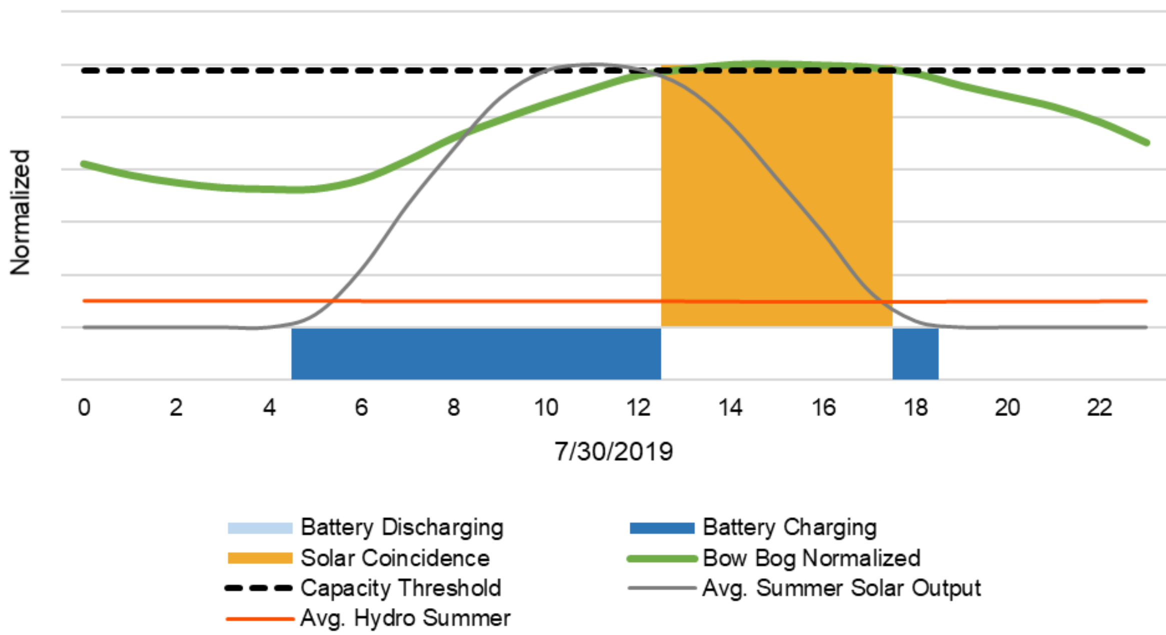
Source: Guidehouse, EDC data

Figure E-22. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – North Keene (12.47 kV)



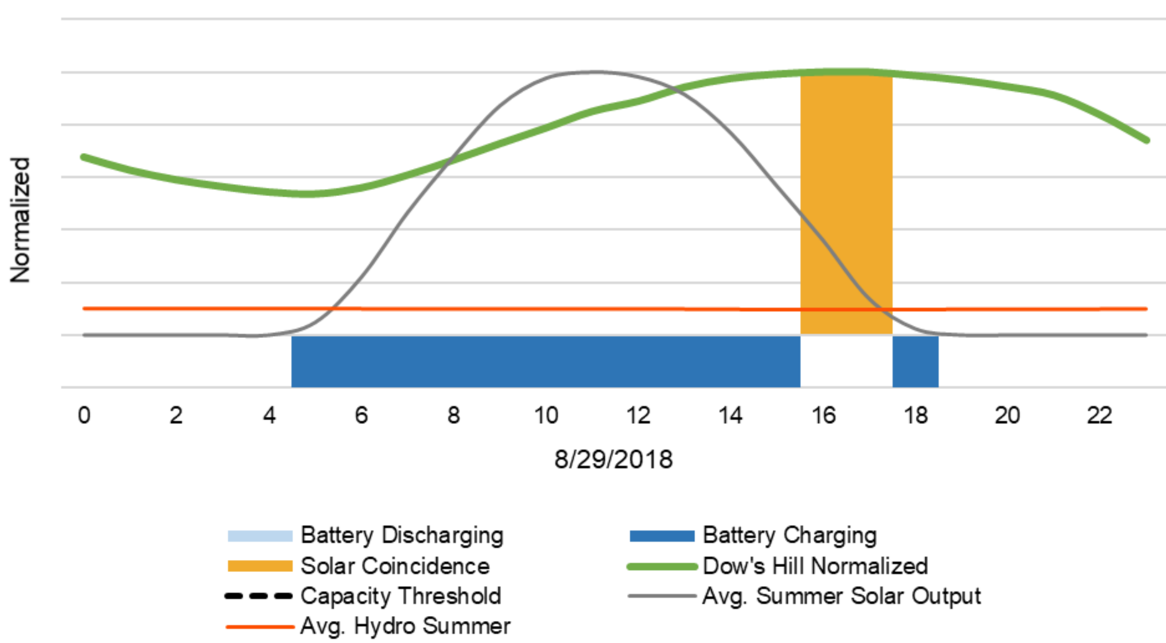
Source: Guidehouse, EDC data

Figure E-23. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – Bow Bog (Non-Bulk)



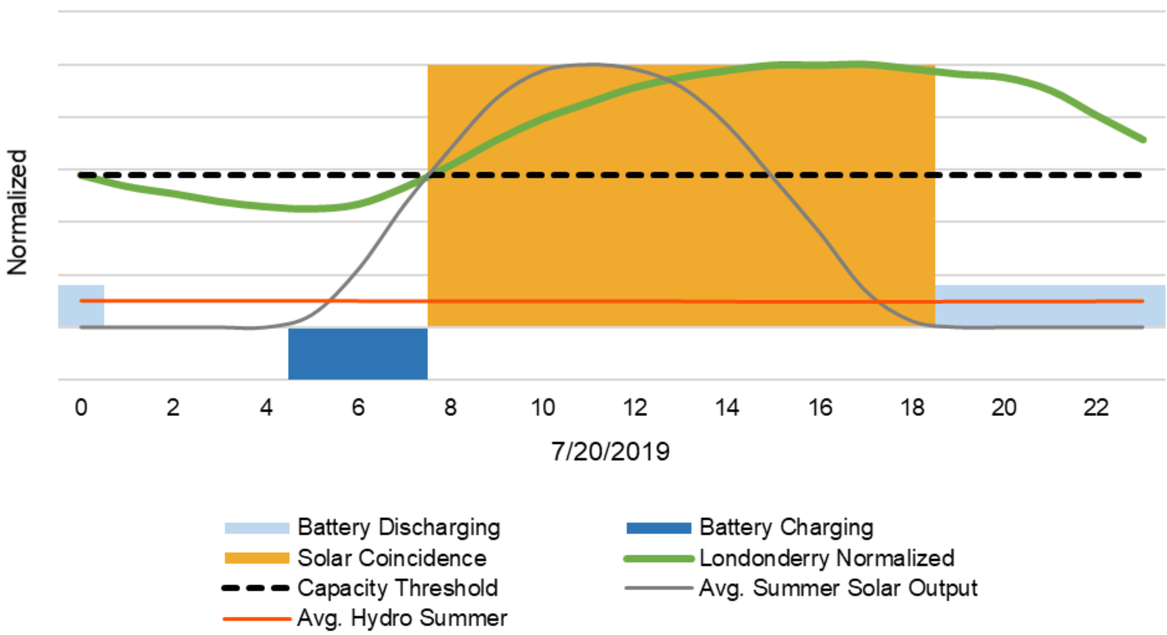
Source: Guidehouse, EDC data

Figure E-24. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – Dow's Hill (Bulk)



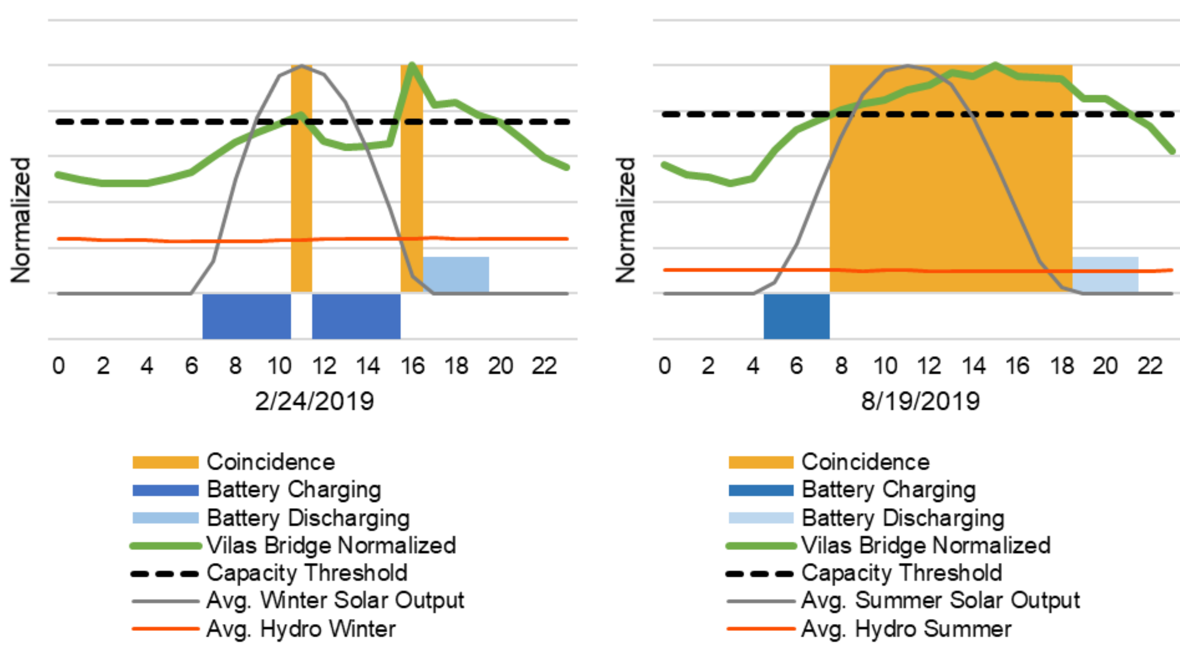
Source: Guidehouse, EDC data

Figure E-25. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – Londonderry (34.5 kV)



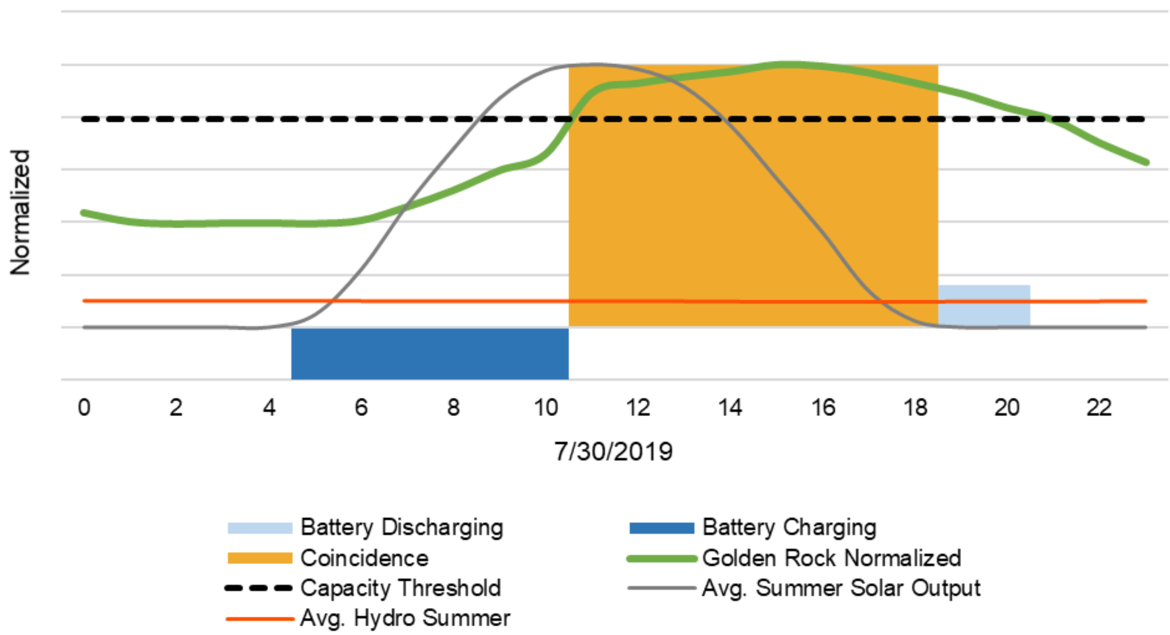
Source: Guidehouse, EDC data

Figure E-26. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – Vilas Bridge (Non-Bulk)



Source: Guidehouse, EDC data

Figure E-27. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – Golden Rock (Bulk)



Source: Guidehouse, EDC data

Appendix F. Glossary

F.1 List of Acronyms and Abbreviations

BEV: Battery Electric Vehicle

DER: Distributed Energy Resources

DG: Distributed Generation

EDC: Electric Distribution Company

EE: Energy Efficiency

EIA: Energy Information Administration

EV: Electric Vehicle

GW: Gigawatt

GWh: Gigawatt-hour

Hydro: Hydroelectric generation

ISO-NE: Independent System Operator New England

kV: Kilovolt

kW: Kilowatt

LCIRP: Least-Cost Integrated Resource Plan

LTE: Long-Term Emergency Rating

LVDG: Locational Value of Distributed Generation

MW: Megawatt

MWh: Megawatt-hour

MVA: Megavolt Ampere

NREL: National Renewable Energy Laboratory

NEM: Net Energy Metering

NWS: Non-Wires Solution

PSM: Physical Solar Model

PUC: New Hampshire Public Utilities Commission

PV: Photovoltaic

RECC: Real Economic Carrying Charges

ROW: Right-of-Way

SCADA: Supervisory Control and Data Acquisition

STE: Short-Term Emergency Rating

TFRAT: Transformer Rate on Non-bulk Transformers (Eversource)

Tx: Transmission

T&D: Transmission and Distribution

VDER: Value of Distributed Energy Resources

VASTTM: Vehicle Adoption Simulation Tool

Xfmr: Transformer

F.2 Glossary of Terms

Bulk Substation: Served by 115 kV transmission on high voltage side of substation transformer

Circuit: Refers to distribution circuits, used interchangeably with “feeder”

Commission: New Hampshire Public Utilities Commission

Capacity Deficiency: Condition under which the electric demand on a line or substation transformer exceeds normal or emergency ratings

Energy Deficiency: The total annual amount of energy, calculated by adding hourly capacity deficiencies, over an entire year

Feeder: Refers to distribution circuits, used interchangeably with circuit

Generation: Equipment and devices used to produce electricity; includes conventional, renewable, and energy storage devices

Guidehouse: Consultant that conducted the LVDG study and prepared this report with review by the Commission Staff

Hydro: Hydroelectric generation

Line: Refers to distribution circuits operating at voltages 34.5 kV and below, and sub-transmission lines up to 69 kV

Location: Indicates a geographic position on the EDCs’ electric system and is used extensively throughout the study to refer to substations, circuits, or sometimes other assets that are part of the electric delivery system. Location is synonymous with a place where utility assets are sited.

Non-Bulk Substation: Substation connected to transmission lines rated 69kV and below on high side of transformer

Output: Electric generation production, typically measured on an hourly basis

Staff: New Hampshire Public Utilities Commission Staff

Sub-transmission: Electric lines rated between 34.5 kV and 69 kV. Only sub-transmission lines rates 34.5 kV are included as potentially avoidable distribution capacity investments in the study; however, the impact of distribution level of investments is analyzed on sub-transmission lines rated up to 69 kV

Traditional Distribution Investments: Lines and substations electric utilities install to address capacity deficiencies; excludes renewable generation and energy storage

Violation: A condition under which EDC planning criteria is not met; usually refers to a capacity deficiency on lines or substation equipment

Appendix G. References

G.1 Report Sources

1. New Hampshire NEM Order
2. New Hampshire LVDG Order approving study scope and timeline
3. New Hampshire VDER Order approving study scope and timeline
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5. SCE RECC Slides
    - https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451488

Appendix H. List of Figures and Tables

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guidehouse.com

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SUMMARY

David Littell is an expert and attorney with more than 30 years of experience in energy, utility, and environmental regulation. The Chair of Bernstein's new Climate Practice Group, he is recognized attorney and national expert with expertise in energy and environmental regulation and markets, he provides valuable guidance to clients, public utility commissions, environmental regulators, and energy officials on how to approach and resolve complex energy, utility, pollution, environmental, and economic challenges. He has a keen understanding of market-based regulatory systems from electricity and gas to carbon trading as well as inter-state regulatory issues; electrical and gas ratemaking and rate design; renewable resource integration; demand response; efficiency and renewable portfolios; planning and assessment of energy and environmental resources; power, transmission, and non-transmission alternatives; gas local distribution company and interstate pipelines; approaches to air, water, land, and cross-media pollution control, and the intricacies of greenhouse gas mitigation and adaptation to climate change. He also has an extensive background on natural resources regulation of bird, amphibian, and aquatic habitats; toxics regulation; and product stewardship.

EDUCATION

Harvard Law School, J.D.,1992, *cum laude*
Princeton University, A.B., 1989, concentration in the Princeton (former Woodrow Wilson) School of Public and International Affairs, *magna cum laude, Phi Beta Kappa*.

PROFESSIONAL EXPERIENCE

2019-present, Bernstein, Shur, Sawyer & Nelson Law Firm — Portland, Maine
Shareholder, Chair of the Climate Practice Group

Attorney Littell represents clients in front of public utilities commissions on electric and gas matters including work on gas supply and balancing arrangements, transportation customer gas contracts, and related gas and electric peak system balancing and electrical system reliability. He also represents and counsels' utilities, merchant transmission developers, renewable energy developers and other clients in commission and utility matters. He has presented testimony before the FERC, the Maine PUC, the NH PUC, the RI PUC, the CT PURA, the MD PSC, the PUCO, the D.C. PUC, the U.S. EPA, the U.S. House of Representatives, state legislative committees and commissions. In addition to those agencies and decision-makers listed above, he has advised the MA DOER, the NH PUC, the Maine PUC, the RI PUC, the NJ BPU, the MI PSC, the MO PSC, and the MN PUC PSC.

2015-2022, Regulatory Assistance Project (RAP) — Portland, Maine
Principal & Senior Advisor

With RAP as a client of Bernstein Shur since 2019, Mr. Littell continues his national work on a broad range of rate design and energy innovation strategies with state officials and utility commissions. He advises state commissioners on rate design and pilots and data consideration related to grid modernization. He also advises commissions and energy offices on power sector transformation, energy efficiency, energy sector technology adoption, distributed energy resource integration, energy efficiency, and the integration of variable renewable energy sources. Mr. Littell has worked with utility regulators, energy regulators and environmental regulators from

20 states providing formal and informal advice on market design, regulatory and program design, and power sector transformation issues. Mr. Littell is the RAP lead on ISO/RTO energy, capacity, and other market design issues for the ISO-NE, NYISO, PJM, and MISO regions.

2010-2015, Maine Public Utilities Commission **Hallowell, Maine**
Commissioner
During his five-year tenure, Mr. Littell was a member of the three-person commission which resolved more than 2,000 cases involving ratemaking, rate design, energy efficiency, renewable energy, distributed generation, electric vehicles, and consumer protection issues. He also played a pivotal role in designing, implementing, and running North America's first market-based greenhouse gas regulatory system, the Regional Greenhouse Gas Initiative. He was an officer of the initiative from 2008 through 2015, serving as chair, vice chair, and treasurer, and taking the lead on policy, operations, and management of the nine-state organization. During his term as commissioner, he also served as vice chairman of the National Association of Regulatory Utility Commissioners' Task Force on Environmental Regulation and Generation. He chaired the energy zone group of the Eastern Interconnection States Planning Committee, which developed the energy zone mapping tool for energy resources across the 38 eastern states.

2005-2010, Maine Department of Environmental Protection **Augusta, Maine**
Commissioner
Mr. Littell led Maine's DEP to approve more investments in Maine's capital base (energy-related, pulp & paper, major industrial and commercial) than any other Maine commissioner before or since while leading environmental protection improvements in Maine's and regional programs. Mr. Littell implemented significant initiatives to address climate change, including the Regional Greenhouse Gas Initiative and Maine's Climate Action Plan to reduce greenhouse gas emissions to 1990 levels by 2010 and 10 percent below 1990 levels by 2020. Maine met the 2010 goal early and is on track to meet the 2020 reduction goal.

At DEP, he managed and led 415 environmental scientists, engineers, environmental and financial specialists, with a budget of roughly $80 million (which he cut 14 times in office while maintaining staff morale). He also served as the environmental expert within the Governor's Cabinet for economic development projects and represented Maine on a numerous regional and national associations and initiatives. He designed and implemented protections for Maine's most significant wildlife and bird habitats as well as aquatic habitats under the Natural Resource Protection Act and the water withdrawal programs. Mr. Littell designed and implemented nation-leading consumer toxic protections in Maine's Kid-Safe Products Law, working closely with Washington State officials on parallel initiatives. While instituting innovative environmental programs, he worked with the Economic Development Department to maintain and expand Maine's economic base through permitting a record amount of capital investment in the state, largely in the energy sector, ranging from wind and tidal projects to large-scale transmission and industrial co-generation.

2003-2005, Maine Department of Environmental Protection **Augusta, Maine**
Deputy Commissioner
Mr. Littell was the chief operating manager for the agency, where he oversaw a budget of $55 million in spending, with $88 million in authority, and operations with a staff of 463 (reduced to 415 by 2010) in three bureaus and 14 divisions. He was the point of contact within the Administration on adoption of the California low-emission vehicle, partial zero-emissions vehicle, and Pavley standards, and managed those processes within the agency and with stakeholders.

He served as the lead economic development and permitting contact within the Administration for major capital and priority projects. He also oversaw Maine's role in the Base Realignment and Closure process. Mr. Littell coordinated with economic development officials to expand and maintain Maine's industrial base, sustaining more than 8,000 at-risk jobs and expanding Maine's commercial and industrial base through the Great Recession.

1992-2003, Pierce Atwood Law Firm **Portland, Maine**
Partner and Attorney
Mr. Littell specialized in project permitting, land-use, environmental litigation, and complex multi-party negotiations with the U.S. Environmental Protection Agency (EPA) and state agencies, hazardous waste cleanups, and wireless communications. He litigated in U.S. District and Maine courts successfully for clients. He acted as lead counsel on the EPA Superfund and hazardous substance sites in a national-precedent-setting settlement resulting in successful liability transfer and site cleanups under his multi-party management. This included negotiating an innovative hazardous waste settlement with the EPA, the U.S. Department of Justice, and hundreds of parties who transferred cleanup obligations to a third party for a cash-out settlement payment. He represented companies spanning from Fortune 50 corporations, leading U.S. telecommunications companies, high-tech and older manufacturing companies, all 13 of the pulp and paper mills in Maine to developers, municipalities, and individuals.

1994-2004 United States Navy Reserve
Lieutenant Commander
Mr. Littell served in the United States Navy Reserve, resigning as a Lieutenant Commander. He served as an intelligence officer with Combat Patrol Squadron 92 (VP-92), U.S. Navy Reserve squadron, and the Tactical Support Center at Brunswick Naval Air Station. He also served in Atlantic Intelligence Command and Joint Forces Command units based in South Weymouth, Massachusetts, and Devens, Massachusetts. He was awarded two individual Navy Achievement citations, expert rifle and pistol shot, and a number of unit citations for his service.

SELECTED RECENT PROJECTS
Regulatory Structures and Market Design

- Mr. Littell is advising the Rhode Island Public Utilities Commission, the Maryland Public Service Commission, the Connecticut Public Utilities Regulatory Authority, the Minnesota Public Utility Commission, and the Michigan Public Service Commission on adoption of performance-based regulation. He has also advised the Pennsylvania Public Utilities Commission and the Ohio Public Utilities Commission on implementation of performance-based regulation.
- Mr. Littell has presented testimony to the U.S. Congress, the U.S. Environmental Protection Agency, and the U.S. Federal Energy Regulatory Commission (FERC). He has also participated in workshops and negotiations with regulators from dozens of U.S. states, six Pacific Rim nations, the U.K. and the UNFCC COP in Copenhagen.
- He has developed an expertise in regulatory approaches to modern data management systems necessary to manage utility transitions to advanced energy markets, and how to set up those market and regulatory rules to facilitate competitive markets.
- Mr. Littell played a pivotal role in designing, founding, successfully launching, and managing the Regional Greenhouse Gas Initiative (RGGI), the first North American regulatory program for greenhouse gas reductions. The market-based program successfully put in place rules coordinated with ten initial states through a centralized administrative and technical assistance entity known as RGGI, Inc., based in New York City. He was an officer and the primary operational officer for seven years, overseeing and managing the staff and financial operations of the multibillion-dollar RGGI market.

Rate, Net Metering, and Program Design

- Mr. Littell has advised and trained more than a half-dozen commissions on rate design and related power sector transformation issues. He focusses his rate design consulting and advice on issues associated with integration of smart grid and advanced energy technologies that all jurisdictions are facing today.
- He advised the New Hampshire Commission on multiple dockets that involve rate design considerations and presented testimony to the New Hampshire Decoupling Commission created by the New Hampshire Legislature to examine the benefits of rate decoupling. David acted as commission adviser in both New Hampshire's Grid Modernization Docket and New Hampshire's 2016-2017 Net Energy Metering Dockets both of which considered and involved rate design to send consumer price signals more effectively. His work continues with advice on pilots and studies emerging from these dockets.
- He is advising the Maryland Public Service Commission on advanced rate-design issues and co-chairing the rate design workgroup in the Public Conference-44 Maryland grid modernization docket.
- Mr. Littell is advising the Connecticut Department of Energy and Environmental Protection on rate design issues associated with proposals for advanced distributed energy resource pilots, and other commissions and state departments on dynamic pricing design.
- He performed rate design training for commissioners and staff of the New Brunswick Energy and Utilities Board and Department of Energy and Resource Development, the Prince Edward Island Regulatory and Appeals Commission, the Newfoundland & Labrador Board of Commissioners of Public Utilities, and the Nova Scotia Utility and Review Board.
- While on the Maine Public Utilities Commission, Mr. Littell participated in and decided rate cases for each of the three investor-owned electrical utilities in Maine and three natural gas companies. Those rate cases, particularly fully litigated cases, were rare, in general occurring once per decade. The cases he decided involved many of the issues facing other commissions nationally and internationally, including rate design, demand-charge, standby fees, and fixed fee proposals among other issues.

Natural Gas Proceedings

- Mr. Littell represents Bucksport Generation, a dual-fueled fast-start gas power plant in a general LDC rate case in Docket. 2021-00024 case involving considerations of impacts of LDC and interstate pipeline tariffs and charges on power plant operations.
- Mr. Littell successfully represented Bucksport Generation in matters in front of the Maine PUC including in Bangor Gas's tariff revision in Docket 2019-000284 to negotiate specific tariff revisions and provisions related to draw tolerances, imbalance, and nomination provisions of Bangor Gas's tariff.
- Mr. Littell has represented a number of state agency confidential clients in consultative relationships involving at least a dozen different matters in front if various state commissions.
- Mr. Littell sat on and ruled on tariff and cost-of-gas cases for each of Maine's three gas local distribution utilities from 2010 to 2015 include capacity acquisitions for transportation and supply provisions for each gas utility.

Power Sector Transformation

- Mr. Littell presented on U.S. regulatory and power market innovations to the U.K. Office of Gas and Electricity Markets (OFGEM) in September 2018.
- Mr. Littell is advising the New Hampshire Public Utilities Commission and staff in its Grid Modernization docket. The docket considers distributed energy resources, time of use rates, distribution grid infrastructure and data needed for modern utility-side and

consumer-side energy management. Mr. Littell chaired a Data Management Workgroup for the NH Grid Modernization Stakeholder Group which considered data management needs of a modern grid and presented recommendations to the full stakeholder group which were adopted by the full stakeholder group.

- Mr. Littell is currently addressing information management and communications issues associated with smart grid implementation, decoupling, and similar mechanisms to facilitate distributed energy resources in different forums and proceedings. He highlights these issues in national fora, including the National Governors Association and the National Smart Grid and Climate Summit, and advises state officials, such as the New Hampshire Legislative Decoupling Commission, the New Hampshire Public Utilities Commission, and other commissions, energy offices, and environmental officials in other states.
- Mr. Littell is advising the Maryland PSC and stakeholders on PC-44 issues including rate design, pilot design, value of solar study scoping issues, and working with other workgroups on competitive markets and suppliers, electric vehicles, interconnection, and other issues. He has facilitated the discussions of the rate design workgroup and participated in meetings with stakeholders individually and collectively.

Energy Efficiency

- Mr. Littell advised the New Hampshire Public Utilities Commission's stakeholder effort to consider establishing an energy efficiency resource standard. The stakeholder effort was with all of New Hampshire's electric and natural gas utilities, as well as energy efficiency and environmental advocates. The successful stakeholder effort transitioned to a formal adjudicatory docket to consider adoption of an energy efficiency resource standard in New Hampshire and culminated in adoption of the first New Hampshire Energy Efficiency Resources Standard in 2016.
- Mr. Littell participated in the Maine Public Utilities Commission's review and oversight of the Efficiency Maine Trust, including approval of the first two three-year energy efficiency triennial plans. These first two triennial plans increased Maine's funding levels for residential, commercial, and industrial energy efficiency programs. The first triennial plan proceeding was significant in that it represented a review of the newly established trust structure legislated by the Maine legislature in 2009.
- While on the Maine Public Utilities Commission, Mr. Littell dissented from efforts to place an artificially low cap on energy efficiency funding in two 2015 decisions. His dissenting view of the proper interpretation of the energy efficiency cap was subsequently legislated in 2015 by large bipartisan majorities, overruling the Governor's veto to legislatively maintain an adequate funding cap for Maine's energy efficiency programs.

Renewable Energy

- Mr. Littell is advising a state commission and stakeholders in two different states on value of solar, and solar energy regulation.
- On the Maine Public Utilities Commission, Mr. Littell wrote extensively on the value of investments in grid-scale renewables to diversify the supply and generation mix. He participated in approval of four wind power purchase contracts, including an offshore wind contract. He also focused on the benefits, costs, and risks of investments in other grid-scale resources, including natural gas.
- Mr. Littell participated in state efforts to assess the value and impact of increased levels of renewable distributed generation in New England on the capacity resource markets. These included state efforts to have independent system operator ISO-New England reduce the installed capacity requirement due to state investments in energy efficiency and distributed solar resources.

Distributed Generation and Distributed Energy Resources

- Mr. Littell advised the state of Connecticut on distributed energy resources, including storage, under Connecticut's new policy framework on battery storage proposals.
- He has advised multiple state commissions on incorporating distributed energy resources (DERs) at higher levels than previously into commission and utility processes including hosting capacity analysis, interconnection processes, and areas to consider for integration of higher levels of DERs at the distribution level.
- Mr. Littell is participating in the Evolution of Demand Response Project examining the role of distributed generation and distributed energy resources (DER), including opportunities and challenges for DER resources, given the current legal, economic, and regulatory context. The EDP Project issued *Demand Response, the Road Ahead* in early 2016.

Resource Planning and Power Market Design

- As part of the Eastern Interconnection States Planning Committee, Mr. Littell participated in a detailed examination of the integration of renewable energy, energy efficiency, and other advanced technologies. The committee evaluated 72 different scenarios showing alternatives for the development of energy resources and transmission in the 38 eastern U.S. states.
- Mr. Littell examined in depth the impacts of overreliance on natural gas-fired generation in New England and consequential costs and risk to New England ratepayers.
- He is assisting state officials with consideration of market designs proposed for capacity and other markets in multiple ISO/RTOs including efforts to integrate state public policies and regional markets.

Air Quality and Climate

- Mr. Littell played a pivotal role in designing, launching, successfully implementing, and managing the Regional Greenhouse Gas Initiative (RGGI), the first North American regulatory program for greenhouse gas reductions. The market-based program successfully put in place rules coordinated with ten initial states through an administrative and technical entity known as RGGI, Inc., based in New York City. He was a chairman and officer and the primary operational officer for seven years, overseeing and managing the staff and financial operations of the multibillion-dollar RGGI market.
- Mr. Littell implemented the Maine Air Toxics Initiative, which established a regulatory and policy framework to address the more than 180 air toxics listed, but thereto not regulated, under the Clean Air Act. This included toxicity weighted emissions factors based on the most current scientific toxicity data and engineering factors. The top policy recommendation put in place to reduce air toxic emissions was to pursue commercial, industrial, and transportation-related efficiency.
- Mr. Littell initiated and implemented a mercury emissions cap for stationary air sources in Maine.
- As Maine's environmental commissioner, Mr. Littell facilitated the East Coast and Mid-Atlantic States development of Regional Haze Standards as chair of the Mid-Atlantic/Northeast Visibility Union, including leading interregional consultations with states in the Midwest and Southeast. These standards resulted in significant reductions of particulate and sulfate compound pollution in East Coast and upwind states, including the Midwest and Southeastern United States.

SELECTED PROCEEDINGS

- Mr. Littell has advised the Maryland PSC's PC-44 docket and its five active workgroups

- Mr. Littell has advised the New Hampshire PUC for five years in three dockets including their Grid Modernization and 2016-2017 Net-Energy Metering dockets and follow-on proceedings.
- Mr. Littell is leading a team advising the Connecticut Public Utilities Regulatory Authority in grid modernization, rate design and energy resource evaluation.
- In the last three years, he has advised public utility commissions, energy offices, environmental agencies, Governor's Offices, and/or Attorney General's offices on energy and environmental issues in 17 states: New Hampshire, Rhode Island, Connecticut, Massachusetts, Maine, New York, Maryland, New Jersey, Pennsylvania, Virginia, Michigan, Ohio, Minnesota, Missouri, Oregon, and California.
- Mr. Littell played a pivotal role in designing, founding, successfully launching, and managing the Regional Greenhouse Gas Initiative (RGGI), the first North American regulatory program for greenhouse gas reductions. The market-based program successfully put in place rules coordinated with ten initial states through a centralized administrative and technical assistance entity known as RGGI, Inc., based in New York City. Mr. Littell was an officer and the primary operational officer for seven years, overseeing and managing the staff and financial operations of the multibillion-dollar RGGI market.
- Mr. Littell participated in the Maine Public Utility Commission's review and oversight of the Efficiency Maine Trust, including approval of the first two three-year energy efficiency triennial plans. These first two triennial plans increased Maine's funding levels for residential, commercial, and industrial energy efficiency programs. The first triennial plan proceeding was significant in that it represented review of the newly established trust structure legislated by the Maine Legislature in 2009.
- As a Maine public utilities commissioner, Mr. Littell considered the value of energy efficiency investments. He dissented from efforts to place a low cap on energy efficiency funding in two 2015 decisions. His view of the proper interpretation of the energy efficiency cap was subsequently legislated in 2015 by wide bipartisan majorities, overruling the Governor's veto to legislatively maintain a higher cap for Maine's energy efficiency programs.
- On the Maine Public Utilities Commission, Mr. Littell participated in review of long-term contracts including approving wind power purchase contracts, including land-based wind projects and offshore wind contracts with Norway's Statoil and then the University of Maine's AquaVentus consortium. The AquaVentus approval is still operative, with the University of Maine project pursuing U.S. Department of Energy funding.
- On the Maine Public Utilities Commission, Mr. Littell also considered the benefits and costs of investments in other grid-scale resources, including land-based wind projects and natural gas:
    - He was part of a two-person majority to approve the Downeast Wind Project proposed by Apex Energy in 2013. In his concurrence, he noted he would have approved two additional wind projects based on reasonable cost-risk management.
    - He was part of a two-commissioner majority to approve a NextEra wind power project in 2014 and another two-commissioner majority to reaffirm that decision in 2015.
    - He was part of a two-commissioner majority to approve the Bowers wind power project in 2014, and later dissented from the commission's 2015 reversal of that decision.
    - In review of potential commission investments in natural gas pipeline inter-state capacity contracts, Mr. Littell both noted the need for new investments in natural gas and raised concerns with unnecessary state intervention in the competitive

markets to support a mature technology and long-term impacts on private investment in the capacity and energy markets.

- As Maine's environmental commissioner, Mr. Littell led the development of East Coast's Regional Haze Standards as chair of the Mid-Atlantic/Northeast Visibility Union. He led inter-regional consultations with states in the Midwest and Southeast. These multi-state standards required modifications of rules and requirements in more than 14 states as well as multiple upwind states, including legislative and rule changes in Maine.
- Mr. Littell oversaw the 2005 amendments to Maine's Natural Resources Protection Act and legislative rulemaking to implement protections for waterfowl, wading bird, shorebird, and vernal pool habitats in Maine. These rules extended Maine's habitat protections to protect the most valuable habitats on a statewide scale and involved bipartisan modifications to the regulatory structure in 2006 to address concerns with economic impacts of these rules. Due to the successful implementation of the significant wildlife habitat programs, subsequent repeated efforts to repeal these habitat protections have failed every year, including two years when the legislature was controlled by the same party as the subsequent Governor.
- Mr. Littell chaired Governor Baldacci's Task Force on Safer Chemicals in 2006, which led to a new regulatory approach and advanced legislation of Maine's Kids Safe Chemical Safety Law in 2007 and implemented the law, making Maine one of the leading U.S. states on consumer protection from toxics contained in consumer products. Under this law and related legislation, Maine banned bisphenol-A and two congeners of brominated flame retardants from consumer products and imposed restrictions on the use of cadmium, formaldehyde, mercury, nonylphenol, arsenic, and phthalates in consumer products.

SELECTED PUBLICATIONS

- David Littell, Camille Kadoch, Phil Baker, Ranjit Bharvirkar, Max Dupuy, Brenda Hausauer, Carl Linvill, Janine Migden-Ostrander, Jan Rosenow, and Wang Xuan of Regulatory Assistance Project; Owen Zinaman and Jeffrey Logan National Renewable Energy Laboratory

(2018). Next-Generation Performance-Based Regulation, 21st Century Power Partnership.
  - Volume 1, Global Lessons for Success: https://www.raponline.org/wp-content/uploads/2018/05/rap_next_generation_performance_based_regulation_volume1_april_2018.pdf
  - Volume 2, Essential Elements of Design and Implementation: https://www.raponline.org/wp-content/uploads/2018/05/rap_next_generation_performance_based_regulation_volume2_april_2018.pdf
  - Volume 3, Innovative Examples from Around the World: https://www.raponline.org/wp-content/uploads/2018/05/rap_next_generation_performance_based_regulation_volume3_april_2018.pdf

  **These papers are also published on NREL's website.
- David Littell and Jessica Shipley, (Aug. 2017) Performance-Based Regulatory Options, A White Paper for the Michigan Public Service Commission, https://www.raponline.org/wp-content/uploads/2017/08/rap-littell-shipley-performance-based-regulation-options-august2017_1.pdf.
- David Farnsworth, David Littell, D., Chris James, & Kelley Speakes-Backman. (2016). *RGGI Program Review: Model to Reduce Uncertainty in State Carbon Plans*. Montpelier, VT: The Regulatory Assistance Project.
- David Littell & David Farnsworth (2016). *Carbon Markets 101: "How to" Considerations for Regulatory Practitioners*. Montpelier, VT: The Regulatory Assistance Project.

- Littell, D. (2014, February). Putting a Price on Carbon: How EPA can establish a U.S. GHG Program for the Electricity Sector. *Public Utilities Fortnightly*.
- Littell, D., & Speakes-Backman, K. (2014, October). Pricing Carbon under EPA's Proposed Rules: Cost Effectiveness and State Economic Benefits. *The Electricity Journal*.
- Littell, D. (2013, October). EPA to Build on State Efforts to Move Toward a Cleaner Power Sector. Carbon Market North America. *Reuters Point Carbon News*, *8*(37).
- Littell, D., Westerman, G., & Burson, M. (2008, October). Confronting Global Warming, Maine's Multi-Sector Initiatives 2003-2008. *Maine Policy Review*.
- Littell, D. (2002). Why More is Required to Address Maine's Childhood Lead-Poisoning Problem. *Maine Policy Review*.
- Littell, D. (1993). Consent and Disclosure in Superfund Negotiations. *Harvard Environmental Law Review*.
- Littell, D. (1991). The Omission of Materials Separation Requirements from Air Standards for Municipal Waste Incinerators: EPA's Commitment to Recycling Up in Flames. *Harvard Environmental Law Review*.

MEDIA ENERGY AND ENVIRONMENTAL SOURCE

- As a former PUC and DEP Commissioner with substantial regulatory and sector expertise, Mr. Littell is a frequent source of media expertise on energy, climate, and environmental matters
- For example, https://www.pressherald.com/2021/04/17/mills-has-chance-to-fill-key-energy-post-as-lepage-appointees-puc-term-ends/?utm_source=Press+Herald+Newsletters&utm_campaign=b2a53d7fb6-PPH_Daily_Headlines_Email&utm_medium=email&utm_term=0_b674c9be4b-b2a53d7fb6-199774569&mc_cid=b2a53d7fb6&mc_eid=59ab4e9f7b

PROFESSIONAL AFFILIATIONS

- NEG/ECP, Co-Chairman, New England Governors/Eastern Canadian Premiers Committee on the Environment, 2006-2007
- Chairman, New England Governors Committee on the Environment, 2006-2007
- RGGI, Chairman, vice chair (2x) and treasurer, Regional Greenhouse Gas Initiative, 2008-2015
- NARUC, Vice chair, National Association of Regulatory Utility Commissioners' Task Force on Environmental Regulation and Generation, 2012-2015
- NRRI, Board of Directors, National Regulatory Research Institute, 2012-2015
- The Climate Registry (TCR), Executive Board, Carbon Registry, 2010-2015
- MANE-VU, Chairman, Mid-Atlantic/Northeast Visibility Union, 2006-2010, which developed the Northeast and Mid-Atlantic States' Regional Haze compliance plan under the Clean Air Act

COMMUNITY INVOLVEMENT

- Maine Audubon, Board Chair, Executive Committee, Strategic Planning Committee, 2014-present
- Portland Trails, former Board President and vice president, board member, 1996-2005, Current Advisory Board Member
- Maine Lake Stewardship Program, Advisory Board Member, 2015-2018
- Lovell Land Trust, Trail Steward
- The Climate Registry, former Executive Committee and board member

- St. Ansgar Lutheran Church, former council member, congregation member

SELECTED HONORS AND AWARDS

- Distinguished Policy Scholar, University of Maine, Orono (2010), recognized for work as Maine's environmental commissioner on habitat protections, the Regional Greenhouse Gas Initiative, product stewardship, and consumer toxics protections
- Leadership Maine (2009-2010), Rho class
- Public Service for the Environment Award by the Sierra Club, Maine Chapter, (2015), for work on the Regional Greenhouse Gas Initiative and as environmental commissioner
- Environmental Achievement by Maine Audubon (2007), for implementation of significant wildlife habitat protections for vernal pools, wading bird, waterfowl, and shorebird habitats, which protected approximately two million acres of these habitats

THE STATE OF NEW HAMPSHIRE
BEFORE THE
NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

TESTIMONY OF

R. Thomas Beach
on behalf of
Clean Energy New Hampshire

CONSIDERATION OF CHANGES TO THE CURRENT NET METERING TARIFF STRUCTURE, INCLUDING COMPENSATION OF CUSTOMER-GENERATORS

Docket No. DE 22-060

December 6, 2023

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THE STATE OF NEW HAMPSHIRE
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NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

DIRECT TESTIMONY OF
R. Thomas Beach on behalf of Clean Energy New Hampshire

CONSIDERATION OF CHANGES TO THE CURRENT NET METERING TARIFF STRUCTURE, INCLUDING COMPENSATION OF CUSTOMER-GENERATORS

Docket No. DE 22-060

December 6, 2023

I. INTRODUCTION

Q: Please state your name, business address and position.

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q: Please describe your experience and qualifications.

A: My experience and qualifications are described in the attached *curriculum vitae*, which is **Attachment RTB-1** to this testimony. As reflected in my CV, I have more than 40 years of experience on rate design and ratemaking issues for natural gas and electric utilities. I began my career in 1981 on the staff at the California Public Utilities Commission (CPUC), working on the implementation of the Public Utilities Regulatory Policies Act of 1978 (PURPA). I also served as a technical advisor to three commissioners from 1984 – 1989. Since leaving the CPUC in 1989, I have had a private consulting practice on energy issues and have appeared, testified, or submitted testimony, studies, or reports on numerous occasions before state regulatory commissions in 20 states, including New Hampshire. My CV includes a list of the formal testimony that I have sponsored before this Commission and in other state regulatory proceedings concerning electric and natural gas utilities.

Q: Please describe your experience on avoided costs, issues related to net energy metering (NEM), and the cost-effectiveness of renewable distributed generation (DG) and other types of distributed energy resources (DERs).

A: I have worked on issues concerning the calculation of avoided cost prices throughout my career, including sponsoring testimony on avoided cost issues in state regulatory proceedings in California, Idaho, Oregon, Montana, Nevada, North Carolina, and Vermont. With respect to benefit-cost issues concerning renewable DG, I have sponsored testimony on NEM and solar economics in New Hampshire and ten other states. Since 2013 I have co-authored benefit-cost studies of NEM or solar DG in New Hampshire as well as Arkansas, Arizona, California, Colorado, North Carolina, South Carolina, South Dakota, and Wyoming. I also co-authored the chapter on Distributed Generation Policy in *America's Power Plan*, a report on emerging energy issues, which was released in 2013.[1] Finally, since 2007, I have sponsored testimony on rate design issues concerning solar DG in general rate case proceedings in Arizona, California, Massachusetts, and Texas.

Q: Please specify your prior testimony on NEM issues before this Commission.

A: I submitted direct and rebuttal testimony in Docket No. DE 16-576, the Commission's last major NEM proceeding, on behalf of the Alliance for Solar Choice (TASC). I also was a co-sponsor of supplemental testimony for TASC and other parties concerning the settlement reached in that docket.

Q: On whose behalf are you testifying today?

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[1] This report was designed to provide policymakers with tools (including rate design changes) to address key questions concerning distributed generation resources. It has been published in *The Electricity Journal*, Volume 26, Issue 8 (October 2013). It is also available at http://americaspowerplan.com/.

A: I am testifying on behalf of Clean Energy New Hampshire (CENH). CENH's mission is to lead New Hampshire's transition to a zero carbon economy, through renewable energy, energy efficiency and beneficial electrification.

Q: What is the purpose of your testimony in this case?

A: CENH has asked me to review the *New Hampshire Value of Distributed Energy Resources: Final Report* prepared for the New Hampshire Department of Energy by Dunsky Energy + Climate Advisors (Dunsky Report).[2] The Dunsky Report develops a model of the benefits of DERs in New Hampshire, and calculates the future rate and bill impacts of expected DER deployment in the state.

CENH is also sponsoring the direct testimony of Mr. David Littell on DER/NEM policy issues.

Q: How is your testimony organized?

A: The first section reviews the Dunsky Report's avoided cost model of the benefits of DERs. The second section modifies Dunsky's analysis of the future rate and bill impacts of expected DER deployment. The final section recommends policy changes for NEM in New Hampshire, based on the modifications that I have made to the Dunsky Report's modeling.

II. REVIEW OF DUNSKY'S MODEL OF THE BENEFITS OF DERS IN NEW HAMPSHIRE

Q: What is your overall evaluation of the Dunsky Report's avoided cost model of the benefits of DERs in New Hampshire?

A: In general, Dunsky has prepared a reasonable, credible, and comprehensive model of the benefits of DERs in New Hampshire. It is particularly important that Dunsky has modeled a comprehensive set of benefits and has forecasted those benefits over a long-term period that captures most of the expected economic life of the most common DERs

[2] The Dunsky Report is Appendix 1 to the testimony of CENH witness Mr. David Littell. Appendix 2 to Mr. Littell's testimony is the appendices to the Report.

that customers install – solar and small hydro. Dunsky also appropriately updated its work in June 2023 to reflect the higher level of avoided costs in New England in the wake of the Covid-19 pandemic, the war in Ukraine, and emerging infrastructure and supply chain constraints.[3] Finally, the Dunsky Report appropriately considers several sensitivity cases, including a high load growth case to estimate the higher avoided costs that will result if the electrification of buildings and transportation increase future electric demand.

Based on my review, I would make small but important revisions to just two of the avoided cost components of the Dunsky model – avoided line losses and avoided distribution costs. I discuss those modifications next.

A. Marginal Line Losses

Q: What is your concern with the avoided line losses that Dunsky used?

A: The line losses avoided by DERs should be evaluated on the basis of the utilities' marginal line losses, not their average losses. The goal of an avoided cost model is to calculate the costs that the utility would incur but for the presence of a kWh of energy or a kW of capacity supplied by a customer who adopts a DER technology. All of the other major components of the Dunsky model – the locational marginal price for energy, the use of the market-clearing price for generation capacity, and the calculation of marginal or avoided T&D costs – appropriately use marginal values that reflect the <u>change</u> in utility costs when a customer provides its own generation. Avoided line losses also should reflect marginal losses – that is, the change in losses due to a kWh of energy or a kW of capacity supplied by a DER. The issue with the Dunsky model is that it uses marginal losses only for the top 100 load hours and average losses for all other hours;[4] it should have used marginal losses in <u>all</u> hours.

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[3] See *New Hampshire Value of Distributed Energy Resources: Addendum*, filed June 8, 2023. This addendum is Appendix 3 to Mr. Littell's testimony.

[4] See Dunsky Report, Appendix C.9.3 (footnote 20) and C.10.3 (footnote 22): "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."

Q: How does Dunsky calculate marginal losses?

A: Dunsky assumes that marginal losses are 1.5 times average losses, citing a study from the Regulatory Assistance Project (RAP) on the avoided/marginal losses associated with another type of DER – energy efficiency.[5]

Q: Do you agree with the use of this rule of thumb for the relationship between marginal and average losses?

A: Yes. From Ohm's Law one can derive the fact that the marginal line losses in an electric circuit are double the average losses.[6] In practice, if a portion (typically about 25%) of the overall losses on a utility system are "no-load" losses associated with energizing the system, then the marginal losses equal 1.5 times average losses (i.e. 1.5 = 2 x [1 - 25%]), where average losses include both the resistive and no-load losses.[7] Here is a graphic comparison of average and marginal line losses from the RAP Line Loss Study cited by Dunsky, for a hypothetical utility with an average annual resistive loss of 7% on its system, and 25% no-load losses. Note that marginal line losses are as high as 20% in the system peak hour, and marginal losses are about 1.5 times average losses <u>in every hour</u>, not just in the top 100 hours.[8]

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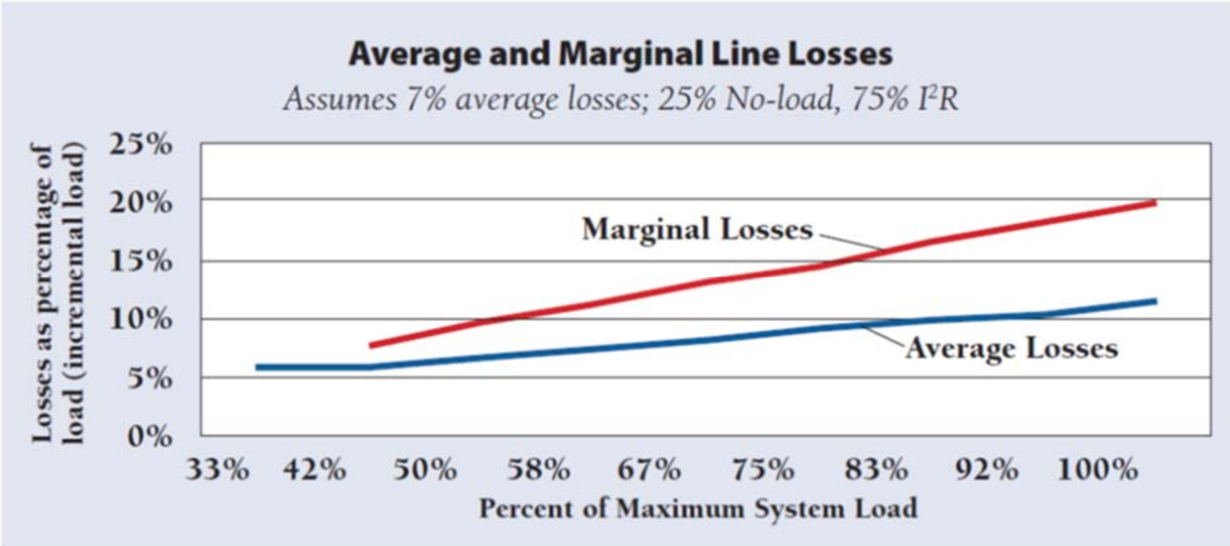
[5] See Lazar and Baldwin, Regulatory Assistance Project, *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements* (August 2011), hereafter "RAP Line Loss Study."

[6] See **Attachment RTB-2** for this derivation. This is widely cited in the literature on the treatment of line losses in utility systems. See RAP Line Loss Study, at page 5: "Mathematically, the formula I^2R reduces the marginal resistive loses to a calculation. At any point on the load duration curve, marginal resistive loses are two-times the average resistive losses at that same point on the load duration curve." See https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf.

Also, Brent Eldridge, Richard P. O'Neill, and Anya Castillo, *Marginal Loss Calculations for the DCOPF, FERC Technical Report on Loss Estimation* (January 24, 2017), at p. 3: "Since losses are approximately quadratic, marginal losses are about twice the average losses."

[7] See RAP Line Loss Study, at p. 5.

[8] *Id.*, at p. 4 (Figure 3).



Assuming that marginal losses are 1.5 times the system average losses across all hours is a conservative (i.e. low) assumption for a DER such as solar, because much of the solar output occurs in the afternoon hours when system loads, and losses, are higher than average.[9] This is an acceptable approximation given that avoided line losses are a relatively small component of the avoided cost value stack.

B. Avoided Distribution Capacity Costs

Q: What are your concerns with the avoided distribution capacity costs used in the Dunsky Report?

A: First, the Dunsky Report is not clear on the nature of the distribution investment data used for this avoided cost component. The report itself says that it calculated the "system-wide avoided cost only," and did not use the locational data on load-related distribution upgrades developed in the Locational Value of Distributed Generation (LVDG) study completed by Guidehouse in 2020.[10] Appendix C.7.3 to the Dunsky

[9] *Id*: "incremental losses during the critical peak period are much larger than the average losses over the year."

[10] Dunsky Report, at p. 10: "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." The LVDG study is included as Appendix 4 to Mr. Littell's testimony.

Report states that the report "[a]ssess[es] actual and planned distribution-related capital expenditures, by utility, to determine which expenditures are load-related." The report provides no indication of how Dunsky ascertained which future distribution capital expenditures were load-related. In discovery, CENH asked the utilities for the distribution investment data that they provided to Dunsky, but did not receive consistent or well-documented data.[11] Generally, it appears that it was the utilities that decided which of their distribution investments were "load-related."[12] Further, despite the statement in the report that these avoided distribution capacity costs were calculated "by utility," the Dunsky Report uses the same avoided distribution capacity cost for all three utilities.

Q: What is your concern with having the utilities segregate out those upgrades that are "load-related"?

A: The problem is that there are no clear standards for this "bottom-up" exercise of categorizing specific distribution investments as "load-related," as distinct from other possible categories such as "reliability-related" or "asset-life-related" or "policy-related" (to state policy goals such as interconnecting renewables to achieve RPS requirements). Load growth is often an indirect or secondary factor in many types of distribution expansions and upgrades. For example, an upgrade may be required for reliability reasons to address contingencies that arise under high-load conditions, or to access new generation resources needed to serve growing peak demands. Even asset replacement projects are demand-related in that they are necessary to keep the grid's capacity from declining, and the replacement facilities may have more capacity than the old equipment. Although peak demand may not be the primary driver of any of these types of upgrades, it may be a secondary driver, and demand has a significant overall influence on the need to invest in grid infrastructure in general. The grid is an integrated network, and thus all

[11] Liberty provided a list of future capacity-related distribution upgrades, but no costs. Unitil's response appears to indicate that it only provided LVDG data to Dunsky, with one minor exception.

[12] For example, Eversource provided Dunsky with its annual investments in "peak load/capacity" distribution upgrades from 2016-2022. These are far smaller than the distribution plant additions that Eversource expects to make from 2023-2027. See Eversource responses to CENH DR 1-5 (confidential) and 1-7 (public).

types of additions to the networked grid may contribute to serving peak demands. Categorizing only certain investments as "load related" or "capacity-related" is likely to understate how transmission costs change as a function of demand.

Q: How do you address this issue in the calculation of avoided distribution capacity costs?

A: A better approach is to use a "top-down" calculation that looks at the long-term change in the utility's overall distribution investments as a function of load growth. To calculate the utilities' avoided transmission capacity costs, I have used a well-accepted regression method. This approach is used by a number of U.S. utilities to determine their long-run marginal transmission or distribution capacity costs that vary with changes in load.[13] The regression model fits incremental transmission or distribution investment additions to peak load growth over time. The slope of the resulting regression line provides an estimate of the marginal cost of transmission or distribution investments associated with changes in peak demand. This marginal cost can be annualized using a real economic carrying charge. The methodology typically uses 15-20 years of data on transmission or distribution investments and annual peak system loads, as reported in FERC Form 1. A portion of this data can be forecast data – for example, for the next 5 years. However, performing this regression analysis on past investments, using FERC Form 1 data, eliminates the uncertainty of forecast data. The regression separates out the influence of load across all of the utility's transmission or distribution investments.

Q: Have you used this approach to calculate the current marginal distribution costs for the New Hampshire utilities?

A: Yes. The results are shown in the first line of **Table 1** below. This approach includes an adder for distribution O&M costs, based on FERC Form 1 data, to capture the ongoing operating costs for marginal distribution investments. As a result, this calculation also incorporates Dunsky's separate component for avoided distribution operating costs.

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[13] For example, Southern California Edison has used this approach for many years to calculate its marginal distribution costs in California regulatory proceedings. See CPUC Application A. 20-10-012, at Exhibit SCE-02, pp. 27-32.

Q: Dunsky's model allocates marginal distribution costs to the hours of the year based on system loads in the top 100 load hours. Do you agree with this allocation?

A: Dunsky's allocation is a reasonable, simple-to-apply approach that appears to capture most of the hours in which distribution circuits peak. Nonetheless, based on my experience with this issue in prior studies, I recommend a more accurate approach of using available substation load data to capture a more granular allocation that considers when various portions of a utility's distribution system peak. To do this, I developed an allocation based on a set of hourly "peak capacity allocation factors" ("PCAFs") derived from recent hourly data on distribution substation loads for each utility.[14] The PCAFs are based on hourly substation loads that are within 10% of the annual peak load at each substation, using this formula:

$$PCAF_s(h) = \frac{(Load_s(h) - Threshold_s)}{\sum_{k=1}^{8760} Max[0, (Load_s(k) - Threshold_s)]}$$

where:

$PCAF_s(h)$ = peak capacity allocation factor for substation *s* in hour *h*,
$Load_s(h)$ = the load for substation *s* in hour *h*, and
$Threshold_s$ = 90% of the substation *s* annual peak load.

All hours where the substation load is below 90% of the annual peak are excluded from the calculation of hourly PCAFs. The loads above 90% of the annual peak are weighted by how much each hour's load exceeds the threshold of 90% of the annual peak.[15] This gives the greatest weight to the annual peak load hour at each substation. The combined

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[14] Eversource, Liberty, and Unitil provided hourly load data from 2022 for 51, 6, and 2 substations, respectively.

[15] This approach has been used in the Avoided Cost Calculator (ACC) model of the benefits of DERs developed by Energy and Environmental Economics (E3), and approved by the CPUC for use in DER-specific proceedings in California. See the documentation for the 2022 ACC (version 1b), at pp. 51-52, 61, and 99-108 (Appendix 14.5), discussing the use of PCAF allocations for avoided transmission and distribution costs, available at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/idsm.

hourly profile of PCAFs across all of the utility's substations is used to allocate the utility's marginal distribution capacity costs to each hour.[16] This is the revised set of avoided distribution capacity and O&M costs that I recommend replace the corresponding costs in the Dunsky model.

Figure 1 provides a 12-months-by-24 hours heat map of the PCAF-based distribution of avoided distribution costs for Eversource.

Figure 1: *PCAF-based Allocation of Avoided Distribution Costs for Eversource*

Hr\Mo	1	2	3	4	5	6	7	8	9	10	11	12	Total
1	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%
3	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%
5	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%
7	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%	0%	0%
9	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
10	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
11	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%
12	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	3%
13	0%	0%	0%	0%	0%	0%	2%	2%	0%	0%	0%	0%	4%
14	0%	0%	0%	0%	0%	0%	3%	5%	0%	0%	0%	0%	8%
15	0%	0%	0%	0%	0%	0%	2%	6%	0%	0%	0%	0%	8%
16	0%	0%	0%	0%	0%	0%	4%	9%	0%	0%	0%	0%	13%
17	0%	0%	0%	0%	0%	0%	4%	7%	0%	0%	0%	0%	12%
18	0%	0%	0%	0%	0%	0%	5%	8%	0%	0%	0%	1%	15%
19	1%	0%	0%	0%	0%	0%	7%	8%	0%	0%	0%	0%	17%
20	0%	0%	0%	0%	0%	0%	4%	4%	0%	0%	0%	0%	10%
21	0%	0%	0%	0%	0%	0%	1%	2%	0%	0%	0%	0%	4%
22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total	**6%**	**0%**	**0%**	**0%**	**0%**	**2%**	**34%**	**52%**	**0%**	**1%**	**0%**	**4%**	**100%**

The PCAF allocation in Figure 1 should be compared to the similar heat map of Dunsky's allocation using the top 100 hours, which is in Appendix C.7.3. The two allocations are similar, with the bulk of avoided distribution costs allocated to afternoon hours in July and August, with a small allocation to evening loads in December and January. The PCAF allocation is more focused on hours later in summer afternoons and also has a small allocation to early morning hours in January. When the Dunsky allocation is applied to a typical solar profile, one kW (nameplate) of solar avoids about 0.51 kW of distribution capacity. This is the capacity contribution or "load match" of

[16] The PCAF allocations at each individual substation are combined using a weighted average based on the annual peak load at each substation.

solar PV to avoiding distribution capacity. The second line of Table 1 shows that, using the PCAF approach applied to substation load data, the comparable PV load matches for the three utilities are lower for Eversource (0.41) and Unitil (0.38) and somewhat higher for Liberty (0.56).

The last three lines of Table 1 complete the derivation of the average avoided distribution capacity and O&M costs for the three utilities, expressed in $ per MWh of solar output.

Table 1: *Avoided Distribution Capacity Costs (includes Avoided O&M)*

Avoided Cost Component	Utilities		
	Eversource	Liberty	Unitil
Marginal Distribution Costs ($/kW-year)	141.12	109.37	99.55
x Effective PV Load Match using Distribution Substation PCAFs	0.411	0.564	0.382
= Distribution Capacity Cost ($/MWh)	58.00	61.68	38.03
÷ Solar Output (kWh per kW-AC)	1,479	1,479	1,479
= Avoided Distribution Capacity ($/MWh)	**39.21**	**41.71**	**25.71**

Q: Can you please summarize your findings on the avoided costs modeled by Dunsky?

A: Yes. The Dunksy avoided cost model undervalues avoided line losses by using marginal line losses only in the top 100 hours. The model also undervalues the marginal costs of distribution capacity and O&M costs, by assuming that a too-small portion of utility investments in distribution are driven by load. On the other side of the coin, the model's use of the top 100 hours to allocate marginal distribution costs across the hours of the year results in PV load match percentages that are too high for Eversource and Unitil, compared to a more accurate method based on granular substation load data. I will assess the impacts of these recommended changes to the avoided cost model in the next section, in which I discuss Dunsky's Rate and Bill Impact analysis.

III. REVIEW OF DUNSKY'S RATE AND BILL IMPACT ANALYSIS

Q: Please describe Dunsky's rate and bill impact (RBI) analysis.

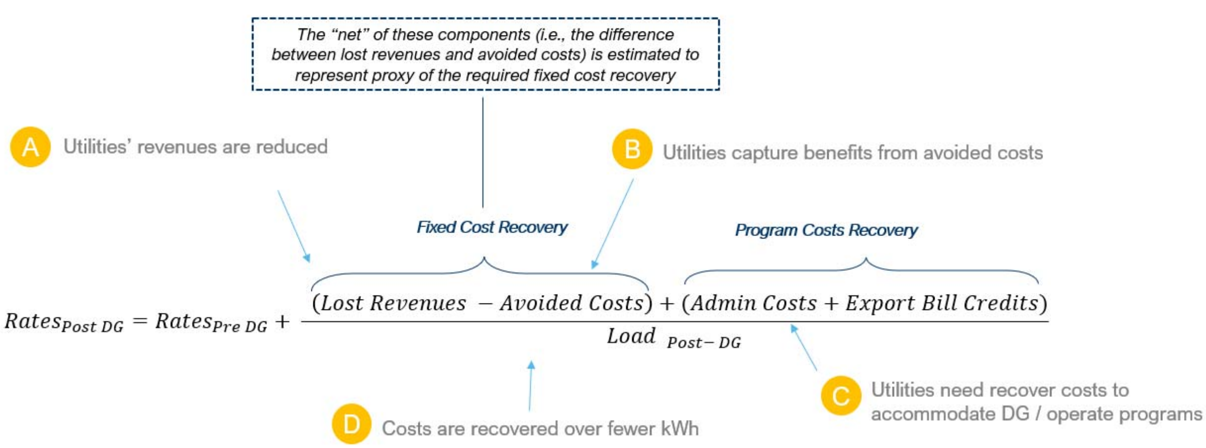
A: Dunsky's RBI assessment is designed to show the impacts on utility ratepayers of future distributed generation (DG) deployment in New Hampshire, considering both the benefits received and the costs incurred by the utilities as a result of incremental DG additions. Dunsky limited its RBI analysis just to solar PV systems. Dunsky shows the rate and bill impacts of forecasted solar deployment on all ratepayers, on non-participating customers, and on DG customers who adopt solar. Dunsky reports these impacts as the average change in customers' rates and bills over the 15-year period from 2021-2035 as a result of solar DG deployment, compared to a case in which none of this new DG is deployed.

Q: Did Dunsky provide a version of their RBI analysis that uses their updated avoided costs in the June 2023 addendum to their report?

A: No, they did not. I have added those updated avoided costs to Dunsky's RBI analysis.

Q: Do you concur with the conceptual framework that Dunsky used in its RBI analysis?

A: Generally, yes. I agree with the formula that Dunsky uses for the rate impacts of DG solar, as shown in this graphic from Section 2.6.3 of the Report.



Q: Did your review of Dunsky's RBI analysis identify any specific issues of concern with portions of the analysis?

A: Yes. My review turned up a number of inconsistencies and possible problems in the RBI spreadsheet model.

- **Use of a different solar profile than in the Dunsky avoided cost model.** In our judgment, the solar profiles used in Dunsky's avoided cost model are reasonable and align with other standard calculators for solar PV output, such as the National Renewable Energy Lab's PVWATTS calculator. However, the RBI spreadsheet uses a different solar profile that is inconsistent with the solar profiles in the avoided cost model and that appears incorrectly to shift solar output to an earlier time of day. The RBI analysis should use the same solar profiles used in the avoided cost model.

- **Use of incomplete or double-counted avoided costs.** The RBI spreadsheet includes a series of flags to designate which avoided costs should apply to future DG. The RBI model that aligns with the results shown in the Dunsky Report does not appear to credit solar DG for avoided generation capacity or DRIPE costs, and it double-counts the avoided risk premium. Excluding or double-counting these avoided costs in the RBI analysis will not value solar DG correctly.

- **Calculation of lost revenues using incorrect export rates.** The calculation of export credits in the Dunsky RBI spreadsheet uses the full volumetric rate as the export credit, and thus fails to pick up the fact that, under the current NEM structure, monthly net exports are priced at less than full retail rates. For residential and small commercial customers (under 100 kW), the export price includes 100% of the generation and transmission rates, but only 25% of the distribution rate. For large commercial customers (over 100 kW), the export rate is limited to only the generation rate component.

- **Assumption that commercial solar customers can avoid demand charges.** The Dunsky RBI analysis calculates lost revenues assuming that commercial customers who install solar can make meaningful reductions in the demand charges that they pay. However, in practice it is difficult for commercial solar customers to reduce their demand charges.

  Dunsky models this reduction in demand charges based on solar's contribution to reducing the coincident peak demands of the New Hampshire utilities. However, this significantly overstates the likely demand charge cost reduction that solar customers can achieve. For some customers, there may be no reduction in demand charges. Commercial demand charges are typically calculated based on the customer's maximum load (in kW) at any time during the monthly billing period, with loads calculated over 15-minute or 30-minute intervals.[17] For example, the coincident peak day in a summer month is likely to be a hot, relatively sunny day with significant solar output. The commercial solar customer's system output is likely to be high on that day, and thus the customer's maximum demand (in kW) on that day may be low. So that peak day is unlikely to be the day which sets the customer's maximum demand for the month, for which the customer is billed a demand charge. The commercial solar customer is most likely to set its maximum demand for the month on a cloudy day when the output of its solar system is low. As a result, the commercial solar customer may achieve little or no demand charge savings.

The essential problem with monthly demand charges is that the solar customer actually may avoid significant demand-related costs – for example, the solar customer's low demand on the coincident peak day may avoid significant generation capacity and transmission costs. However, those savings will not be recognized if the customer pays for those costs in a much higher demand charge for the month based on its higher demand on a cloudy day (when system demands are low).[18]

Commercial rates also can have demand charge "ratchets" based on prior months' loads that bill the customer for a percentage of their highest load over a recent historical period, if that exceeds the current month's maximum load.[19] Demand ratchets essentially impose a floor on the demand reductions that a customer can achieve.

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[17] Eversource, for example, uses the maximum demand averaged over a 30-minute period to assess demand charges in its Rate G and Rate LG commercial schedules.

[18] This issue has been demonstrated and addressed, for example, in California, where the CPUC approved a series of commercial rate designs for the three major California investor-owned utilities with reduced demand charges (replaced with higher volumetric time-of-use rates) that are available to commercial customers who install solar DG. See CPUC Application A. 12-12-003, *Prepared Direct Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association*, served May 10, 2013. Also see CPUC Decision No. 14-12-080, adopting "Option R" rates with reduced demand charges for Pacific Gas & Electric's commercial solar customers, at p. 20:

> "We are persuaded by SEIA's arguments that the current demand charge structure unfairly charges solar customers more for coincident demand related capacity costs than they actually cause PG&E to incur. SEIA's analysis clearly demonstrates that for the five customers chosen by PG&E for its analysis, individual customers' maximum peak period demands did not coincide with the monthly summer peak demands on PG&E's system. Moreover, the average peak period loads were significantly lower than the highest loads for which these customers were billed."

[19] For example, Eversource's LG rate has such a demand ratchet that effectively imposes a minimum demand charge each month linked to a percentage of the customer's maximum demand over the prior 11 months.

- **9.54% factor applied to both avoided transmission costs and transmission lost revenues.** The Dunsky RBI model applies this factor to both the avoided transmission costs and transmission lost revenues, dramatically reducing both. Dunsky says that "the rate impacts assessment assumes only the portion [of transmission costs] attributable to the New Hampshire load as a percentage of the ISO-NE system, which is approximately 9.54%."[20] But New Hampshire ratepayers pay in their rates for 100% of the New England transmission costs allocated to them, and they can avoid 100% of New England ISO transmission charges allocated to the New Hampshire utilities if they reduce their demand during the hours when transmission costs are assessed. This is what is correctly assumed in Dunsky's avoided cost model, but not in its RBI analysis. This 9.54% factor should be eliminated.

In addition, the Dunsky RBI model predates the joint testimony of the utilities proposing, in concept, application fees for new NEM participants. The utilities then supplemented their testimony in discovery, providing a straw proposal for such fees. As discussed in Mr. Littell's testimony, CENH does not oppose the implementation of reasonable application fees, provided the utilities also commit to providing timely service in interconnecting DG customers. An application fee would provide a revenue stream to offset some of the program administration costs included in the Dunsky RBI analysis.

Q: Have you re-calculated Dunsky's RBI results based on all of the issues you have identified in your testimony?

A: Yes. My revised RBI results use (1) Dunsky's updated avoided costs, (2) modifications to address the inconsistencies and problems in the RBI analysis noted above, and (3) revenues from an application fee (based on the utilities' straw proposal), then add (4) marginal line losses in all hours, and finally incorporate (5) the revised avoided distribution costs presented in Table 1 above (with a PCAF-based allocation across hours). **Table 2** shows the cumulative impacts of each of these changes, in terms of the average bill impacts on non-participating Eversource ratepayers over the years 2021-2035, when these changes are made, step by step, to the Dunsky RBI analysis.

Several points about Table 2 need to be emphasized, so that what the table shows is clear. First, the bill impacts shown in the table represent the average change in

[20] See Dunsky Report, at Appendix F.2.2.

customers' bills over all 15 years (2021-2035), compared to a No DG case in which incremental solar DG is not deployed. Second, the starting points for showing the impacts of these changes are the bill impacts on non-participating Eversource ratepayers shown in Figure 30 of the Dunsky Report.[21] These are shown in the first line of the table. Table 2 then makes the successive changes to the RBI analysis shown in the subsequent lines; each line shows the cumulative impact of the change listed in that line plus all of the changes in the preceding lines. Thus, the impacts shown in the bottom line ["Changes to avoided costs"] of the table include all of the changes we made to the RBI analysis. The bottom-line result of these changes is a small reduction of 1% to 2% in the rate and bill impacts for non-participating Eversource customers, compared to Dunsky's RBI analysis.

Table 2: *Impact of Changes to RBI Analysis – Non-participating Eversource Customers*
NOTE: Results in each row include the impacts of all changes made in the prior rows.

Issues		**2021 – 2035 Bill Impact (%)**		
		Residential	SG	LG
Start:	Start: Dunsky RBI analysis – Figure 30	+ 1.03%	+ 0.46%	+ 0.84%
Changes:	Updated avoided costs	+ 0.80%	+ 0.33%	+ 0.68%
[Results in each row include all prior changes.]	Solar profile from avoided cost model	+ 0.44%	+ 0.11%	+ 0.45%
	Use complete avoided costs	+ 0.07%	- 0.10%	+ 0.17%
	Corrected export rates	- 0.05%	- 0.13%	+ 0.17%
	No avoided demand charges	n/a	- 0.31%	- 0.37%
	Remove 9.54% factor on Transmission	-0.27%	- 0.56%	- 0.88%
	Add application fee revenues	- 0.29%	- 0.57%	- 0.88%
	Changes to avoided costs: • Marginal line losses in all hours • Avoided distribution costs (Table 1)	- 0.51%	- 0.70%	- 1.05%

[21] The bill impacts on non-participating Eversource Large General (LG) customers shown in Figure 36 is + 0.5%. The version of the Dunsky RBI analysis that CENH received in discovery showed a bill impact on LG customers of + 0.8%. This difference is unexplained. We have used the higher LG bill impact as the starting point in Table 2.

I have performed analyses similar to the one shown in Table 2 for Liberty and Unitil. The bottom-line results for all three utilities are presented in Table 3, showing the bill impacts after making all changes to the RBI analysis discussed in my testimony.

Table 3: *Impact of Changes to RBI Analysis – Non-participating Customers*

Utility	**2021 – 2035 Bill Impact (%)**		
	Residential	SG	LG
Eversource	- 0.51%	- 0.70%	- 1.05%
Liberty	+ 0.30%	- 0.15%	- 1.07%
Unitil	+ 0.19%	- 0.14%	- 0.08%
Average	**- 0.4%**	**- 0.6%**	**- 0.9%**

Note: **Table 3** includes all **Table 2** changes for each utility. Average results are weighted by each utility's sales.

Table 3 shows that, when all of these changes are made, the result is that future DER deployment in New Hampshire will result in small <u>decreases</u> in the rates and bills for all non-participating commercial ratepayers and for Eversource's non-participating residential customers. There would be slight rate and bill increases for the non-participating residential customers of Liberty and Unitil. On average statewide, across all three utilities, net metered DG installations will provide a small net benefit to customers, including to customers who do not install solar. Although the changes that I have made to the Dunsky RBI analysis have small impacts, they do reverse the findings of the Dunsky Report that future DER development would result in slight rate and bill increases for non-participants. My revisions support a conclusion that future DER deployment in New Hampshire will result in slight rate and bill decreases for most non-participants.

IV. IMPACTS OF RECOMMENDED CHANGES TO NET METERING

Q: In light of the results of your analysis, what adjustments could be made to NEM policy in New Hampshire?

A: CENH has asked me to assess whether adjustments to the current design of the export rates paid to solar customers could be made, without burdening non-participating ratepayers, in order to provide a stronger incentive for customers to adopt DERs. I used our revised version of the RBI model to assess the bill impacts on non-participating ratepayers if export rates for all customers – residential and small & large commercial – were set at the full volumetric retail rate for each class, assuming all of the changes modeled in Table 2. Those bill impacts are shown in **Table 4** below, for all three utilities. On average statewide, non-participating ratepayers in all three rate classes would continue to realize small net bill reductions after this change in policy to return to full retail NEM based on all volumetric rate components for each class.

Table 4: *Impact of Full Retail NEM – Non-participating Customers*

Utility	2021 – 2035 Bill Impact (%)		
	Residential	SG	LG
Eversource	- 0.27%	- 0.64%	- 1.04%
Liberty	+ 0.53%	+ 0.08%	- 1.05%
Unitil	+ 0.40%	- 0.10%	- 0.08%
Average	**- 0.1%**	**- 0.5%**	**- 0.9%**

Note: **Table 4** includes all of the **Table 2** changes for each utility, plus full retail NEM. Average results are weighted by each utility's sales.

Q: Does Mr. Littell's policy testimony for CENH recommend the use of full volumetric export rates to compensate solar DG customers?

A: No, it does not. Mr. Littell recommends a continuation of monthly netting for residential and small commercial customers, with export rates for residential and small commercial customers set using 100% of generation and transmission rates and 50% of distribution rates. He also recommends that large commercial customers should continue to have their imports and exports netted on an hourly basis, with the export rate set at the sum of [a] 100% of the default generation rate; [b] 50% of the volumetric distribution rate; and [c] a volumetric ($ per kWh) transmission adder of 50% of the avoided transmission costs for a solar profile in each year from 2021-2035 as determined by the Dunsky avoided cost model. This transmission adder averages $0.024 per kWh from 2021-2035.[22] In particular, the transmission adder recognizes that solar customers are likely to avoid

[22] This avoided transmission cost is also in real dollars, so it should be escalated with inflation over time.

transmission costs, but, as discussed above, are unlikely to be able to reduce the transmission-related demand charges that they are billed by utilities such as Eversource.

Q: Have you modeled the rate and bill impacts of Mr. Littell's proposal on non-participating customers?

A: Yes, I have. They are presented in **Table 5**.

Table 5: *Impact of CENH Proposal – Non-participating Customers*

Utility	**2021 – 2035 Bill Change (%)**		
	Residential	SG	LG
Eversource	- 0.43%	- 0.68%	- 1.04%
Liberty	+ 0.38%	- 0.07%	- 1.06%
Unitil	+ 0.26%	- 0.12%	- 0.08%
Average	**- 0.3%**	**- 0.6%**	**- 0.9%**

Note: **Table 5** includes all of the **Table 2** changes for each utility, plus export rates for residential and SG that include 100% of generation and transmission rates and 50% of distribution rates. Export rates for LG customers use 100% of generation rates, 50% of volumetric distribution rates, plus 50% of avoided transmission costs for solar. Average results are weighted by each utility's sales.

Q: Does this complete your direct testimony?

A: Yes, it does.

Attachment RTB-1

Experience and Qualifications

of

R. Thomas Beach

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the U.S., and Canada.

Since 1989, Mr. Beach has had an active consulting practice on policy, economic, and ratemaking issues concerning renewable energy development, the restructuring of the gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning independent power generation. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of the Public Utilities Regulatory Policies Act of 1978.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning Renewable Portfolio Standard programs, including program structure and rate impacts. He has also worked for the solar industry on rate design and net energy metering issues, on the creation of the California Solar Initiative, as well as on a wide range of solar issues in many other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, standby rates, greenhouse gas emission regulations, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

   - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

   - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

   - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

   - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

   - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar thermal power plants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

   - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

   - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

   - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

   - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

- *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

- *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

- *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

- *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

- *Natural gas rate design issues; rate parity for solar thermal power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

- *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

- *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

- *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    - *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

    - *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

    - *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

    - *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

    - *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

    - *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

    - *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

    - *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

    - *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

    - *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

    - *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

    - *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

    - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

    - *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

    - *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

    - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

- *Electric rate design issues that impact customers installing solar photovoltaic systems.*

63. a. Phase II Direct Testimony on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
    b. Phase II Rebuttal Testimony on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

- *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

- *Electric rate design issues that impact customers installing solar photovoltaic systems.*

67. Prepared Rebuttal Testimony on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

- *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

    - *Local reliability benefits of a new natural gas storage facility.*

69. Prepared Direct Testimony on behalf of **The Vote Solar Initiative** (A. 10-11-015—June 1, 2011)

    - *Distributed generation policies; utility distribution planning.*

70. Prepared Reply Testimony on behalf of the **Solar Alliance** (A. 10-03-014—August 5, 2011)

    - *Electric rate design for commercial & industrial solar customers.*

71. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 11-06-007—February 6, 2012)

    - *Electric rate design for solar customers; marginal costs.*

72. a. Prepared Direct Testimony on behalf of the **Northern California Indicated Producers** (R.11-02-019—January 31, 2012)
    b. Prepared Rebuttal Testimony on behalf of the **Northern California Indicated Producers** (R. 11-02-019—February 28, 2012)

    - *Natural gas pipeline safety policies and costs*

73. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 11-10-002—June 12, 2012)

    - *Electric rate design for solar customers; marginal costs.*

74. Prepared Direct Testimony on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002—June 19, 2012)

    - *Natural gas pipeline safety policies and costs*

75. a. Testimony on behalf of the **California Cogeneration Council** (R. 12-03-014—June 25, 2012)
    b. Reply Testimony on behalf of the **California Cogeneration Council** (R. 12-03-014—July 23, 2012)

    - *Ability of combined heat and power resources to serve local reliability needs in southern California.*

76. a. Prepared Testimony on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—November 16, 2012)
    b. Prepared Rebuttal Testimony on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—December 14, 2012)

    - *Allocation and recovery of natural gas pipeline safety costs.*

77. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 12-12-002—May 10, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

78. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 13-04-012—December 13, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

79. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 13-12-015—June 30, 2014)

    - *Electric rate design for commercial & industrial solar customers; residential time-of-use rate design issues.*

80. a. Prepared Direct Testimony on behalf of **Calpine Corporation** and the **Indicated Shippers** (A. 13-12-012—August 11, 2014)
    b. Prepared Direct Testimony on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—August 11, 2014)
    c. Prepared Rebuttal Testimony on behalf of **Calpine Corporation** (A. 13-12-012—September 15, 2014)
    d. Prepared Rebuttal Testimony on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—September 15, 2014)

    - *Rate design, cost allocation, and revenue requirement issues for the gas transmission system of a major natural gas utility.*

81. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (R. 12-06-013—September 15, 2014)

    - *Comprehensive review of policies for rate design for residential electric customers in California.*

82. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 14-06-014—March 13, 2015)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

83. a. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A.14-11-014—May 1, 2015)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Energy Industries Association** (A. 14-11-014—May 26, 2015)

    - *Time-of-use periods for residential TOU rates.*

84. Prepared Rebuttal Testimony on behalf of the **Joint Solar Parties** (R. 14-07-002 — September 30, 2015)

    - *Electric rate design issues concerning proposals for the net energy metering successor tariff in California.*

85. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 15-04-012—July 5, 2016)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

86. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 16-09-003 — April 28, 2017)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

87. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 17-06-030 — March 23, 2018)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

88. Prepared Direct and Rebuttal Testimony on behalf of **Calpine Corporation** (A. 17-11-009 – July 20 and August 20, 2018)

    - *Gas transportation rates for electric generators, gas storage and balancing issues*

89. Prepared Direct Testimony on behalf of **Gas Transmission Northwest LLC** and the **City of Palo Alto** (A. 17-11-009 – July 20, 2018)

    - *Rate design for intrastate backbone gas transportation rates*

90. Prepared Direct Testimony on behalf of **EVgo** (A. 18-11-003 – April 5, 2019)

    - *Electric rate design for commercial electric vehicle charging*

91. Prepared Direct and Rebuttal Testimony on behalf of **Vote Solar** and the **Solar Energy Industries Association** (R. 14-10-003 — October 7 and 21, 2019)

    - *Avoided cost issues for distributed energy resources*

92. Prepared Direct and Rebuttal Testimony on behalf of **EVgo** (A. 19-07-006 – January 13 and February 20, 2020)

    - *Electric rate design for commercial electric vehicle charging*

93. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 19-03-002 — March 17, 2020)

    - *Electric rate design issues for solar and storage customers*

EXPERT WITNESS TESTIMONY BEFORE THE ARIZONA CORPORATION COMMISSION

1. Prepared Direct, Rebuttal, and Supplemental Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. E-00000J-14-0023, February 27, April 7, and June 22, 2016).
   - *Development of a benefit-cost methodology for distributed, net metered solar resources in Arizona.*

2. Prepared Surrebuttal and Responsive Testimony on behalf of the **Energy Freedom Coalition of America** (Docket No. E-01933A-15-0239 – March 10 and September 15, 2016).
   - *Critique of a utility-owned solar program; comments on a fixed rate credit to replace net energy metering.*

3. Direct Testimony on behalf of the **Solar Energy Industries Association** (Docket No. E-01345A-16-0036, February 3, 2017).

4. Direct and Surrebuttal Testimony on behalf of **The Alliance for Solar Choice and the Energy Freedom Coalition of America** (Docket Nos. E-01933A-15-0239 (TEP), E-01933A-15-0322 (TEP), and E-04204A-15-0142 (UNSE) – May 17 and September 29, 2017).

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits on behalf of the **Colorado Solar Energy Industries Association** and the **Solar Alliance**, (Docket No. 09AL-299E – October 2, 2009). https://www.dora.state.co.us/pls/efi/DDMS_Public.Display_Document?p_section=PUC&p_source=EFI_PRIVATE&p_doc_id=3470190&p_doc_key=0CD8F7FCDB673F1043928849D9D8CAB1&p_handle_not_found=Y
   - *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits on behalf of the **Vote Solar Initiative** and the **Interstate Renewable Energy Council**, (Docket No. 11A-418E – September 21, 2011).
   - *Development of a community solar program for Xcel Energy.*

3. Answer Testimony and Exhibits, plus Opening Testimony on Settlement, on behalf of the **Solar Energy Industries Association**, (Docket No. 16AL-0048E [Phase II] – June 6 and September 2, 2016).
   - *Rate design issues related to residential customers and solar distributed generation in a Public Service of Colorado general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

1. Direct Testimony on behalf of **Georgia Interfaith Power & Light and Southface Energy Institute, Inc.** (Docket No. 40161 – May 3, 2016).

    - *Development of a cost-effectiveness methodology for solar resources in Georgia.*

EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

1. Direct Testimony on behalf of the **Idaho Conservation League** (Case No. IPC-E-12-27—May 10, 2013)

    - *Costs and benefits of net energy metering in Idaho.*

2. a. Direct Testimony on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — April 23, 2015)
   b. Rebuttal Testimony on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — May 14, 2015)

    - *Issues concerning the term of PURPA contracts in Idaho.*

2. a. Direct Testimony on behalf of the **Sierra Club** (Case No. IPC-E-17-13 — December 22, 2017)
   b. Rebuttal Testimony on behalf of the **Sierra Club** (Case No. IPC-E-17-13 — January 26, 2018)

EXPERT WITNESS TESTIMONY BEFORE THE MASSACHUSETTS DEPARTMENT OF PUBLIC UTILITIES

1. Direct and Rebuttal Testimony on behalf of **Northeast Clean Energy Council, Inc.** (Docket D.P.U. 15-155, March 18 and April 28, 2016)

    - *Residential rate design and access fee proposals related to distributed generation in a National Grid general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

1. Prepared Direct Testimony on behalf of **Vote Solar** (Case No. U-18419—January 12, 2018)

2. Prepared Rebuttal Testimony on behalf of the **Environmental Law and Policy Center, the Ecology Center, the Solar energy Industries Association, Vote Solar, and the Union of Concerned Scientists** (Case No. U-18419 — February 2, 2018)

EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

1. Direct and Rebuttal Testimony on Behalf of **Geronimo Energy, LLC**. (In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process [OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240, September 27 and October 18, 2013])

   - *Testimony in support of a competitive bid from a distributed solar project in an all-source solicitation for generating capacity.*

EXPERT WITNESS TESTIMONY BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

1. Pre-filed Direct and Supplemental Testimony on Behalf of **Vote Solar and the Montana Environmental Information Center** (Docket No. D2016.5.39, October 14 and November 9, 2016).

   - *Avoided cost pricing issues for solar QFs in Montana.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

   - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

   - *QF pricing issues in Nevada.*

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

   - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

4. a. Prepared Direct Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket Nos. 15-07041 and 15-07042 –October 27, 2015).
   b. Prepared Direct Testimony on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 1, 2016).

c. Prepared Rebuttal Testimony on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 5, 2016).

- *Net energy metering and rate design issues in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

1. Prepared Direct and Rebuttal Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. DE 16-576, October 24 and December 21, 2016).

   - *Net energy metering and rate design issues in New Hampshire.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011) http://164.64.85.108/infodocs/2011/3/PRS20156810DOC.PDF

   - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits on behalf of the **New Mexico Independent Power Producers** (Case No. 11-00265-UT, October 3, 2011)

   - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

1. Direct, Response, and Rebuttal Testimony on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014; Docket E-100 Sub 140; April 25, May 30, and June 20, 2014)

   - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

April 25, 2014: http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=89f3b50f-17cb-4218-87bd-c743e1238bc1
May 30, 2014: http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=19e0b58d-a7f6-4d0d-9f4a-08260e561443
June 20, 2104: http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=bd549755-d1b8-4c9b-b4a1-fc6e0bd2f9a2

2. Direct Testimony on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018; Docket E-100 Sub 158; June 21, 2019)

- *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

- *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

3. Direct Testimony on Behalf of the **Oregon Solar Energy Industries Association** (UM 1910,01911, and 1912 — March 16, 2018).

- *Resource value of solar resources in Oregon*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1. Direct Testimony and Exhibits on behalf of **The Alliance for Solar Choice** (Docket No. 2014-246-E – December 11, 2014)
https://dms.psc.sc.gov/attachments/matter/B7BACF7A-155D-141F-236BC437749BEF85

- *Methodology for evaluating the cost-effectiveness of net energy metering*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF TEXAS

1. Direct Testimony on behalf of the **Solar Energy Industries Association** (SEIA) (Docket No. 44941 – December 11, 2015)

   - *Rate design issues concerning net metering and renewable distributed generation in an El Paso Electric general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

1. Direct Testimony on behalf of the **Sierra Club** (Docket No. 15-035-53—September 15, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE VERMONT PUBLIC SERVICE BOARD

1. Pre-filed Testimony of R. Thomas Beach and Patrick McGuire on Behalf of **Allco Renewable Energy Limited** (Docket No. 8010 — September 26, 2014)

   - *Avoided cost pricing issues in Vermont*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

Direct Testimony and Exhibits on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011) http://www.scc.virginia.gov/docketsearch/DOCS/2gx%2501!.PDF

- *Cost-effectiveness of, and standby rates for, net-metered solar customers.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

Attachment RTB-2

Why Marginal Line losses in an Electric Circuit are Double Average Losses

What is the relationship between marginal and average line losses on an electric circuit? Consider a conductor (e.g. a wire) carrying an electric current between two terminals. Ohm's Law states that the current through the conductor is proportional to the voltage drop ($V = V_A - V_B$) across the conductor:

$$V = I \times R,$$

where V = voltage (volts), I = current (amperes), and R = resistance (ohms) of the conductor. The line losses (watts) due to heating in the circuit is equal to the voltage times the current:

$$\text{Total Line Loss} = P = I \times V = I \times (I \times R) = I^2 \times R$$

This indicates the total line loss in the conductor is proportional to the square of the total current. The voltage drop across the conductor provides an indication of the <u>average</u> line loss per unit of current, i.e. the total line loss divided by the total current:

$$\text{Average Line Loss} = P / I = I \times R$$

The <u>marginal</u> line loss for a small change in current (for example, if the voltage is increased slightly) is equal to the derivative of the total line loss with respect to current:

$$\text{Marginal Loss} = \partial P/\partial I = 2 \times I \times R$$

This shows that the marginal line losses are double the level of average line losses that occur due to resistance in the circuit. This result is widely cited in the literature on the treatment of line losses in utility systems.[23]

[23] See Lazar and Baldwin, Regulatory Assistance Project, *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements* (August 2011), at page 5: "Mathematically, the formula I^2R reduces the marginal resistive loses to a calculation. At any point on the load duration curve, marginal resistive loses are two-times the average resistive losses at that same point on the load duration curve." See https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf.

Also see Brent Eldridge, Richard P. O'Neill, and Anya Castillo, *Marginal Loss Calculations for the DCOPF, FERC Technical Report on Loss Estimation* (January 24, 2017), at p. 3: "Since losses are approximately quadratic, marginal losses are about twice the average losses."