Status and Cost & Benefit Analysis of Maine's 2024 Solar Market

Prepared for:

Maine Public Utilities Commission

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1 Executive Summary

In the 2023 Legislative session, L.D. 327 "An Act to Provide Maine Ratepayers with Equitable Access to Interconnection of Distributed Generation Resources" was enacted (the Act).[1] The Act directed the Maine Public Utilities Commission (Commission) to "…provide a summary report of its findings under subsection 1 to the joint standing committee of the Legislature having jurisdiction over energy matters" by January 1st of the following calendar year.

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[2], 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.

The Commission has engaged Sustainable Energy Advantage, LLC (SEA) for consulting services to conduct an in-depth, structured, and comprehensive analysis of Maine's solar energy development for calendar year 2024. This document describes SEA's methodology and quantification of the basic trends in the solar markets in calendar year 2024 and the relative cost and benefits of Maine solar installations for projects during the 2024 calendar year 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 Maine's solar energy development for calendar year 2024. A graphical summary of the analysis provided in Figure 1 and a tabular summary in Table 1. Importantly (and with more detail provided in Section 2.4), unless otherwise stated explicitly, the analysis takes a general societal impact perspective (versus, for example, a ratepayer impact perspective).

[1] See http://www.mainelegislature.org/legis/bills/getPDF.asp?paper=SP0148&item=3&snum=131
[2] See https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3474.html

Figure 1 –
Maine's Calendar Year 2024 Solar Energy Development Summary Costs & Benefits in Millions of Dollars

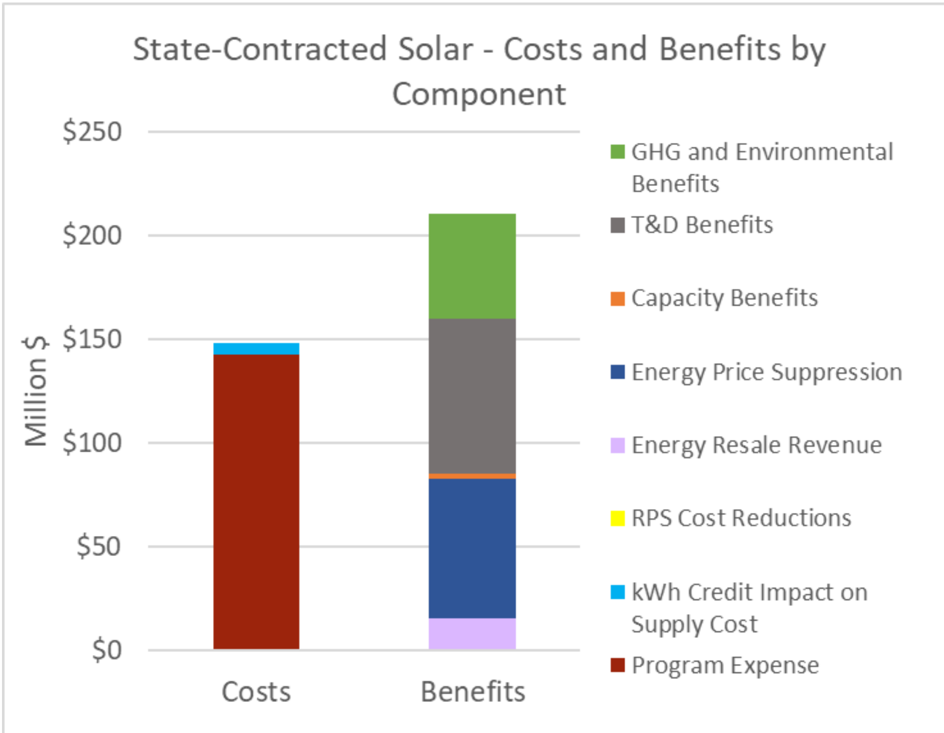


Table 1 -
Maine's Calendar Year 2024 Solar Energy Development Summary Costs & Benefits in Millions of Dollars

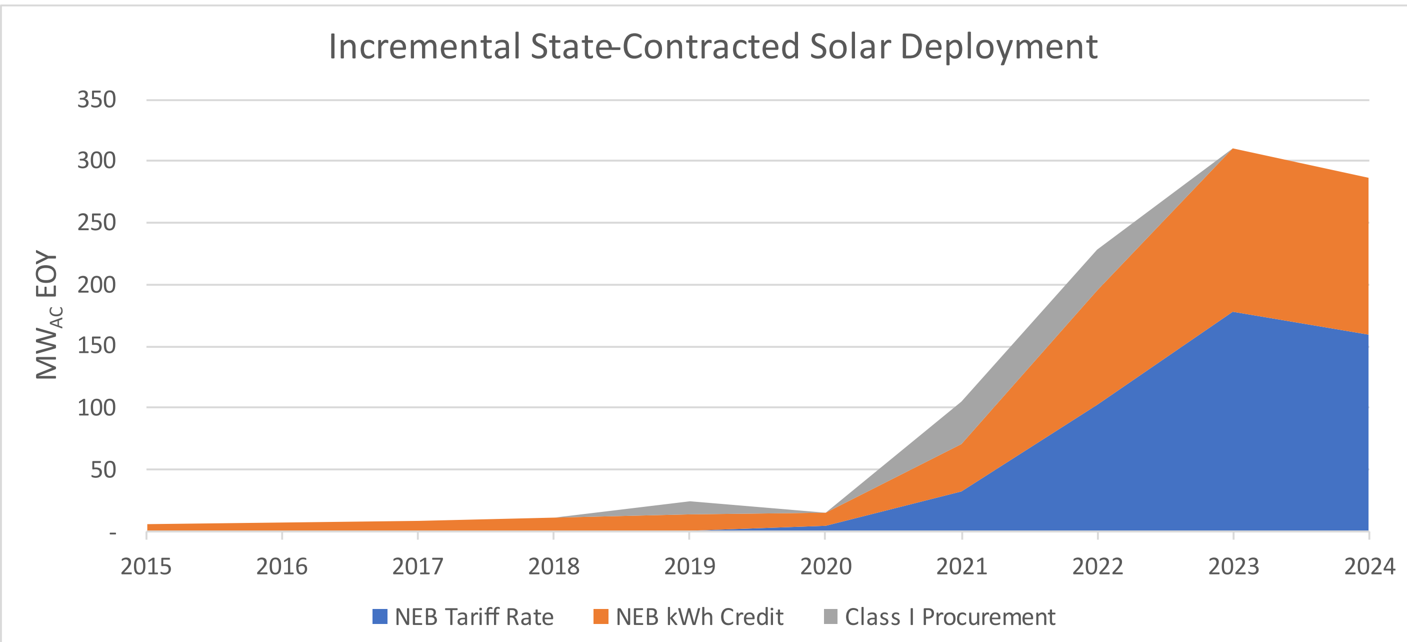
Benefit / Cost Category	Costs	Benefits
Program Expense	$142.66	N/A
kWh Credit Impact on Supply Cost	$5.75	N/A
RPS Cost Reductions	N/A	$0.00
Energy Resale Revenue	N/A	$15.75
Energy Price Suppression	N/A	$67.11
Capacity Benefits	N/A	$2.66
Transmission and Distribution (T&D) Benefits	N/A	$74.44
GHG and Environmental Benefits	N/A	$50.51
Totals	$148.41	$210.48

SEA calculates that in calendar year 2024 program expenses for solar projects were $148.41 million and the program benefits for solar projects were $210.48 million. Note that these numbers include the costs and benefits for all NEB and renewable procurement solar 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 and to a lesser extent the renewable procurements (see Figure 2) which are estimated to end calendar year 2024 with an installed capacity of 935.4 and 77.3 MW_{AC} respectively.

Likely drivers of the growth included the open-ended structure of the NEB program (i.e., no MW cap) with a large addressable market and favorable economics; this occurred even with the headwinds of a difficult interconnection environment.

Figure 2 –
Incremental Maine Solar Development by Calendar Year and Program Type



2 Introduction

In the 2023 Legislative session, L.D. 327 "An Act to Provide Maine Ratepayers with Equitable Access to Interconnection of Distributed Generation Resources" was enacted (the Act).[3] The Act directed the Maine Public Utilities Commission (Commission) to "…provide a summary report of its findings under subsection 1 to the joint standing committee of the Legislature having jurisdiction over energy matters" by January 1st of the following calendar year.

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

[3] See http://www.mainelegislature.org/legis/bills/getPDF.asp?paper=SP0148&item=3&snum=131

2.1 LD 327 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[4], as well as the basic trends in solar energy markets, and the relative costs and benefits from solar energy development, <u>including but not limited to</u>:

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 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

SEA has endeavored to conduct a detailed, bottom-up analysis practicable within the legislatively mandated schedule and data constraints. As such, in coordination with the Commission, SEA conducted a comprehensive review of publicly available data to support the legislatively mandated analysis. 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. We note the following data was incorporated into this analysis.

- Some data leveraged are currently publicly available. For example, data from the
    - AESC 2024 study;
    - CMP and Versant monthly NEB reports (see Docket 2020-00199).
- Some data leveraged will become publicly available. For example, monthly data that will be submitted as a component of the EDC stranded cost filings.
- Some data are confidential and will remain so per SEA's non-disclosure agreement with the EDCs. For example, hourly production data for individual projects. As applicable, SEA aggregates data reported to respect confidentiality.
- Given the January 1, 2025 requirement for submitting a calendar year 2024 analysis, some data for the last few months of 2024 were not available at the time of report drafting in December 2024. SEA's approach to estimation of missing data is discussed in Section 3.1.

[4] See https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3474.html

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
Revenue from the sale of renewable energy credits	Revenue from the sale of renewable energy certificates (RECs). We note that this benefit was quantified separately from other benefits, as it is not a benefit transferred to the EDC through contracts for projects operational in 2024.
Societal benefits through avoided greenhouse gas emissions	Societal Benefits from Greenhouse Gas (GHG) Reduction
Reduced electricity prices	SEA quantified the following benefits associated with reduced electricity prices: • Energy Resale Revenue • Energy Demand reduction induced price effects (DRIPE) • Cross-Fuel DRIPE
Avoided or reduced costs associated with electricity capacity requirements	SEA quantified the following benefits associated with recued capacity costs: • Capacity Buyout Revenue • Uncleared Capacity Value • Capacity DRIPE • Reduced Share of Capacity Costs
Avoided or reduced costs associated with environmental compliance requirements	AESC 2024 does not include a benefit for avoided NOx emissions. Given this and considering that such benefits are *de minimis* compared to other benefit components, this component is not modeled. However, it is worth noting that some degree of costs associated with environmental compliance are embedded within energy prices, and thus are still considered in this analysis to the extent that energy re-sale revenue avoids such costs.
Avoided or reduced costs associated with portfolio requirements established in section 3210	Avoided/Reduced Costs Associated with RPS Requirements
Avoided or reduced costs associated with renewable energy credit price suppression	REC price suppression
Avoided or reduced costs associated with electricity transmission and distribution (T&D) costs	SEA quantified the following benefits related to reduced T&D costs: • Avoided Transmission Upgrades • Avoided Distribution Upgrades • Avoided Transmission and Distribution Line Losses • T&D plant extensions or upgrades funded by solar project sponsors

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. Various perspectives have been applied to related energy efficiency evaluation analyses, but importantly for this analysis the question is whether to take:[5]

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

Given that the Act requires the consideration of GHG benefits, a general societal impact perspective is justified in that GHG benefits relate to the global impact of emissions, as opposed to impacts specific to Maine or, more specifically, Maine ratepayers.

A Maine-only societal impact perspective also 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 solar project 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 for a subset of our analysis.

3 Detailed Approach to Modeling

3.1 General Issues and Approach

The Act requires an analysis of all program-supported solar development. The two programs supporting development assessed in this analysis are:

- The Net Energy Billing (NEB) Program – The NEB program, in its current form, functions like a combination of a net metering program and a virtual net metering program open to distributed generation 5 MW_{AC} and under; and
- Renewable Procurements – SEA's analysis focused on projects in operation in 2024. A majority of such projects were selected in a 2015 procurement pursuant to 35-A M.R.S. §3210-C and Chapter 316 of the PUC rules. A single project was selected through the community based renewable energy pilot program pursuant to 35-A M.R.S. §3602 and Chapter 325 of the PUC rules. These procurements involve competitive bidding for distributed and utility-scale renewable energy. Notably, the procurements do not necessarily require RECs to be included as a product taken title to by the EDC via a resulting Power Purchase Agreement (PPA).

[5] For example, see https://docs.cpuc.ca.gov/published/FINAL_DECISION/105926-03.htm

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)[6] 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.
- Several considerations are specific to the NEB program.
    - First, the NEB program is comprised of two program variants:
        - 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. For the purpose of the analysis of the kWh Credit program in this report, SEA focuses exclusively on the benefits and costs of solar PV.
        - The Tariff Rate program, which provides monetary credits on the EDC electric bills of program participants. Tariff Rate projects include non-solar projects. To produce results for only solar projects, 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.[7]
            - 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.[8]
    - 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 approach differs 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).

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[6] 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.
[7] See 35-A MRSA §3209-B(5)(A), here: https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3209-B.html
[8] See 35-A MRSA §3209-B(5)(A-1), here: https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3209-B.html

  - 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 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.
- Renewable procurements generally select larger resources as compared to the NEB program. As such, SEA assumed that such facilities are transmission-connected (as opposed to NEB projects which are assumed to be distribution-connected). This assumption has implications for the calculation of T&D benefits, as discussed in various sections below. In addition, projects may or may not include the sale of RECs to the EDC under PPAs. However, it is SEA's understanding that none of the selected solar projects operational in 2024 included the sale of RECs to the utility. As such, REC revenue was not included in the benefit stack for such projects (but is discussed separately, see Section Quantification of REC Revenue4.2).

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.[9]

Lastly, given the January 1, 2025 requirement for submitting a calendar year 2024 report, some data for the last few months of 2024 were not available at the time of report drafting in December 2024.[10] To address this, SEA indexed 2024 data available YTD (through September for CMP and through October for Versant) to 2023 data for each applicable component, such that the share of benefits/costs realized during the missing months was consistent with the shares realized in calendar year 2023. This adjustment was applied to kWh from FTM generation, payments to projects, and energy re-sale revenue.

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

[9] 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
[10] Versant provided data through October whereas CMP provided data through September

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.

- **Production Data:** The approach to quantifying production varied by program variant, discussed below.
  - **Renewable Procurement:** The EDCs provided hourly production data for all solar facilities procured through renewable procurements.
  - **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 of 60% to reflect that projects typically achieve commercial operation in the second half of the year. 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 September 31, 2024. Given this data does not cover all of 2024, SEA estimated the total capacity of NEB projects reaching commercial operation in 2024 based on the average monthly capacity installed YTD. 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. Renewable Procurement solar project capacities were provided to SEA by the EDCs and verified with public data.

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.

<u>Data Source</u>

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

<u>Discussion</u>

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 procured and in the NEB program do not physically avoid the consumption of energy, in the context of renewable procurement and the NEB Tariff Rate program variant, the analogous benefit is energy re-sale revenue.

3.5 Capacity Buyout Revenue

<u>Overview</u>

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

<u>Data Source</u>

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

<u>Discussion</u>

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, instead projects are treated as "load reducers". For Renewable Procurement projects, the EDCs reported that, after commercially reasonable efforts, all projects failed to obtain capacity supply obligations. 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 EDCs in the region 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.[11] 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.

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 renewable procurement facilities and NEB Tariff Rate projects) do not accrue this benefit.

Data Source:

AESC 2024 inputs were utilized.

Discussion:

[11] 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

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 Maine 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.[12] 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.

Transmission benefits are only applicable to projects connected to the distribution system, as transmission-connected facilities do not reduce transmission-level load. As such, renewable procurement facilities connected to the transmission system are not assumed to accrue this benefit. 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:

To calculate the estimated load reductions on the transmission system during peak periods resulting from DG projects, SEA calculated the annual peak 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.

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

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[12] 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/

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). Transmission-connected facilities (which are assumed to include renewable procurement facilities) and NEB 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 (expressed as a percent of nameplate capacity), as described above. The coincident factor was then used to calculate the reductions in RNS expenses, per MW, for each technology assessed.

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.

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. Transmission-connected facilities (which are assumed to include renewable procurement facilities) do not accrue this benefit.

Data Source:

To compute energy-related benefits, SEA utilized EDC-specific line losses, provided by level of service (e.g., secondary, primary, sub-transmission).[13] 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.[14]
To compute capacity-related benefits, SEA utilized AESC 2024 recommended transmission and distribution marginal capacity line losses, as discussed below.[15]

Discussion:
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.

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 appropriate share is a difficult task. Nonetheless, inclusion of such investments as a benefit component is required by statue. 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.

[13] 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
[14] See page 11: https://www.iso-ne.com/static-assets/documents/2023/03/transmission_planning_technical_guide_app_j_load_modeling.pdf
[15] See page 100: https://www.synapse-energy.com/sites/default/files/inline-images/AESC%202024%20May%202024.pdf

As such, SEA assumed that 25% of total interconnection costs paid to fund system upgrades were shared benefits based on SEA's professional judgment.[16] Given that the actual share of costs delivering shared benefit may be different, SEA conducted a sensitivity analysis assuming either 100%, 50%, or 0% share of costs delivered shared benefits. A table providing the range of benefits, program wide, by assumption is provided below in Table 3:

Table 3 –
T&D Upgrade Benefits – Sensitivity Results

Share of costs assumed to deliver shared benefits	Program-Wide Benefits (Million $)
0%	0.00
25%	0.35
50%	0.70
100%	1.40

3.9 Demand Reduction Induced Price Effects (DRIPE)

<u>Overview:</u>
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").

<u>Data Source:</u>
AESC 2024 (Counterfactual #5) DRIPE values specific to Maine were utilized.

<u>Discussion:</u>
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 or kWh Credit program projects, for which hourly data was not available. For renewable procurement projects, actual hourly production data was used for each EDC.

Given that Energy DRIPE and Cross-Fuel DRIPE values are partially a function of the underlying price of electricity each year, SEA supplemented AESC-forecasted LMPs with actual LMPs through September.

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.

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[16] 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.

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.

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.[17] 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 the NEB program and participating through procurements 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 3.15.5. This is because, from the general societal perspective, REC revenue is considered a cost

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

shift from buyers to sellers of RECs, and thus cancels out to zero net benefits (putting aside small transaction costs). Nonetheless, LD 327 requires a quantification of such benefits. To address this requirement, SEA describes estimated revenues in Section 4.2.

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.[18] 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.

[18] 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.

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.

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.[19]

3.14 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.

Renewable Procurements: The cost of procured facilities was provided by the EDCs on an aggregate basis and is a function of each facility's production multiplied by the facility's applicable PPA rate. Given that procured projects are expected to be transmission-connected, SEA added costs associated with the integration of transmission-connected facilities applicable to such projects. Costs per MWh of transmission-connected solar was derived from National Renewable Energy Laboratory (NREL) analysis and was broken out by intrastate and "Rest of Pool" (ROP) impacts.[20]

Tariff Rate Program:

[19] 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.
[20] See Gorman et al. 2019, here: https://eta-publications.lbl.gov/sites/default/files/td_costs_formatted_final.pdf

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 3.15, 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.

Administrative Costs:

In addition to per-kWh program expenses, SEA collected total costs associated with the administration of the solar program from the EDCs. CMP provided costs associated with the NEB program only, while Versant provided costs for both renewable procurement and the NEB program. 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.

3.15 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.[21] 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

[21] 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.

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 4 describes generally the impact of the kWh Credit program for various LSE cost/benefit drivers. From Table 4, 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 3.15.4 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 3.15.5.

Table 4 – 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 3.15.5 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 3.15.4 for a detailed discussion

3.15.1 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.

3.15.2 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 3.15.3) 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 3.15.3 for further discussion.

3.15.3 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 5 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 5 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 5 –
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%

3.15.3.1 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 6; the total average FE LSE DS revenue is $721,313,110.

Table 6 –
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 5 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 7 –
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 5, 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 5, 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[22] 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.

3.15.4 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.[23]

We demonstrate this in Table 8, 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

[22] 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*.

[23] 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 8 – 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.[24] 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.[25]
    - 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.

3.15.5 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.

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[24] 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.

[25] 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 9 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.[26] 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 9 –
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.

[26] 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

3.15.6 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 Maine solar programs for calendar year 2024 is provided below, with a graphical summary of the analysis provided in Figure 3 and a tabular summary in Table 10. 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 3 –
Calendar Year 2024 Maine Solar Programs Summary Costs and Benefits

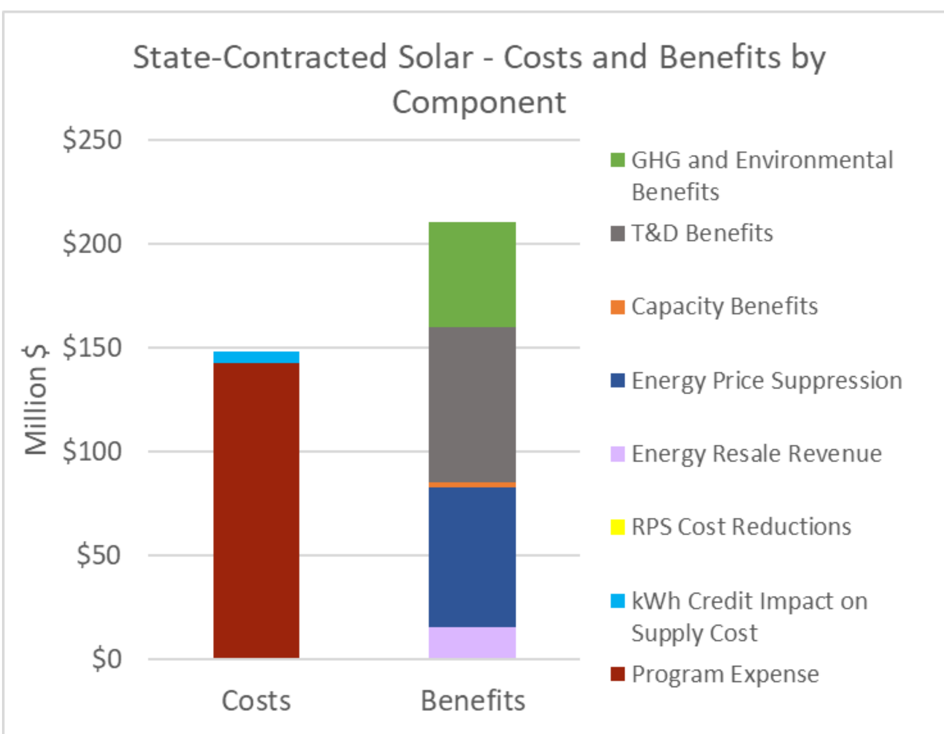


Table 10 -
Calendar Year 2024 Maine Solar Programs Summary Cost and Benefit in Millions of Dollars

Benefit / Cost Category	Costs	Benefits
Program Expense	$142.66	N/A
kWh Credit Impact on Supply Cost	$5.75	N/A
Renewable Portfolio Standard (RPS) Cost Reductions	N/A	$0.00
Energy Resale Revenue	N/A	$15.75
Energy Price Suppression	N/A	$67.11
Capacity Benefits	N/A	$2.66
T&D Benefits	N/A	$74.44
GHG and Environmental Benefits	N/A	$50.51
Totals	$148.41	$210.48

SEA calculates that the Maine solar programs 2024 calendar year program expenses were $148.41 million, and the program benefits were $210.48 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.

Figure 4 and Table 11 provide a summary of the Maine solar program costs and benefits by the program described in Section 3.1. Solar projects from both the NEB program and renewable procurements are found to have benefits exceeding costs.

Figure 4 –
2024 Maine Solar Programs Summary Costs and Benefits in Millions of Dollars

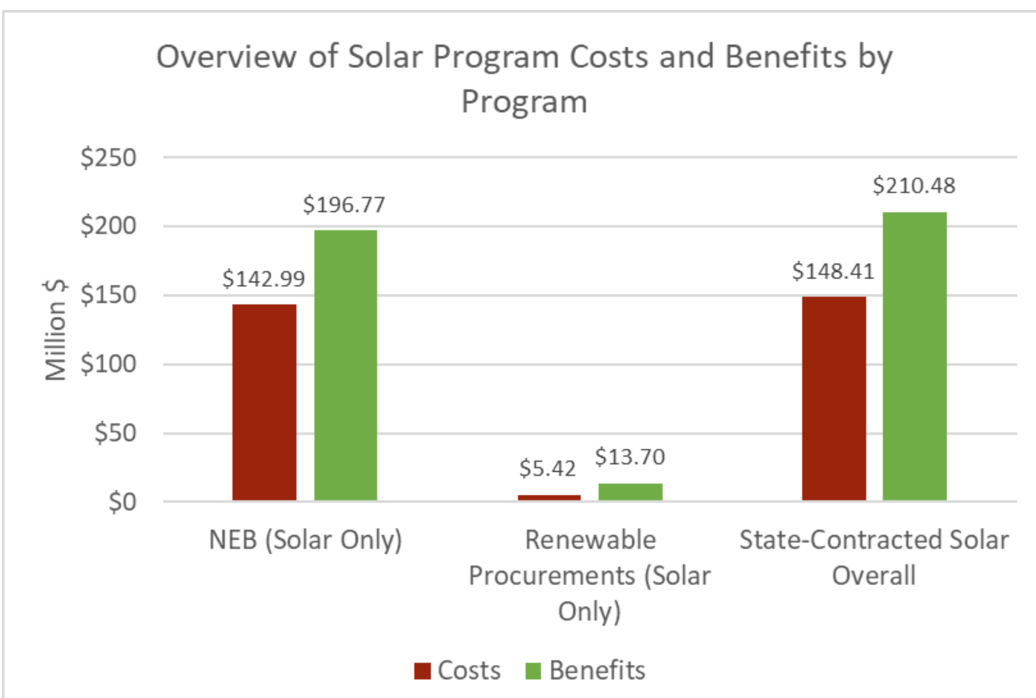


Table 11 -
2024 Maine Solar Programs Summary Costs and Benefits in Millions of Dollars

Program Variant	Costs	Benefits	Benefit-Cost Ratio
NEB Program for Solar Projects	$142.99	$196.77	1.38
Renewable Procurement Solar Projects	$5.42	$13.70	2.53
Total – Solar Projects	$148.41	$210.48	1.42

Next, Figure 5 provides a summary of the Maine solar programs costs and benefits on a million dollar per MW_{AC} basis. The solar only projects for the NEB program have benefits exceeding costs by about a 38% margin, while the solar only renewable procurement projects have benefits exceeding costs by more than a 2:1 margin.

Figure 5 –
2024 Maine Solar Program Summary of Costs and Benefits per MW

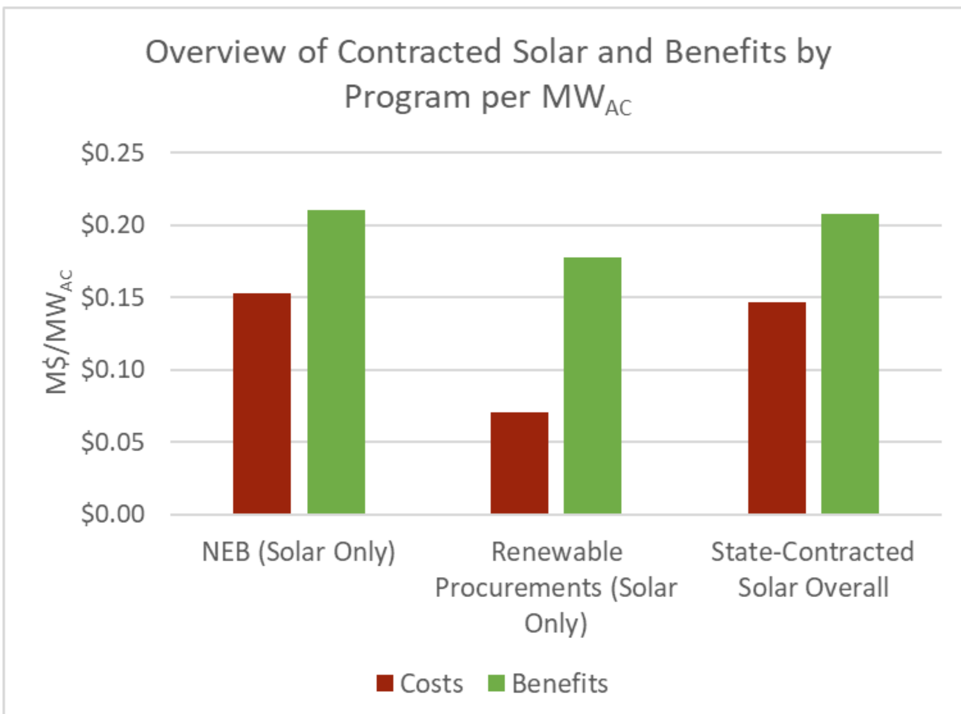


Table 12 provides a breakdown of component categories by total value, whereas Table 13 provides such figures on a million dollar per MW_{AC} basis for apples-to-apples comparisons across programs. A discussion of the relative benefits and costs of each program is provided below in approximate order of significance:

- **Program Costs:** The costs for the solar components of the NEB and renewable procurements are (as noted above) a fraction of the total benefits.
- **T&D Benefits**: While T&D benefits are a significant fraction of NEB program benefits, the renewable procurements have no T&D benefits. This occurs because we assume the renewable procurement projects are interconnected at the transmission system level, while all the NEB projects are interconnected at the distribution level.
- **GHG and Environmental Benefits / Energy Price Suppression / RPS Cost Reductions**: Benefits that are a function of project production (e.g., GHG benefits, energy price suppression, REC price suppression) are roughly equal per-MW for the renewable procurements versus the NEB program. Renewable procurement benefits are slightly higher on

a per-MW basis given such projects are generally larger and are expected to have a higher capacity factor as compared to NEB projects (which includes smaller BTM projects). In addition, procured solar projects were operational for all of 2024, whereas NEB projects continued to come online in 2024, and thus did not realize a full year's worth of production for each MW.

- **Energy Resale Revenue**: The energy resale benefits for the NEB program are much smaller than renewable procurement benefits on a relative basis (to total benefits for each program) because there are no energy resale benefits for the solar production under the NEB kWh Credit program variant.
- **Capacity Benefits:** Capacity Benefits are negligible for the NEB program. Rarely do NEB projects try to qualify for capacity benefits and even fewer successfully qualify. This contrasts to the procured solar projects that typically attempt to qualify for ISO-NE capacity benefits. However, given that the projects assessed in this analysis were unable to obtain competitive capacity supply obligations (CSOs), benefits are negligible for procured projects as well.

Table 12 -
Summary Comparison of NEB Solar vs. Renewable Procurements (Total $)

Benefit / Cost Category	NEB Solar Program (Millions $ or MW_{AC} w/ % of Total Benefits)	Renewable Procurements (Millions $ or MW_{AC} w/ % of Total Benefits)	Renewable Procurements as % of NEB
MW_{AC}	935.39	77.27	8.3%
Program Expense	$137.24	$5.42	3.9%
kWh Credit Impact on Supply Cost	$5.75	$0.00	0.0%
T&D Benefits	$74.42	$0.02	0.0%
GHG and Environmental Benefits	$46.39	$4.12	8.9%
Energy Price Suppression	$61.24	$5.87	9.6%
RPS Cost Reductions	$0.00	$0.00	N/A
Energy Resale Revenue	$12.07	$3.69	30.6%
Capacity Benefits	$2.66	$0.00	0.0%
Total Benefits	$196.77	$13.70	7.0%

Table 13 -
Summary Comparison of NEB Solar vs. Renewable Procurements ($/MW)

Benefit / Cost Category	NEB Solar Program (Millions $/$MW_{AC}$)	Renewable Procurements (Millions $/$MW_{AC}$)	Renewable as % of NEB
Program Expense	$0.147	$0.070	47.8%
kWh Credit Impact on Supply Cost	$0.080	$0.000	0.34%
T&D Benefits	$0.050	$0.053	107.58%
GHG and Environmental Benefits	$0.050	$0.053	107.6%
Energy Price Suppression	$0.065	$0.076	116.1%
RPS Cost Reductions	$0.000	$0.000	N/A
Energy Resale Revenue	$0.013	$0.048	370.0%
Capacity Benefits	$0.003	$0.000	0.0%
Total Benefits	$0.210	$0.177	84.3%

4.2 Quantification of REC Revenue

As discussed in Section 3.11, REC revenue is not accounted for in the benefit stack presented in Section 3.15.5. 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). Nonetheless, the Act requires a quantification of such benefits which is provided below in Table 14.

Table 14 -
Estimated REC Revenue by Solar Program

Program	REC Revenue (M$)
NEB (Solar only)	44.88
Renewable Procurements	4.15
Total	49.03

4.3 Sensitivity Analysis of Maine Societal and Ratepayer Impact 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 15, 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 are only considered a benefit for the Ratepayer Perspective as this benefit represents a cost shift from general ratepayers to facility owners.

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 establishing programs like 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 solar incentive programs.

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.[27] 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.

NOx emission benefits are also included in the Maine Perspective, as such benefits are a more local pollutant (e.g., ground-source ozone) as compared to GHG emissions. However, such benefits are minuscule compared to other benefit components, and thus do not materially impact results. The benefits are excluded from the Ratepayer Perspective.

Table 15 - 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
kWh Credit Impact on Supply Cost	Include	Include	Include
Lost Utility Revenues	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
Non-embedded GHG emissions	Include	Include	Exclude
Reduced RPS Obligation	Exclude	Exclude	Include
REC Price Suppression (Intrastate)	Include	Include	Include
REC Price Suppression (ROP)	Include	Exclude	Exclude

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

Table 16 provides a summary comparison of the cost and benefits by modeling perspective. Overall, the Maine Perspective benefits are slightly less than the solar project program expenses. This is primarily because the Maine Perspective has significantly lower benefits for the RPS Cost Reductions and Energy Price Suppression categories than the Societal Perspective because the Maine Perspective does not include the benefits of the Maine NEB and procurement programs 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). The Program Expense, Energy Resale and GHG benefit and cost categories do not vary from the Societal Perspective to the Maine Perspective. The Ratepayer Perspective is identical to the Societal Perspective apart from marginally higher RPS cost reductions (see Section 3.12) and the exclusion of benefits relating to GHG emissions reductions.

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 16 -
2024 Solar 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	$142.66	N/A	N/A	N/A	100%	100%
kWh Credit Impact on Supply Cost	$5.75	N/A	N/A	N/A	100%	100%
RPS Cost Reductions	N/A	$0.00	$0.00	$5.11	100%	N/A
Energy Resale Revenue	N/A	$15.75	$15.75	$15.75	100.0%	100.0%
Energy Price Suppression	N/A	$67.11	$9.13	$9.13	13.6%	13.6%
Capacity Benefits	N/A	$2.66	$4.83	$4.83	181.8%	181.8%
T&D Benefits	N/A	$74.44	$53.57	$53.57	72.0%	72.0%
GHG and Environmental Benefits	N/A	$50.51	$50.51	$0.00	100.0%	0.0%
Totals	$148.41	$210.48	$133.81	$88.40	63.6%	42.0%

5 Maine Solar Energy Development and Basic Solar Energy Market Trends

LD 327 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,[28] as well as the basic trends in solar energy markets, which state in part the following:

*2. **State solar energy generation goals.** When encouraging the development of solar energy generation, the State shall pursue cost-effective developments, policies and programs that advance the following goals:*

> *A. Ensuring that solar electricity generation, along with electricity generation from other renewable energy technologies, meaningfully contributes to the generation capacity of the State through increasing private investment in solar capacity in the State; [PL 2013, c. 562, §1 (NEW).]*
>
> *B. Ensuring that the production of thermal energy from solar technologies meaningfully contributes to reducing the State's dependence on imported energy sources; [PL 2013, c. 562, §1 (NEW).]*
>
> *C. Ensuring that the production of electricity from solar energy meaningfully contributes to mitigating more costly transmission and distribution investments otherwise needed for system reliability; [PL 2013, c. 562, §1 (NEW).]*
>
> *D. Ensuring that solar energy provides energy that benefits all ratepayers regardless of income level; [PL 2013, c. 562, §1 (NEW).]*
>
> *E. Increasing the number of businesses and residences using solar technology as an energy resource; and [PL 2013, c. 562, §1 (NEW).]*
>
> *F. Increasing the State's workforce engaged in the manufacturing and installation of solar technology. [PL 2013, c. 562, §1 (NEW).]*

The incremental growth in installed NEB and procured solar is provided in provided in Table 17 which is projected to end calendar year 2024 with an installed capacity of 935.4 and 77.3 MW_{AC} respectively. Graphically, the recent large incremental increases in the growth of the NEB program and to a lesser extent the renewable procurements are shown in Figure 6 and cumulatively in Figure 7.

Table 17 -
Incremental Growth in Maine Solar MW_{AC} Installed by Year & Program Type

Year	NEB Tariff Rate	NEB kWh Credit	Renewable Procurement
1994-2015	0.0	17.3	0.0
2016	0.0	7.1	0.0
2017	0.0	8.3	0.0
2018	0.0	11.3	0.0
2019	1.0	12.8	9.9
2020	4.1	10.5	0.0
2021	32.7	38.2	34.2
2022	103.1	91.8	33.2
2023	178.6	131.5	0.0
2024	160.1	126.9	0.0
Total	479.7	455.7	77.3

[28] https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3474.html

Figure 6 –
Incremental Maine Solar Development by Calendar Year and Program Type

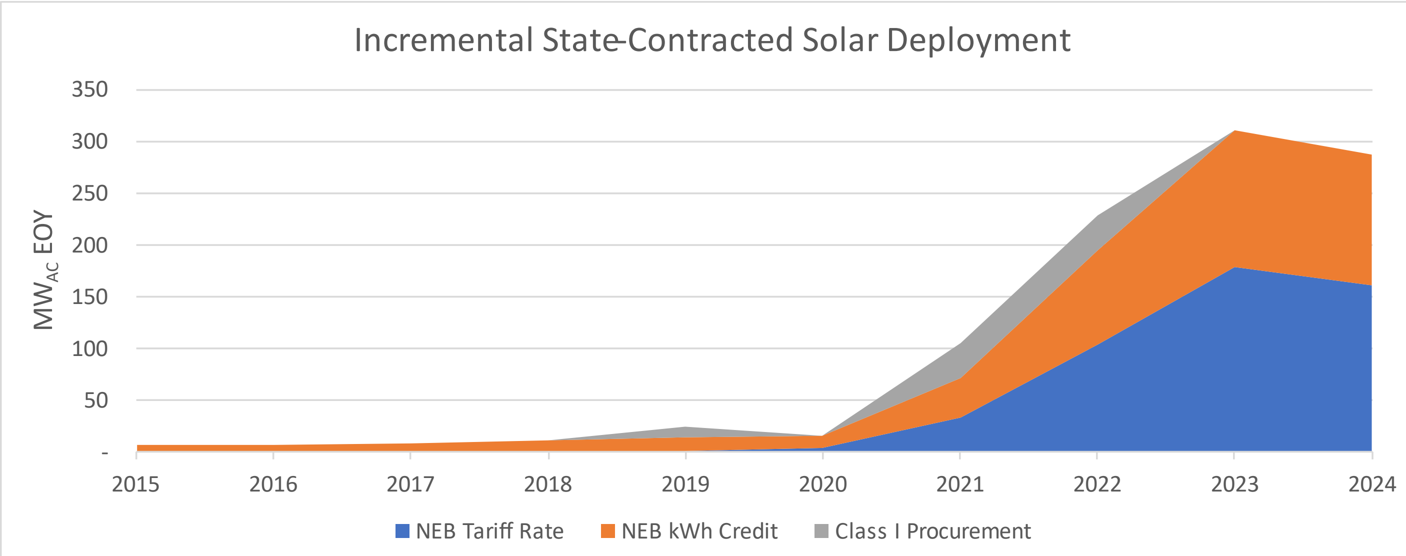
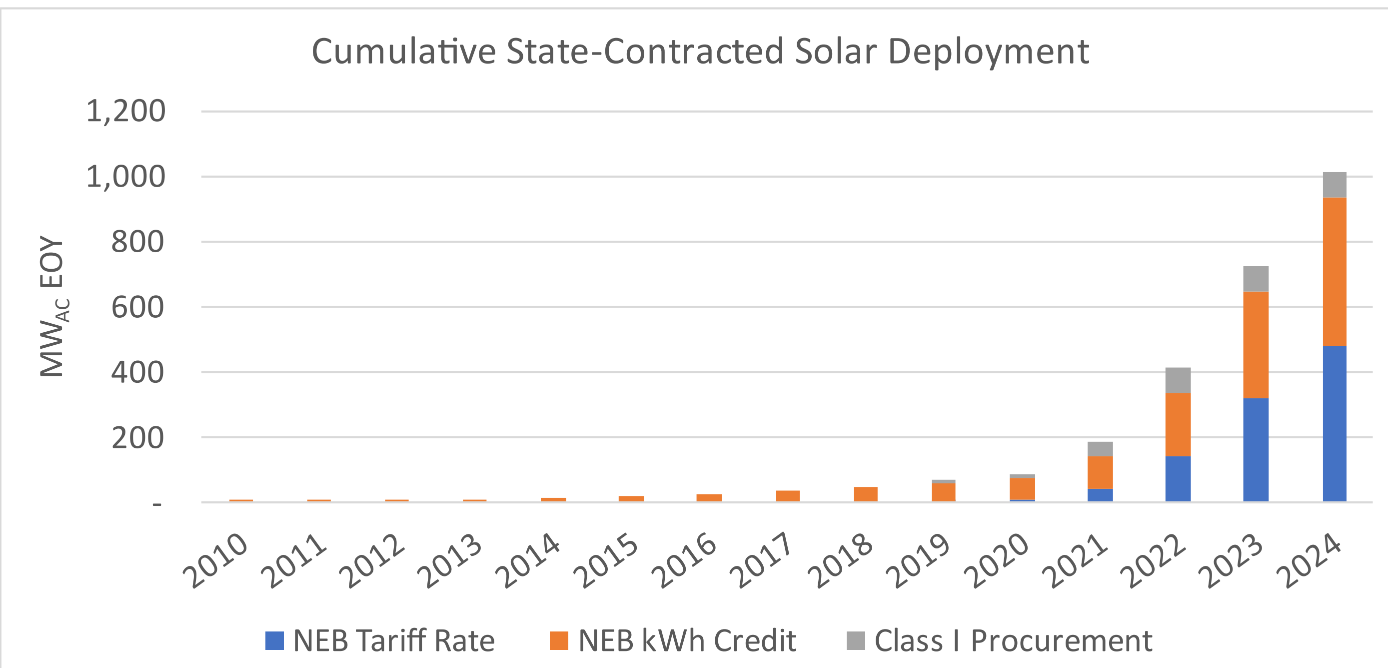


Figure 7 –
Cumulative Maine Solar Development by Calendar Year and Program Type



Likely drivers of the growth included the open-ended structure of the NEB program (i.e., no MW cap) with a large addressable market and favorable economics; this occurred even with the headwinds of a difficult interconnection environment.

As for adherence to Maine's solar energy generation goals, goals A, E and F have been met by the large amount of in-state solar development. Goal D (*Ensuring that solar energy provides energy that benefits all ratepayers regardless of income level*) was more the focus of the Maine Perspective analysis, and it appears that the costs slightly outweigh the benefits from that perspective. At this time, it is unclear whether goals B (*Ensuring that the production of thermal energy from solar technologies meaningfully contributes to reducing the State's dependence on imported energy sources*) and C (*Ensuring that the production of electricity from solar energy meaningfully contributes to mitigating more costly transmission and distribution investments otherwise needed for system reliability*) have been met.

A Appendix A – Component-level Results

A.1 Solar Programs (2024) – Societal Perspective

Component Category	Components	CMP – Procurements	Versant - BHD - Procurements	Versant - MPD - Procurements	CMP - NEB	Versant - BHD - NEB	Versant - MPD - NEB
Program Expense	Project PPA Expenses	$3,231,389	$1,564,177	$0	$51,141,754	$13,406,146	$10,140,017
Program Expense	Lost Utility Revenues	$0	$0	$0	$50,596,565	$9,676,756	$1,410,371
kWh Credit Impact on Supply Cost	SO Cost	$0	$0	$0	$5,040,208	$566,774	$138,321
Program Expense	Program Admin	$0	$15,952	$0	$558,099	$243,925	$67,408
Energy Resale Revenue	Energy Resale Revenue	$1,993,867	$1,693,776	$0	$7,744,605	$2,223,370	$2,098,283
Capacity Benefits	Capacity Buyout Revenue	$0	$0	$0	$0	$0	$0
T&D Benefits	Interconnection upgrade benefits	$5,451	$15,198	$0	$264,932	$42,517	$16,937
Program Expense	Transmission integration costs (Intrastate)	$32,487	$23,453	$0	$0	$0	$0
Program Expense	Transmission integration costs (ROP)	$321,372	$232,008	$0	$0	$0	$0
Capacity Benefits	Capacity Value (Intrastate)	$0	$0	$0	$46,870	$6,180	$1,698
Capacity Benefits	Capacity Value (ROP)	$0	$0	$0	$430,995	$56,825	$15,613
Capacity Benefits	Reduced Share of Capacity Costs	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - energy (Intrastate)	$259,663	$186,439	$0	$4,695,107	$600,991	$0
Energy Price Suppression	Price suppression - energy (ROP)	$1,629,145	$1,173,992	$0	$29,696,746	$3,790,854	$0
Capacity Benefits	Price Suppression - Capacity (Intrastate)	$0	$0	$0	$154,199	$21,339	$0
Capacity Benefits	Price Suppression - Capacity (ROP)	$0	$0	$0	$1,691,874	$234,137	$0
Energy Price Suppression	Price suppression - electric-gas (Intrastate)	$821	$668	$0	$10,621	$1,287	$0
Energy Price Suppression	Price suppression - electric-gas (ROP)	$12,410	$10,099	$0	$160,531	$19,451	$0
Energy Price Suppression	Price suppression - electric-gas-electric (Intrastate)	$193,822	$164,772	$0	$2,692,534	$327,009	$0

Component Category	Components	CMP – Procurements	Versant - BHD - Procurements	Versant - MPD - Procurements	CMP - NEB	Versant - BHD - NEB	Versant - MPD - NEB
Energy Price Suppression	Price suppression - electric-gas-electric (ROP)	$1,220,021	$1,020,166	$0	$17,145,979	$2,096,602	$0
T&D Benefits	Reduced transmission costs (Intrastate)	$0	$0	$0	$17,975,361	$2,541,167	$1,005,624
T&D Benefits	Reduced transmission costs (ROP)	$0	$0	$0	$15,935,217	$2,252,753	$891,489
T&D Benefits	Reduced Share of Transmission Costs	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced distribution costs	$0	$0	$0	$17,026,441	$2,106,482	$528,834
T&D Benefits	Reduced T&D losses - capacity (Intrastate)	$0	$0	$0	$4,151,260	$360,709	$104,034
T&D Benefits	Reduced T&D losses - capacity (ROP)	$0	$0	$0	$2,103,501	$180,266	$54,850
T&D Benefits	Reduced T&D losses - energy (Intrastate)	$0	$0	$0	$1,829,725	$146,113	$22,538
T&D Benefits	Reduced T&D losses - energy (ROP)	$0	$0	$0	$4,445,720	$365,297	$68,991
GHG and Environmental Benefits	Non-embedded GHG emissions	$2,445,333	$1,677,090	$0	$39,425,521	$4,908,218	$2,054,621
RPS Cost Reductions	Reduced RPS Obligation	$0	$0	$0	$0	$0	$0

A.2 Solar Programs (2024) – Maine Perspective

Component Category	Components	CMP – Procurements	Versant - BHD - Procurements	Versant - MPD - Procurements	CMP - NEB	Versant - BHD - NEB	Versant - MPD - NEB
Program Expense	Project PPA Expenses	$3,231,389	$1,564,177	$0	$51,141,754	$13,406,146	$10,140,017
Program Expense	Lost Utility Revenues	$0	$0	$0	$50,596,565	$9,676,756	$1,410,371
kWh Credit Impact on Supply Cost	SO Cost	$0	$0	$0	$5,040,208	$566,774	$138,321
Program Expense	Program Admin	$0	$15,952	$0	$558,099	$243,925	$67,408
Energy Resale Revenue	Energy Resale Revenue	$1,993,867	$1,693,776	$0	$7,744,605	$2,223,370	$2,098,283
Capacity Benefits	Capacity Buyout Revenue	$0	$0	$0	$0	$0	$0
T&D Benefits	Interconnection upgrade benefits	$5,451	$15,198	$0	$264,932	$42,517	$16,937
Program Expense	Transmission integration costs (Intrastate)	$32,487	$23,453	$0	$0	$0	$0
Program Expense	Transmission integration costs (ROP)	$0	$0	$0	$0	$0	$0
Capacity Benefits	Capacity Value (Intrastate)	$0	$0	$0	$46,870	$6,180	$1,698
Capacity Benefits	Capacity Value (ROP)	$0	$0	$0	$0	$0	$0
Capacity Benefits	Reduced Share of Capacity Costs	$0	$0	$0	$4,001,644	$566,440	$36,229
Energy Price Suppression	Price suppression - energy (Intrastate)	$259,663	$186,439	$0	$4,695,107	$600,991	$0
Energy Price Suppression	Price suppression - energy (ROP)	$0	$0	$0	$0	$0	$0
Capacity Benefits	Price Suppression - Capacity (Intrastate)	$0	$0	$0	$154,199	$21,339	$0
Capacity Benefits	Price Suppression - Capacity (ROP)	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas (Intrastate)	$821	$668	$0	$10,621	$1,287	$0
Energy Price Suppression	Price suppression - electric-gas (ROP)	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas-electric (Intrastate)	$193,822	$164,772	$0	$2,692,534	$327,009	$0
Energy Price Suppression	Price suppression - electric-gas-electric (ROP)	$0	$0	$0	$0	$0	$0

Component Category	Components	CMP – Procurements	Versant - BHD - Procurements	Versant - MPD - Procurements	CMP - NEB	Versant - BHD - NEB	Versant - MPD - NEB
T&D Benefits	Reduced transmission costs (Intrastate)	$0	$0	$0	$17,975,361	$2,541,167	$1,005,624
T&D Benefits	Reduced transmission costs (ROP)	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced Share of Transmission Costs	$0	$0	$0	$4,730,417	$654,644	$45,652
T&D Benefits	Reduced distribution costs	$0	$0	$0	$17,026,441	$2,106,482	$528,834
T&D Benefits	Reduced T&D losses - capacity (Intrastate)	$0	$0	$0	$4,151,260	$360,709	$104,034
T&D Benefits	Reduced T&D losses - capacity (ROP)	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced T&D losses - energy (Intrastate)	$0	$0	$0	$1,829,725	$146,113	$22,538
T&D Benefits	Reduced T&D losses - energy (ROP)	$0	$0	$0	$0	$0	$0
GHG and Environmental Benefits	Non-embedded GHG emissions	$2,445,333	$1,677,090	$0	$39,425,521	$4,908,218	$2,054,621
RPS Cost Reductions	Reduced RPS Obligation	$0	$0	$0	$0	$0	$0

A.3 Solar Programs (2024) – Ratepayer Perspective

Component Category	Components	CMP – Procurements	Versant - BHD – Procurements	Versant - MPD - Procurements	CMP - NEB	Versant - BHD - NEB	Versant - MPD - NEB
Program Expense	Project PPA Expenses	$3,231,389	$1,564,177	$0	$51,141,754	$13,406,146	$10,140,017
Program Expense	Lost Utility Revenues	$0	$0	$0	$50,596,565	$9,676,756	$1,410,371
kWh Credit Impact on Supply Cost	SO Cost	$0	$0	$0	$5,040,208	$566,774	$138,321
Program Expense	Program Admin	$0	$15,952	$0	$558,099	$243,925	$67,408
Energy Resale Revenue	Energy Resale Revenue	$1,993,867	$1,693,776	$0	$7,744,605	$2,223,370	$2,098,283
Capacity Benefits	Capacity Buyout Revenue	$0	$0	$0	$0	$0	$0
T&D Benefits	Interconnection upgrade benefits	$5,451	$15,198	$0	$264,932	$42,517	$16,937
Program Expense	Transmission integration costs (Intrastate)	$32,487	$23,453	$0	$0	$0	$0
Program Expense	Transmission integration costs (ROP)	$0	$0	$0	$0	$0	$0
Capacity Benefits	Capacity Value (Intrastate)	$0	$0	$0	$46,870	$6,180	$1,698
Capacity Benefits	Capacity Value (ROP)	$0	$0	$0	$0	$0	$0
Capacity Benefits	Reduced Share of Capacity Costs	$0	$0	$0	$4,001,644	$566,440	$36,229
Energy Price Suppression	Price suppression - energy (Intrastate)	$259,663	$186,439	$0	$4,695,107	$600,991	$0
Energy Price Suppression	Price suppression - energy (ROP)	$0	$0	$0	$0	$0	$0
Capacity Benefits	Price Suppression - Capacity (Intrastate)	$0	$0	$0	$154,199	$21,339	$0
Capacity Benefits	Price Suppression - Capacity (ROP)	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas (Intrastate)	$821	$668	$0	$10,621	$1,287	$0
Energy Price Suppression	Price suppression - electric-gas (ROP)	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas-electric (Intrastate)	$193,822	$164,772	$0	$2,692,534	$327,009	$0
Energy Price Suppression	Price suppression - electric-gas-electric (ROP)	$0	$0	$0	$0	$0	$0

Component Category	Components	CMP – Procurements	Versant - BHD – Procurements	Versant - MPD - Procurements	CMP - NEB	Versant - BHD - NEB	Versant - MPD - NEB
T&D Benefits	Reduced transmission costs (Intrastate)	$0	$0	$0	$17,975,361	$2,541,167	$1,005,624
T&D Benefits	Reduced transmission costs (ROP)	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced Share of Transmission Costs	$0	$0	$0	$4,730,417	$654,644	$45,652
T&D Benefits	Reduced distribution costs	$0	$0	$0	$17,026,441	$2,106,482	$528,834
T&D Benefits	Reduced T&D losses - capacity (Intrastate)	$0	$0	$0	$4,151,260	$360,709	$104,034
T&D Benefits	Reduced T&D losses - capacity (ROP)	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced T&D losses - energy (Intrastate)	$0	$0	$0	$1,829,725	$146,113	$22,538
T&D Benefits	Reduced T&D losses - energy (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	$0	$0	$0	$4,432,075	$627,781	$47,677