Analysis of 2024 Net Benefits of Net Energy Billing Program

Prepared for:

Maine Public Utilities Commission

Sustainable Energy Advantage, LLC
161 Worcester Rd, Suite 503
Framingham, MA 01701
www.seadvantage.com
508.665.5850

March 31, 2025

Table of Contents

1 Executive Summary

In the 2023 Legislative session, LD 1986 "An Act Relating to Net Energy Billing and Distributed Solar and Energy Storage Systems" was enacted (the Act).[1] The Act directs the Maine Public Utilities Commission (Commission) to annually determine the net energy billing (NEB) costs and benefits of distributed generation (DG) under NEB and provide the results for the prior year in annual reports to the legislature by March 31st. The Act also requires designation of which benefits and costs are monetized and who such benefits accrue to.

The Commission has engaged Sustainable Energy Advantage, LLC (SEA) for consulting services to conduct an in-depth, structured, and comprehensive evaluation to determine the net benefits of DG under Maine's two NEB program variants (the kilowatt hour credit program and the tariff rate program).[2] This document describes SEA's methodology and quantification of the calendar year 2024 net benefits of NEB for projects within three electric distribution companies (EDCs) service territories.

- Central Maine Power (CMP);
- Versant Power - Bangor Hydro District (Versant-BHD); and,
- Versant Power - Maine Public District (Versant-MPD).

Leveraging both public, soon to be public and confidential data sources, including the most recent relevant publicly available, New England regional avoided energy supply cost study, SEA quantified the benefits and costs of the NEB program for calendar year 2024. A graphical summary of the analysis provided in Figure 1 and a tabular summary in Table 1.

[1] See http://www.mainelegislature.org/legis/bills/getPDF.asp?paper=SP0815&item=3&snum=131
[2] Legislation describing these programs can be found at https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3209-A.html and https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3209-B.html

Figure 1 –
Calendar Year 2024 NEB Program Summary Cost and Benefit

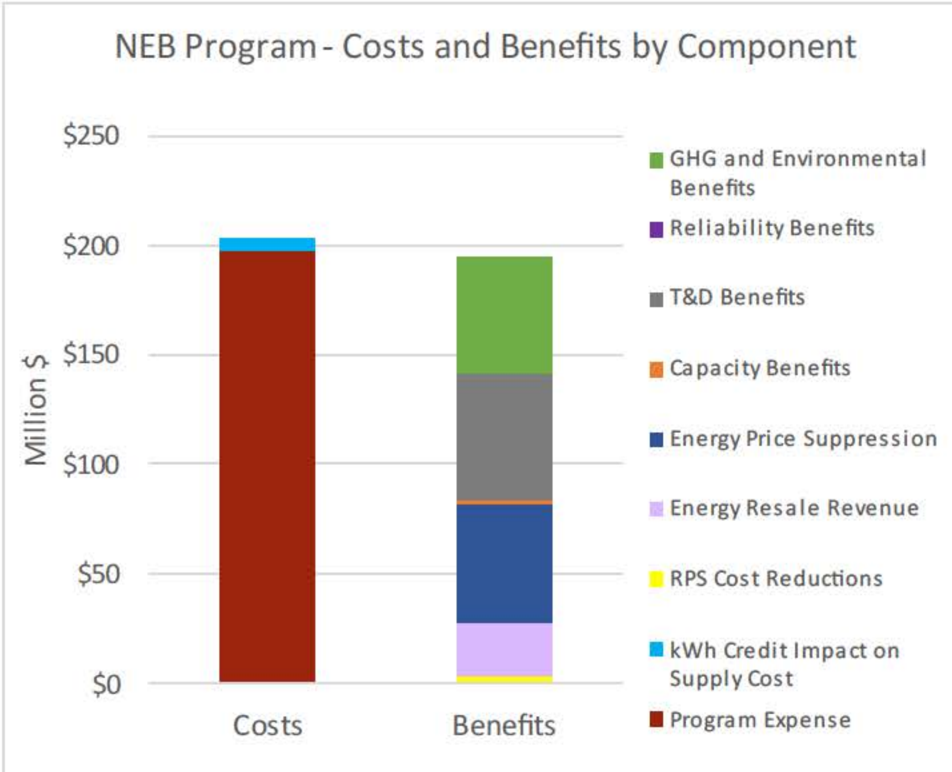


Table 1 -
2024 NEB Program Summary Cost and Benefit in Millions of Dollars

Benefit / Cost Category	Costs	Benefits
Program Expense	**$197.16**	N/A
kWh Credit Impact on Supply Cost	**$5.67**	N/A
RPS Cost Reductions	N/A	**$3.66**
Energy Resale Revenue	N/A	**$24.11**
Energy Price Suppression	N/A	**$53.51**
Capacity Benefits	N/A	**$2.35**
Transmission and Distribution (T&D) Benefits	N/A	**$57.85**
Reliability Benefits		**$0.00**
GHG and Environmental Benefits	N/A	**$53.11**
Totals	**$202.84**	**$194.58**

SEA calculates that the NEB 2024 calendar year program expenses were $202.84 million, and the program benefits were $194.58 million. Note that the cost and expenses are for all NEB projects operating in 2024. Thus, the impact of projects as old as 1994 are included in the analysis.

These results were based on recent large increases in the growth of the NEB program which ended calendar year 2024 with an installed capacity of 935.4 MW_{AC}. Likely drivers of the growth included the open-ended structure of the NEB program (i.e., no MW cap) with a substantial addressable market and favorable economics; this occurred even with the headwinds of a difficult interconnection environment.

2 Introduction

In the 2023 Legislative session, LD 1986 "An Act Relating to Net Energy Billing and Distributed Solar and Energy Storage Systems" was enacted (the Act).[3] The Maine Public Utilities Commission (Commission) is tasked per LD 1986 with providing annual reports on the net benefits of the Net Energy Billing (NEB) to the legislature by March 31st of the following calendar year. The Act also requires designation of which benefits and costs are monetized and who such benefits accrue to.

The Commission has engaged Sustainable Energy Advantage, LLC (SEA) for consulting services to conduct an in-depth, structured, and comprehensive evaluation to determine the net benefits of distributed generation under the Maine's two NEB program variants (the kilowatt hour program and the tariff rate program).[4] Working hand-in-hand with the Commission, this document describes SEA's methodology and quantification of the calendar year 2024 net benefits of the NEB program for projects within three electric distribution companies (EDCs) service territories.

- Central Maine Power (CMP);
- Versant Power - Bangor Hydro District (Versant-BHD); and,
- Versant Power - Maine Public District (Versant-MPD).

This report contains various updates to SEA's December 31, 2024 report on the costs and benefits of state-contracted solar pursuant to LD 327. These updates reflect various modeling improvements and corrections resulting from SEA's independent research and the feedback received through the Commission's Docket 2024-00149 proceeding. A discussion of updates made relative to the LD 327 report can be found in Appendix A.

2.1 LD 1986 Reporting Requirements

The Act requires the Commission to monitor the level of solar energy development in Maine in relation to the goals set forth in 35-A M.R.S. § 3474[5], as well as the basic trends in solar energy markets, and the relative costs and benefits from solar energy development, including but not limited to:

A. Revenue from the sale of renewable energy credits;
B. Societal benefits through avoided greenhouse gas emissions;
C. Reduced electricity prices; and
D. Avoided or reduced costs associated with:
    (1) Electricity capacity requirements;
    (2) Environmental compliance requirements;
    (3) Portfolio requirements established in section 3210;
    (4) Renewable energy credit price suppression; and
    (5) Electricity transmission and distribution costs.

We observe that the statutory reporting requirements listed above in this subsection notably do not include project sponsor costs (i.e., the costs to develop, install and maintain a solar project). As such we infer that the requested cost / benefit

[3] See http://www.mainelegislature.org/legis/bills/getPDF.asp?paper=SP0815&item=3&snum=131
[4] Legislation describing these programs can be found at https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3209-A.html
[5] See https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3474.html

analysis was from a programmatic basis perspective (versus a project sponsor basis). More detail on analysis perspective is provided in Section 2.4.

2.2 General Approach & Data Sources

The Act defines benefits of distributed generation under NEB and, requires the Commission to provide analysis regarding such benefits, as follows:[6]

1. Avoided energy and capacity costs. In determining avoided energy and capacity costs, the Commission must use reasonable estimates of energy and capacity market prices and account for transmission and distribution line losses. The Commission may determine different avoided costs for different time periods, including, but not limited to, peak and off-peak periods and summer and winter periods;
2. Avoided transmission and distribution costs. In determining avoided transmission and distribution costs, the Commission must use estimates of the marginal transmission and distribution costs and may determine different avoided costs for different time periods;
3. Avoided fossil fuel costs. The Commission must determine avoided fossil fuel costs based on estimated reductions in oil, gas or other fossil fuel use and estimated market prices for these fuels;
4. Avoided transmission and distribution line losses;
5. Demand reduction induced price effects (DRIPE);
6. Transmission and distribution plant extensions or upgrades funded by net energy billing customers; and
7. Any other benefits identified by the Commission.

The Act states that when determining the benefits of distributed generation under Net Energy Billing, the Commission must use any available regional avoided energy supply cost study that the Commission finds to be applicable to the determination and has been developed through a transparent process, with input from state agencies, public advocates and utilities or energy efficiency administrators from at least three other states in New England. When relevant information specific to a state is not provided in the regional study, the Commission may use the regional information in the regional study or information from other sources supported by evidence developed in the record. Given this, a majority of modeling inputs, if not available through historic data, were taken from the 2024 Avoided Energy Supply Costs in New England (AESC) study. Much of the non-AESC sourced data to support this analysis is collected by the two EDCs and then reported to the Commission in both publicly available and confidential formats. SEA, via the Commission, requested and worked collaboratively with the EDCs to access data to support the analysis herein.

The Act further defines NEB costs as all legitimate and verifiable costs incurred by a transmission and distribution utility directly attributable to net energy billing. NEB costs do not include any costs incurred by a project sponsor as defined in section 3209-A, subsection 1, paragraph D, a net energy billing customer or any other entity, as determined by the commission by rule.[7]

The Act also requires an annual report to be submitted by March 31 of each year to the Energy, Utilities and Technology (EUT) Committee of the Maine Legislature. The report must include, but is not limited to, costs authorized to be collected by transmission and distribution utilities in rates and benefits directly received by ratepayers. The Act specifies that the Commission must distinguish costs and benefits that are monetized from costs and benefits that are not monetized, and for those costs or benefits that are monetized, the Commission must specify the entities to which the monetized value

[6] See Section 5 of LD 1986, here https://www.mainelegislature.org/legis/bills/getPDF.asp?paper=SP0815&item=3&snum=131
[7] See Section 5 of LD 1986, here https://www.mainelegislature.org/legis/bills/getPDF.asp?paper=SP0815&item=3&snum=131

accrues, which may include, but are not limited to, electricity customers, electricity supply providers and transmission and distribution utilities.

2.3 Components Included in the Cost / Benefit Analysis

In Table 2 we detail our approach to quantifying the costs and benefits for solar projects for calendar year 2024 for each of the following components organized by the legislatively mandated net benefit categories presented in Section 2.1.

Table 2 –
Adopted Benefits by Legislatively Mandated Benefit Category

Legislatively Mandated Benefit Category	SEA Adopted Benefit Category
Avoided energy and capacity costs	SEA quantified the following benefits associated with avoided energy and capacity costs: • Energy resale revenue • Capacity Buyout Revenue • Uncleared Capacity Value • Reduced Share of Capacity Costs
Avoided transmission and distribution costs	SEA quantified avoided transmission upgrades and avoided distribution upgrades
Avoided fossil fuel costs	SEA assumes that avoided costs pertain to the utilization of fossil fuels at electricity generators supplying Maine retail customers. As such, our view is that these costs are fully embedded into wholesale energy prices, and in part embedded in energy capacity prices, captured above.
Avoided transmission and distribution line losses	SEA quantified avoided transmission and distribution line losses
Demand reduction induced price effects (DRIPE)	SEA quantified the following DRIPE Benefits: • Energy DRIPE • Capacity DRIPE • Cross-Fuel DRIPE • Renewable Energy Certificate (REC) price suppression
Transmission and distribution plant extensions or upgrades funded by net energy billing customers	SEA quantified assumed benefits associated with transmission and distribution plant extensions or upgrades funded by net energy billing customers
Any other benefits identified by the Commission	SEA, in coordination with the Commission, identified the following additional benefits: • Avoided/Reduced Costs Associated with RPS Requirements • Societal Benefits from Greenhouse Gas (GHG) Reduction • Avoided Environmental Compliance Costs • Improved generation reliability

2.4 Choosing a Perspective for the Net Benefits Analysis

While the Act prescribed many aspects of the required annual report (as summarized in Section 2.1), it did not prescribe the perspective of the net benefit analysis. Examples of perspectives that have been applied to related energy efficiency evaluation analyses can be found here, but importantly for this analysis the question is whether to take:

- A ratepayer impact perspective,
- A general societal impact perspective; or
- A Maine-only societal impact perspective

Given that the Act requires, at minimum, the consideration of "costs authorized to be collected by T&D utilities in rates and benefits directly received by ratepayers," a ratepayer impact perspective could be justified. However, the Act also provides the PUC with discretion to consider additional benefits which could include costs and benefits from a societal perspective.

Given this, SEA determined that a general societal impact perspective is also justified in that the impetus for many of Maine's policies promoting renewable energy (including NEB) is the reduction of GHG emissions. As the benefits GHG emission reductions are tied to global (vs. local Maine or even regional New England) GHG emission reductions, a general societal perspective, which incorporates a global perspective is justified.

Lastly, a Maine-only societal impact perspective could be justified, in that some benefits (e.g., NEB projects that lower Maine's ISO-NE coincident peak demand and thus lower its share of ISO-NE Regional Network Service transmission costs allocated to Maine ratepayers) would be included in such a perspective. Importantly, the general societal impact perspective of NEB program net benefits analysis does not include benefits from the reduction of Maine's ISO-NE coincident peak demand costs, as such a perspective views such reductions as a cost shift from Maine ratepayers to ratepayers of other New England states and so are netted out to zero. Conversely, a Maine-only societal impact perspective does not include energy price suppression impacts experienced by other states in ISO-NE.

Given the above considerations, for this report we have decided to primarily take a general societal impact perspective. As such, all our base analysis is conducted from this perspective. Nonetheless, in Section 4.3 we provide a sensitivity analysis of the Maine-only societal impact perspective in addition to the ratepayer impact perspective as compared to the general societal impact perspective.

3 Detailed Approach to Modeling

3.1 General Issues and Approach

Our analysis considered many of the idiosyncrasies of the NEB program and the Maine electricity landscape, which included:

- While most of Maine (~95% of Maine's load)[8] is within the Independent System Operator – New England (ISO-NE) footprint including CMP and Versant-BHD, Versant-MPD (~5% of Maine's load) is within the Northern Maine Independent System Administrator (NMISA) footprint for which there is no comprehensive, publicly available, regional avoided energy supply cost study, as AESC only covers ISO-NE. At times we adapt ISO-NE analysis to apply to the Versant-MPD service territory.
- The NEB program is comprised of two program variants:

[8] See the "Load" tab of https://www.maine.gov/mpuc/sites/maine.gov.mpuc/files/inline-files/Standard%20Offer%20Migration%20Stats%20through%20Nov%202023.xls to make the calculation.

- The kWh Credit program, which provides kWh credits on the EDC electric bills of program participants. The kWh Credit program existed for years prior to the expansion of the NEB program to include the Tariff Rate program variant, with generators online as early as 1994. The kWh Credit program is largely dominated by solar photovoltaic (PV) projects but contains some quantity of non-solar generators. Given the dominance of solar PV in the program, and the expectation that solar PV will constitute the vast majority of installations going forward, SEA chose to focus exclusively on the benefits and costs of solar PV in the kWh Credit program. By default, kWh Credit projects are treated as load reducers, which impacts the application of benefits, as discussed in Section 3. However, SEA adjusted its methodology to reflect that generating resources over 500 kW in Versant's MPD territory are not considered load reducers, regardless of NEB program variant.[9]
- The Tariff Rate program, which provides monetary credits on the EDC electric bills of program participants. Tariff Rate projects include non-solar projects. We note that, for the purposes of calculating commercial operation date -specific benefits for non-solar projects, we assume that all hydro projects had commercial operation dates pre 2010 given SEA's understanding that hydro participating the Tariff Rate program variant were operational prior to their enrollment in the program. SEA designated the technology of each project for the purposes of categorizing project-level data by technology. For aggregated program-wide data (e.g., program costs), values were assigned by technology based on the share of production contributed by each technology for each EDCs. The Tariff Rate program variant itself has two variants.
  - The original Tariff Rate program where the monetary credits are calculated as a function of the retail rates set at the beginning of each calendar year.[10]
  - The alternative Tariff Rate program where the monetary credits are set as a fixed 2.25% annual inflator applied to the 2020 original Tariff Rate program rates. The alternative Tariff Rate is applicable to projects failing to meet certain milestone requirements and represents over 100 MW of operational capacity as of end-of-year 2024.[11]

- NEB Program generators either can be electrically connected with an EDC customer's load and, from a utility's perspective, behind the EDC customer's revenue meter (i.e., behind-the-meter or BTM) and thus physically offsetting some or all the electricity that would have been consumed from the EDC's distribution grid without the program generator. Alternatively, program generators can be connected not with an EDC customer's load, with the only electrical load being the requirements of the project itself (e.g., project lighting, inverters, communications); this load is called (project) parasitic load. If a NEB project only has parasitic load, it is electrically connected (from the EDC's perspective) in front-of-the-meter (FTM). This detail is relevant here because, while the EDCs meter the total project output for FTM projects (as the parasitic load is typically miniscule compared to gross project electricity production), the EDCs do not meter the production of BTM NEB projects (though they do measure the input and output channels with their metering and are able to calculate net consumption). As a result, our analysis and quantification approaches differ for FTM vs. BTM NEB projects. Specifically, we have confirmed with the EDCs that it is reasonable to assume all Tariff Rate projects are FTM and that kWh Credit projects are a mix of FTM (e.g., community solar projects) and BTM (e.g., residential household solar).
  - It is worth noting that, in SEA's previous analysis covering calendar year 2023, references to "BTM" in the methods section were used to refer to the portion of energy consumed on-site, rather than the full production of projects with a BTM metering arrangement. SEA has refined its approach and now refers

[9] This revision was informed by Versant's response to data request ReVI-003-006 in Docket 2024-00149.
[10] See 35-A MRSA §3209-B(5)(A), here: https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3209-B.html
[11] See 35-A MRSA §3209-B(5)(A-1), here: https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3209-B.html

specifically to BTM energy consumed on-site or exported. As such, any reference to BTM projects more generally can be understood to refer to projects with a BTM metering arrangement.

In addition to the program-specific considerations described above, SEA considered several general methodological decisions relating to cost benefit analyses of DG programs. The most significant consideration is if economic development benefits should be considered in the analysis. SEA decided not to include economic development benefits because the consideration of such benefits was not required by statute and because prior cost-benefit analysis of the NEB program conducted by Synapse Energy Economics and SEA on behalf of the DG Stakeholder Group determined that economic development benefits should not be quantified in the benefit stack but should instead be considered separately as a supplemental consideration.[12]

Given the general issues just detailed, in the following subsections for each net benefit component, we describe the

- data sources for the component,
- methodology in calculating the net benefits of the component,
- any simplifying assumptions made, and
- additional clarifying commentary as appropriate.

3.2 AESC Inputs

As discussed above, most inputs informing benefit quantification, if not provided directly by the EDCs, were derived from the AESC 2024 Study. The AESC is a forward-looking study released every three years and is the product of a study process overseen by New England regulators, state energy offices, and a team of consultants (including the prime author Synapse Energy Economics and SEA as a contributor). The study is designed to assist New England States in evaluating the cost effectiveness of policies and programs. The AESC was originally developed in the context of evaluating energy efficiency programs, but most inputs are applicable to the evaluation of renewable energy programs.

For the purposes of this analysis, SEA utilized Counterfactual #5, as it most closely approximates a future in which states pursue the development of renewable energy. According to the AESC 2024, the counterfactual models “a future in which program administrators continue to install new energy efficiency, active demand management, and building electrification resources.” Notable differences from the AESC 2021 inputs utilized in SEA’s 2023 BCA include the omission of NOx benefits. As such, these benefits (which are very small relative to other benefits quantified) were not considered in this analysis.

AESC 2024 inputs used in this analysis were translated to nominal dollars assuming a discount rate of 2% (the default assumption in AESC 2024).

3.3 Quantification of Program MW and MWh

All benefits considered in this analysis are either energy (MWh) or capacity (MW) denominated. As such, quantifying the applicable volumes of energy and capacity for each EDC, program variant, technology, and commercial operation date is a necessary first step to assessing the total benefits per segment. SEA utilized actual program volumes wherever possible in its analysis. Specific data sources, assumptions, and limitations are discussed below.

---

[12] See final report here: https://www.maine.gov/energy/sites/maine.gov.energy/files/inline-files/Final%20Report%20of%20the%20DG%20Stakeholder%20Group_with%20appendix.pdf

- **Production Data:** The approach to quantifying production varied by program variant, discussed below.
  - **Tariff Rate:** SEA received actual hourly production data for all CMP projects enrolled in the Tariff Rate program. Versant provided actual monthly production data by project for the Tariff Rate Program.
  - **kWh Credit Program:** SEA received actual monthly production data for kWh exports from both EDCs, disaggregated by rate class. Because the EDCs do not meter production used on-site of BTM NEB projects, such production was estimated by SEA based on the assumed capacity of BTM kWh Credit program projects (discussed below). Production estimates assumed a 17% AC capacity factor, an annual production degradation rate of 1%, and a de-rate to year-one production unique to each utility based on the share of capacity online in 2024 in each month. Given that a substantial portion of the MW installed in 2024 came online late in the year, SEA made various adjustments to benefit components expressed in $/MW terms (e.g., avoided T&D investments) to appropriately discount benefits to reflect that a significant portion of the projects considered in the analysis were not online during summer months in which peak load is experienced. SEA received data from utilities regarding the volume of projects assumed metered BTM. For such projects, SEA estimates energy consumed on-site separately from energy exported to the grid. Specifically, SEA assumes that 35% of energy is exported to the grid, based on the EDC data regarding actual kWh Credit program exports (which include both FTM and BTM).
- **Capacity Data:** SEA collected data on project capacities by EDC, technology, and commercial operation dates from the EDC's monthly NEB reports in Docket 2020-00199, as of December 31, 2024. SEA received data from the EDCs regarding the metering arrangement and interconnection voltage for each project, which was used to inform the applicability of certain benefit components.

3.4 Revenue from Energy Resale

Overview

Energy re-sale revenue gained by the EDCs from production provided by operational procured and NEB-enrolled projects was considered in this analysis. For the purposes of this analysis, this benefit is unique to the Tariff Rate program, as projects enrolled in the Tariff Rate program variant serve as generators in ISO-NE markets. This is distinguished from projects in the kWh Credit program that act as load reducers. This can take effect on the level of an individual EDC customer for BTM consumption of NEB production, or for the EDC as a whole for out channel export NEB production.

Data Source

EDC revenue from energy re-sale from Tariff Rate program was provided by the EDCs to SEA on a monthly basis.

Discussion

In the context of the AESC, this benefit is most similar to "avoided energy", which represents the avoided costs of having load serving entities procure energy on the wholesale market because of the energy transferred to the EDCs through participation in DG programs. However, given that FTM projects participating in the NEB program do not physically avoid the consumption of energy, in the context of the NEB Tariff Rate program variant, the analogous benefit is energy re-sale revenue.

3.5 Capacity Buyout Revenue

Overview

This benefit captures revenue received by the EDCs from NEB or procured project owners electing to buyout capacity rights from the EDC.

Data Source

Revenue collected in 2024 from capacity buyouts was provided to SEA by the EDCs.

Discussion

In the context of the AESC, this benefit is most similar to "avoided capacity", which represents the avoided cost of building or procuring capacity to meet the peak demand of the generation system. Generally, avoided capacity benefits would be a function of capacity benefits monetized by the EDCs through successfully bidding project capacity into the Forward Capacity Market (FCM). However, both CMP and Versant stated that NEB project capacity is not currently being monetized for either the Tariff Rate or kWh Credit program. However, projects in the kWh Credit program are treated as "load reducers". As such, SEA only focused on revenues from capacity buyout.

The monetization of NEB program capacity represents a potential source of untapped program benefits. However, the challenges associated with successfully bidding DG project capacity into the FCM, and the risk of penalties associated with failure to perform during a scarcity event, have generally dissuaded responsible parties from monetizing capacity rights associated with DG projects. Given this, it is SEA's expectation that potential benefits associated with monetizing capacity are modest. In addition, there are benefits from having the projects treated as load reducers, and these benefits may well outweigh the modest potential benefits of monetizing capacity (see Section 3.6).

Capacity buyout agreements differ in structure depending on the buyout agreement in question (e.g., upfront payment vs revenue share agreement). For the purposes of this analysis, SEA only considered revenues collected in 2024. As such, revenues from projects electing to pay an up-front fee for capacity buyout prior to 2024 were not included in the analysis.

Versant noted that any capacity buyout revenues collected were folded into aggregate program revenues reported to SEA (which are predominantly energy related and utilized in the "Energy Resale Revenue" component). As such, SEA did not apply separate capacity buyout revenue for Versant to prevent double counting of revenues.

3.6 Uncleared Capacity

Overview

Despite not monetizing capacity rights (e.g., not bidding project capacity into the FCM), the capacity of projects still provides benefits to ratepayers in Maine and ISO-NE more broadly via uncleared capacity value. Uncleared capacity value reflects how uncleared project capacity impacts the development of inputs to ISO New England's FCM.[13] Specifically, the impact on historical data utilized by ISO-NE of projects serving as load reducers are assumed to reduce forecasted Installed Capacity Requirement (ICR) utilized in the FCM. As such, only NEB kWh Credit projects, which serve as load reducers, accrue this benefit.

---

[13] See page 159 of 2024 AESC for a detailed discussion of such benefits, here: https://www.synapse-energy.com/sites/default/files/inline-images/AESC%202024%20May%202024.pdf

Data Source:
SEA utilized AESC 2024 (Counterfactual #5) assumptions for the value of uncleared capacity.

Discussion:
Uncleared capacity utilizes a "phase-in" and "phase-out" schedule that relates the value per MW in any given year to the resource's commercial operation date. The phase in and out is applied to reflect the lag between a resource coming online and the resource's impact influencing ISO-NE study assumptions. Specifically, the 2024 AESC assumes that benefits from uncleared capacity do not start until 5 years after their installation date. Given the limited capacity of NEB project online pre-2019, uncleared capacity benefits are modest relative to other benefit components.

3.7 Reduced Share of Capacity Costs

Overview
Resources acting as load reducers (e.g., NEB kWh Credit projects) that generate energy during Maine's monthly peak hours can reduce the share of capacity costs paid for by Maine (thereby resulting in a cost shift to other New England ratepayers). Resources that act as generator assets (which are assumed to include NEB Tariff Rate projects) do not accrue this benefit.

Data Source:
AESC 2024 inputs were utilized.

Discussion:
To calculate the estimated load reductions during peak periods resulting from NEB project production, SEA calculated the annual peak coincident MW (expressed as a percent of nameplate capacity), by comparing peak ISO-NE load (as provided by AESC 2024) to a representative production curve for solar in Maine. The representative production curve was taken from PVWatts, assuming a facility located in Southern Maine.[14] The resulting factor was used to de-rate the full value per MW-year of avoided capacity costs to a technology-specific value, based on each technology's production coincidence with peak periods.

Given that this benefit represents a shifting of costs to other regional states, it is only included as a benefit in this analysis for the Maine-only societal impact perspective and the ratepayer impact perspective.

3.8 Transmission and Distribution Benefits

3.8.1 Avoided Transmission and Distribution Investments

Overview
Distribution-connected resources that generate energy during periods of high demand could reduce future needed transmission- and distribution-level grid investments. As such, the value of such avoided investments is considered in this analysis.

[14] PVWatts is a tool developed by the National Renewable Energy Laboratory (NREL) which estimates hourly PV production based on specific locations, found here: https://pvwatts.nrel.gov/. Production estimates were scaled to result in a capacity factor of 18%, consistent with findings from the 2023 NEB BCA regarding average solar capacity factors program-wide.

Transmission benefits are applicable to all NEB projects as all projects are assumed to be connected to the distribution system. For distribution benefits, this benefit is applicable to projects connected to the distribution system that are BTM, or FTM facilities that are interconnected at secondary voltage levels given that such facilities could reduce downstream distribution-level load.

Data Source:

For transmission benefits, SEA utilized AESC 2024 assumptions specific to Maine for the value per MW-year of avoided transmission capacity. Specifically, the AESC provides separate values per MW-year of avoided transmission for intrastate transmission upgrades and transmission upgrades serving ISO-NE (which are referred to as Pooled Transmission Facilities (PTF) upgrades). For distribution benefits, SEA utilized AESC 2024 assumptions specific to Maine for the value per MW-year of avoided distribution capacity. The studies referenced by the AESC 2024 provide a range of possible values. Consistent with the AESC 2024, SEA adopted mid-point estimates. Both values were provided in 2020 dollars and were translated to 2024 dollars assuming an inflation rate of 2% (consistent with the inflation rate assumed in AESC 2024).

Discussion:

First, SEA assumed that intrastate transmission investments would be a function of the magnitude of Maine's peak load, whereas interstate investments would be a function of the ISO-NE system-wide peak. To calculate the estimated load reductions on Maine's transmission system during peak periods resulting from DG projects, SEA calculated Maine's annual peak before and after assumed NEB load reductions utilizing the AESC-provided 2024 load curve as compared to the NEB program's estimated hourly generation. Estimated hourly generation was a function of both actual hourly production (in the case of CMP's Tariff Rate Program) and estimates derived from PVWatts. This approach was designed to accurately capture the impact of diminishing marginal returns from solar load reductions, as sufficient solar generation is expected to shift peak hours to periods in which further solar production would not contribute to further peak reductions. To calculate the estimated load reductions during ISO-NE's system peak, SEA calculated coincident MW (expressed as a % of nameplate capacity), as discussed in Section 3.7. The resulting factor was used to de-rate the full value per MW-year of avoided transmission capacity to a technology-specific value, based on each technology's production coincidence with peak periods. Given that the NEB program's relative contribution to ISO-NE system-wide peak reductions is smaller as compared to intrastate peak reductions, SEA took a simplified approach.

To calculate the estimated load reductions on the distribution system during peak periods resulting from DG resources, SEA calculated the share of annual production contributing to reductions in the top 100 peak hours of the year. To do this, SEA utilized a forecast of hourly load (as provided by AESC 2024) as compared to a representative production curve for solar in Maine. The resulting factor was used to calculate a per MWh value capturing avoided distribution capacity, based on solar production's coincidence with peak periods.

For both transmission and distribution benefits, SEA considered the use of actual system peaks, as reported by ISO-NE, in 2024 as compared to actual project production (for Tariff rate projects for which hourly production data was supplied). However, given that this benefit is intended to capture the impact of load reducing resources on system planning, using weather-neutral values are more likely to approximate the assumptions in forming system planning. In practice, system planning occurs on longer time horizons than the single year focused on in this analysis. As such, it is unlikely that a single year's production would influence system planning and yield such benefits. However, when viewed in the context of the broader NEB program, which has had multiple years of projects come online (and thereby influencing system planning over longer time horizons), it is likely that such benefits would be realized. As such, the benefits contained in this report represent the share of total program benefits that could be attributed to production occurring in 2024.

3.8.2 Avoided Maine Regional Network Service Share

Overview

Resources acting as load reducers that generate energy during Maine's monthly peak hours can reduce the share of Regional Network Service (RNS) transmission costs paid for by Maine (thereby cost shift to other New England ratepayers). Tariff Rate projects do not accrue this benefit given that they do not act as load reducers.

Data Source:

SEA utilized the 2024 RNS charge as provided by ISO-NE.

Discussion:

To calculate the estimated load reductions during peak periods resulting from DG projects, SEA calculated the average 12-month coincident MW before and after estimated load reductions from the NEB program to compute the program's total contribution to peak reductions. Load reductions were estimated as a function of total kWh Credit program production multiplied by hourly scalars as provided by PVWatts. This approach was designed to accurately capture the impact of diminishing marginal returns from solar load reductions, as sufficient solar generation is expected to shift peak hours to periods in which further solar would not contribute to further peak reductions.

Given that this benefit represents a shifting of costs to other regional states, it is only included in this analysis for the Maine-only societal impact perspective and the ratepayer impact perspective. Lastly, this benefit was not applied for any project located in Versant's MPD service territory, as MPD is outside of ISO-NE and thus MPD load reduction would not accrue ISO-NE RNS related cost reductions.

3.8.3 Avoided Transmission and Distribution Line Losses

Overview

Generation from distribution-connected distributed generation can reduce the load on the transmission and distribution system. This avoids the transfer of energy across distribution or transmission lines and thereby reduces any lost energy associated with such transfer. This yields both energy and capacity related benefits.

Data Source:

To compute energy-related benefits, SEA utilized EDC-specific line losses, provided by level of service (e.g., secondary, primary, sub-transmission).[15]
To compute capacity-related benefits, SEA utilized AESC 2024 recommended transmission and distribution marginal capacity line losses, as discussed below.[16]

Discussion:

CMP's reported line losses exclude losses from pooled transmission facilities (PTF). As such, SEA added 2.5% to such losses to approximate the PTF losses, based on ISO-NE's estimated line losses from transmission facilities.[17] Given that all EDC-

[15] Available here for Versant: https://www.versantpower.com/suppliers-and-partners/rates/line-loss-factors/
Available here for CMP: https://www.cmpco.com/w/load-profiles
[16] See page 100: https://www.synapse-energy.com/sites/default/files/inline-images/AESC%202024%20May%202024.pdf
[17] See page 11: https://www.iso-ne.com/static-assets/documents/2023/03/transmission_planning_technical_guide_app_j_load_modeling.pdf

reported losses were expressed as average losses, SEA multiplied such losses by 1.5 to approximate the applicable marginal loss rate, based on the ratio of average to marginal losses reported in AESC 2024.

To compute energy-related benefits for FTM projects, SEA assigned avoided line loss benefits equal to the line losses applicable to one level of voltage greater than the project's interconnection voltage. For instance, a FTM project interconnected at secondary voltage receives benefits applicable to the line losses of serving primary voltage. For BTM projects, this same treatment was applied to energy assumed to be exported, whereas energy assumed to be consumed on-site received the full avoided line loss benefits associated with serving the project's interconnection voltage.

Versant's responses to data requests in Docket 2024-00149 suggested that distribution-level line losses were not avoided for a majority of NEB facilities, and that, in many cases, NEB facilities may increase line losses.[18] Given this, SEA excluded all distribution-level line loss benefits for projects located in Versant's service territory from the analysis, assuming that on net the potential benefits of some projects cancel out the potential costs of others.

To compute capacity-related benefits, SEA scaled the AESC's recommended marginal capacity loss factor of 16% based on the ratio of the calculated energy-related avoided losses (discussed above) to the AESC's recommended marginal energy loss factor of 9%.

To compute a total benefit related to avoided line losses, the adopted energy line losses input was multiplied by kWh-denominated benefits discussed elsewhere in this analysis, and the adopted capacity line losses input was multiplied by kW-denominated benefits discussed elsewhere in this analysis.

3.8.4 Transmission And Distribution Upgrades Funded by NEB Customers

Overview

Distributed generation interconnecting to the distribution system is often required to fund system upgrades to the distribution or transmission system to facilitate such interconnection. These upgrades can deliver shared benefits to all ratepayers if they provide reliability benefits or accelerate upgrades that would have been required eventually in business-as-usual system planning.

Data Source:

The EDCs provided a list of the associated costs, if any, paid to fund upgrades to the transmission and distribution system for projects considered in this analysis.

Discussion:

First, SEA amortized the investments using a linear allocation of costs across an assumed useful life of 40 years for the upgraded assets (i.e., assumed a straight-line depreciation). Next, SEA considered the share of such investments that contribute to shared benefits to all ratepayers. Assigning the share of interconnection fees that contribute to shared benefits for all ratepayers is a difficult task. Nonetheless, inclusion of such investments as a benefit component is required by statute. Shared benefits delivered will be a function of the specific location, timing, and grid conditions in question. An analysis of this depth was not possible for the purposes of this report. However, analysis conducted by the EDCs in response to data requests in Docket 2024-00149 provided illustrative examples regarding the share of interconnection expenses that

[18] See Versant's response to Data Request ReVI-003-003

could deliver shared benefits for the specific sample of upgrades assessed. In general, the EDCs found that, for the upgrades assessed, a limited share of the upgrades were expected to deliver benefits to ratepayers.[19] However, the EDCs acknowledged that, more broadly, an accounting of program-wide shared benefits from interconnection costs would require a detailed engineering study which is not possible under the scope of this analysis. Given this uncertainty, SEA assumed that 10% of total interconnection costs paid to fund system upgrades resulted in shared benefits.[20] Given these assumptions and the annualization of costs over the upgrades assumed useful life, this component delivers minimal benefits relative to other benefit categories.

3.9 Demand Reduction Induced Price Effects (DRIPE)

Overview:

DRIPE benefits relate to the impact on market prices resulting from an increase in low-cost supply or reduction in demand for a commodity. In the context of this analysis, renewable resources with low marginal costs tend to drive down prices by shifting the supply curve to the right. This dynamic applies to capacity, energy, and natural gas prices (through reduced demand for gas-generated electricity, called "Cross-Fuel DRIPE").

Data Source:

AESC 2024 (Counterfactual #5) DRIPE values specific to Maine were utilized.

Discussion:

For Energy DRIPE, which varies based on peak/off-peak period and season, hourly 2024 production data from all CMP Tariff Rate projects was utilized to calculate the share of annual production occurring in each period for the NEB program. These shares were applied to production from Versant Tariff Rate projects and all kWh Credit program projects, for which hourly data was not available.

Given that Energy DRIPE and Cross-Fuel DRIPE values are partially a function of the underlying price of electricity each year, SEA substituted AESC-forecasted LMPs with actual LMPs for all of 2024.[21]

DRIPE values in any given year are contingent on the commercial operation date of the resource in question. As such, DRIPE values were calculated separately for each commercial operation year represented in projects operational in the NEB program in 2024 (i.e., were calculated separately for each cohort year). Capacity DRIPE values were only applied to NEB kWh Credit projects, as such projects are the only projects assumed to accrue uncleared capacity benefits by virtue of them acting as load reducers. SEA confirmed with CMP that, although NEB Tariff Rate projects are not bid into the capacity market, they do not act as load reducers from a capacity perspective given their treatment as generator assets in energy markets.

Given that Versant–MPD operates outside of ISO-NE and does not have an organized wholesale energy or capacity market, SEA did not quantify DRIPE benefits for projects in this area. Although DRIPE benefits could theoretically apply, as even bilateral contracts are negotiated with a theoretical supply curve in mine, the quantification of such benefits for the MPD would be very difficult and speculative at best.

[19] For example, see responses to ReVI-005-005, ReVI-005-008, ReVI-004-003, ReVI-004-009

[20] SEA notes that, pursuant to Ch 324 of the Commission's rules, certain T&D upgrade costs are socialized for Level 1 projects. This cost was not quantified in this analysis. Given that Level 1 projects are not expected to trigger significant system upgrade expenses, SEA does not expect this cost to be substantial relative to the benefits quantified in Section 3.8.4.

[21] For clarity, we note the calculation of DRIPE benefits is the only instance in our modeling where LMPs are directly included in calculations. Conversely, direct energy re-sale benefits for Tariff Rate projects are implicitly based on actual 2024 LMPs, but are reported directly by EDCs and thus do not require bottom-up calculations involving hourly LMPs.

3.10 Renewable Energy Certificate (REC) Price Suppression

Overview:

Similar to DRIPE benefits, additional supply of Class I RECs into the regional marketplace can suppress regional Class I REC prices, thus reducing the cost of meeting RPS obligations for impacted RPS markets. Given that most RECs generated from NEB-participating projects are eligible in all Class I markets, this price suppression effect is realized in more than just Maine's RPS market. Although this is not a DRIPE benefit contained in the ASEC (given the AESC's focus on energy efficiency programs, which do not involve the generation of RECs) the concept behind this benefit is largely similar.

Data Source:

SEA utilized production data from the EDCs to estimate Class I REC creation. REC price suppression was calculated using SEA's suite of New England Renewable Energy Market Outlook (REMO) models, discussed below.

Discussion:

To calculate the REC price suppression impact of the NEB program, SEA utilized modeling completed for its 2024-2 REMO briefing.[22] Base case assumptions were adopted. Two separate modeling runs were completed, one containing NEB program capacity, and one excluding NEB program capacity. The differences in forecasted 2024 Class I prices in each state market were then calculated. Results demonstrated no reduction in the price of regional Class I markets. As such, there was no benefit associated with this component computed.

3.11 REC Revenue

Overview:

Projects in both NEB programs are eligible to generate Maine Class I RECs and are also eligible for most of the regional New England Class I markets (with certain exclusions for out-of-state RECs generated by BTM facilities, though even Maine BTM facilities are eligible to register as Massachusetts Class I RECs). In both the NEB program and the power purchase agreements (PPAs) from procured facilities operational in 2024, RECs are not a product transferred to the EDCs included in the cost of such contracts. As such, RECs represent an additional value stream to program revenue through the sale of such RECs to the regional market.

Data Source:

Price quotes in October of 2024 for 2024 Maine Class I were taken from multiple REC brokers and averaged to derive a price for use in modeling.

Discussion:

Given that the primary perspective of this analysis is from a societal lens, REC revenue is not accounted for in the benefit stack presented in Section 3.16.5. This is because, from the general societal perspective, REC revenue is considered a cost shift from buyers to sellers of RECs and thus cancels out to zero net benefits (putting aside small transaction costs).

[22] For details on the New England REMO service, see here: https://www.seadvantage.com/new-england-remo/

3.12 Reduced RPS Requirements

Overview:

RPS costs are a function of the cost of RECs, the RPS requirement (expressed as a percentage of obligated load), and the size of the obligated load (in MWh). Resources acting as load reducers (e.g., NEB kWh credit projects) reduce the total load from which the compliance obligation for any given year is calculated. Thus, such projects acting as load reducers provide benefits in the form of reductions in total RPS costs.

To address this, in its orders granting new RPS certification, the PUC requires that for BTM facilities, "the facility owners must retain GIS certificates or otherwise obtain GIS certificates necessary to satisfy Maine's RPS for that portion of the BTM load that is served by the facilities." As such, in the context of Maine, the total volume of RECs retired should not change because of BTM load reductions, but the party responsible for fulfilling RPS requirements with such load does change.[23] Thus, for BTM facilities, SEA only applied this benefit for the ratepayer impact perspective to reflect that RECs retired to fulfill RPS obligations related to BTM load reductions bears a cost on the facility owner to the benefit of the general ratepayer. For all other tests, reductions associated with BTM load are considered a cost shift and thus do not yield any net benefits. However, given there is no parallel requirement for FTM facilities acting as load reducers to fulfill RPS requirements associated with such load reduction, these benefits are applied under all tests.

Data Source:

Price quotes in October of 2024 for 2024 Maine Class I and II REC prices were taken from multiple REC brokers and averaged to derive a price for use in modeling.

Discussion:

SEA considered the benefits of avoided Class I and II RPS costs. Assumed 2024 REC prices by class were de-rated by the applicable 2024 RPS minimum standard for each class, adjusted for exemptions (which equals 21.6% for Maine Class I, 30% for Maine Class II), to reflect that one MWh of load reduction results in the avoided purchase of only a partial REC.

3.13 Societal Benefits from Greenhouse Gas Reduction

Overview:

Renewable energy contributes zero-carbon energy to the grid, reducing the greenhouse gas (GHG) intensity of energy consumed. The benefits of these GHG emissions reductions are quantified and considered in this analysis.

Data Source:

AESC 2024 values (from Counterfactual #5) were used to compute the marginal non-embedded emissions benefits per MWh of generation. "Non-embedded" refers to the portion of benefits that are not already accounted for (or "embedded") in wholesale energy prices via fees from the Regional Greenhouse Gas Initiative (RGGI). AESC 2024 values for the social cost of carbon (SCC) were used to translate abated emission volumes into dollar values.

Discussion:

The impetus behind much of the focus on incenting renewable energy relates to the impacts of climate change and the GHG reduction benefits offered by renewable generators. Given this, the inclusion of such benefits in a benefit-cost analysis of renewable energy programs is critical to capture the scope of costs and benefits informing the genesis of such programs.

[23] We note that kWh Credit NEB facilities are not required to certify as RPS eligible, and thus not all BTM load will be subject to such provisions.

Quantifying the GHG benefits from renewable generation is a function of the estimated volume of GHG avoided multiplied by the assumed SCC. Each component is discussed below:

> **Marginal GHG reduction:** The marginal reduction in GHG resulting from a MWh of renewable generation is calculated in the AESC based on the applicable peak/off-peak period and season. Similar to the approach taken for Energy DRIPE, SEA utilized hourly production data from CMP for Tariff Rate projects to inform the share of annual MWh applicable to each period.
>
> **SCC:** SEA utilized the recommended SCC from AESC 2024, which represents the most up to date SCC adopted by the U.S. Environmental Protection Agency (EPA) as of November 2022. The SCC is then transformed by the AESC "user interface" to remove embedded costs attributed to RGGI costs, thus preventing the doubling counting of costs that are embedded in energy costs.

Finally, SEA subtracts the assumed average ME Class I REC price in 2024 from the total $/MWh non-embedded GHG benefit (see Section 3.12 for a discussion of assumed REC values). This is done because RECs represent an environmental attribute whose value includes the benefits of GHG reduction from renewable generation. Given that the EDCs do not obtain title to RECs under the NEB program (e.g. project owners can sell RECs independently), failing to subtract assumed REC value from the total non-embedded GHG benefit would result in double counting of environmental benefits, as a portion of the environmental value will be claimed outside of the program via the purchase and retiring of RECs.[24]

3.14 Improved Generation Reliability

<u>Overview:</u>

Projects operating as load reducers shift the demand curve for capacity to the left, thereby increasing the volume of resources above the installed capacity requirement that are able to clear in capacity auctions. This increase is associated with improved reliability.

<u>Data Source:</u>

AESC 2024 values (Counterfactual #5) specific to Northern New England were used to compute the reliability benefits per MW applicable to each technology assessed.

<u>Discussion:</u>

For 2024, AESC computes de minimis reliability benefits for Northern New England. As such, this benefit component contributes a very small portion of overall program benefits. Given that the AESC 2024 is designed for resources with measure years starting in 2024, it is possible that the impact of older resources would have a more significant impact on 2024 reliability outcomes. However, given that the AESC does not clearly separate out the relationship between a resources COD and the magnitude of impact for reliability benefits (as is done with other benefits that include an explicit "phase-in" and "phase-out" schedule), SEA simply adopted AESC 2024-reported reliability benefits for Northern New England for the analysis as a conservative assumption.

---

[24] We note that, given that the RECs generated through NEB facilities are not pinned to Maine, it is possible that the RECs are retired to fulfill another state's RPS obligations and that such state would claim the environmental benefits associated with such RECs in a potential benefit-cost analyses. As such, there is some potential for double counting across states. However, this potential is outside the scope of this analysis.

In addition, Versant's responses to data requests in Docket 2024-00149 suggested that, in many cases, NEB facilities may decrease grid reliability.[25] Given this, SEA excluded reliability benefits for projects located in Versant's service territory from the analysis, assuming that on net the potential benefits of some projects cancel out the potential costs of others.

3.15 Modeling Cost Components

Overview:

The costs of the solar program differ substantially by program variant. A discussion of costs by program variant is provided below.

Tariff Rate Program:

As discussed in Section 3.1, the Tariff Rate Program variant provides monetary credits to participating customers based on facility production of the project to which they are subscribed. The specific rate is dependent on if a project is enrolled in the original Tariff Rate program (where the monetary credits are calculated as a function of the retail rates set at the beginning of each calendar year) or the alternative Tariff Rate program (where the monetary credits are set as a fixed 2.25% annual inflator applied to the 2020 original Tariff Rate program rates).

For the purposes of SEA's analysis, SEA did not distinguish between the two Tariff Rate compensation variants, as total Tariff Rate program variant costs were provided by the EDCs on a monthly basis aggregated across all Tariff Rate projects. Such costs represented the actual monetary credits applied to participating customers' bills in 2024.

kWh Credit Program:

As discussed in Section 3.1, the kWh Credit program variant provides kWh credits on the EDC electric bills of NEB participants. As a result, billed kWh offset through the program results in a reduction in revenues received by the EDCs. The "lost revenue" represents a cost that must be recovered from ratepayers.

To quantify such costs, kWh program costs for energy exports were provided by the EDCs in the form of lost distribution revenues, consistent with filings made through regular stranded cost proceedings. These costs, however, do not represent the full costs associated with the kWh Credit Program, as other wire charges designed to cover costs associated with transmission costs, Electricity Lifeline Program (ELP) costs, and Efficiency Maine Trust (EMT) costs are impacted as well. As such, SEA utilized the kWh of energy exports under the kWh Credit program, by rate class, provided by the EDCs to compute total costs based on all volumetric (per-kWh) wire charges.

SEA computed the lost revenues associated with BTM production consumed on-site (which are not included in the kWh of energy exports provided by the EDCs) based on the estimated production from BTM facilities, as discussed in Section 3.3.

We note that the kWh Credit program variant results in a reduction in billed kWh as compared to the kWh consumed by EDC customers. As addressed below in subsection 3.16, this disconnect of billed kWh to consumed kWh impacts the cost of providing retail supply by load serving entities (i.e., competitive electricity providers and Standard Offer providers) as compared to the counter factual of the absence of the kWh Credit program.

[25] See Versant's response to ReVI-003-019

Administrative Costs:

In addition to per-kWh program expenses, SEA collected total costs associated with the administration of the NEB program from the EDCs. NEB costs were allocated to each program variant based on the share of capacity participating in each program. Overall, administrative costs are insignificant compared to other program expenses.

3.16 Impacts of kWh Credit Program on Retail Generation Supply Costs

For purposes of this report, we define the following:

- Standard Offer Providers (SOPs) provide retail electricity generation services to standard offer customers
- Competitive Energy Providers (CEPs) provide retail electricity generation services to customers not on standard offer service (i.e., those customers that chosen to contract with willing competitive retailers)
- Load Serving Entities (LSEs) are inclusive of both SOPs and CEPs

CEPs can choose which customers they are willing to serve, while SOPs are mandated to serve any customer that chooses to be on Standard Offer service. We presume because of additional carrying costs and risks that are part and parcel of providing retail electricity generation services to kWh Credit recipients (that are described in more detail below) that the vast majority of CEPs do not have interest in serving mass market customers that receive kWh Credit program credits, and that such customers are either not offered a chance to sign up with a CEP or the CEP terminates or does not renew their contract with a customer as quickly as possible. For simplicity's sake for modeling the kWh Credit program's impact, we assume that kWh Credit program recipients are taking standard offer service and served by SOPs.

The impacts on LSEs of the kWh Credit program not only include fewer kWh served by LSEs, but also timing of responsibilities (and payments), change in load shape, and increased risks. We make the following additional assertions and observations regarding the kWh Credit Program's impact on retail generation supply costs.

- Many of the impacts described herein result in cost shifts from CEPs to SOPs, that is from LSEs of retail electric shopping customers to LSEs of non-shopping retail electric customers. While this may be an important consideration for Maine's stakeholders and policymakers, in general, such a pure cost shift does not have an aggregate impact on costs to Maine ratepayers, nor have a societal aggregate cost impact. As such, while these cost shifts are described below, they are neither quantified nor included in the benefit-cost calculations for this report as they net to zero impact.
- SOPs must account for the direct impact of the kWh Credit program on retail generation supply costs as they are required to provide last resort service. Conversely, CEPs can structure contracts and offerings to exclude kWh Credit program recipients as their customers.
- The sum of the aggregate kWh wholesale obligation of all LSEs for a settlement month within an EDC footprint (i.e., the total system load for an EDC) does not change between ISO-NE initial settlement and final resettlement. That is the total system load for an EDC for a billing month is based on the sum of hourly generation and net ties and this calculation implicitly accounts for the kWh Credit program load reduction for that billing month. At the initial ISO-NE settlement the energy associated with the kWh Credit load reduction is allocated to unaccounted for energy (UFE) and spread to all LSEs on a pro-rata basis based on the sum of each LSEs' customers' metered load for the month. Conversely, at the final ISO-NE resettlement the energy associated with the kWh Credit load reduction is

not allocated to UFE but assigned to the LSEs of customers who are kWh Credit recipients.[26] This accounting method has the following implications.

- The share of kWh allocated to each LSE changes from initial settlement to final resettlement based on the share of kWh Credit recipients of each LSE. Specifically, during ISO-NE's initial settlement process the allocation of kWh Credits to customers of kWh Credit program recipients is not accounted for. That means at initial settlement LSEs of kWh Credit recipients are obligated for more kWh than they will ultimately be obligated to pay for at final resettlement, and further those LSEs of kWh Credit recipients must wait until final resettlement (typically five months) before their kWh obligation is appropriately decremented.
- Conversely, all other LSEs who do not have kWh Credit recipients as customers reap the time value of money benefit from a lower kWh obligation in the period between initial settlement as compared to final settlement given that sum of the aggregate kWh obligation of all LSEs for a settlement month within an EDC footprint does not change between initial and final settlement.
- The UFE decreases between initial settlement and final resettlement by the kWh Credits assigned to LSEs during the EDC accounting process (so basically the kWh Credits change from UFE to accounted for energy and that now accounted for energy at resettlement is decremented for LSEs with customers who are kWh Credit recipients).

- Assuming no banking of kWh Credits after final ISO-NE resettlement, each LSE is obliged to pay for only the kWh consumed by their customers (metered load adjusted for losses and UFE) net of the kWh Credits assigned to their customers.

Table 3 describes generally the impact of the kWh Credit program for various LSE cost/benefit drivers. From Table 3, the following drivers need to be quantified to estimate the benefit and cost impacts from a ratepayer and societal perspective. They include:

- Fixed Costs: Capacity
- Fixed Costs: Direct
- Volumetric Risk

In the following subsections, we address the modeling approach of each in turn. We then address the complications imposed by kWh Credit banking in section 3.16.4 and then conclude with a discussion of banked kWh credits and implications regarding the change in load shape settled for kWh credit recipients in section 3.16.5.

[26] See CMP's presentation to the NEPOOL Meter Reading Working Group of September 13, 2024, 2024-09-13 MRWG A02 Net Energy Billing Load Reducers.

Table 3 – kWh Credit Program's Impact on Calendar Year 2024 LSE Costs

LSE Cost / Benefit Driver	Metric of Impact	Method of Impact on LSEs w/ kWh Credit Recipients	Overall Direction of Impact on LSE $/kWh Costs	Quantified in BCA?	Comment
Energy - Decrease in Total Sold	kWh	None	None	N/A	Via resettlement process LSEs only pay for energy based on the kWh consumed net kWh Credit allocations
Ancillary Services	Peak kW via share of load	None	None	N/A	Via resettlement process LSEs only pay for ancillary services based on the kWh share of load after netting kWh Credit allocations
Energy - Change in Load Shape Settled	kWh	Weighted cost of kWh supplied	Varies by LSE, but neutral across all LSEs.	No, only a cost shift	Load reducer provides socialized benefits to some LSEs, and socialized cost to other LSEs. See section 3.16.5 for detailed discussion.
Fixed Costs: Capacity	Peak kW	Fewer kWh sold to spread predetermined Peak Load Contribution (PLC) costs over	Increase in avg. costs to LSEs of kWh Credit recipients	Yes	While no overall change in total fixed costs recovered, consistent with impacts on T&D rates of fewer kWh sold this impact is considered a ratepayer and societal cost increase
Fixed Costs: Direct	Labor & Systems	Fewer kWh sold to spread fixed costs of doing business over	Increase in avg. costs to LSEs of kWh Credit recipients	Yes	
Volumetric Risk	kWh	Additional kWh volume volatility	Increase in total costs to LSEs of kWh Credit recipients	Yes	LSEs need to account for changes in NEB project production on kWh load obligation (e.g., weather variations)
Working Capital	kWh	Difference of kWh obligation at initial settlement vs. kWh obligation at resettlement	Varies by LSE, but neutral across all LSEs. LSEs of kWh Credit recipients experience higher costs.	No, only a cost shift	Avg. difference between initial and resettlement monetary outlay by cost of working capital over five months.
ISO-NE Financial Assurance	kWh	Difference of kWh obligation at initial settlement vs. kWh obligation at resettlement	Varies by LSE, but neutral across all LSEs. LSEs of kWh Credit recipients experience higher costs	No, only a cost shift	Financial assurances based on LSE obligation at initial settlement
Banking of kWh Credits	kWh	Multiple	Varies. Increased costs from added risks, all other impacts are cost shifts	No	See Section 3.16.4 for a detailed discussion

3.16.1 Quantifying Fixed Costs: Capacity

Overview

Each existing New England retail electric customer has an installed capacity tag (ICAP tag, denominated in kW) per their usage during the ISO-NE annual peak hour of the preceding year. The ICAP tag (or ISO-NE peak load contribution - PLC) is set annually and is assessed to the LSE of the retail customer on a monthly basis. This ICAP tag dollar assessment is fixed for a one-year period regardless of the kWh attributed to the customer (and ultimately their LSE) in a given billing month. Thus, as the kWh Credit program decreases the kWh attributed to kWh Credit recipients the annual ICAP tag dollar assessment remains fixed for those same recipients, and therefore the $/kWh rate needed to cover the fixed ICAP tag dollar assessment increases. For SOP providers, this $/kWh impact would be spread over all the SOP's customers in the same customer class, as SOP providers are not allowed to price discriminate within a customer class.

Data Source:

- Capacity prices are sourced from the results of the ISO-NE forward capacity auctions.
- Monthly ICAP Tag data for EDCs for all standard offer customers in a specific rate class valued at true-up (resettlement) or, if not available, at initial settlement, is sourced from the EDC's standard offer auction bidder's information page.
- Monthly billed load data for EDCs for all standard offer customers in a specific rate class is also sourced from the EDC's standard offer auction bidder's information page.
- Monthly applied NEB kWh Credits data is sourced from the EDC's standard offer auction bidder's information page.

Discussion:

To calculate the estimated impact of the kWh Credit program on "uncovered" capacity costs caused by the decrease in kWh billed via the application of kWh Credits requires the following components which were broken out by EDC and customer class on a monthly basis:

- ICAP cost in dollars. Such costs represent the EDC/customer class cost obligation of PLC, which is equivalent to the EDC/customer class kW of the ICAP tag multiplied by the $/kW-Month ISO-NE capacity price.
- Percentage difference in billed load caused by the kWh Credit program. This is calculated by estimating the EDC/customer class change in gross billed load in kWh (without the kWh Credit program) vs. the kWh net billed load in practice (with the kWh Credit program) to determine the percentage difference in billed load.

To calculate total costs, we multiply that percentage difference of billed load caused by kWh Credit program (e.g., 5%) by the relevant ICAP costs in dollars, which results in the kWh Credit program impact in dollars.

3.16.2 Quantifying Fixed Costs: Direct

Overview

There are fixed costs to serve as a Maine SOP (i.e., costs that do not vary with the size of the load served). These include costs related to:

- Preparing and submitting bids
- Data systems and personnel to process and manage SOP obligations
- Accounting systems
- Legal counsel

A decrease in billed kWh, all else equal, will require higher per-kWh charges to cover such fixed costs.

Data Source:

- Consumer Price Index (CPI-U) data, used to adjust the estimated fixed costs to account for inflation, is sourced from the U.S. Bureau of Labor Statistics.

Discussion:

We do not have access to what the typical fixed costs for a Maine SOP are, as we have no data sources to reference. Nonetheless, in the next section (Section 3.16.3) on Volumetric Risk we describe a metric "Risk Premium+" which is inclusive of SOP fixed costs, and thus we are able to estimate the combination of additional volumetric risk and uncovered fixed costs that are imposed by the kWh Credit Program. Please refer to Section 3.16.3 for further discussion.

3.16.3 Quantifying Cost of Added Volumetric Risk

Overview

Volumetric risk imposed on LSEs of kWh Credit recipients is likely hedged with some combination of:

- Electricity put options (right to sell at a strike price)
- Electricity call options (right to purchase at a strike price)
- Weather-related "dirty hedges" that imperfectly hedge for risk that include puts and calls

All other things being equal, as MW volume of NEB kWh Credit projects increases, the variance of MWh ultimately supplied on ISO-NE resettlement increases, therefore requiring additional hedging per MWh ultimately supplied.

Data Sources:

- Monthly billed load data for EDCs for all standard offer customers in a specific rate class is sourced from the EDC's standard offer auction bidder's information page.
- SOP rates by EDC by rate class are sourced from the EDC's standard offer auction bidder's information page.
- Estimates of risk premium and fixed costs for SOPs are derived from analysis contained in the Joint Petition Of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company for Approval of Their Default Service Programs (Brattle Testimony). This analysis is specific to FirstEnergy Pennsylvania electric utilities. Specific references are as follows:
    - Pages 479-511 of the PDF for Discussion / Testimony. More specifically
        - A discussion of what is in Table 2, where "Risk Premium" would be more appropriately labeled "Risk Premium & Other Costs" or "Risk Premium+"
        - Table 2 from the testimony where "Risk Premium" (more appropriately labeled "Risk Premium & Other Costs" or "Risk Premium+") encompasses everything above the passthrough of wholesale costs.
    - Pages 536-539 of the PDF for tables which provide the estimated cost components that comprise the default service rates for the four FirstEnergy Pennsylvania electric utilities.
- Annual load data for FirstEnergy Pennsylvania electric utilities is sourced from the U.S. Energy Information Administration (EIA).

Discussion:

Unsurprisingly, a review of literature resulted in a general lack of real-world examples of the risk premium imposed on LSEs in electricity markets akin to Maine's load-following retail market. It is unsurprising, given that this is a niche topic, and that LSEs in competitive retail markets are understandably reticent regarding how they manage risk (it is proprietary).

Nonetheless, SEA identified one relevant study that provides an estimate of the costs of managing such risk for the default service electricity rates for FirstEnergy's Pennsylvania utilities. Pennsylvania's default service is similar to Maine's standard offer service. Both are load-following provider of last resort of retail generation service offering in a competitive retail electricity market where the investor-owned utilities have divested their generation assets. Given the similarities and lack of alternatives, we have leveraged and adapted the findings from the FirstEnergy study as an important input to estimate costs associated with risk (including fixed costs) assuming they are likely comparable to the risks (and fixed costs) of Maine's standard offer.

Table 4 displays an adaptation and extension of the FirstEnergy average estimated risk premium in default service full-requirements auctions (October 2016-April 2021). The labeling "Risk Premium+" is used because as the Brattle Testimony states on page 502 of the PDF.

> *Therefore, the "risk premium"... may be larger than the "true risk-premium" to the extent that any material costs have been omitted.*

We presume that a material cost omitted by the Brattle Testimony is the fixed cost to bid for and serve the First Energy default service customers. Table 4 provides a computation of what the *Risk Premium+* is as a percentage of the average default service price and results in an unweighted average of 4.4% (see column F)

Table 4 –
Adaptation of the FirstEnergy (FE) Average Estimated Risk Premium in Default Service (DS) Full-Requirements Auctions (October 2016-April 2021)

(A) FE DS Results Oct 2016 through Apr 2021	(B) Risk Premium+ ($/MWh)	(C) Risk Premium+ (% of No Risk Premium+ Price)	(D = B/C) No Risk Premium+ Price	(E=B+D) Avg. DS Full-Requirements Auction Results	(F=E/B) Risk Premium+ (% of DS Full-Requirements Auction Results)
Met-Ed	$2.95	5.96%	$49.50	$52.45	5.6%
Penelec	$2.15	4.63%	$46.44	$48.59	4.4%
Penn Power	$2.24	4.10%	$54.63	$56.87	3.9%
West Penn Power	$1.54	3.54%	$43.50	$45.04	3.4%
Unweighted Avg.	$2.22	4.6%	$48.52	$50.74	4.4%

3.16.3.1 Separating the FE DS Risk Premium+ Metric into Costs Associated with Volumetric Risk from Fixed Costs

The Risk Premium+ is the estimated percentage of the default service $/MWh price above and beyond the wholesale full requirements costs and includes the costs of both the volumetric risk and the fixed costs. To appropriately estimate the cost impact of Maine's kWh Credit program on Maine's LSEs, we need to disaggregate the FE example Risk Premium+ costs associated with volumetric risk from fixed costs.

To do so, we next calculate the total average annual costs for bidding and serving the fixed price auction as a FE default service supplier as displayed in Table 5; the total average FE LSE DS revenue is $721,313,110.

Table 5 – Computation of Annual Avg. Costs for Bidding and Serving FE Fixed Price Auction by Default Service Suppliers (October 2016-April 2021)

(A) FE DS Results Oct 2016 through Apr 2021	(B) Avg. DS Full-Requirements Auction Results	(C) Avg. Annual Fixed Price Default Service MWh Served	(D = B*C) Annual Avg. Revenue for Bidding and Serving FE Fixed Price Auction
Met-Ed	$52.45	4,490,383	$235,505,497
Penelec	$48.59	3,899,721	$189,472,969
Penn Power	$56.87	2,190,547	$124,585,489
West Penn Power	$45.04	3,813,019	$171,749,155
Unweighted Avg. / Total	$50.74	14,393,670	$721,313,110

Assuming the fixed costs are $1,000,000 then the fixed costs of serving FE DS load are 0.14% of the average annual revenue to serve FE DS load ($1,000,000 / $721,313,110 = 0.14%, or $1,000,000/14,393,670 = $0.069/MWh).

We then use the "*Risk Premium+*" metrics from Table 4 and an estimate of what the fixed costs to bid and serve are (e.g., $1,000,000) to net out fixed costs which results in an estimate of the "True Risk Premium %".

Table 6 – Disaggregating True Risk Premium and Fixed Costs from the Risk Premium+ Metric

FE DS Metric	FE DS Metric Value	Comment
(A) Risk Premium+ $/MWh	$2.22	See Table 4, Column B
(B) Fixed Costs Avg. $/MWh	$0.069	As computed above. Fixed Costs do not scale with MWh served but do scale w/ inflation.
(C) Risk Costs	$2.151	C = A-B; Risk and ancillary service costs scale with the size of the auction prices
(D) True Risk Premium as % of "Risk Premium+"	96.9%	D = C/A
(E) Risk Premium+ as % of DS Full-Requirements Auction Results	4.4%	See Table 4, Column F
(F) True Risk Premium % (Disaggregated from Fixed Costs as % of DS Full-Requirements Auction Results)	4.2%	F = D*E
(G) Cumulative Inflation (2019-2024)	22.74%	Consumer Price Index Data
(H) Fixed Costs in 2019 Dollars	$1,000,000	As assumed
(I) Fixed Costs in 2024 Dollars	$1,227,444	I = (1+G)*H

With an estimate of the "True Risk Premium %" net fixed costs, we then can calculate the impact of additional base hedging costs (by EDC by customer class) attributable to Maine's kWh Credit program. We do so for the small and medium customer classes[27] for each of the EDCs by

- Multiplying the average Standard Offer pricing in $/MWh by the True Risk Premium %, which results in the Base Risk Costs in $/MWh (i.e., without added risk costs for kWh Credit Program Variability and net fixed cost premium). This results in Base Risk Costs in $/MWh that vary between $4.00 and $5.50/MWh depending on EDC and customer class.
- Multiplying the Base Risk Costs in $/MWh by kWh Credit Production / Billed Load (%) for each EDC and customer class (e.g., 1% to 13% depending on EDC and customer class) to result in the Additional Hedging Costs Attributable to kWh Credit Program ($/MWh).

Finally, we multiply the Additional Hedging Costs Attributable to kWh Credit Program ($/MWh) by the Annual MWh of Standard Offer load to result in the Additional Hedging Costs Attributable to kWh Credit Program in dollars for each EDC and customer class.

In parallel, we calculate the "additional" (uncovered) fixed costs that are imposed by the kWh Credit program by leveraging the same estimate of fixed costs to bid and serve FirstEnergy default service load (e.g., $1,000,000) discounted by the kWh Credit Production as a percent of billed load and then adjusted for inflation so it applies to the Maine SOP.

Finally, we note, if we estimated a higher or lower fixed costs to bid and serve load, then that will result in a respectively lower or higher "True Risk Premium %" to apply to the Maine SOP case. Thus, the joint accounting for the impacts of risk-premium and fixed costs are bounded by the leveraged results of the Brattle Testimony.

3.16.4 Banking of kWh Credits

<u>Overview</u>

Another feature of the kWh Credit program is the ability of customers to bank kWh Credits for up to 12 months from the month in which the credits were generated. While banking kWh Credits affects the retail load billed to customers (that is, the kWh for which a customer must pay in each month and therefore the retail revenue an LSE receives), it does not impact the wholesale load obligation of LSEs. That is, banking kWh credits, or using banked kWh credits, does not affect the LSE's load obligation in a given month.[28]

We demonstrate this in Table 7, below. This table illustrates the impact of banking on an LSE serving a single customer receiving kWh credits. The table illustrates how, when kWh credits (column b) received exceed customer consumption (column a) in a given month, credits can be banked (column d). Critically, however, the LSE's wholesale load obligation (after resettlement, column e) is always equal to the difference between customer consumption (a) and credits received (b), *regardless of whether any banking occurs*. In this example in which there is a single customer, this means that a LSE's load obligation would be negative in months in which credits received exceed customer consumption (in practice, this does not

[27] We exclude the large customer class as SOP costs for the large customer class are primarily a straight monthly variable pass-through of ISO-NE wholesale costs and thus any risk premium associated with the large customer class is structurally different than the risk premium for the small and medium customer classes where the standard offer pricing is set the year prior. Thus, the True Risk Premium % for the large customer class standard offer class is likely minimal and certainly much smaller than the True Risk Premium % of the small and medium customer classes. Finally, the percentage of customer class load being served by SOPs for the large customer class is much smaller than that of the small and medium customer classes, making the relative impact of kWh Credit banking even smaller for the large customer class and probably *de minimis*.

[28] This does not mean that the ability of customers to bank kWh Credits does not affect the cost of suppliers to serve customers these customers. The narrow conclusion here (that banking or drawing down on banked kWh credits does not affect a supplier's wholesale load obligation).

happen, as credits received never exceed customer consumption when aggregated over a supplier's full set of customers). Still, the example illustrates how banking *does not change the wholesale load obligation of an LSE*.

Table 7 –
NEB Credit Banking Simple Example

	(a) Customer Consumption	(b) kWh Credits Received	(c) Customer Billed kWh	(d) Cumulative Banked Credits	(e) RES Wholesale Load Obligation (a - b)
Jan	500	100	400	0	400
Feb	500	200	300	0	300
Mar	500	600	0	100	-100
Apr	500	700	0	300	-200
May	500	400	0	200	100
Jun	500	100	200	0	400
Total	**3000**	**2100**	**900**	**600**	**900**

Those kWh credits are assigned to customers and ultimately to their LSEs in the specific billing month, regardless of whether the kWh Credits will be credited to the customer's bill in the billing month or banked for later use (or if not used, the credits expire). Thus, occurrence or not of banking of kWh Credits does not impact the initial settled nor the final re-settled wholesale load obligation of an LSE.

Put a different way, it is the assignment of credits to a customer of a LSE that impacts the wholesale load obligation of an LSE, while the banking of kWh Credits has no impact on the wholesale load obligation of an LSE. Conversely, the banking of kWh Credits does impact LSEs retail revenue collections by postponing the date when full diminution of kWh that can be billed by an LSE caused by kWh Credits occurs.

Thus, the subtlety of the impact of kWh Credit banking on LSEs that must be emphasized is the difference of impacts between wholesale load obligation of an LSE (no impact) vs. retail revenue collections for an LSE (impacts as described next).

Given the above, we next discuss the implications of banked kWh Credits for LSEs. To pay for wholesale energy purchased from ISO-NE, LSEs must finance the carrying cost of the difference between initial wholesale settlement and final wholesale resettlement. This occurs regardless of banking behavior, and thus banking kWh Credits has no additional impact on wholesale cost to serve retail load.

Nonetheless as also discussed above, there are impacts of banked credits on retail revenue collections for LSEs that have yet to be accounted for. First, we note that the LSE serving customers changes over time. This means that the LSE serving the customer when the kWh Credit was banked, may not be the LSE serving the customer when kWh Credit banked generation is used to decrease the customer's bill. We further note that some kWh Credits are never used as they expire on a 12-month rolling basis (old credits are used first).

Regardless of these specific idiosyncrasies, we note the following impacts of banked kWh Credits on LSE's billing of their customers and ultimately on the LSE's retail revenue collections:

- For banked credits that are ultimately used by customers to offset their retail consumption there are two impacts:
  - First, there is a delay of the decrement of revenue caused by the delay when the kWh Credits are applied (as compared to the no banking of kWh Credit case). This delay in the decrement of retail revenue improves the cashflow of an LSE as compared to the kWh Credits being utilized by the customer recipient in the billing month they were assigned. This, probably modest, delay helps to moderate the working capital costs of LSEs serving kWh Credit recipients and thus moderates the ratepayer and societal costs.
  - Second, there is a mismatch between the LSEs decrement of the wholesale cost of energy procured by a LSE, and the LSE's retail revenue received for providing retail generation services. That is, if kWh Credits received by a customer in June are banked and not used by the customer until October, then the decrement of retail revenue will be based on the $/kWh retail rate applicable in October (and not June).
    - The mismatch described just above could be a swing either way as its impact could conceivably be a marginal benefit or cost to an LSE. Further because there is close to a fixed SOP rate for residential and small commercial customers for the entire calendar year, it would make little difference on nominal retail rate collection if the kWh Credit was applied in June vs. October for this customer class.[29] Regardless, and generally, as it is unclear whether the impact would be positive or negative to a LSE, we assume there is no overall impact to model from this effect.
    - Regardless of whether the impact is positive or negative to an LSE's retail revenue collection, the chance of such a swing is a risk the LSE needs to account for, and thus an added cost to LSEs that would not occur in the absence of the kWh Credit program. Managing this risk is a cost impact to ratepayers and a societal cost increase as well.
- For unused kWh credits that are lost to customers (i.e., expired credits), an LSE (as described above) has its wholesale load obligation decremented upon wholesale resettlement, but we assume never has its retail revenue decremented for the equivalent kWh.[30]
  - As compared to recipients that don't bank kWh Credits, this impact is a marginal benefit to LSEs (as it decreases their net cost to serve), and overall, a marginal benefit shift back to ratepayers (at the expense of program participants).

In summary, except for the added risks, the impact of kWh Credit banking on LSEs is either a wash or a marginal decrease in the overall costs in serving kWh Credit recipients. Unfortunately, we have no basis to estimate the impact of kWh Credit banking as we do not have information on the scale of kWh Credits banked nor how long the credits are banked for. We presume such impacts will be a secondary or tertiary order impacts, and for this analysis assume that such impacts are zero. Future analysis should request from the EDCs as much information on banked kWh Credits to facilitate a possible quantification of this impact.

3.16.5 Change in Load Shape Settled

This impact represents the difference in the shape of customer load and solar production, which, because of how the energy resettlement process adjusts the load obligation of suppliers serving kWh Credit customers, is socialized across a set of customers.

---

[29] In 2024 we note that CMP's small customer class standard offer rates dropped from $0.108363/kWh from Jan-Jun to $0.106363/kWh from Jul-Dec.   Bangor-Hydro's small customer class standard offer rates changed similarly $0.10763/kWh to $0.102630/kWh. Maine Public District's were fixed at $0.112850/kWh for the entire year.

[30] It is possible that the EDCs decrement the LSEs kWh billed for the expired banked credits, but the realization that this was an issue to be confirmed by SEA with the EDCs came up too late in the report writing process to be incorporated into this analysis. Regardless, any impacts are probably small and would not significantly impact the overall conclusions of this analysis.

Discussion:

To illustrate this impact, consider the simple example provided in Table 8 in which five hours are considered (but one can imagine this representing a month). In this example, PV production (column (a)) generates kWh Credits which are assigned to the customer with load represented in column (b). Because the total PV production is equal to the load over the period, the supplier's wholesale load obligation associated with the customer is reduced to zero in every hour. As discussed in Appendix C.1 to SEA's report titled "Ratepayer Value Analysis of Maine's Net Energy Billing (NEB) Resources:
Load Reducers vs. Generator Assets", this load obligation is applied as a proportional reduction of the entire load shape, as opposed to simply adding PV production and load by hour.[31] Therefore, the supplier's wholesale cost (column (g)) is zero. Column (d) tracks the system load on an hour-by-hour basis. Multiplying this column by the hourly price in column (e) yields the actual market cost/revenue in column (f). Despite the sum of the PV production and load being the same over the full period, their different shapes yield a market cost that does not equal zero. In the example, the total market obligation (not the supplier's post-resettlement obligation) is $410. As already established, the wholesale cost for the supplier is zero, so the $410 must be recovered from some set of customers.

Table 8 – Illustration of PV Production Shape Socialization

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Hour	PV Production	Load	Adjusted load (supplier's obligation)	Net load (a-b)	Price	Actual market cost (d*e)	Paid by supplier	Needs to be recovered
1	100	0	0	100	$10	$1,000	$0	($1,000)
2	50	-20	0	30	$50	$1,500	$0	($1,500)
3	20	-50	0	-30	$3	($90)	$0	$90
4	70	-70	0	0	$1	$0	$0	$0
5	0	-100	0	-100	$20	($2,000)	$0	$2,000
Total	**240**	**-240**	**0**	**0**		**$410**	**$0**	**($410)**

As noted above, this impact is specific to the kWh Credit program, and, more specifically, only applies when resources are treated as Load Reducers. In 2024, the market value of the solar is lower than the market cost of the load, which is consistent with the example provided above. Given the assumption that kWh Credit program recipients are served by SOPs, the shift in value occurs between SOPs and suppliers of non-large competitive supply customers, as the benefit is realized only by SOPs, and then recovered from suppliers of all non-large competitive supply customers. Suppliers of large customers are unaffected by this impact, as their loads are not adjusted for Unaccounted for Energy (UFE).

However, given that this impact represents a cost shift, it is not considered in the benefit-cost calculation.

[31] Report available at: https://www.maine.gov/mpuc/sites/maine.gov.mpuc/files/inline-files/ME%20PUC%20Value%20of%20DG%20-%20LD%20327-Final%20Report.pdf

3.16.6 Avoided Energy as a kWh Credit Program Benefit

SEA did not compute an avoided energy benefit applicable to the kWh Credit program. Although it is true that the kWh Credit program reduces the total kWh that must be procured by load serving entities, there is no avoided energy benefit associated with such reductions to ratepayers in general as such reductions are paid for by and benefits accrue to program participants. More specifically, the benefits associated with avoided energy accrue, for example, to the kWh Credit project subscriber (in the form of a reduction to billed kWh usage) and the project owner (in the form of the kWh Credits to sell to subscribers).

Benefits applicable to such participants were not considered given that the inclusion of such benefits would require a shift in perspective to that of the program participant. Given the legislative mandate to consider "costs authorized to be collected by T&D utilities in rates and benefits directly received by ratepayers," SEA determined that such a perspective was not appropriate for this analysis. Also importantly, for this analysis SEA interpreted "benefits directly received by ratepayers" as those benefits which any ratepayer would receive outside participation in the NEB program (i.e., NEB program nonparticipants).

4 Results and Findings

4.1 General Societal Perspective

The results of SEA's analysis quantifying the benefits and costs of the NEB program for calendar year 2024 are provided below, with a graphical summary of the analysis provided in Figure 2 and a tabular summary in Table 9. Benefit components displayed below are an aggregation of more granular components, organized by component category. For a more detailed breakdown of individual benefit components, please see Appendix A.

Figure 2 –
Calendar Year 2024 NEB Summary Costs and Benefits

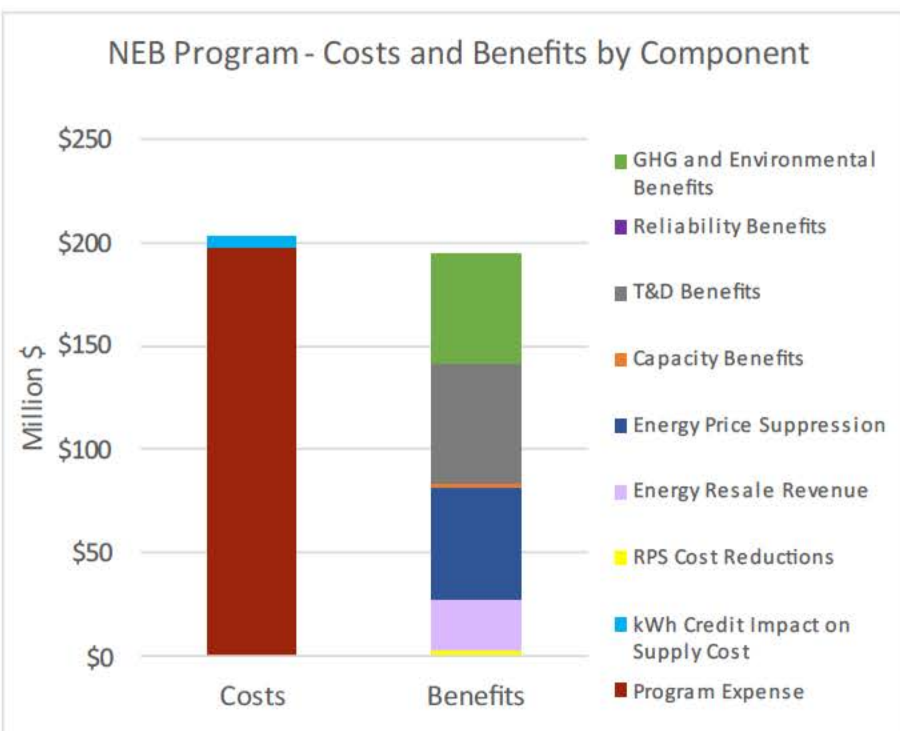


Table 9 - Calendar Year 2024 NEB Summary Cost and Benefit in Millions of Dollars

Benefit / Cost Category	Costs	Benefits
Program Expense	$197.16	N/A
kWh Credit Impact on Supply Cost	$5.67	N/A
Renewable Portfolio Standard (RPS) Cost Reductions	N/A	$3.66
Energy Resale Revenue	N/A	$24.11
Energy Price Suppression	N/A	$53.51
Capacity Benefits	N/A	$2.35
T&D Benefits	N/A	$57.85
Reliability	N/A	$0.00
GHG and Environmental Benefits	N/A	$53.11
Totals	$202.84	$194.58

SEA calculates that the NEB program's 2024 calendar year program expenses were $202.84 million, and the program benefits were $194.58 million. Note that the cost and expenses are for all solar projects operating in 2024. Thus, the impact of projects as old as 1994 are included in the analysis. The reduction in program-wide net benefits relative to the 2023 calendar year BCA is primary a function of:

- A lack of REC Price suppression benefits identified, as compared to the 2023 analysis in which such benefits represented a sizable share of total benefits
- Evolutions to SEA's methodology used to compute benefits related to peak shaving, which better capture the diminishing returns of solar on marginal peak load reductions
- Actual LMPs coming in lower than AESC forecasted LMPs for 2024

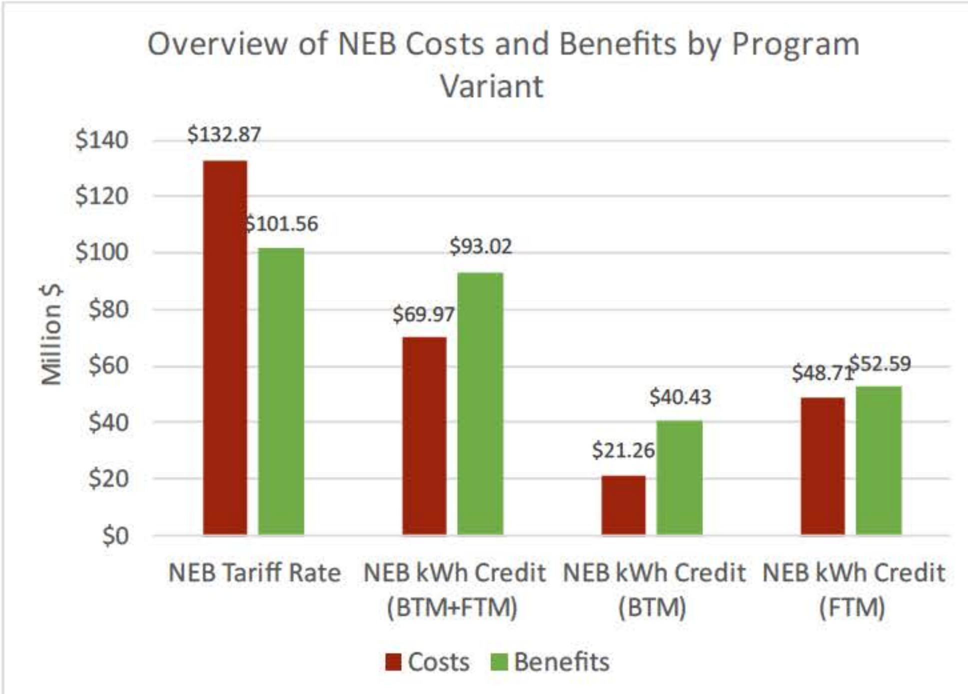
Adjustments to account for the back-loading of installations in 2024, which limit the benefits projects interconnecting late in the year can deliver in 2024

Figure 3 and Table 10 provide a summary of the Maine solar program costs and benefits by the program variants described in Section 3.1. The Tariff Rate program variant was found to have costs exceeding benefits, whereas the kWh Credit program variant was found to have benefits exceeding costs, with significant net benefits for BTM projects.

Table 10 - 2024 NEB Program Variant Summary Cost and Benefit in Millions of Dollars

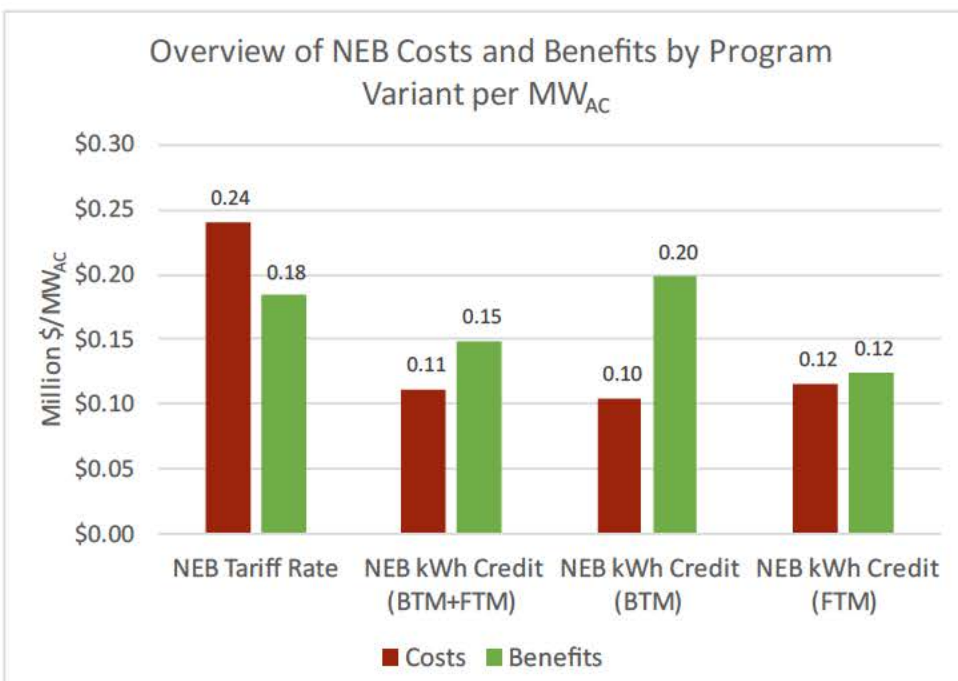
Program Variant	Costs	Benefits	Benefit-Cost Ratio
NEB Tariff Rate	$132.87	$101.56	0.76
NEB kWh Credit	$69.97	$93.02	1.33
NEB kWh Credit (BTM)	$21.26	$40.43	1.90
NEB kWh Credit (FTM)	$48.71	$52.59	1.08
NEB Program Total	$202.84	$194.58	0.96

Figure 3 –
2024 NEB Program Variant Summary Costs and Benefits in Millions of Dollars



Next, Figure 4 provides a summary of the NEB program costs and benefits by the program variants on a million-dollar per MW_{AC} basis.

Figure 4 –
2024 NEB Program Variant Per MW Summary Costs and Benefits



The preceding begs the question why does the kWh Credit program variant yield greater net benefits than the Tariff Rate program variant in calendar year 2024? The answer is that, although the Tariff Rate program delivers greater total benefits per MW, the cost per MW is significantly greater, resulting in net costs per MW as compared to the kWh Credit program which delivers significant net benefits. Table 11 provides a breakdown of total value by component category, whereas Table 12 provides such figures on a million-dollar per MW_{AC} basis for apples-to-apples comparisons across program variants.

A discussion of the relative benefits and costs of each program variant is provided below in approximate order of significance:

- **Program Costs:** First note that, on a per-MW basis, the kWh Credit program variant is less than half the costs of the Tariff Rate. This is because, for kWh Credit projects, program expenses do *not* include the full avoided $/kWh charges. Instead, because the production from kWh Credit projects is treated as a load reducer, program costs are a function of lost transmission and distribution revenue, and do not include the generation component of the retail rate. Conversely, for the original Tariff Rate program participants, the full cost of the Tariff Rate (which is a derivative of the full $/kWh retail rate) is being provided as a dollar denominated credit and shows up in the Program Expense category. These findings are partially offset by the inclusion of costs related to the kWh Credit program variant's impact on Standard Offer rates. However, such costs are relatively small compared to direct program expenses quantified and do not change the conclusion that the kWh Credit program variant includes lower costs on an absolute and relative basis.
- **T&D Benefits**: The kWh Credit Program variant accrues a lot more of these benefits, because BTM projects (which are only kWh Credit program variant projects) accrue both avoided distribution and transmission benefits, while FTM projects (which are both kWh Credit program variant and Tariff Rate program variant projects) accrue primarily avoided transmission benefits.
- **kWh-denominated Benefits**: Benefits that are a function of project production (e.g., GHG benefits, energy price suppression, REC price suppression) are higher per-MW for the Tariff Rate program variant because the capacity factor of small BTM projects is typically lower than capacity factor of large FTM projects for the same location. In addition, the Tariff Rate program portfolio includes non-solar projects which have a significantly higher capacity factor, contributing to greater production per MW on a program-variant-wide basis.
- **Load Reducer Benefits:** Because projects participating in the kWh Credit program variant act as load reducers, they are the only projects for which benefits associated with reducing the Maine RPS Compliance Obligation, uncleared capacity value, and capacity DRIPE benefits accrue. In addition, for the Maine Test (discussed in Section 4.3), these are the only projects for which benefits associated with reduced share of capacity and transmission costs accrue.
- **Energy Resale Revenue:** kWh Credit program variant projects do not receive energy resale benefits. Conversely, projects enrolled in the Tariff Rate program serve as generators in ISO-NE markets and received a total of $24.11 million for energy resale benefits in 2024. This occurs because, as discussed above in Section 3.1, the kWh Credit program variant projects act as load reducers and thus they are not directly monetized by selling the energy on the wholesale market, while the energy output from the Tariff Rate projects are monetized by the EDCs.

Table 11 -
Summary Comparison of Tariff Rate vs. kWh Credit 2024 NEB Program Variants (Total $)

Benefit / Cost Category	Tariff Rate (Millions $ or MW_{AC})	kWh Credit (Millions $ or MW_{AC})	kWh Credit as % of Tariff Rate
MW_{AC}	552.44	626.16	113.3%
Program Expense	$132.87	$64.29	48.4%
kWh Credit Impact on Supply Cost	$0.00	$5.67	N/A
T&D Benefits	$20.10	$37.75	185.8%
GHG and Environmental Benefits	$29.08	$24.03	82.6%
Energy Price Suppression	$27.91	$25.59	91.7%
RPS Cost Reductions	$0.00	$3.66	N/A
Energy Resale Revenue	$24.11	$0.00	0.0%
Reliability Benefits	$0.00	$0.00	N/A
Capacity Benefits	$0.36	$1.99	557.5%
Total Benefits	$101.56	$93.02	91.4%

12 Table -
Summary Comparison of Tariff Rate vs. kWh Credit 2024 NEB Program Variants ($/MW)

Benefit / Cost Category	Tariff Rate (Millions $/$MW_{AC}$)	kWh Credit (Millions $/$MW_{AC}$)	kWh Credit as % of Tariff Rate
Program Expense	$0.24	$0.10	42.7%
kWh Credit Impact on Supply Cost	$0.00	$0.01	N/A
T&D Benefits	$0.04	$0.06	163.9%
GHG and Environmental Benefits	$0.05	$0.04	72.9%
Energy Price Suppression	$0.05	$0.04	80.9%
RPS Cost Reductions	$0.00	$0.01	N/A
Energy Resale Revenue	$0.04	$0.00	0.0%
Reliability Benefits	$0.000	$0.000	N/A
Capacity Benefits	$0.001	$0.003	491.8%
Total Benefits	$0.18	$0.15	80.6%

4.2 Monetization of Benefits and Costs

The Act specifies that the Commission must distinguish costs and benefits that are monetized from costs and benefits that are not monetized, and for those costs or benefits that are monetized, the Commission must specify the entities to which the monetized value accrues, which may include, but are not limited to, electricity customers, electricity supply providers and transmission and distribution utilities. A discussion of which benefit and cost components are monetized, and to which parties those values accrue, is provided below.

While all benefits and costs assessed in this analysis are quantified in dollar terms (as is necessary in a benefit-cost analysis to provide apples-to-apples comparisons across components), not all benefits will have their impact realized in dollar terms (e.g., environmental benefits are not provided in dollar terms). Still, defining what constitutes monetization is difficult, as many benefit components are expected to result in dollar value impacts, but through mechanisms that do not involve the direct transfer of funds through the NEB program. On the other hand, certain components are clearly monetized (e.g., PPA payments to projects). To address this nuance, SEA has classified benefit component monetization into the following categories:

- Direct – Components which involved the direct transfer of funds between parties, facilitated by the NEB program.
- Indirect – Components for which impacts are experienced in dollar value terms, but for which the mechanism driving the impact is an indirect effect of the NEB program.
- Not Monetized – Components for which impacts are not exclusively experienced in dollar terms. The use of the word "exclusively" is meant to reflect that for certain non-monetized benefits (such as GHG benefits), the quantification of impacts does include consideration of economic damages which will eventually be experienced in dollar terms. However, such benefits are broader in scope and include more difficult-to-quantify impacts such as impacts on human health.

Components with monetization designations, including the party to which value accrues, are provided in Table 13 (we note that "ROP" stands for "Rest of Pool", and designates benefits accruing to neighboring states within ISO-NE):

Table 13 -
Benefit & Cost Components Included by Monetization Designation

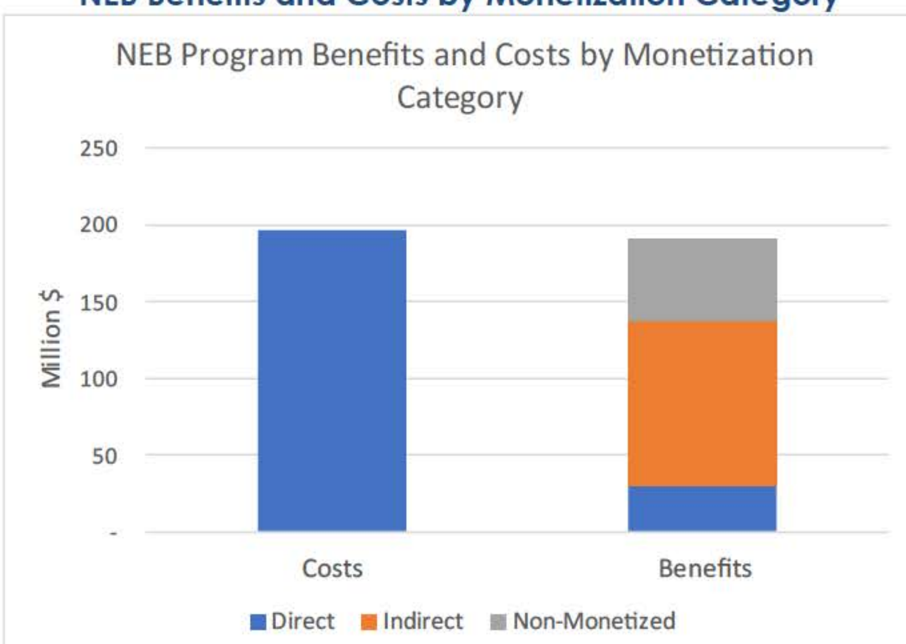
Component	Monetization	Category	Impacted Party
Project PPA Expenses	Direct	Cost	ME Ratepayers
Lost Utility Revenues	Direct	Cost	ME Ratepayers
kWh Credit Impact on Supply Cost	Direct	Cost	ME Ratepayers (Standard Offer Customers Only)
Program Admin	Direct	Cost	ME Ratepayers
Energy Resale	Direct	Benefit	ME Ratepayers
Capacity Buyout Revenue	Direct	Benefit	ME Ratepayers
Interconnection upgrade benefits	Indirect	Benefit	ME Ratepayers
Uncleared capacity value (Intrastate)	Indirect	Benefit	ME Ratepayers
Uncleared capacity value (ROP)	Indirect	Benefit	Non-ME ISO-NE Ratepayers
Reduced Share of Capacity Costs	Indirect	Benefit	ME Ratepayers
Price suppression - energy (Intrastate)	Indirect	Benefit	ME Ratepayers, at expense of Non-ME ISO-NE Ratepayers
Price suppression - energy (ROP)	Indirect	Benefit	Non-ME ISO-NE Ratepayers
Price suppression - capacity (Intrastate)	Indirect	Benefit	ME Ratepayers
Price suppression - capacity (ROP)	Indirect	Benefit	Non-ME ISO-NE Ratepayers
Price suppression - electric-gas (Intrastate)	Indirect	Benefit	ME Ratepayers
Price suppression - electric-gas (ROP)	Indirect	Benefit	Non-ME ISO-NE Ratepayers
Price suppression - electric-gas-electric (Intrastate)	Indirect	Benefit	ME Ratepayers
Price suppression - electric-gas-electric (ROP)	Indirect	Benefit	Non-ME ISO-NE Ratepayers
Reduced transmission costs (Intrastate)	Indirect	Benefit	ME Ratepayers
Reduced transmission costs (ROP)	Indirect	Benefit	Non-ME ISO-NE Ratepayers
Reduced Share of Transmission Costs	Indirect	Benefit	ME Ratepayers, at expense of Non-ME ISO-NE Ratepayers
Reduced distribution costs	Indirect	Benefit	ME Ratepayers

Component	Monetization	Category	Impacted Party
Reduced T&D losses - capacity (Intrastate)	Indirect	Benefit	ME Ratepayers
Reduced T&D losses - capacity (ROP)	Indirect	Benefit	Non-ME ISO-NE Ratepayers
Reduced T&D losses - energy (Intrastate)	Mixed	Benefit	ME Ratepayers
Reduced T&D losses - energy (ROP)	Mixed	Benefit	Non-ME ISO-NE Ratepayers
Improved generation reliability (Intrastate)	Indirect	Benefit	ME Ratepayers
Improved generation reliability (ROP)	Indirect	Benefit	Non-ME ISO-NE Ratepayers
Non-embedded GHG emissions	Non-Monetized	Benefit	Society
Reduced RPS Obligation	Indirect	Benefit	ME Ratepayers
REC Price Suppression (Intrastate)	Indirect	Benefit	ME Ratepayers
REC Price Suppression (ROP)	Indirect	Benefit	Non-ME ISO-NE Ratepayers

Benefits that relate to reducing the share of transmission or capacity expenses paid for by Maine ratepayers do not offer net benefits on a societal level because they are essentially a cost shift from Maine ratepayers to ratepayers in other ISO-NE states. As such, these components could be considered a benefit or a cost depending on the perspective. Next, reduced T&D losses for energy are denoted as both Indirect and Non-Monetized given that they are a function of all kWh denominated benefits, which include Non-Monetized GHG and NO_X benefits. Lastly, REC revenue was not considered as a benefit in this analysis, as RECs are not a product that is purchased by the EDCs through the NEB program. However, it is worth noting that the monetization of REC benefits would be considered a "Direct" monetization, with benefit accruing to the project owner.

Figure 5 shows a breakdown of the total program benefits and cost by each category. We note that reduced T&D energy losses were included in the non-monetized category, given a large portion of these benefits relate to GHG benefits.

Figure 5 –
NEB Benefits and Costs by Monetization Category



4.3 Sensitivity Analysis of Maine Societal and Ratepayer Perspectives

Per the discussion in Section 2.4, we have conducted the above net benefit analysis from a societal impact perspective (Societal Perspective). In this subsection we provide a sensitivity analysis from the Maine-only societal impact perspective (Maine Perspective) in addition to a ratepayer impact perspective (Ratepayer Perspective). Before doing so it is instructive to compare what net benefit analysis components are included in each perspective as is provided in Table 14 where ROP stands for "Rest of Pool", or the rest of the ISO-NE power pool outside of Maine.

As should be expected, any components that only impact the ROP (i.e., New Hampshire, Vermont, Massachusetts, Connecticut, and Rhode Island) are excluded from the Maine Perspective and the Ratepayer Perspective but are included in the Societal Perspective. In addition, "Reduced Share of Capacity Costs" and "Reduced Share of Transmission Costs" to Maine ratepayers are included in the Maine Perspective and the Ratepayer Perspective but excluded from the Societal Perspective because the overall ISO-NE (more or less) fixed capacity and transmission costs are allocated to each state based on each state's impact on the regional T&D system. Thus, from the Societal Perspective, a reduction in Maine's share of such costs just represents a cost transfer to other New England state ratepayers, and not a true benefit.

As discussed in Section 3.12, reduced RPS requirements applicable to BTM projects are only considered a benefit for the Ratepayer Perspective as this benefit represents a cost shift from general ratepayers to facility owners. Lastly, reliability benefits are not included in the Ratepayer Perspective, as such benefits are based on the "Value of Lost Load" (VoLL) which is a measure of willingness to pay for improved reliability, but not a monetizable benefit for ratepayers.

Notably, SEA has chosen to include Non-embedded GHG emissions benefits in the Maine Perspective. This is because the recognition of the importance of reducing GHG emissions is a primary motivator for the establishment of programs such as the NEB program. Such goals have been legally recognized by Maine, as the legislature has formalized GHG reduction requirements in P.L. 2019 Chapter 476, which requires the State to reduce carbon emissions by 45% relative to 1990 levels by 2030 and 80% by 2050. Given this, although such benefits are global in scale, omission of them would be antithetical to the motivations informing the establishment of the NEB program.

This determination is in line with best practices and prior analysis. First, the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources notes that societal impacts should be accounted for to the extent that they contribute to a jurisdiction's energy policy goals.[32] In contrast, ROP energy suppression benefits are not an express goal of Maine, but rather are a side effect of the NEB program (and are thus not included in the Maine Perspective). Lastly, prior benefit-cost analysis of the NEB program conducted by Synapse Energy Economics and Sustainable Energy Advantage on behalf of the DG Stakeholder Group (see final report) adopted a Maine Perspective and included GHG benefits. GHG benefits are excluded from the Ratepayer Perspective.

[32] See page 16, here: https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf

Table 14-
Benefit & Cost Components Included by Analysis Perspective

Component	Societal Impact Perspective	Maine-only Societal Impact Perspective	Ratepayer Impact Perspective
Project PPA Expenses	Include	Include	Include
Lost Utility Revenues	Include	Include	Include
kWh Credit Impact on Supply Cost	Include	Include	Include
Program Admin	Include	Include	Include
Energy Resale Revenue	Include	Include	Include
Capacity Buyout Revenue	Include	Include	Include
Interconnection upgrade benefits	Include	Include	Include
Uncleared capacity value (Intrastate)	Include	Include	Include
Uncleared capacity value (ROP)	Include	Exclude	Exclude
Reduced Share of Capacity Costs	Exclude	Include	Include
Price suppression - energy (Intrastate)	Include	Include	Include
Price suppression - energy (ROP)	Include	Exclude	Exclude
Price suppression - capacity (Intrastate)	Include	Include	Include
Price suppression - capacity (ROP)	Include	Exclude	Exclude
Price suppression - electric-gas (Intrastate)	Include	Include	Include
Price suppression - electric-gas (ROP)	Include	Exclude	Exclude
Price suppression - electric-gas-electric (Intrastate)	Include	Include	Include
Price suppression - electric-gas-electric (ROP)	Include	Exclude	Exclude
Reduced transmission costs (Intrastate)	Include	Include	Include
Reduced transmission costs (ROP)	Include	Exclude	Exclude
Reduced Share of Transmission Costs	Exclude	Include	Include
Reduced distribution costs	Include	Include	Include
Reduced T&D losses - capacity (Intrastate)	Include	Include	Include
Reduced T&D losses - capacity (ROP)	Include	Exclude	Exclude
Reduced T&D losses - energy (Intrastate)	Include	Include	Include
Reduced T&D losses - energy (ROP)	Include	Exclude	Exclude
Improved generation reliability (Intrastate)	Include	Include	Include
Improved generation reliability (ROP)	Include	Exclude	Exclude
Non-embedded GHG emissions	Include	Include	Exclude
Reduced RPS Obligation	Exclude for BTM	Exclude for BTM	Include
REC Price Suppression (Intrastate)	Include	Include	Include
REC Price Suppression (ROP)	Include	Exclude	Exclude

Table 15 provides a summary comparison of the cost and benefits by modeling perspective. The Program Expense, kWh Credit Impact on Supply Cost, Energy Resale and GHG & Environmental Benefits benefit / cost categories do not vary from the Societal Perspective to the Maine Perspective. The Ratepayer Perspective is identical to the Maine Perspective apart from marginally higher RPS cost reductions (see Section 3.12) and the exclusion of benefits relating to GHG emissions reductions or reliability benefits. The Maine Perspective and Ratepayer Perspective have significantly lower benefits for the RPS Cost Reductions, Energy Price Suppression, and Reliability Benefits component categories than the Societal Perspective because the Maine Perspective and Ratepayer Perspective do not include the benefits of the Maine NEB program that are reaped by other New England states (e.g., does not include the benefits associated with ROP).

Conversely, the Capacity Benefits and T&D Benefits are greater for the Maine Perspective and the Ratepayer Perspective, because some of those benefits accrue to Maine ratepayers only while increasing rates by the same aggregate amount for ratepayers in other New England states (and are thus considered cost shifts from the Societal Perspective).

Details on the individual component level results that make up the results of each component category by benefit-cost analysis perspective, program type, EDC and technology are provided in Appendix A.

Table 15 -
2024 NEB Program Summary Cost and Benefit in Millions of Dollars by Analysis Perspective

Benefit / Cost Category	Costs	Societal Perspective Benefits	Maine Perspective Benefits	Ratepayer Perspective Benefits	Maine Perspective Benefits (% of Societal)	Ratepayer Perspective Benefits (% of Societal)
Program Expense	$197.16	N/A	N/A	N/A	N/A	N/A
kWh Credit Impact on Supply Cost	$5.67	N/A	N/A	N/A	N/A	N/A
RPS Cost Reductions	N/A	$3.66	$3.66	$5.48	100.0%	149.9%
Energy Resale Revenue	N/A	$24.11	$24.11	$24.11	100.0%	100.0%
Energy Price Suppression	N/A	$53.51	$7.23	$7.23	13.5%	13.5%
Capacity Benefits	N/A	$2.35	$4.96	$4.96	211.2%	211.2%
T&D Benefits	N/A	$57.85	$40.98	$38.82	70.8%	67.1%
Reliability Benefits	N/A	$0.00	$0.00	$0.00	9.8%	0.0%
GHG and Environmental Benefits	N/A	$53.11	$53.11	$0.00	100.0%	0.0%
Totals	$202.84	$194.58	$134.05	$80.61	68.9%	41.4%

As shown above, the Maine Perspective benefits are less than the NEB program expenses. It is also worth noting that, although overall costs exceed benefits under this perspective, benefits continue to exceed costs for BTM projects in the kWh Credit program variant specifically (with costs roughly equal to benefits for FTM projects in the kWh Credit program). Ratepayer Perspective benefits are lower than both the Societal and Maine Perspective. Still, benefits for BTM kWh Credit program projects are higher than costs under the Ratepayer Perspective due to the significant T&D benefits assumed for such projects.

A Appendix A – Component-level Results

A.1 Tariff Rate Program (2024) – Societal Perspective

Component Category	Components	CMP - Solar	CMP - Wind	CMP - Hydro	Versant - BHD - Solar	Versant - BHD - Wind	Versant - BHD - Hydro	Versant - MPD - Solar	Versant - MPD - Wind	Versant - MPD - Hydro
Program Expense	Project PPA Expenses	$86,844,566	$1,824,942	$10,114,157	$13,945,296	$0	$9,976,248	$9,689,946	$0	$73,979
Program Expense	Lost Utility Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
kWh Credit Impact on Supply Cost	kWh Credit Impact on Supply Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0
Program Expense	Program Admin	$230,195	$2,869	$18,408	$97,600	$0	$7,410	$42,672	$0	$911
Energy Resale Revenue	Energy Resale Revenue	$15,105,645	$394,415	$2,379,842	$2,582,983	$0	$1,847,826	$1,788,976	$0	$13,658
Capacity Benefits	Capacity Buyout Revenue	$0	$0	$357,330	$0	$0	$0	$0	$0	$0
T&D Benefits	Interconnection upgrade benefits	$41,605	$0	$31,192	$14,690	$0	$1,115	$11,458	$0	$245
Capacity Benefits	Uncleared capacity value (Intrastate)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capacity Benefits	Uncleared capacity value (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capacity Benefits	Reduced Share of Capacity Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - energy (Intrastate)	$2,111,782	$24,880	$0	$274,760	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - energy (ROP)	$13,533,430	$156,817	$0	$1,762,684	$0	$0	$0	$0	$0
Capacity Benefits	Price suppression - capacity (Intrastate)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capacity Benefits	Price suppression - capacity (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas (Intrastate)	$4,544	$125	$58	$542	$0	$46	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas (ROP)	$68,678	$1,891	$876	$8,190	$0	$701	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas-electric (Intrastate)	$1,178,781	$26,850	$0	$142,746	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas-electric (ROP)	$7,527,102	$164,380	$0	$922,349	$0	$0	$0	$0	$0

Component Category	Components	CMP - Solar	CMP - Wind	CMP - Hydro	Versant - BHD - Solar	Versant - BHD - Wind	Versant - BHD - Hydro	Versant - MPD - Solar	Versant - MPD - Wind	Versant - MPD - Hydro
T&D Benefits	Reduced transmission costs (Intrastate)	$1,855,712	$23,127	$148,396	$434,607	$0	$32,995	$337,177	$0	$7,195
T&D Benefits	Reduced transmission costs (ROP)	$6,711,090	$92,671	$594,620	$853,955	$0	$132,211	$751,128	$0	$28,831
T&D Benefits	Reduced Share of Transmission Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced distribution costs	$1,776,305	$8,482	$69,944	$496,750	$0	$120,150	$386,449	$0	$998
T&D Benefits	Reduced T&D losses - capacity (Intrastate)	$118,154	$1,473	$9,448	$16,798	$0	$1,275	$13,491	$0	$288
T&D Benefits	Reduced T&D losses - capacity (ROP)	$837,841	$11,569	$74,235	$64,718	$0	$10,020	$58,928	$0	$2,262
T&D Benefits	Reduced T&D losses - energy (Intrastate)	$1,726,740	$34,582	$184,129	$147,413	$0	$92,201	$104,364	$0	$792
T&D Benefits	Reduced T&D losses - energy (ROP)	$1,483,796	$22,689	$62	$114,812	$0	$30	$0	$0	$0
Reliability Benefits	Improved generation reliability (Intrastate)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reliability Benefits	Improved generation reliability (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
GHG and Environmental Benefits	Non-embedded GHG emissions	$19,517,315	$432,113	$2,551,997	$2,543,168	$0	$2,042,620	$1,978,467	$0	$16,959
RPS Cost Reductions	Reduced RPS Obligation	$0	$0	$0	$0	$0	$0	$0	$0	$0
RPS Cost Reductions	REC Price Suppression (Intrastate)	$0	$0	$0	$0	$0	$0	$0	$0	$0
RPS Cost Reductions	REC Price Suppression (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0

A.2 kWh Credit Program (2024) – Societal Perspective

Component Category	Components	CMP - BTM Solar	Versant - BHD - BTM Solar	Versant - MPD - BTM Solar	CMP - FTM Solar	Versant - BHD - FTM Solar	Versant - MPD - FTM Solar
Program Expense	Project PPA Expenses	$0	$0	$0	$0	$0	$0
Program Expense	Lost Utility Revenues	$14,315,264	$3,859,796	$1,299,895	$35,867,310	$7,232,130	$1,255,953
kWh Credit Impact on Supply Cost	kWh Credit Impact on Supply Cost	$1,504,841	$194,721	$87,421	$3,428,783	$391,052	$66,833
Program Expense	Program Admin	$0	$0	$0	$293,574	$141,894	$27,791
Energy Resale Revenue	Energy Resale Revenue	$0	$0	$0	$0	$0	$0
Capacity Benefits	Capacity Buyout Revenue	$0	$0	$0	$0	$0	$0
T&D Benefits	Interconnection upgrade benefits	$0	$0	$0	$60,736	$13,767	$163
Capacity Benefits	Uncleared capacity value (Intrastate)	$36,391	$2,002	$141	$1,040	$594	$265
Capacity Benefits	Uncleared capacity value (ROP)	$334,642	$18,407	$1,296	$9,568	$5,459	$2,440
Capacity Benefits	Reduced Share of Capacity Costs	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - energy (Intrastate)	$401,621	$81,606	$0	$1,491,263	$233,957	$0
Energy Price Suppression	Price suppression - energy (ROP)	$2,624,711	$530,437	$0	$9,446,847	$1,478,425	$0
Capacity Benefits	Price suppression - capacity (Intrastate)	$118,726	$6,766	$0	$4,257	$2,204	$0
Capacity Benefits	Price suppression - capacity (ROP)	$1,302,667	$74,233	$0	$46,707	$24,180	$0
Energy Price Suppression	Price suppression - electric-gas (Intrastate)	$1,087	$195	$0	$3,278	$476	$0
Energy Price Suppression	Price suppression - electric-gas (ROP)	$16,432	$2,941	$0	$49,549	$7,193	$0
Energy Price Suppression	Price suppression - electric-gas-electric (Intrastate)	$238,434	$45,195	$0	$845,496	$122,829	$0
Energy Price Suppression	Price suppression - electric-gas-electric (ROP)	$1,515,894	$290,015	$0	$5,376,521	$788,443	$0
T&D Benefits	Reduced transmission costs (Intrastate)	$1,320,310	$502,555	$269,258	$1,706,486	$380,568	$84,961
T&D Benefits	Reduced transmission costs (ROP)	$2,080,512	$446,278	$157,092	$5,066,147	$636,700	$93,386
T&D Benefits	Reduced Share of Transmission Costs	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced distribution costs	$11,386,495	$1,928,816	$845,466	$1,141,791	$362,610	$60,452

Component Category	Components	CMP - BTM Solar	Versant - BHD - BTM Solar	Versant - MPD - BTM Solar	CMP - FTM Solar	Versant - BHD - FTM Solar	Versant - MPD - FTM Solar
T&D Benefits	Reduced T&D losses - capacity (Intrastate)	$653,643	$65,451	$13,779	$500,955	$53,995	$5,190
T&D Benefits	Reduced T&D losses - capacity (ROP)	$1,194,806	$47,864	$12,528	$639,505	$50,500	$7,518
T&D Benefits	Reduced T&D losses - energy (Intrastate)	$2,442,968	$143,072	$59,438	$1,454,234	$143,920	$19,881
T&D Benefits	Reduced T&D losses - energy (ROP)	$521,715	$35,101	$0	$1,044,448	$96,943	$0
Reliability Benefits	Improved generation reliability (Intrastate)	$3	$0	$0	$9	$0	$0
Reliability Benefits	Improved generation reliability (ROP)	$25	$0	$0	$82	$0	$0
GHG and Environmental Benefits	Non-embedded GHG emissions	$6,039,742	$1,056,639	$406,642	$14,040,550	$2,166,799	$317,601
RPS Cost Reductions	Reduced RPS Obligation	$932,912	$162,581	$63,232	$2,125,641	$326,507	$48,340
RPS Cost Reductions	REC Price Suppression (Intrastate)	$0	$0	$0	$0	$0	$0
RPS Cost Reductions	REC Price Suppression (ROP)	$0	$0	$0	$0	$0	$0

A.3 Tariff Rate Program (2024) – Maine Perspective

Component Category	Components	CMP - Solar	CMP - Wind	CMP - Hydro	Versant - BHD - Solar	Versant - BHD - Wind	Versant - BHD - Hydro	Versant - MPD - Solar	Versant - MPD - Wind	Versant - MPD - Hydro
Program Expense	Project PPA Expenses	$86,844,566	$1,824,942	$10,114,157	$13,945,296	$0	$9,976,248	$9,689,946	$0	$73,979
Program Expense	Lost Utility Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
kWh Credit Impact on Supply Cost	kWh Credit Impact on Supply Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0
Program Expense	Program Admin	$230,195	$2,869	$18,408	$97,600	$0	$7,410	$42,672	$0	$911
Energy Resale Revenue	Energy Resale Revenue	$15,105,645	$394,415	$2,379,842	$2,582,983	$0	$1,847,826	$1,788,976	$0	$13,658
Capacity Benefits	Capacity Buyout Revenue	$0	$0	$357,330	$0	$0	$0	$0	$0	$0
T&D Benefits	Interconnection upgrade benefits	$41,605	$0	$31,192	$14,690	$0	$1,115	$11,458	$0	$245
Capacity Benefits	Uncleared capacity value (Intrastate)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capacity Benefits	Uncleared capacity value (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capacity Benefits	Reduced Share of Capacity Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - energy (Intrastate)	$2,111,782	$24,880	$0	$274,760	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - energy (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capacity Benefits	Price suppression - capacity (Intrastate)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capacity Benefits	Price suppression - capacity (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas (Intrastate)	$4,544	$125	$58	$542	$0	$46	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas-electric (Intrastate)	$1,178,781	$26,850	$0	$142,746	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas-electric (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0

Component Category	Components	CMP - Solar	CMP - Wind	CMP - Hydro	Versant - BHD - Solar	Versant - BHD - Wind	Versant - BHD - Hydro	Versant - MPD - Solar	Versant - MPD - Wind	Versant - MPD - Hydro
T&D Benefits	Reduced transmission costs (Intrastate)	$1,855,712	$23,127	$148,396	$434,607	$0	$32,995	$337,177	$0	$7,195
T&D Benefits	Reduced transmission costs (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced Share of Transmission Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced distribution costs	$1,776,305	$8,482	$69,944	$496,750	$0	$120,150	$386,449	$0	$998
T&D Benefits	Reduced T&D losses - capacity (Intrastate)	$231,675	$2,887	$18,526	$32,937	$0	$2,501	$26,453	$0	$564
T&D Benefits	Reduced T&D losses - capacity (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced T&D losses - energy (Intrastate)	$1,726,740	$34,582	$184,129	$147,413	$0	$92,201	$104,364	$0	$792
T&D Benefits	Reduced T&D losses - energy (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reliability Benefits	Improved generation reliability (Intrastate)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reliability Benefits	Improved generation reliability (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
GHG and Environmental Benefits	Non-embedded GHG emissions	$19,517,315	$432,113	$2,551,997	$2,543,168	$0	$2,042,620	$1,978,467	$0	$16,959
RPS Cost Reductions	Reduced RPS Obligation	$0	$0	$0	$0	$0	$0	$0	$0	$0
RPS Cost Reductions	REC Price Suppression (Intrastate)	$0	$0	$0	$0	$0	$0	$0	$0	$0
RPS Cost Reductions	REC Price Suppression (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0

A.4 kWh Credit Program (2024) – Maine Perspective

Component Category	Components	CMP - BTM Solar	Versant - BHD - BTM Solar	Versant - MPD - BTM Solar	CMP - FTM Solar	Versant - BHD - FTM Solar	Versant - MPD - FTM Solar
Program Expense	Project PPA Expenses	$0	$0	$0	$0	$0	$0
Program Expense	Lost Utility Revenues	$14,315,264	$3,859,796	$1,299,895	$35,867,310	$7,232,130	$1,255,953
kWh Credit Impact on Supply Cost	kWh Credit Impact on Supply Cost	$1,504,841	$194,721	$87,421	$3,428,783	$391,052	$66,833
Program Expense	Program Admin	$0	$0	$0	$293,574	$141,894	$27,791
Energy Resale Revenue	Energy Resale Revenue	$0	$0	$0	$0	$0	$0
Capacity Benefits	Capacity Buyout Revenue	$0	$0	$0	$0	$0	$0
T&D Benefits	Interconnection upgrade benefits	$0	$0	$0	$60,736	$13,767	$163
Capacity Benefits	Uncleared capacity value (Intrastate)	$36,391	$2,002	$141	$1,040	$594	$265
Capacity Benefits	Uncleared capacity value (ROP)	$0	$0	$0	$0	$0	$0
Capacity Benefits	Reduced Share of Capacity Costs	$859,542	$162,167	$48,641	$2,961,331	$355,941	$44,486
Energy Price Suppression	Price suppression - energy (Intrastate)	$401,621	$81,606	$0	$1,491,263	$233,957	$0
Energy Price Suppression	Price suppression - energy (ROP)	$0	$0	$0	$0	$0	$0
Capacity Benefits	Price suppression - capacity (Intrastate)	$118,726	$6,766	$0	$4,257	$2,204	$0
Capacity Benefits	Price suppression - capacity (ROP)	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas (Intrastate)	$1,087	$195	$0	$3,278	$476	$0
Energy Price Suppression	Price suppression - electric-gas (ROP)	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas-electric (Intrastate)	$238,434	$45,195	$0	$845,496	$122,829	$0
Energy Price Suppression	Price suppression - electric-gas-electric (ROP)	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced transmission costs (Intrastate)	$1,320,310	$502,555	$269,258	$1,706,486	$380,568	$84,961
T&D Benefits	Reduced transmission costs (ROP)	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced Share of Transmission Costs	$1,395,730	$461,901	$0	$3,194,819	$657,667	$0
T&D Benefits	Reduced distribution costs	$11,386,495	$1,928,816	$845,466	$1,141,791	$362,610	$60,452

Component Category	Components	CMP - BTM Solar	Versant - BHD - BTM Solar	Versant - MPD - BTM Solar	CMP - FTM Solar	Versant - BHD - FTM Solar	Versant - MPD - FTM Solar
T&D Benefits	Reduced T&D losses - capacity (Intrastate)	$1,281,652	$128,336	$27,017	$982,266	$105,872	$10,176
T&D Benefits	Reduced T&D losses - capacity (ROP)	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced T&D losses - energy (Intrastate)	$2,442,968	$143,072	$59,438	$1,454,234	$143,920	$19,881
T&D Benefits	Reduced T&D losses - energy (ROP)	$0	$0	$0	$0	$0	$0
Reliability Benefits	Improved generation reliability (Intrastate)	$3	$0	$0	$9	$0	$0
Reliability Benefits	Improved generation reliability (ROP)	$0	$0	$0	$0	$0	$0
GHG and Environmental Benefits	Non-embedded GHG emissions	$6,039,742	$1,056,639	$406,642	$14,040,550	$2,166,799	$317,601
RPS Cost Reductions	Reduced RPS Obligation	$932,912	$162,581	$63,232	$2,125,641	$326,507	$48,340
RPS Cost Reductions	REC Price Suppression (Intrastate)	$0	$0	$0	$0	$0	$0
RPS Cost Reductions	REC Price Suppression (ROP)	$0	$0	$0	$0	$0	$0

A.5 Tariff Rate Program (2024) – Ratepayer Perspective

Component Category	Components	CMP - Solar	CMP - Wind	CMP - Hydro	Versant - BHD - Solar	Versant - BHD - Wind	Versant - BHD - Hydro	Versant - MPD - Solar	Versant - MPD - Wind	Versant - MPD - Hydro
Program Expense	Project PPA Expenses	$86,844,566	$1,824,942	$10,114,157	$13,945,296	$0	$9,976,248	$9,689,946	$0	$73,979
Program Expense	Lost Utility Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
kWh Credit Impact on Supply Cost	kWh Credit Impact on Supply Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0
Program Expense	Program Admin	$230,195	$2,869	$18,408	$97,600	$0	$7,410	$42,672	$0	$911
Energy Resale Revenue	Energy Resale Revenue	$15,105,645	$394,415	$2,379,842	$2,582,983	$0	$1,847,826	$1,788,976	$0	$13,658
Capacity Benefits	Capacity Buyout Revenue	$0	$0	$357,330	$0	$0	$0	$0	$0	$0
T&D Benefits	Interconnection upgrade benefits	$41,605	$0	$31,192	$14,690	$0	$1,115	$11,458	$0	$245
Capacity Benefits	Uncleared capacity value (Intrastate)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capacity Benefits	Uncleared capacity value (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capacity Benefits	Reduced Share of Capacity Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - energy (Intrastate)	$2,111,782	$24,880	$0	$274,760	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - energy (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capacity Benefits	Price suppression - capacity (Intrastate)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capacity Benefits	Price suppression - capacity (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas (Intrastate)	$4,544	$125	$58	$542	$0	$46	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas-electric (Intrastate)	$1,178,781	$26,850	$0	$142,746	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas-electric (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0

Component Category	Components	CMP - Solar	CMP - Wind	CMP - Hydro	Versant - BHD - Solar	Versant - BHD - Wind	Versant - BHD - Hydro	Versant - MPD - Solar	Versant - MPD - Wind	Versant - MPD - Hydro
T&D Benefits	Reduced transmission costs (Intrastate)	$1,855,712	$23,127	$148,396	$434,607	$0	$32,995	$337,177	$0	$7,195
T&D Benefits	Reduced transmission costs (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced Share of Transmission Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced distribution costs	$1,776,305	$8,482	$69,944	$496,750	$0	$120,150	$386,449	$0	$998
T&D Benefits	Reduced T&D losses - capacity (Intrastate)	$231,675	$2,887	$18,526	$32,937	$0	$2,501	$26,453	$0	$564
T&D Benefits	Reduced T&D losses - capacity (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced T&D losses - energy (Intrastate)	$1,156,916	$23,170	$123,367	$98,767	$0	$61,775	$69,924	$0	$531
T&D Benefits	Reduced T&D losses - energy (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reliability Benefits	Improved generation reliability (Intrastate)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reliability Benefits	Improved generation reliability (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
GHG and Environmental Benefits	Non-embedded GHG emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0
RPS Cost Reductions	Reduced RPS Obligation	$0	$0	$0	$0	$0	$0	$0	$0	$0
RPS Cost Reductions	REC Price Suppression (Intrastate)	$0	$0	$0	$0	$0	$0	$0	$0	$0
RPS Cost Reductions	REC Price Suppression (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0

A.6 kWh Credit Program (2024) – Ratepayer Perspective

Component Category	Components	CMP - BTM Solar	Versant - BHD - BTM Solar	Versant - MPD - BTM Solar	CMP - FTM Solar	Versant - BHD - FTM Solar	Versant - MPD - FTM Solar
Program Expense	Project PPA Expenses	$0	$0	$0	$0	$0	$0
Program Expense	Lost Utility Revenues	$14,315,264	$3,859,796	$1,299,895	$35,867,310	$7,232,130	$1,255,953
kWh Credit Impact on Supply Cost	kWh Credit Impact on Supply Cost	$1,504,841	$194,721	$87,421	$3,428,783	$391,052	$66,833
Program Expense	Program Admin	$0	$0	$0	$293,574	$141,894	$27,791
Energy Resale Revenue	Energy Resale Revenue	$0	$0	$0	$0	$0	$0
Capacity Benefits	Capacity Buyout Revenue	$0	$0	$0	$0	$0	$0
T&D Benefits	Interconnection upgrade benefits	$0	$0	$0	$60,736	$13,767	$163
Capacity Benefits	Uncleared capacity value (Intrastate)	$36,391	$2,002	$141	$1,040	$594	$265
Capacity Benefits	Uncleared capacity value (ROP)	$0	$0	$0	$0	$0	$0
Capacity Benefits	Reduced Share of Capacity Costs	$859,542	$162,167	$48,641	$2,961,331	$355,941	$44,486
Energy Price Suppression	Price suppression - energy (Intrastate)	$401,621	$81,606	$0	$1,491,263	$233,957	$0
Energy Price Suppression	Price suppression - energy (ROP)	$0	$0	$0	$0	$0	$0
Capacity Benefits	Price suppression - capacity (Intrastate)	$118,726	$6,766	$0	$4,257	$2,204	$0
Capacity Benefits	Price suppression - capacity (ROP)	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas (Intrastate)	$1,087	$195	$0	$3,278	$476	$0
Energy Price Suppression	Price suppression - electric-gas (ROP)	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas-electric (Intrastate)	$238,434	$45,195	$0	$845,496	$122,829	$0
Energy Price Suppression	Price suppression - electric-gas-electric (ROP)	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced transmission costs (Intrastate)	$1,320,310	$502,555	$269,258	$1,706,486	$380,568	$84,961
T&D Benefits	Reduced transmission costs (ROP)	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced Share of Transmission Costs	$1,395,730	$461,901	$0	$3,194,819	$657,667	$0
T&D Benefits	Reduced distribution costs	$11,386,495	$1,928,816	$845,466	$1,141,791	$362,610	$60,452

Component Category	Components	CMP - BTM Solar	Versant - BHD - BTM Solar	Versant - MPD - BTM Solar	CMP - FTM Solar	Versant - BHD - FTM Solar	Versant - MPD - FTM Solar
T&D Benefits	Reduced T&D losses - capacity (Intrastate)	$1,281,652	$128,336	$27,017	$982,266	$105,872	$10,176
T&D Benefits	Reduced T&D losses - capacity (ROP)	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced T&D losses - energy (Intrastate)	$1,636,788	$95,858	$39,823	$974,337	$96,427	$13,320
T&D Benefits	Reduced T&D losses - energy (ROP)	$0	$0	$0	$0	$0	$0
Reliability Benefits	Improved generation reliability (Intrastate)	$0	$0	$0	$0	$0	$0
Reliability Benefits	Improved generation reliability (ROP)	$0	$0	$0	$0	$0	$0
GHG and Environmental Benefits	Non-embedded GHG emissions	$0	$0	$0	$0	$0	$0
RPS Cost Reductions	Reduced RPS Obligation	$1,398,234	$243,675	$94,771	$3,185,878	$489,364	$72,452
RPS Cost Reductions	REC Price Suppression (Intrastate)	$0	$0	$0	$0	$0	$0
RPS Cost Reductions	REC Price Suppression (ROP)	$0	$0	$0	$0	$0	$0