Final Report of the Distributed Generation Stakeholder Group

Submitted to the Joint Standing Committee on Energy, Utilities and Technology

January 6, 2023

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List of acronyms and terms

AESC	**Avoided Energy Supply Costs in New England study**
BCA	Benefit-Cost Analysis
BCR	Benefit-Cost Ratio
CEIC	Clean Energy Incentive Credit
CHP	Combined heat and power
C&I	Commercial and Industrial
DER	Distributed energy resource
DG	Distributed generation
GEO	Governor's Energy Office
IRA	Inflation Reduction Act
ITC	Investment Tax Credit
kW	Kilowatts
kWh	Kilowatt-hours
LD	Legislative Document
MRS	Maine Revised Statutes
MW	Megawatts
NEB	Net energy billing
NSPM	National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources
OPA	Office of the Public Advocate
PPA	Power Purchase Agreement
PUC	Public Utilities Commission
RBPA	Rate, bill and participant impact analysis
REC	Renewable Energy Credit (or Certificate)
SEA	Sustainable Energy Advantage
Synapse	Synapse Energy Economics
Synapse team	Synapse Energy Economics and Sustainable Energy Advantage
The Act	P.L. 2021 ch. 390 (L.D. 936 An Act To Amend State Laws Relating to Net Energy Billing and the Procurement of Distributed Generation)
The Committee	The Joint Standing Committee on Energy, Utilities and Technology
The Stakeholder Group	The Distributed Generation Stakeholder Group
T&D	Transmission and Distribution

Introduction

The 130th Legislature enacted P.L. 2021 ch. 390 (LD 936 – An Act To Amend State Laws Relating to Net Energy Billing and the Procurement of Distributed Generation, hereafter "the Act") on July 1, 2021. The Act established additional eligibility requirements for distributed generation (DG) resources enrolling in the net energy billing (NEB) programs established by 35-A MRS §3209-A and §3209-B, repealed the requirement that the Maine Public Utilities Commission (PUC) conduct procurements for distributed generation resources under 35-A MRS §3482, and directed the Governor's Energy Office (GEO), in collaboration with the PUC, to convene a stakeholder group to "consider various distributed generation project programs to be implemented between 2024 and 2028[1] and the need for improved grid planning." The Act further directed the submission of two reports by the stakeholder group, the first interim report to be submitted by January 1, 2022, and the second final report to be submitted by January 1, 2023.

Pursuant to the requirements set forth by the Act, the GEO, in collaboration with the PUC, formed the Distributed Generation Stakeholder Group (the Stakeholder Group). The GEO submits this final report, informed by the Stakeholder Group, to the Joint Standing Committee on Energy, Utilities and Technology consistent with the requirements of the Act. **This report does not represent the entire preferences or position of any member of the stakeholder group.** This report is the product of eighteen public stakeholder meetings and work sessions, significant technical analysis, and input from stakeholders and the public.

Summary of this report

This report includes the following sections:

- **Stakeholder Group Process** describes the work of the Distributed Generation Stakeholder Group, including its purpose, all meetings, broad public engagement efforts, and results of those efforts.
- **Existing Distributed Generation Programs** provides an overview of the pre-existing distributed generation programs, primarily the net energy billing programs currently available, as well as the previously-implemented Distributed Generation Procurement.
- **Successor Program** proposes a successor program for distributed generation, consistent with LD 936. The successor program proposed in this section would result in substantial new renewable energy deployment, supporting achievement of Maine's renewable energy and emissions reduction requirements as well as energy storage goals; would result in significant ratepayer benefits, including reducing overall electricity rates for all Maine ratepayers; and would ensure future distributed generation deployment accounts for land use, equity, and other important considerations as well as maximizes access to federal benefits for Maine.

[1] The Stakeholder Group referred to this future program generally as the "successor program," and continues the use of that term throughout this report.

Stakeholder group process

Membership

In establishing the Stakeholder Group, the Act specified a required list of representatives to be appointed to the group to inform its work. The following individuals served as members of the Stakeholder Group. In addition to the input of its members, the Stakeholder Group benefited from expertise and perspective provided by independent experts and advocates that presented during the Stakeholder Group's meetings and members of the public that weighed in through written and verbal comments.

- Dan Burgess, Governor's Energy Office
- Philip Bartlett, Public Utilities Commission
- William Harwood, Office of the Public Advocate
- Anthony Buxton, Preti Flaherty Beliveau & Pachios on behalf of Industrial Energy Consumers Group
- Bob Cleaves, Dirigo Solar
- Peter Cohen, Central Maine Power
- Neal Goldberg, Maine Municipal Association
- Mike Judge, Coalition for Community Solar Access
- Arielle Silver Karsh/David Norman, Versant Power
- Sharon Klein, University of Maine School of Economics
- Fortunat Mueller, ReVision Energy
- Jeremy Payne, Maine Renewable Energy Association
- Jessica Robertson, New Leaf Energy (formerly Borrego)
- Phelps Turner, Conservation Law Foundation
- Amy Winston/Jesse McKinnell, Coastal Enterprises, Inc.

The GEO is grateful to all members of the Stakeholder Group for contributing their time, expertise, and input throughout this extensive process. Numerous members of the public also attended meetings and provided input at multiple times through public comment, written feedback, and participation in work sessions, all of which benefitted the work of the Stakeholder Group. Finally, the work of the Stakeholder Group was also supported with significant time and engagement from staff of various entities, especially members of the GEO:

- Ethan Tremblay, Energy Policy Analyst
- Caroline Colan, Clean Energy Fellow
- Celina Cunningham, Deputy Director

Public Input Process

All meetings of the Stakeholder Group were open to the public, hosted with both in person and virtual attendance allowed, with specified time on the agenda for comment. Written feedback from the public was accepted at any time throughout the process and was specifically solicited for a period of 30-days upon issuing a proposed successor program framework. Feedback from a broader group of experts and interested parties was additionally sought out regarding program considerations for land use and equitable access to the benefits of DG which were identified as priority focus areas by the Stakeholder Group. The GEO hosted two work sessions to discuss these topics and provide an opportunity for additional stakeholder engagement.

Written comments provided throughout the stakeholder process to date, as well as presentations from meetings, meeting summaries, and other materials are available online at https://www.maine.gov/energy/studies-reports-working-groups/current-studies-working-groups/dg-stakeholder-group.

Interim report

As directed by the Act, the Distributed Generation Stakeholder Group submitted an interim report to the Joint Standing Committee on Energy, Utilities and Technology (the Committee) on December 31, 2021. The interim report identified initial areas of consensus established by the Stakeholder Group, discussed holistic grid planning matters, identified a framework for the successor program, and established the process through which the successor program would be designed.

Initial areas of consensus

In order to summarize general principles where the Stakeholder Group found agreement, the interim report established the following consensus statements to describe areas where all members of the Stakeholder Group found themselves in general agreement with one another.

- *Distributed generation resources will play an important role in the state's achievement of greenhouse gas reduction requirements, renewable energy requirements, and goals for continued growth of the clean energy sector.*
- *Distributed generation resources have the potential to produce benefits to the electric system, as well as to the state, through avoided costs as well as resilience, environmental, public health, and economic benefits. The extent to which these benefits should be incorporated as objectives of a successor program requires additional analysis and discussion.*
- *Any program to promote distributed generation resources should be designed in a manner that optimizes net benefits and ratepayer cost-effectiveness and considers resources developed through existing net energy billing programs – as well as considers input from a broad range of stakeholders, and specifically accounts for barriers faced by low- and moderate-income, fixed-income, and historically marginalized communities.*
- *The Stakeholder Group intends to continue working in 2022 to refine the approach for optimizing cost-effectiveness and the manner by which a successor program should pursue these objectives.*

2022 meetings

In 2022, the Stakeholder Group held nine meetings to develop a successor program framework that accounts for several state policy goals and objectives. All meetings were open to the public and included dedicated periods for the public to provide comment. Meetings were primarily held in a hybrid format with attendees joining in-person in Augusta and virtually by Zoom. The content of each meeting in 2022 is summarized in Table 1.

Table 1

Meeting Date	Summary
June 21	GEO staff provided a progress review and status update to the Stakeholder Group covering the group's purpose and directives pursuant to LD 936, the key points of consensus reached in the interim report, and recent legislation and context including the status of the existing net energy billing program. This was followed by a proposed workplan for the final report including a timeline for report development and planning of issue-focused work sessions.
July 19	Stakeholders were provided with a planning template for the issue-focused work sessions aimed at creating continuity across topics and input from diverse stakeholders. Stakeholders discussed key objectives of the issue-focused work sessions and a process for finalizing details and holding work sessions in the fall. As requested by the Stakeholder Group, Central Maine Power and Versant each provided an update on their respective cluster study processes and the current pipeline for solar projects in Maine.
August 31	Technical experts from Synapse Energy Economics, Inc. (Synapse) and Sustainable Energy Advantage, LLC (SEA), who contracted with the GEO to assist in the work of the Stakeholder Group, joined the meeting. The Synapse team presented their proposed study plan, a schedule of work to be completed, and led a workshop to develop the "Maine Test" for cost-effectiveness.
September 20	In their second workshop, the Synapse team shared the feedback they received from stakeholders on the "Maine Test" and the technical details of the finalized test to be used in the cost-benefit analysis of distributed generation. SEA presented detailed background and supporting information for several potential program designs and modeling options to inform their model of projected revenue requirements for a range of supply blocks, or different configurations of distributed generation projects, and the associated results of various program design options.
October 4	The Solar Energy Industries Association (SEIA) presented to the Stakeholder Group on the anticipated impact of the Inflation Reduction Act (IRA) on domestic solar markets, including on supply chains, labor policy, low-income access, domestic content requirements, and siting considerations. Synapse and SEA presented their third workshop to the Stakeholder Group, with a focus on several proposed program designs to be modeled in the benefit-cost analysis. Consultants also discussed proposed supply blocks and potential sensitivities.
October 18	Equity and Access Work Session – See summary below.
October 19	Land Use Work Session – See summary below.
November 17	GEO staff provided a summary and overview of the key takeaways from each of the two issue-focused work sessions: Equity and Access, and Land Use. Synapse led their fourth workshop, a presentation and discussion of the draft benefit-cost and rate impact analyses.

Meeting Date	Summary
November 22	SEA presented draft project revenue requirement modeling results for policy cases 1-4 plus an additional case representing the straw proposal. GEO staff presented the straw proposal or proposed framework for a distributed generation successor program. The presentation included background information on state policy objectives related to distributed generation and outlined how this program proposal meets the requirements laid out by LD 936. The successor program framework was made available for public comment at this time.
December 6	Synapse presented updated modeling results accounting for Stakeholder Group feedback and including the addition of sensitivity analysis results – energy storage, high and low avoided T&D costs, and discount rate sensitivities. The GEO provided an overview of the remaining work to be completed to deliver a final report to the Legislature in early January.
December 20	Synapse presented the results of their economic impact analysis of the hybrid program. GEO staff reviewed and facilitated a discussion on the public comments received in response to the LD 936 Proposed Successor Program Framework.

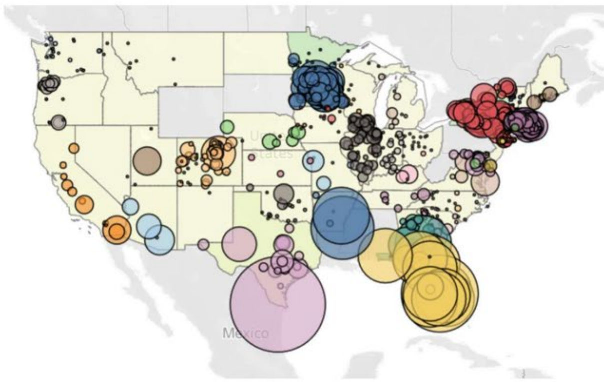
Issue-focused work sessions

In addition to the nine Stakeholder Group meetings, two issue-focused work sessions were hosted by the GEO to obtain broader input from interested parties and subject matter experts. The interim report of the Stakeholder Group called for targeted issue-focused work sessions to engage additional stakeholders and members of the public to obtain input on considerations for the successor program. Considerations related to land use and equitable access to distributed generation benefits were identified as priority areas for additional stakeholder engagement. GEO staff hosted two sessions in October where the public was invited to provide feedback on these topics in the context of a successor program.

Equity and Access

The Equity and Access Work Session consisted of an overview of the Distributed Generation Stakeholder Group, followed by three presentations from subject matter specialists: Jessica Scott, Governor's Office of Policy Innovation and the Future, presented recommendations of the Maine Climate Council Equity Subcommittee related to distributed generation; Jenny Heeter, National Renewable Energy Laboratory, presented findings from a study on community solar deployment, subscription savings, and impact on energy burden; and Max Joel, New York State Energy Research and Development Authority, presented New York's approach to the design and implementation of equitable distributed generation programs, particularly the New York Solar for All program. Figure 1 below presented by Jenny Heeter from the National Renewable Energy Laboratory illustrates the deployment of community solar projects across the country – in total, 30 states have more than 5.2 gigawatts (GW) of community solar installed as of 2022.

Figure 1



Source: Sharing the Sun Database Release

- 30 states have ≥ 5MW of installed community solar
  - New Jersey is the latest state to break 5 MW of installed capacity, moving from 0 to 9 MW installed capacity
  - Fastest growing states in 2021 (based on % capacity) included Texas, Florida, Rhode Island, Maine, and Illinois.
- 10 states and Washington, DC have <5MW of installed community solar
- Some states have no installed community solar

Following the presentations, a panel including the three presenters joined by Megan Hannan, Executive Director of the Maine Community Action Partnership, and Abbe Ramanan, Project Director for the Clean Energy States Alliance, discussed the contents of the presentations, their implications for distributed generation, and key perspectives related to the topics of equity and access. After the panel discussion, all attendees were invited to join breakout rooms to engage in dialogue and share their perspectives on the topic. In total 42 participants joined the session by Zoom.[2]

Key themes discussed at the session included:

- Broad support for a streamlined and accessible program with clear and tangible benefits
- Emphasis on consumer protection
- Program implementation should align with other state climate and efficiency programs
- Broad support for a program that allows DG to be utilized to reduce energy burdens for LMI customers
- Maximize the benefits of the IRA
- Expand the definition of benefits
- Ensure program benefits accrue to all, whether or not they participate

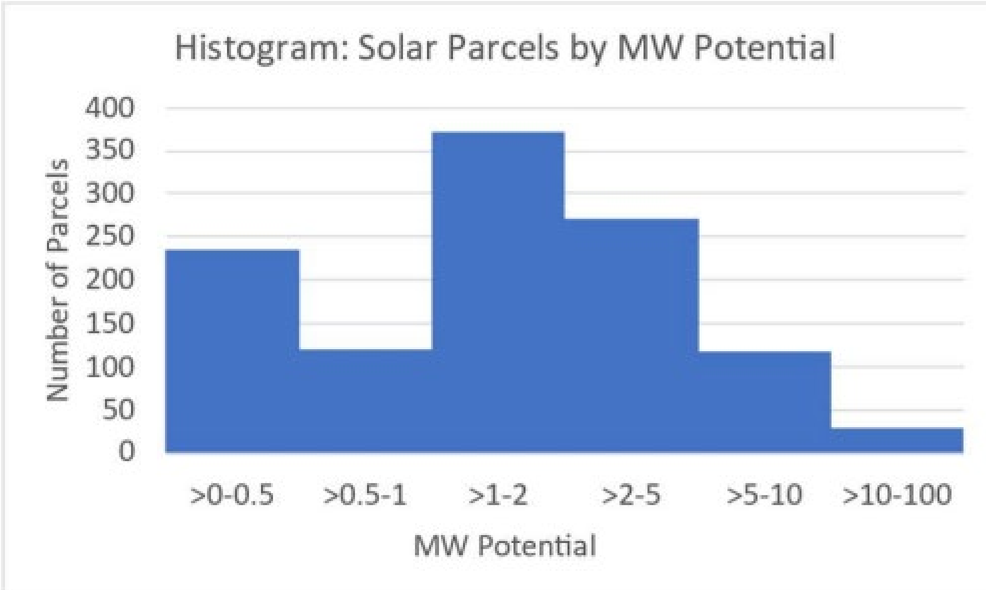
Land Use

The Land Use Work Session similarly consisted of an overview of the Stakeholder Group's work and was followed by three topical presentations: Nancy McBrady, Bureau of Agriculture, Food and Rural Resources at the Maine Department of Agriculture, Conservation and Forestry, provided an overview of the process and key takeaways from the Agricultural Solar Stakeholder Group; Rob Wood, The Nature Conservancy, presented findings from new consultant work on the technical potential for renewable development on disturbed land in Maine; and Eric Sroka, Maine Department of Environmental Protection, provided an overview of the Maine Brownfield Program. Figure 2 is drawn from a

[2] A complete summary of the Equity and Access Work Session is available here: https://www.maine.gov/energy/sites/maine.gov.energy/files/inline-files/Summary%20and%20comments_DG%20Equity%20and%20Access%20Work%20Session_Oct%2018%202022.pdf

presentation by Rob Wood of The Nature Conservancy in Maine, illustrating the estimated solar capacity by parcel on parcels of degraded lands (brownfields, capped landfills, gravel pits, etc.) in the state.

Figure 2



Following the presentations, a panel including the three presenters joined by Eliza Donoghue, Director of Advocacy and Staff Attorney at Maine Audubon, Ellen Griswold, Vice President and Deputy Director at Maine Farmland Trust, Matt Kearns, Chief Development Officer at Longroad Energy, and Neal Goldberg, Legislative Advocate at Maine Municipal Association, discussed the contents of the presentations, their implications for distributed generation, and key perspectives related to the topic of land use. After the panel discussion, all attendees were invited to join breakout rooms to engage in dialogue and share their perspectives on the topic. Forty-five participants joined the session by Zoom.[3]

Key themes discussed at the session included:

- Support for encouraging development in priority areas such as brownfields, while recognizing successful climate mitigation hinges on cost effective renewable deployment
- Improved access to data
- Program design should align with existing state programs and resources
- Maximize the benefits of the IRA
- Need for additional planning capacity at the municipal and regional level
- Desire for standardized regulatory and financial guidance
- Ensure program delivers benefits to ratepayers and communities
- Program design should encourage the pairing of battery storage with DG

[3] A complete summary of the Land Use Work Session is available here: https://www.maine.gov/energy/sites/maine.gov.energy/files/inline-files/Summary%20and%20comments_DG%20Land%20Use%20Session_Oct%2019%202022.pdf

The Inflation Reduction Act

In August 2022, Congress passed the Inflation Reduction Act (IRA), legislation that directs billions of dollars in spending to climate change related programs aimed at accelerating the deployment of clean energy technologies, reducing emissions, lowering energy prices, and building the resiliency of our energy system. This legislation created substantial new opportunities to support and lower the cost of renewable energy projects that often result in incremental costs, such as projects on brownfield sites or projects serving LMI communities.

Pending final guidance from the U.S. Department of the Treasury, bonus federal Investment Tax Credits (ITC) and a future Clean Energy Incentive Credit (CEIC) will be available to qualifying clean energy projects sited in "energy communities"[4] or serving low income or disadvantaged communities as defined by the law. Additionally, the IRA allows all qualified projects 5 MW or less to include certain interconnection costs in their total costs eligible for the ITC or CEIC. The Stakeholder Group agreed that where possible, the successor program should align program design with IRA criteria to maximize cost recovery and minimize program costs while also encouraging resource diversity.

At the time of this report, components of the IRA implementation including guidance pertaining to new ITC, PTC and CEIC eligibility are still in process by a variety of federal government agencies.

[4] As defined by 26 USC § 45(b)(11)(B).

Existing distributed generation programs

Background

In 2019 Maine law changed to encourage the development of distributed generation (DG) resources, which are defined by statute as an electric generating facility with a nameplate capacity of less than 5 megawatts (MW) that uses a renewable fuel or technology and is located in the service territory of a transmission and distribution utility in the State (35-A M.R.S. §3481(5)). The primary mechanisms driving current distributed generation development are the two net energy billing (NEB) programs: kilowatt-hour credit and tariff rate. In 2021, through passage of the Act the Legislature placed a limit on projects eligible to participate and included a goal of 750 MW of distributed generation developed under the net energy billing programs.

Kilowatt-hour credit program

This program is available to all investor-owned utility customers. Through the kilowatt-hour (kWh) credit program, NEB participants receive a credit for every kWh provided to the grid from their distributed generation. These credits can be used to offset future charges on a one-to-one basis during billing periods when the participant uses more energy than they generate. Unused credits expire after one year. (35-A M.R.S. §3209-A.)

Tariff rate program

This program is available to non-residential investor-owned utility customers. Through the tariff rate program, NEB participants enter a twenty-year contract to receive dollar credits for generation provided to the grid at a rate determined annually by the Maine Public Utilities Commission (PUC). These bill credits cannot cause a customer's utility bill to decrease below $0 in any given billing period, and any unused credits expire after one year. (35-A M.R.S. §3209-B.)

In 2022, P.L. 2021 ch. 659 (LD 634) reformed compensation for all C&I tariff projects that did not commence continuous construction efforts by September 1, 2022. The results of this bipartisan reform are summarized below.

Distributed Generation Solicitation

In addition to the net energy billing programs, in 2019 the Legislature directed the PUC to procure up to 375 MW of distributed generation resources through a series of five solicitations, or blocks. The first block was conducted in 2020, but was found uncompetitive by the Commission. The Commission based its ruling on:

- The significant level of attrition in the number of bidders and projects that occurred during each stage of the procurement;
- The observed bid prices and bidding behavior, as well as the ultimate clearing price of greater than 19 cents per kWh, which indicated that the Block 1 bidding did not reflect cost-based bids; and
- Accepting excessively high prices to set the clearing price for Block 1 would drive the results of the remaining four rounds of DG procurement and result in significant costs to ratepayers.

The law also required the Commission to deliver a report to the Joint Standing Committee on Energy, Utilities and Technology with recommendations if the procurement was deemed unsuccessful.[5] In its report, the Commission made the following recommendations:

- Recommendation #1 – Consider modifying the uniform clearing auction structure of the procurement to an alternative structure that promotes bids reflective of actual project costs and does not tie procurement pricing to that of preceding blocks;
- Recommendation #2 – Consider replacing the requirement for the project sponsor to have obtained all federal, state, and local approvals and permits with a requirement that the project sponsor has submitted completed applications for all such approvals;
- Recommendation #3 – Consider making explicit that projects that need ISO-NE I.3.9 approval prior to interconnecting may bid if they have an otherwise unconditional executed interconnection agreement.

In 2021, LD 936 removed the requirement for the Commission to conduct future procurements under this program. As a result, no distributed generation or future procurements are currently operating or planned for development under this program.

Current status

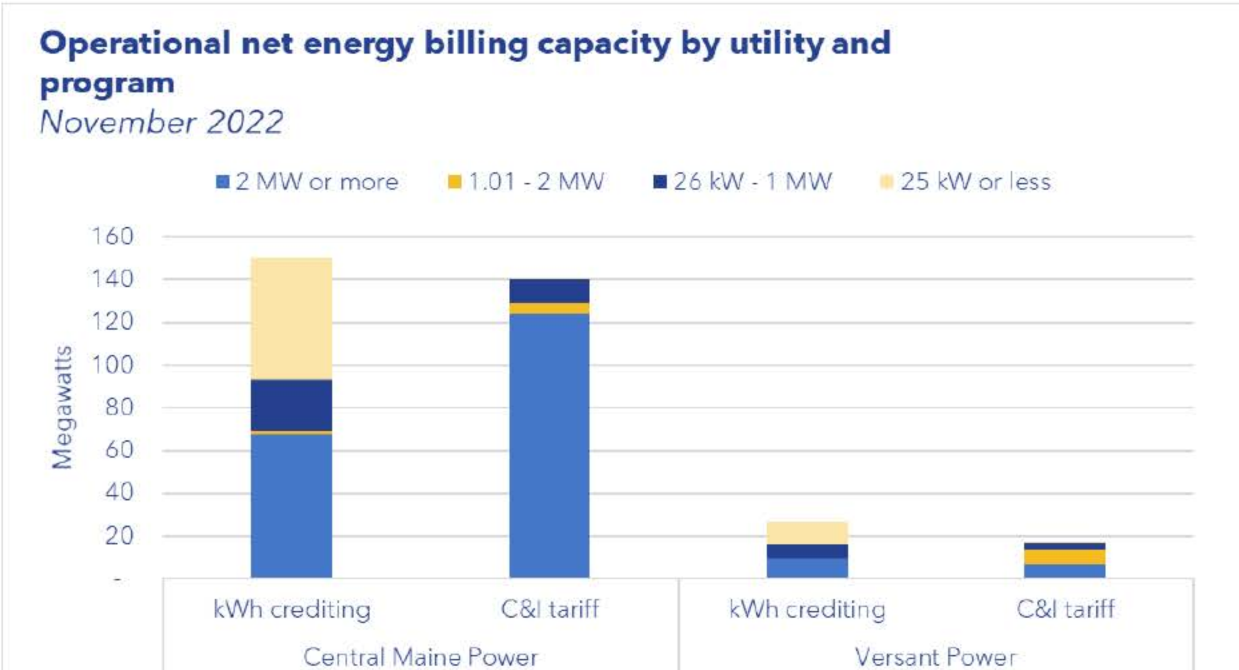
The net energy billing programs have stimulated substantial development of distributed generation resources, driven largely by solar photovoltaic projects. Unless otherwise noted, analysis reported in this section is based on monthly net energy billing reports filed by Central Maine Power and Versant Power in PUC docket 2020-00199 reporting data through November 30, 2022.

Operational projects

As of November 30, 2022, a total of 335 megawatts of operational capacity was enrolled in net energy billing. Of these 335 megawatts, 295 are solar photovoltaic; 30 are hydroelectric; 5 are wind, and the remaining 5 are a variety of combined heat and power (CHP) and biofuel projects. As demonstrated in Figure 3, projects between 2 and 5 megawatts account for 62% of operational net energy billing capacity, with projects less than 25 kilowatts accounting for 20% and the remaining 18% largely projects less than 1 megawatt but more than 25 kilowatts. The smallest projects are likely predominantly rooftop projects, and as a result are almost entirely enrolled in the kWh netting program.

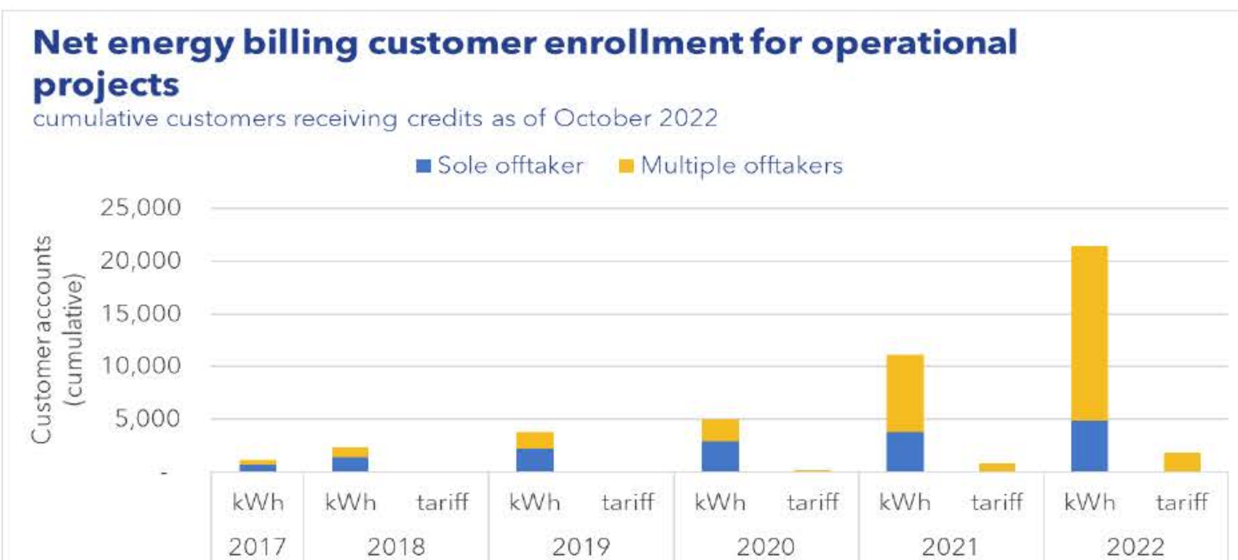
[5] The Commission's Report on Renewable Distributed Generation Solicitation dated November 10, 2020 is available here: https://www.maine.gov/tools/whatsnew/attach.php?id=3590211&an=1

Figure 3



Approximately 23,000 utility customer accounts are currently participating in an operational shared net energy billing arrangement, as illustrated in Figure 4. Not included in this figure are the number of customers who have enrolled with a net energy billing project that is not yet operational, as this data is not available.

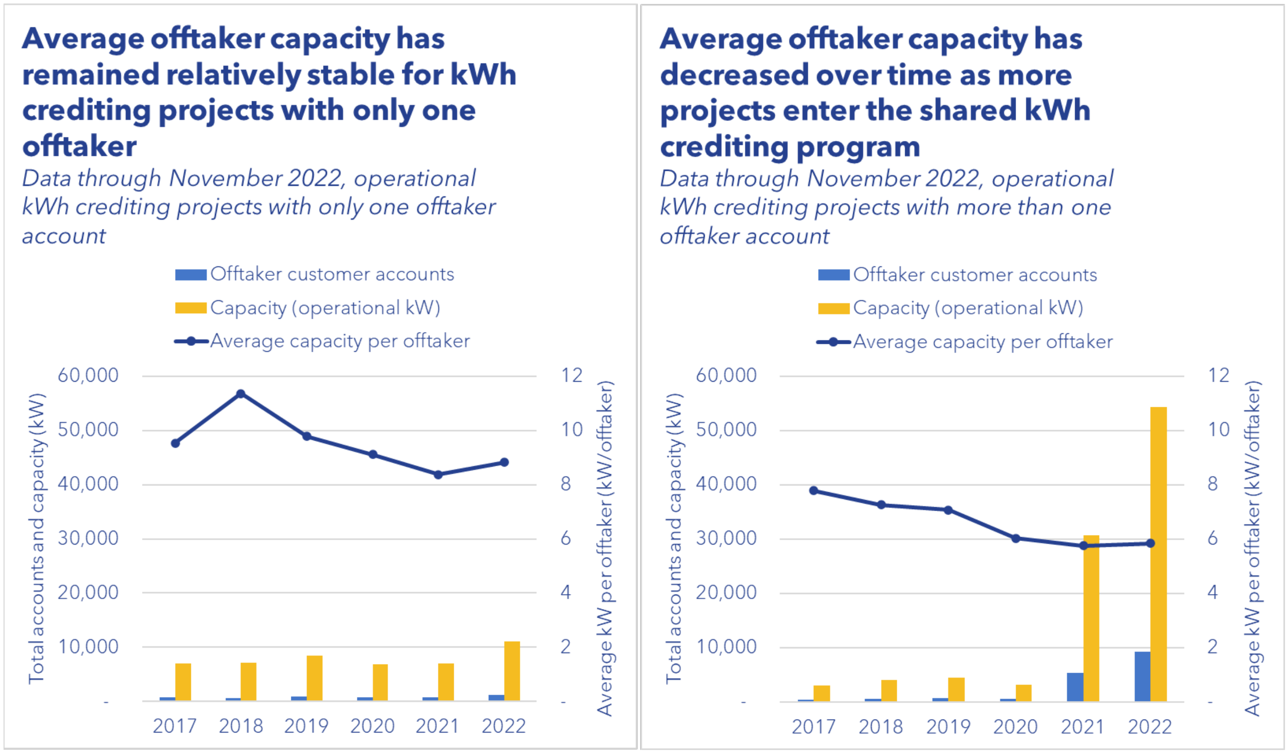
Figure 4



Average offtaker capacity refers to the total operational capacity, in kilowatts, divided by the total number of customer accounts enrolled as offtakers. This metric indicates the average amount of capacity assigned to each offtaker in the program. Figure 5 illustrates the average offtaker capacity in

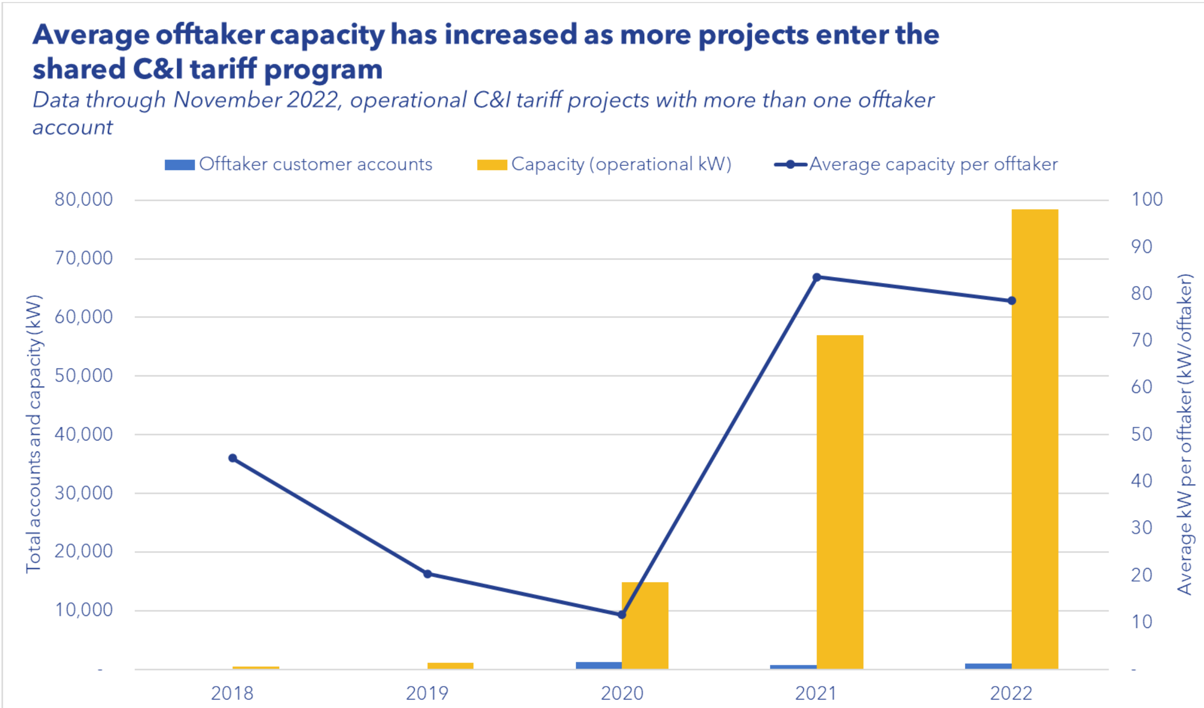
the kWh netting program, on the left for projects with only one offtaker (such as a rooftop solar project serving a single household) and on the right for projects with multiple offtakers (such as a shared community solar project).

Figure 5



Similarly, Figure 6 illustrates the average offtaker capacity in the C&I tariff program. Only projects with multiple offtakers are shown; there are only five operational projects in the C&I tariff program with a single offtaker, and they average 133 kilowatts.

Figure 6



Project pipeline

A total of 1,747 megawatts of capacity is reported in the pipeline for the net energy billing programs. Of this, 1,285 megawatts have executed net energy billing agreements.

As of November 30, 2022, a total of 1,747 megawatts (MW) of distributed generation resources were enrolled in or seeking enrollment in the net energy billing programs. As discussed below, this does not mean these MWs have achieved the necessary milestones to participate in the current programs. These resources are summarized by utility and program type in Figure 7. "Active Not Operational" projects have executed a net energy billing agreement but are not yet operating, and "Pending" projects have applied for a net energy billing agreement but have not yet executed it. Figure 8 presents the same data as Figure 7, separating planned capacity by the net energy billing program in which it has enrolled.

LD 936 established certain milestones that must be met by projects between 2 and 5 megawatts seeking to participate in the net energy billing programs. Milestones required include interconnection agreements, net energy billing agreements, and non-ministerial permits from certain state and local authorities. Furthermore, such projects must reach commercial operation by December 31, 2024 or seek a good-cause exemption from the Commission. On October 5, 2022, the Commission reported a total of 257 projects totaling 1,083 megawatts had certified to the Commission that they had achieved all milestones except for commercial operation.[6]

[6] https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId=%7b1B5C282D-7B4D-41B6-BFD4-868ADB8D6EAC%7d&DocExt=pdf&DocName=%7b1B5C282D-7B4D-41B6-BFD4-868ADB8D6EAC%7d.pdf

Figure 7

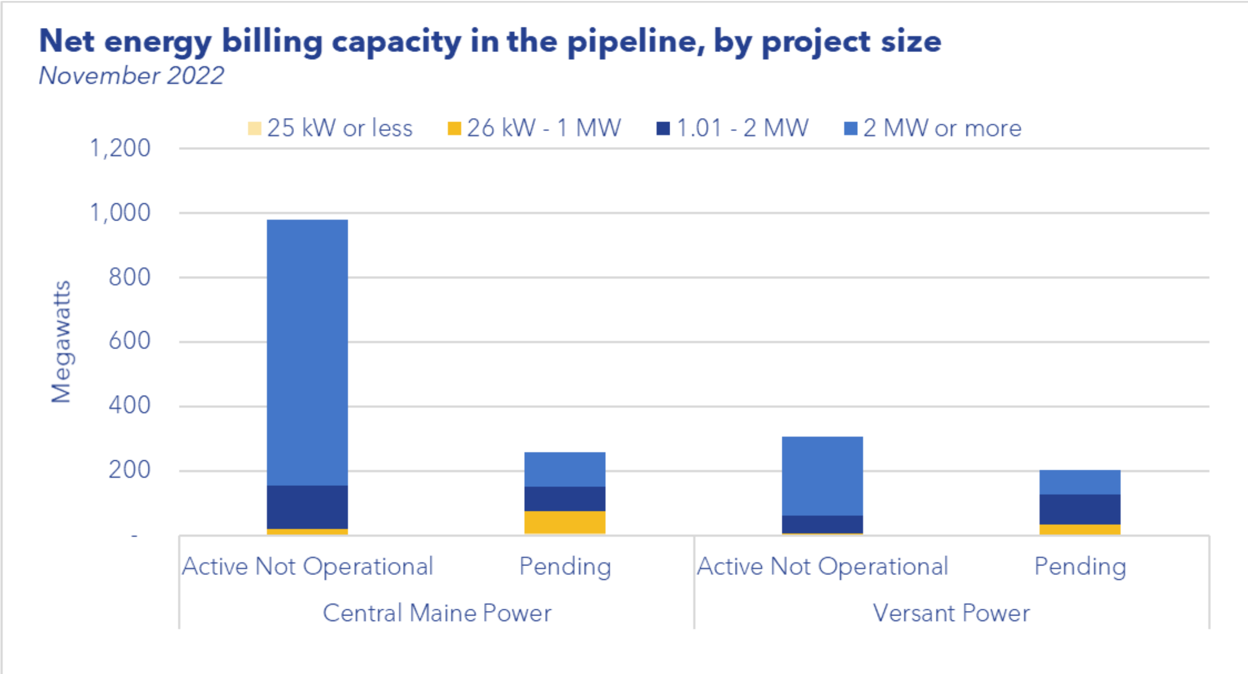
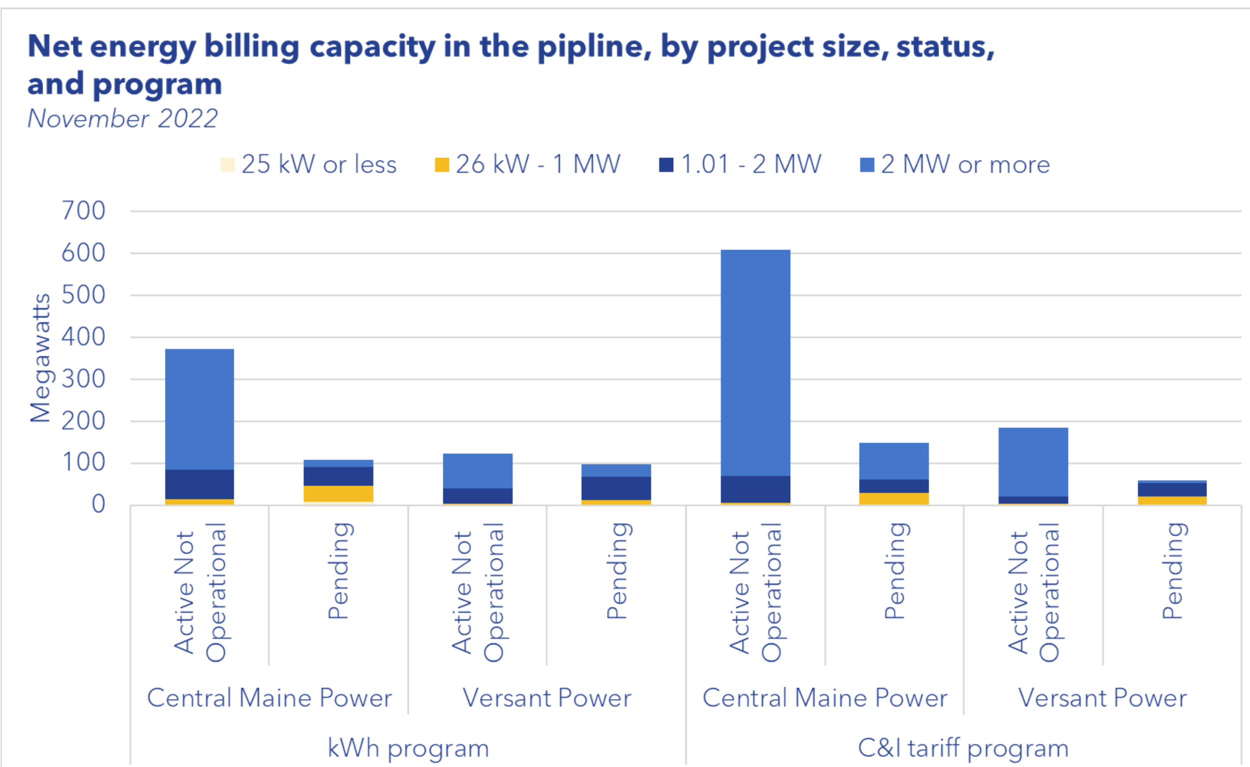


Figure 8



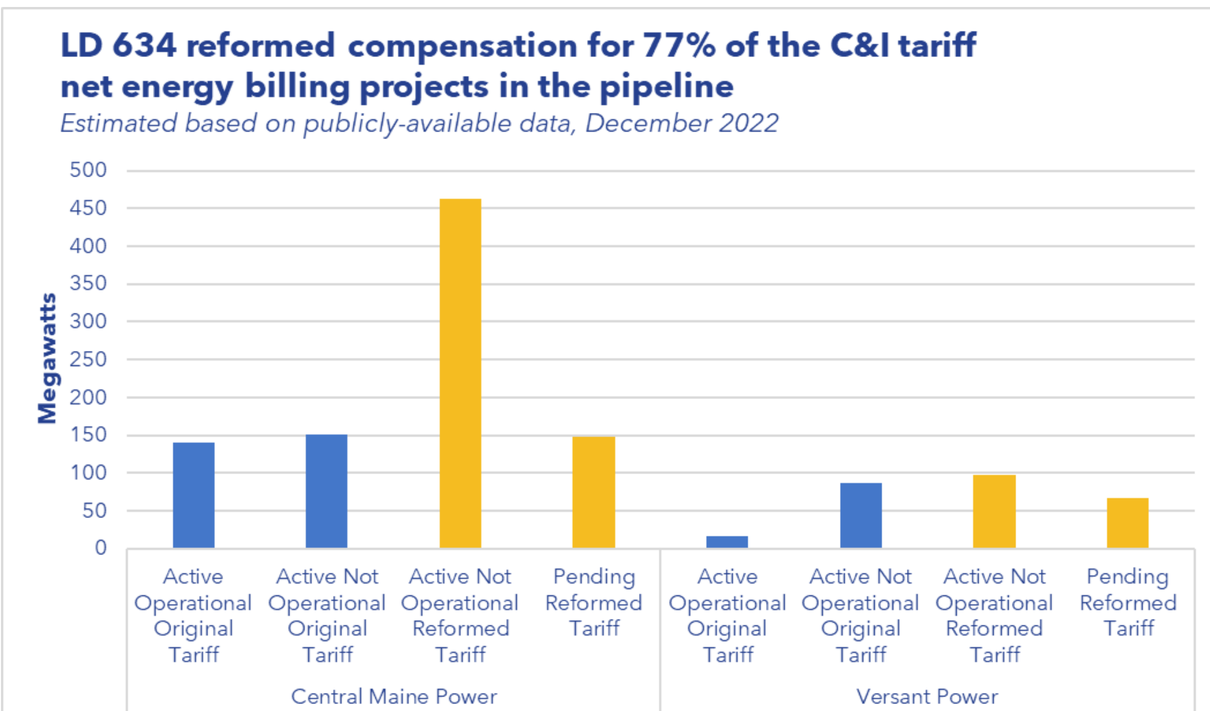
Based on the average offtaker capacity illustrated in Figure 5 and Figure 6, as well as the potential net energy billing capacity in the program pipeline illustrated in Figure 8, an estimated additional 82,000 –

117,000 customers could enroll in the program as offtakers for currently planned projects in the kWh netting program, and an estimated additional 15,800 – 17,000 customers could enroll as offtakers for currently planned projects in the C&I tariff program.

LD 634

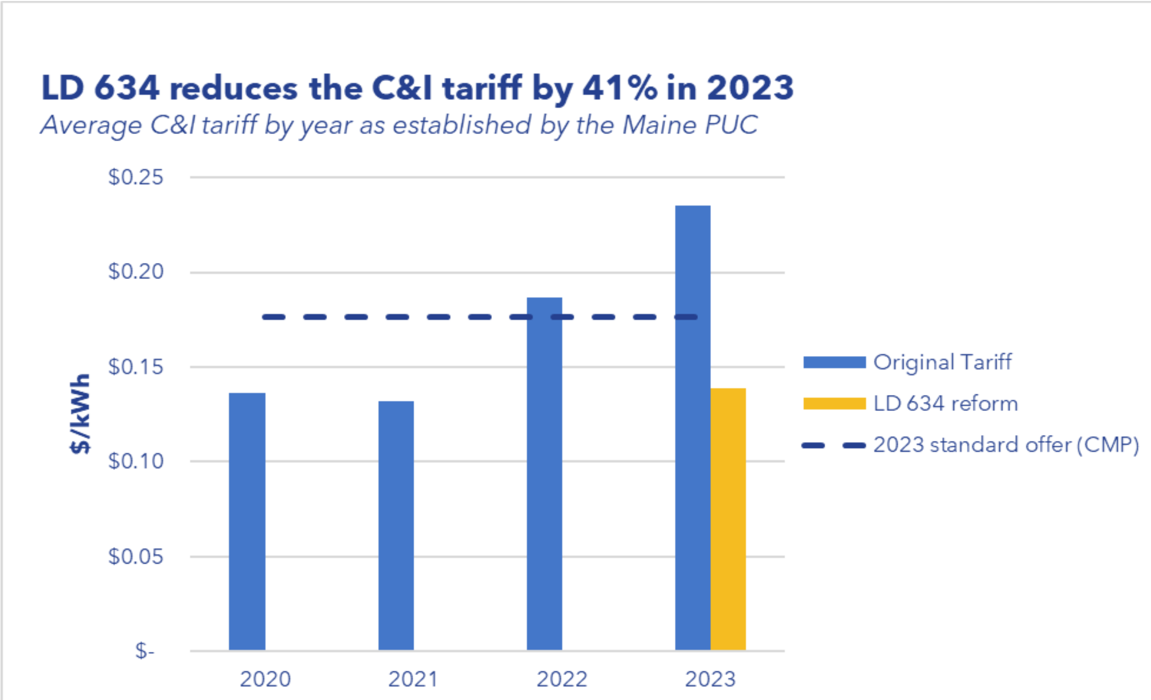
Following a report from the PUC highlighting the volatility of C&I tariff net energy billing program costs in December 2021,[7] the Legislature enacted P.L. 2021 ch. 659 (LD 634) in 2022. LD 634 reformed compensation for all C&I tariff projects that did not commence continuous construction efforts by September 1, 2022. LD 634 decoupled C&I tariff compensation from both the standard offer and transmission and distribution rates. Projects subject to the LD 634 reform instead receive a fixed rate annually, beginning at the 2020 C&I tariff levels (approximately $0.13/kWh) and escalating moderately each year thereafter. This reform significantly reduces the volatility in C&I tariff rates for an estimated 77% of planned C&I tariff projects, as illustrated in Figure 9 and reduced the rate that would have been provided to projects by 41% for this year, as illustrated in Figure 10.

Figure 9



[7] PUC analysis from December 2021 (please note that this analysis has not been updated to reflect program changes and electricity prices): https://www.maine.gov/tools/whatsnew/attach.php?id=6139652&an=1

Figure 10



Interconnection process

The interconnection process for distributed generation resources is typically governed by Chapter 324 of the Maine Public Utilities Commission rules.[8] As stated in Section 1 of the rule, Chapter 324 "establishes procedures and requirements related to generators that are subject to Commission jurisdiction that are seeking to interconnect to a Transmission and Distribution (T&D) Utility's Distribution System (which, as defined [in the rule] includes the T&D Utility's transmission and distribution systems)." Chapter 324 includes multiple levels of review based on the capacity and configuration of interconnecting generators. These are:

A. **Level 1** - For certified, inverter-based facilities that: (a) pass the applicable screens; and (b) have a power rating of twenty-five kilowatts (25 kW) or less on Radial or Spot Network systems.

B. **Level 2** - For certified generating facilities that: (a) pass the applicable specified screens; (b) do not qualify for Level 1; and (c) have a power rating of two megawatts (2 MW) or less.

C. **Level 3** - For certified generating facilities that: (a) pass the applicable screens; (b) do not qualify for Level 1 or Level 2; (d) have a power rating of ten megawatts (10 MW) or less; and (e) do not export power to the T&D Distribution System.

D. **Level 4** - For all generating facilities that do not qualify for Level 1, Level 2 or Level 3.

[8] Discussion of Chapter 324 in this report refers to the current effective rule, adopted January 8, 2022 and available from the Commission here: https://www.maine.gov/sos/cec/rules/65/407/407c324.docx

Given these definitions, most distributed generation facilities enrolled in net energy billing or a successor program can be assumed to be treated as Level 4 interconnecting facilities (if between 2 and 5 megawatts) or potentially as Level 2 interconnecting facilities (if less than 2 megawatts and located in an area with relatively little pre-existing distributed generation).

Level 4 interconnecting facilities are placed in a publicly-accessible interconnection[9] queue published by the applicable T&D utility. A distributed generator does not need to be enrolled in net energy billing to obtain a position in an interconnection queue. In addition, not all projects enrolled in net energy billing are listed in Level 4 interconnection queues.

Chapter 324 establishes timelines and requirements for various studies to be completed by the T&D utility, at the interconnecting facility's expense, that assess the potential impact of the generator on the existing distribution system and determine any necessary upgrades to accommodate the interconnection. Under the rule, any necessary upgrades are funded by the interconnecting customer.

In addition to Chapter 324, the ISO-New England Tariff[10] establishes obligations of market participants and other customers, which include requirements related to ensuring the reliability of the transmission system. Under these requirements, T&D utilities conduct additional studies of distributed generators that may, either individually or when aggregated as "clusters," produce a significant adverse impact on the transmission system. So-called "cluster studies" involve additional review, funded by the interconnecting customers, and are subject to review and approval by the ISO-New England Reliability Committee. Additional information regarding the cluster study process is available from a presentation on the topic to the Distributed Generation Stakeholder Group by Central Maine Power on July 19, 2022.[11]

As of this report, Central Maine Power reported that four cluster studies totaling 72 active projects and 256 megawatts had been completed, and fifteen cluster studies totaling 118 active projects 418 megawatts were underway or slated to commence, with most currently scheduled to be completed in spring or summer 2023. Central Maine Power further reported that 123 active projects totaling 539 MW received the requisite approval from ISO-New England prior to the triggering of the cluster study process.

Also as of this report, Versant Power reported that, for the Bangor Hydro District, three cluster studies totaling 76 active projects and approximately 268 MW had been completed, and one cluster study

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[9] The Level 4 interconnection queues published by Central Maine Power and Versant Power are available here: Central Maine Power: https://www.cmpco.com/wps/portal/cmp/networksfooter/suppliersandpartners/servicesandresources/interconnection/!ut/p/z0/fY7BCsIwEES_xUOPstFWqcciWhEjeFDaXEqIaY3WTZqkxc83PQki3maHnXkDDApgyAfVcK808jbcJVtW8YxudsmaHFOarMgpiQ_nPL-Q7SKGPbD_D6FhbumaNsAM97epwlpD4aQdlJCO49VKp3sbNBQKvbRCI0ox8sesuncdy4AF18uXh0I8DW9s9VkZkVrrkIuI641plbRjq-HWY5DB_YGKyDfKPFiZumzyBkc75O8!/?current=true&urile=wcm%3Apath%3A%2FCMPAGR_Navigation%2FFooter%2FSuppliersandPartners%2FServicesAndResources%2FInterconnection%2F
Versant Power: https://www.versantpower.com/energy-solutions/connecting-renewable-resources/distributed-generation-interconnection-process/

[10] https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_1/sect_i.pdf

[11] https://www.maine.gov/energy/sites/maine.gov.energy/files/inline-files/CMP%20DG%20Cluster%20Studies_20220719.pdf

containing 22 projects totaling approximately 44 MW was expected to be completed in summer 2023. For the Maine Public District, Versant Power reported one cluster study with 37 projects totaling 113 MW had been completed, and one cluster study with 32 projects totaling approximately 54 MW was expected to be completed in summer 2023.

Lessons learned

The Stakeholder Group periodically discussed various implications of the existing distributed generation programs, particularly net energy billing. This discussion was largely focused on the Stakeholder Group's directive under LD 936 to inform the design and implementation of the successor program proposed in this report. **There are a wide variety of viewpoints among the Stakeholder Group on Maine's existing solar programs and the full impacts of modifications made to them. The following points are consolidated from the extensive discussions of the Stakeholder Group and are not intended to represent the consensus of the group, nor the entirety of the perspective of any member.**

- Net energy billing has stimulated substantial solar development, increasing the volume of new renewable energy in Maine.
- Deploying distributed generation can deliver significant benefits, which may accrue to ratepayers, program participants, or others depending on program design. Some benefits may be achievable through other avenues, and some are unique to distributed generation.
- Shared net energy billing has enabled the participation of a broad range of residential, municipal, commercial, and industrial customers in solar development.
- Linking C&I tariff net energy billing project compensation to retail rates initially drove volatility and higher costs, although the previously discussed reform is likely to have addressed a significant portion of this issue.
- The absence of clear objectives and opportunities for flexibility, through mechanisms such as program caps, and responsibility for program outcomes have contributed to a lack of clarity about the initial programs among some stakeholders and limits the opportunity for potential program modifications or improvements.
- Experience with the existing net energy billing programs has stimulated a range of feedback from many stakeholders, which should be considered in the development and implementation of any successor program.

Successor program

The primary directive for the Distributed Generation Stakeholder Group pursuant to LD 936 is to "consider various distributed generation project programs to be implemented between 2024 and 2028." LD 936 charges the members of the Stakeholder Group to "assist in the development and production of [this report]." Members of the Stakeholder Group represent a wide range of perspectives and interests, and thus bring a variety of preferences and priorities to this task. Each member participated in the process, providing input and engaging in constructive dialogue that produced this proposed successor program. This proposal, while not the entire preference of any single stakeholder, represents the product of input from all.

Technical analysis

Consistent with the consensus of the Stakeholder Group established in the Interim Report, the GEO retained expert contractors Synapse Energy Economics, Inc. (Synapse) and Sustainable Energy Advantage, LLC (SEA; jointly, the Synapse team) to provide technical expertise in support of the Stakeholder Group's work. Synapse and SEA were contracted to:

- support the Stakeholder Group in formulating a benefit-cost analysis (BCA) to be used in determining the net benefits of distributed generation programs;
- quantify and compare various distributed generation program options in terms of net benefits (using the BCA) and rate, bill, and participant impacts.

The Synapse team participated in seven meetings of the Stakeholder Group between August and December 2022, during which they presented proposed methods, data sources, and draft results, obtaining and incorporating input from the Stakeholder Group at multiple stages. A complete summary of this technical work is included as Appendix A.

Benefit-cost analysis and rate impact analysis are separate, but related, analyses that can inform stakeholders about the potential impacts of distributed generation programs. The Synapse team applied both methods of analysis, emphasizing that each provide useful, distinct information. The differences between these metrics are summarized in Table 2 below. For additional details, refer to Appendix A.

Table 2

Key Considerations	Cost-Effectiveness Analysis	Rate Impact Analysis
Answers the question:	*Which utility DER investments are expected to have benefits that exceed costs?* Cost-effectiveness indicates the extent to which different utility investments will reduce utility costs and achieve other policy goals, regardless of how the benefits and costs are distributed across different customers.	*How much will utility DER investments impact rates for one group of customers compared to another?*
Results of the analysis are expressed as:	Present value of revenue requirements, benefit-cost ratios, and net benefits. These metrics are important for regulators and other stakeholders to understand cost-effectiveness, but do not provide any information relevant to rate impacts.	Long-term impacts on rates (in ¢/kWh or percent changes to rates) or in terms of long-term bill impacts (in $ per month or percent changes to bills). These metrics are important for regulators and other stakeholders to understand rate impacts but do little to inform benefit-cost analyses.

Benefit-cost analysis results

Benefit-cost analysis is "a systematic approach for assessing the cost-effectiveness of investments by consistently and comprehensively comparing the benefits and costs of individual or multiple types of DERs with each other."[12] Benefits and costs are typically compared as a ratio, with total benefits divided by total costs to produce a benefit-cost ratio (BCR). A BCR of 1 would indicate that benefits and costs are exactly equal, while a BCR greater than 1 would indicate benefits are greater than costs; conversely, a BCR less than 1 would indicate costs are greater than benefits.

The Synapse team utilized the process and methods specified as national best practices in the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources, or NSPM, a publication of the National Energy Screening Project. According to the National Energy Screening Project, the NSPM has been utilized in jurisdictions across the country – including Arkansas, Colorado, Maryland, Michigan, Minnesota, New Hampshire, Rhode Island, Washington, and Washington, D.C. – to formulate or update benefit-cost analysis tools with stakeholder input. Furthermore, the NSPM has been referenced or incorporated into utility plans, PUC dockets, or other jurisdictional documents in an additional 28 states. Benefits and costs proposed by the Synapse team and incorporated into the BCA

[12] *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*, August 2020 (NSPM), p. i. https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/

framework applied for this report are summarized below in Table 3.[13] Refer to Appendix A for additional information.

Table 3

Type of Impact	Impact	Benefit or Cost?	Method
Generation	Avoided Energy Cost	Benefit	AESC 2021
	Avoided Capacity Cost	Benefit	AESC 2021
	Avoided Environmental Compliance	Benefit	AESC 2021
	Avoided RPS Compliance Costs	Benefit	AESC 2021
	Market Price Effects ("DRIPE")	Benefit	AESC 2021
Transmission	Avoided PTF Costs	Benefit	Efficiency Maine assumptions
	Avoided Non-PTF Costs	Benefit	Efficiency Maine assumptions – only applied to BTM
Distribution	Avoided Distribution Costs	Benefit	Efficiency Maine assumptions – only applied to BTM
General	Renewable Energy Credit Prices	Benefit	Sustainable Energy Advantage (SEA) "CREST" Model
	DG Costs	Cost	Based on program design and total cost from SEA "CREST" Model
	Program Administration Costs	Cost	Input from utilities ($600,000 for first 5 years, $300,000 for remaining generation period)
Societal	Avoided CO_2	Benefit	AESC 2021
	Avoided NOx	Benefit	AESC 2021

Consistent with the requirements of LD 936, the Synapse team proposed multiple successor program design options for consideration by the Stakeholder Group. These options were formulated based on existing programs previously or currently implemented in Maine and in other jurisdictions, particularly other New England states. As previously noted, the Inflation Reduction Act was passed by Congress and enacted in August 2022, and the Stakeholder Group articulated a particular interest in understanding the potential implications of this legislation for the successor program options.

The benefit-cost ratios for three successor program options modeled by the Synapse team, as well as for the original C&I tariff program (prior to the reform enacted by LD 634) are summarized below in Figure 11.[14] Descriptions of the differences between each program option are detailed in Appendix A. With benefit-cost ratios greater than 1, all three potential successor program options would produce positive net benefits, while the original tariff program, if continued, would produce net costs. The program option that would maximize net benefits is the fourth option, referred to as "Wholesale PPA," with an estimated $1.71 in benefits resulting from every $1.00 of cost.

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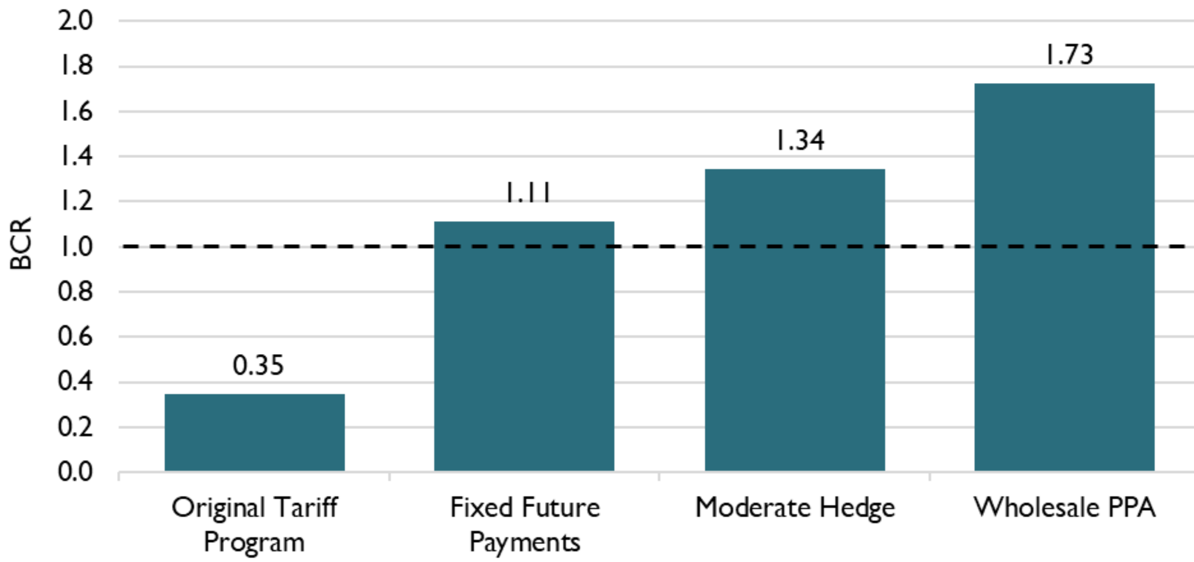
[13] AESC refers to the 2021 Avoided Energy Supply Costs in New England study. For more information, see Appendix A and https://www.synapse-energy.com/avoided-energy-supply-costs-new-england-aesc

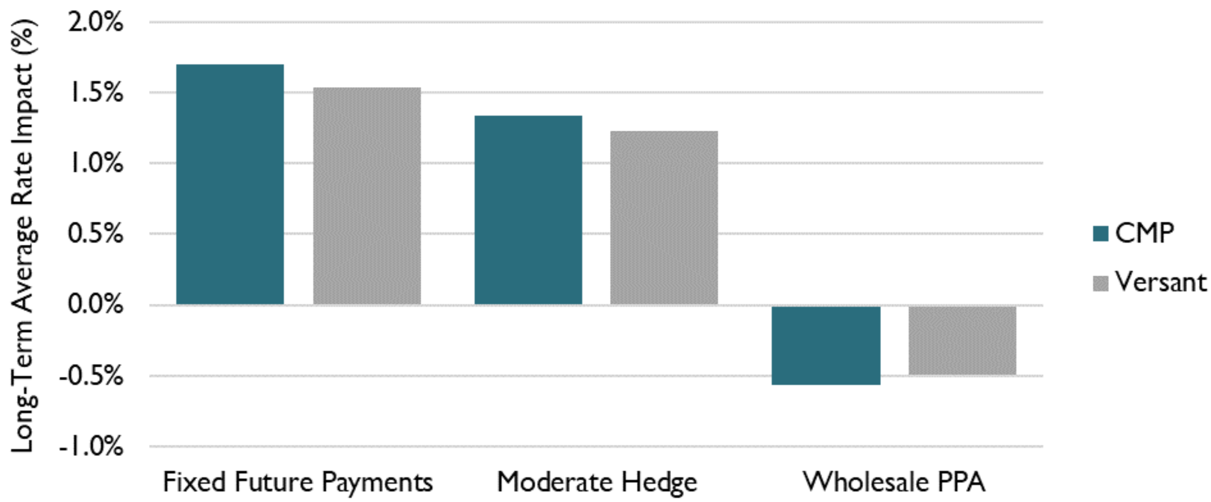
[14] The Original Tariff Program was not considered by the Stakeholder Group as a successor program option, and thus was not a primary focus of the Synapse team's analysis. However, LD 936 directs the Stakeholder Group to also estimate impacts of the original net energy billing program. Of the multiple program iterations, the Original Tariff Program had the highest enrollment and was selected for this analysis. Furthermore, the Original Tariff Program was deemed to be a useful benchmark against which to compare other options. The Original Tariff Program analyzed here has been significantly reformed through bipartisan legislation (LD 634) as discussed earlier in this report.

Figure 11



Pursuant to LD 936, the Stakeholder Group sought to consider a successor program that optimizes net benefits (i.e. achieves the highest benefit-cost ratio) and ratepayer cost-effectiveness (i.e. achieves the lowest estimated ratepayer impact). As discussed, analysis conducted for the Stakeholder Group found that multiple program design approaches would yield cost-effective successor programs, meaning the modeled benefits exceed the costs. However, only one program design resulted in negative ratepayer impacts (i.e. rates would go down as a result of the program), although the successor program options with positive ratepayer impacts (rates would increase as a result of the program) appeared relatively modest to some stakeholders. Rate impacts from the various options analyzed by the Synapse team are illustrated in Figure 12. For more detail, refer to Appendix A.

Figure 12



Based on the initial modeling results summarized in Figure 11 and Figure 12, the Stakeholder Group discussed a “hybrid” program option that would combine important aspects of both the “Wholesale PPA” option, which is the most cost-effective and lowers electricity rates for all customers, and the “Moderate Hedge” option, which is also highly cost-effective and enables direct participation in distributed generation by identified offtakers. The “hybrid” option including energy storage is the successor program proposed in this section.

The results of the benefit cost analysis and the rate, bill and participant impact analysis also revealed several key findings that shaped the chosen program design, summarized by the Synapse team as:

1. Successor DG program can be designed to provide significant net benefits to all utility customers on average.
2. Successor DG programs can be designed to provide long-term average *reductions* in rates – thereby eliminating any cost-shifting among customers.
3. Successor DG Programs can pay developers significantly less than retail rates and still encourage deployment of DG resources.
4. Successor DG programs can use competitive bidding processes and/or administratively set prices based on contemporaneous price information that incorporate future learning curves to drive down costs of renewable energy procurement.
5. Successor DG programs that provide developers with fixed prices over time will significantly reduce the cost of these program relative to those that provide increasing prices over time.
6. Larger capacity solar projects are less expensive per unit than smaller capacity projects.
7. There are tradeoffs between policy goals and costs of successor program implementation, but provisions of the Inflation Reduction Act help to balance the scales in some instances by

encouraging LMI participation and siting of clean energy on brownfield sites and certain other federally incentivized locations.

8. There are tradeoffs between the number of direct beneficiaries (offtakers) in a program and the financial impacts faced by non-participants. The more program participants, the higher the rate and bill impacts for non-participants, and vice-versa.

9. If given proper dispatch incentives, battery storage can be deployed in conjunction with solar PV at incremental costs that are significantly less than incremental benefits.

See Appendix A for additional detail.

Proposed successor program

The Stakeholder Group discussed various considerations related to the overall structure of a distributed generation program to be implemented between 2024 and 2028. The Stakeholder Group published an earlier iteration of this proposal for public feedback, and has modified elements of the proposal as a result of comments received from the public.

Successor program priorities

Consistent with the directives of LD 936, the successor program is designed to:

- **Build low-cost renewable energy** to save Maine people money and continue growing Maine's clean energy economy;
- **Ensure opportunities** for competitive cost-effective distributed renewable energy and storage are captured to **benefit Maine ratepayers;**
- Maximize the opportunity to **direct federal financial incentives** to continue deploying cost-effective community-scale renewable energy that delivers tangible benefits to Maine communities;
- Deploy the incremental benefits to Maine community-scale renewable energy to **reduce energy burdens** faced by low- and moderate-income households; and
- **Align** community-scale renewable energy deployment with **siting incentives funded by the federal government**, directing future development to previously disturbed sites including brownfields to minimize impacts.

Program capacity

LD 936 provides direction for determining the total size or "program target" for a successor program. Programs are typically measured either in terms of the amount of capacity (in megawatts) they are designed to achieve, or the amount of generation or load (in megawatt-hours). LD 936 specifies the "optimum total amount of distributed generation for the program period" as "7% of total load based on operational capacity," after "subtracting the total amount of megawatts of commercially operational distributed generation resources developed in excess of [750 megawatts]."

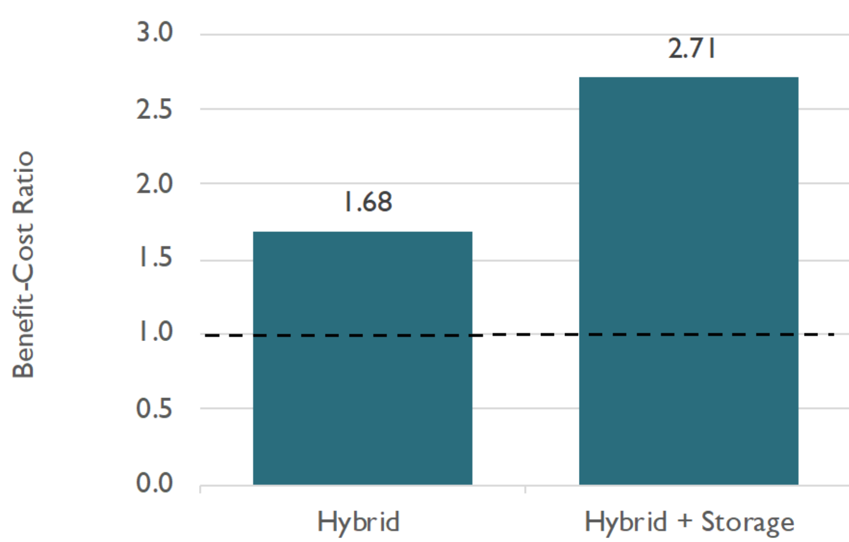
Analysis provided to the Stakeholder Group estimates this program target, which is expressed in terms of generation or load, would result in approximately 560 megawatts over five years (2024-2028), or approximately 112 megawatts per year assuming the successor program targets distributed solar and/or solar paired with energy storage projects. This calculation is a projection prepared by the Synapse team as specified in LD 936, and assumes approximately 916 megawatts of distributed generation ultimately reach operation under the existing net energy billing programs (based on Sustainable Energy Advantage's Renewable Energy Market Outlook service).[15]

The Stakeholder Group expressed differing viewpoints regarding the successor program target. Several observed the 7% quantity specified in LD 936 does not appear to be the result of specific planning criteria or analysis. Some stakeholders preferred a larger quantity of DG, while others preferred a smaller quantity, including some who advocated for no future distributed generation. Among stakeholders who supported the establishment of a successor program, many agreed the reliance on uncertain future development to establish the program target may undermine the ability of a successor program to attract robust participation.

Program cost-effectiveness and rate impacts

The Synapse team analyzed the proposed successor program using the same methods as the previously considered successor program options. In the following figures (and throughout Appendix X), the Synapse team refers to this as the "hybrid" program option. In addition, at the request of the Stakeholder Group, the Synapse team analyzed the program with the inclusion of energy storage technologies paired with solar generation, referred to in this section and Appendix A as "Hybrid + Storage." The benefit-cost analysis results are summarized in Figure 13, which demonstrates that the increased benefits because of energy storage significantly outweigh the incremental costs. The proposed successor program, which includes the requirement for energy storage, is the most cost-effective program considered, and maximizes the associated ratepayer savings.

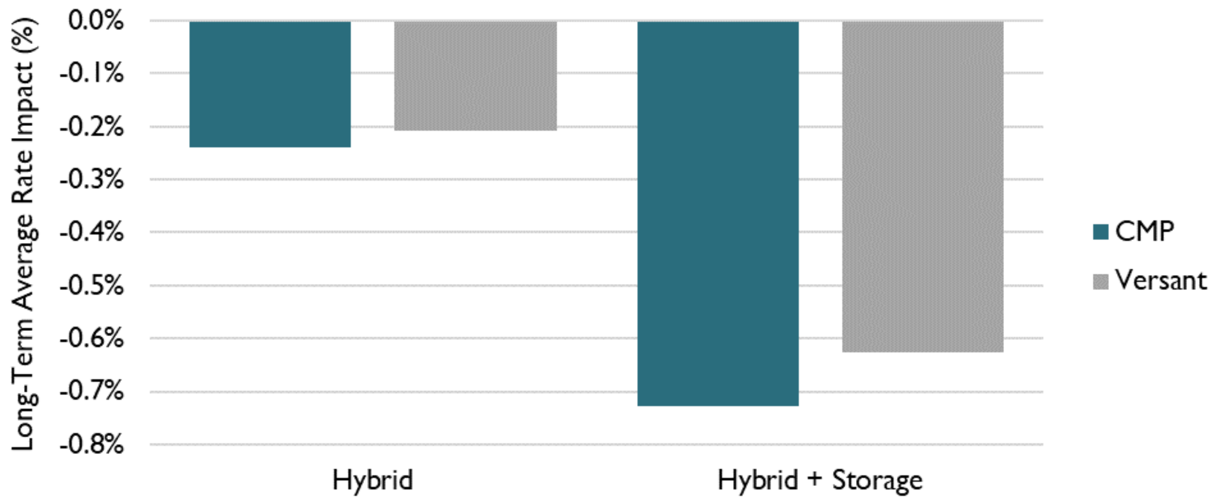
Figure 13



[15] See slide 16 here: https://www.maine.gov/energy/sites/maine.gov.energy/files/inline-files/ME%20DG%20Stakeholder%20Mtg%20Nov-17.pdf

Figure 14 illustrates the anticipated rate impacts resulting from the proposed successor program, which range between 0.6% and 0.7% rate decreases for all utility customers because of the program when energy storage is included.

Figure 14



Program Eligibility

The Act denotes that for the purposes of the successor program for distributed generation to be implemented between 2024 and 2028, "distributed generation" means a renewable energy project with a nameplate capacity of no more than 5 megawatts. The Stakeholder Group generally considered eligible distributed generation for the successor program to mean a distributed generation resource between one and five megawatts. Currently, new projects between 1 and 2 megawatts would be eligible for participation in either net energy billing or the successor program. Given the different compensation mechanisms, and the substantial benefits anticipated from the successor program, most Stakeholders agreed projects of this size that are not collocated with load should be directed to the successor program.

Table 4

Program Component	Capacity Allocation	Eligible Projects	Project Selection	Siting	Offtake
Competitive Procurement	Not less than 70% of annual program target.	Distributed generation paired with storage.	Projects submit sealed bids to sell energy and RECs at a fixed price, or fixed price with an annual escalator. Projects are selected beginning with the lowest qualified bids until the total capacity of all selected projects equals at least 70% of the annual program target. Projects are awarded a power purchase agreement no greater than 20 years with the applicable T&D utility at their bid price.	Projects sited on previously disturbed or degraded lands, including brownfields, capped landfills, and gravel pits will be evaluated at 85% of their bid price.[16]	Attributes purchased from all projects would be monetized by the PPA counterparty to maximize value to ratepayers. A portion of the resulting revenue would be allocated to provide a financial benefit to low- and moderate-income ratepayers that complies with forthcoming guidance to obtain an incremental 20% ITC.
Community Access	Up to 30% of annual program target.	Distributed generation paired with storage owned by a municipality, tribe, school or state entity.	Eligible projects may enroll on a first-come, first-served basis with compensation set at the capacity-weighted 50th percentile of selected bids in the competitive procurement.[17] PPA terms are otherwise equivalent to those in the competitive procurement.	Projects sited on previously disturbed or degraded lands, including brownfields, capped landfills, and gravel pits will receive an equivalent price adjustment.[18]	Attributes purchased from all projects would be monetized by the PPA counterparty to maximize value to ratepayers. Revenue realized by the project owner would be available to offset energy bills or provide other public benefit as determined by the project owner.

[16] For example, if a project sited on a brownfield submits a bid at $0.10/kilowatt-hour, it will be selected as if it bid $0.085/kilowatt-hour. All selected projects will receive their bid price.
[17] For example, if competitively procured bids range uniformly from $0.05 - $0.10/kilowatt-hour, the Community Access price would be $0.075/kilowatt-hour.
[18] For example, if the Community Access price were $0.075/kilowatt-hour, a brownfield-sited project would receive $0.088/kilowatt-hour.

Competitive Procurement

The successor program will harness competitive solicitations to drive down program costs. Solicitations will be administered annually for up to 70% of the annual program target generation and renewable energy attributes. Project developers will submit sealed bids, and those selected will receive their bid price.

Due to the Inflation Reduction Act, distributed generation projects that provide certain financial benefits to qualified low- and moderate-income households may be eligible for additional ITC benefits as high as 20%.[19] Ensuring direct benefits to low- and moderate-income households could contribute to alleviating disproportionately high energy burdens born by those households, and could bring the added benefit of lowering the cost of distributed generation procured under the program by enabling project owners to realize the incremental ITC. The successor program should make every reasonable effort to provide a clear, administratively streamlined mechanism to deliver specific benefits to qualifying households that enables project owners to maximize access to the federal tax benefit, thereby further lowering the cost of the program to the benefit of all ratepayers. In the view of some stakeholders, this proposal satisfies the directive of LD 936 that the successor program support projects with "identified residential, commercial and institutional customers."

Community Access

Some stakeholders observed that not all entities that may benefit from deploying distributed generation will be well-suited to participating in a competitive procurement. However, there was broad recognition that a competitively-set price that is available to certain public entities, including municipalities, tribes, schools, and state agencies could stimulate additional "community access" distributed generation that produces broad public benefits. Accordingly, the successor program would allocate up to 30% of its annual capacity to be available on a first-come, first-served basis to eligible public interest entities. Projects owned by these entities would receive a PPA equivalent to those awarded under the competitive solicitation, with energy and RECs purchased at the capacity-weighted 50th percentile of the most recent competitive procurement, adjusted for preferred project attributes in an equivalent manner to the competitive procurement. Under this arrangement, community access projects would not increase the average cost of the program.

Multiple stakeholders observed the importance of preventing projects that are awarded a PPA in a competitive solicitation from entering the community access program, given that some will have bid below the 50th percentile price which is awarded to community access projects.

In the event any annual capacity is not assigned to specific projects, either through the competitive procurement process or the community access process, it should be re-allocated to the appropriate

[19] This provision of the IRA is subject to additional clarification through forthcoming guidance issued by the U.S. Department of the Treasury. The 20% bonus ITC would be incremental to the "base" 30% ITC available to most projects that meet minimum standards, resulting in at least a 50% ITC for qualifying projects, and potentially more if additional "bonus" tax credits were obtained. The amount of qualifying projects is capped nationally at 1.8 GW per year; the allocation of this cap is not yet known.

process in subsequent years such that the overall program target is still achieved by the end of the multi-year program period.

Siting on Disturbed Lands

Under the Inflation Reduction Act, distributed generation projects sited in certain "energy communities," which include certain brownfield sites, are eligible to receive an incremental 10% investment tax credit.[20] Analysis conducted by the Synapse team demonstrates this new federal incentive may in many cases make brownfield-sited projects cost-competitive with "greenfield" projects, which are generally understood to have been the lowest-cost projects prior to the Inflation Reduction Act.

A broad range of stakeholders who participated in the Stakeholder Group's Land Use Work Session identified siting future distributed generation projects on previously disturbed or developed lands, such as brownfields, as a priority where possible to reduce potential siting conflicts, maximize the re-use of land that may have limited other options for re-use, and avoid potential impacts to land with other valuable functions (such as prime farmland or important ecological characteristics). Furthermore, to the extent siting of new renewable energy on previously disturbed lands is a priority, distributed generation is generally the scale of development most likely to achieve this objective given the size and characteristics of existing disturbed parcels, as illustrated in Figure 2.

The successor program should provide a modest bid preference for projects sited on disturbed lands, particularly those that realize the incremental ITC established under the Inflation Reduction Act. By evaluating projects sited on disturbed lands at 85% of their bid price, the successor program should result in primarily cost-competitive projects developed on these preferred sites while relying on the federal ITC to fund all or most of any incremental cost that may be incurred by the project developer.

Energy Storage

Energy storage paired with distributed generation can provide a suite of additional benefits. Analysis conducted by the Synapse team demonstrated that under a simplified program model, comparable to similar programs in neighboring states, energy storage that is configured to charge from the distributed generation and discharge to the grid during an evening period significantly increases the value of the distributed generation and increases the ratepayer savings achieved through the program. This is largely because storage enables distributed solar to deliver the energy during times when it is needed most, avoiding otherwise more costly capacity resources.

The Stakeholder Group generally agreed requiring the inclusion of energy storage for the successor program would be appropriate. However, certain questions remain with respect to the specific

[20] This provision of the IRA is subject to additional clarification through forthcoming guidance issued by the U.S. Department of the Treasury. The 10% ITC would be incremental to the "base" 30% ITC available to most projects that meet minimum standards, resulting in at least a 40% ITC for various projects, and potentially more if additional "bonus" tax credits were obtained. Stakeholder Group members differed in their interpretation of the IRA language implementing this provision, highlighting the importance of forthcoming guidance to provide clarity.

parameters of the program design, including the dispatch and performance requirements that may be required under the program.

Program Administration

The proposed successor program was designed to be presented to the Legislature as directed by LD 936. Should the Legislature enact a successor program, the Stakeholder Group recognized the need for further development of the program design, including additional policy-driven considerations. Examples include decisions that depend on future federal guidance related to implementation of the Inflation Reduction Act; additional design criteria related to the performance of energy storage resources; and specific criteria and definitions related to the implementation of siting preferences. To the extent additional policy-related implementation is necessary, the Stakeholder Group views the GEO as well-suited to continue leading program design in close coordination with the PUC. The PUC would then be responsible for adopting and operating the procurement.

Public input

The Distributed Generation Stakeholder Group published a draft of the successor program proposed in this report for public feedback.[21] Feedback was accepted from November 23, 2022 until December 14, 2022. A total of 27 commenters submitted written feedback, including nine members of the Distributed Generation Stakeholder Group. The Stakeholder Group reviewed these comments and subsequently incorporated multiple modifications to the successor program proposed in this report suggested by commenters. Comments were submitted by the following entities; those marked with an asterisk (*) are members of the Distributed Generation Stakeholder Group:

- AARP Maine
- BlueWave
- Branch Renewable Energy
- Central Maine Power*
- Coalition for Community Solar Access*
- Kenneth A. Colburn
- Dirigo Solar*
- Amanda Dwelley
- Peter Evans
- Green Lantern Development
- Industrial Energy Consumer Group*
- Sharon Klein*
- Maine Farmland Trust
- Maine Municipal Association*
- Natural Resources Council of Maine
- New Leaf Energy*
- Office of the Public Advocate*

[21] https://www.maine.gov/energy/sites/maine.gov.energy/files/inline-files/LD%20936%20proposed%20successor%20framework_for%20public%20comment.pdf

- ReVision Energy*
- ReWild Renewables
- Sierra Club Maine
- Sol Systems
- Solar Energy Association of Maine
- Standard Solar, Inc.
- The Nature Conservancy in Maine
- US Solar
- Verogy
- Versant Power*

All comments received in response to the LD 936 Proposed Successor Program Framework are available here: https://www.maine.gov/energy/sites/maine.gov.energy/files/inline-files/LD%20936%20Successor%20Framework%20Public%20Comments_FINAL.pdf

Appendix A

Distributed Generation Successor Program in Maine

An Economic Assessment

Prepared for the Maine Governor's Energy Office and the Distributed Generation Stakeholder Group

January 5, 2022

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CONTENTS

EXECUTIVE SUMMARY

The purpose of this report is to discuss and present the results of the economic analysis conducted to evaluate potential successor programs to existing renewable distributed generation (DG)[1] programs in Maine. Synapse Energy Economics (Synapse) and Sustainable Energy Advantage (SEA) were hired by the Governor's Energy Office (GEO) to provide technical support, expertise, and modeling for the evaluation of potential successor program designs in coordination with the Distributed Generation Stakeholder Working Group (DGSG), convened by the GEO pursuant to LD 936.[2] The primary goal of our work was to support the DGSG by evaluating potential successor program designs and identifying design features that will result in the most cost-effective deployment of distributed generation in Maine.

Synapse and SEA modeled the costs and benefits of various program designs to illuminate key findings for the state of Maine. We evaluated potential successor programs using analytical frameworks that are often employed in the energy utility sector: (1) benefit-cost analysis (BCA) and (2) rate, bill, and participation analysis. BCAs "involve a systematic approach for assessing the cost-effectiveness of investments by consistently and comprehensively comparing the benefits and costs of individual or multiple types of DERs with each other."[3] Rate, bill, and participation analyses (RBPA) indicate "the extent to which DER investments might lead to distributional equity or cost allocation concerns."[4]

The BCA relies upon a framework, referred to as the "Maine test," developed with input from the DGSG. This test accounts for all utility system costs and benefits, environmental impacts, and job impacts.

We model three successor DG programs to identify the effects of different program designs. The key differences among these programs include: (a) assigning the renewable energy credits (RECs) to project developers versus the utilities, (b) assigning the capacity rights to project developers, and (c) modeling a "wholesale PPA" approach where the utility purchases all DG output, rather than transferring some portion of DG benefits to participants in the program.

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[1] Maine law defines distribution generation as "renewable," including in the definition of net energy billing. Per Public Utilities Code Title 35-A, Section 3209-A, Net Energy Billing, Part 1b: "'Distributed generation resource' means an electric generating facility that uses a renewable fuel or technology under section 3210, subsection 2, paragraph B-3 and is located in the service territory of a transmission and distribution utility in the State." This report thus refers to "DG" and "renewables" synonymously.

[2] Public Law 2021 Chapter 390. LD 936, *An Act to Amend State Laws Relating to Net Energy Billing and the Procurement of Distributed Generation*, Available at: https://legislature.maine.gov/legis/bills/display_ps.asp?LD=936&snum=130.

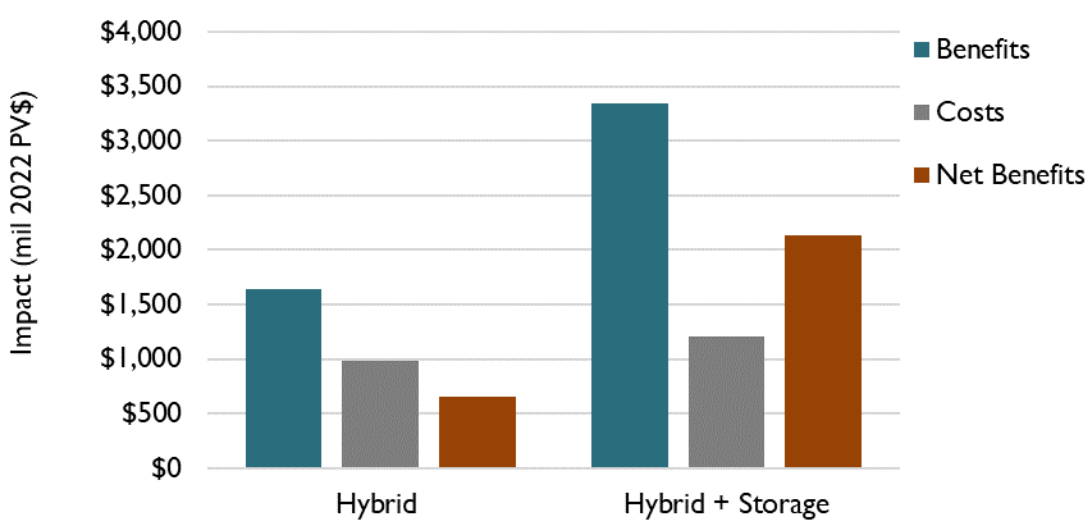
[3] National Energy Screening Project. 2020. *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*. E4TheFuture, Synapse Energy Economics, Energy Futures Group, ICF, Pace Energy and Climate Center, Schiller Consulting, Smart Electric Power Alliance. (NESP), p. i.

[4] NESP, p. xxii.

Based on findings from these successor program options, we created a fourth iteration with input from the DGSG, referred to as the Hybrid Program. This adopts the most promising design features seen to minimize costs, maximize benefits, and meet the goals of LD 936 of the three program options. Our analysis finds this program to be very cost-effective, with a benefit-cost ratio of 1.67 and net benefits of $660 million (in 2022 present value dollar terms). The Hybrid Program is also expected to result in small reductions in electricity rates on average over the study periods, relative to a scenario where no successor DG program is implemented.

Using the Hybrid Program we analyzed the costs and benefits of combining storage technologies with DG resources, and we conducted several sensitivities to test the robustness of key modeling assumptions. Our analysis finds that storage technologies can increase the benefits of DG by significantly more than the incremental cost. Figure 1 presents the costs, benefits, and net benefits of these two programs. Adding storage technologies increases the net benefits from $660 million to $2,133 million (in 2022 present value dollar terms).

Figure 1. BCA Results for the Hybrid and Hybrid Plus Storage Programs



Our conclusions from the analysis and results described throughout the report are as follows:

1. Successor DG programs can be designed to provide significant net benefits to all utility customers on average.

2. Successor DG programs can be designed to provide long-term average *reductions* in rates – thereby eliminating any cost-shifting among customers.

3. Successor DG Programs can pay developers significantly less than retail rates and still encourage deployment of DG resources.

4. Successor DG programs can use competitive bidding processes and/or administratively set prices based on contemporaneous price information that incorporate future learning curves to drive down costs of renewable energy procurement.

5. Successor DG programs that provide developers with fixed prices over time will significantly reduce the cost of these program relative to those that provide increasing prices over time.

6. Larger capacity solar projects are less expensive per unit than smaller capacity projects.

7. There are tradeoffs between policy goals and costs of successor program implementation, but provisions of the Inflation Reduction Act help to balance the scales in some instances by encouraging LMI participation and siting of clean energy on brownfield sites and certain other federally incentivized locations.

8. There are tradeoffs between the number of direct beneficiaries (offtakers) in a program and the financial impacts faced by non-participants. The more program participants, the higher the rate and bill impacts for non-participants, and vice-versa.

   - Despite these tradeoffs, it is possible to design a program with direct participants that is nearly as cost-effective as a program with no direct beneficiaries.

9. If given proper dispatch incentives, battery storage can be deployed in conjunction with solar PV at incremental costs that are significantly less than incremental benefits.

1. INTRODUCTION

The purpose of this report is to discuss and present the results of the economic analysis conducted to evaluate potential successor programs to existing renewable distributed generation (DG)[5] programs in Maine. Synapse Energy Economics (Synapse) and Sustainable Energy Advantage (SEA) were hired by the Governor's Energy Office (GEO) to provide technical support, expertise, and modeling for the evaluation of potential successor program designs in coordination with the Distributed Generation Stakeholder Group (DGSG), convened by the GEO pursuant to LD 936.[6] The primary goal of our work is to support the DGSG by evaluating potential successor program designs and identifying design features that will result in the most cost-effective deployment of distributed generation in Maine.

LD 936 established a goal of 750 megawatts (MW) of distributed generation under the net energy billing (NEB) programs established in 35-A MRS §3209-A and §3209-B. This program provided bill offsets to participants with a DG installation of less than 5 megawatts (MW), pursuant to additional consumer protection criteria.[7] These came in the form of bill discounts based on retail rates for non-residential customers, and kilowatt hour (kWh) credits for residential customers (or non-residential customers that elect this option).[8] LD 936 set a limit on distributed generation resources between 2 and 5 MW eligible for enrollment in net energy billing and provided an end date of December 31, 2024, for entry into the program for these resources.

Per LD 936, the charge of the DGSG is to "consider various distributed generation project programs [a "successor program"] to be implemented between 2024 and 2028 and the need for improved grid planning."[9] The DGSG produced an interim report[10] in December 2021 establishing initial areas of

[5] Maine law defines distribution generation as "renewable," including in the definition of net energy billing. Per Public Utilities Code Title 35-A, Section 3209-A, Net Energy Billing, Part 1b: "'Distributed generation resource' means an electric generating facility that uses a renewable fuel or technology under section 3210, subsection 2, paragraph B-3 and is located in the service territory of a transmission and distribution utility in the State." This report refers to "DG" and "renewable DG" synonymously.

[6] Public Law 2021 Chapter 390. LD 936, *An Act to Amend State Laws Relating to Net Energy Billing and the Procurement of Distributed Generation*, Available at: https://legislature.maine.gov/legis/bills/display_ps.asp?LD=936&snum=130.

[7] 35-A MRS §3209-A. *Net Energy Billing.* Available at: https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3209-A.html.

[8] Maine Public Utilities Commission. "Net Energy Billing." Available at: https://www.maine.gov/mpuc/regulated-utilities/electricity/neb.

[9] Public Law 2021 Chapter 390. LD 936, *An Act to Amend State Laws Relating to Net Energy Billing and the Procurement of Distributed Generation*, Section 4. Available at https://legislature.maine.gov/legis/bills/display_ps.asp?LD=936&snum=130.

[10] Distributed Generation Stakeholder Group. 2021. *Interim Report of the Distributed Generation Stakeholder Group.* Submitted to the Joint Standing Committee on Energy, Utilities, and Technology. Available at:

consensus and describing a framework and intended process to examine potential successor programs. These areas of consensus included the following:

1. Distributed generation resources will play an important role in the state's achievement of greenhouse gas reduction requirements, renewable energy requirements, and goals for the continued growth of the clean energy sector.

2. Distributed generation resources have the potential to produce benefits to the electric system, as well as to the state, through avoided costs as well as resilience, environmental, public health, and economic benefits. The extent to which these benefits should be incorporated as objectives of a successor program requires additional analysis and discussion.

3. Any program to promote distributed generation resources should be designed in a manner that optimizes net benefits and ratepayer cost-effectiveness and considers resources developed through existing net energy billing programs. It should also consider input from a broad range of stakeholders and specifically account for barriers faced by low- and moderate-income, fixed-income, and historically marginalized communities.

4. The Stakeholder Group intends to continue working in 2022 to refine the approach for optimizing cost-effectiveness and the manner by which a successor program should pursue these objectives.[11]

From August 2022 through December 2022, Synapse and SEA attended and presented at six DGSG meetings to solicit stakeholder input and identify potential program designs that were assessed for cost-effectiveness and rate, bill, and participant impacts (RBPAs).

The benefit-cost analyses (BCAs) and RBPAs presented here provide a quantitative, objective basis for Maine to consider as it develops a renewable distributed generation successor program. We evaluate and compare the costs, benefits, and rate impacts of several potential program designs, including solar DG plus storage, each of which achieves similar but slightly different policy objectives, in order to compare and contrast viable programmatic design elements. This report summarizes the results of these analyses. We discuss key takeaways in Section 10 and in the Executive Summary above.

The remaining sections of the report are presented as follows: Section 2 discusses the successor program designs, developed with input from the DGSG; Section 3 provides an overview of the economic analyses conducted—cost-effectiveness tests and rate, bill, and participant analyses—to evaluate successor program designs; Sections 4 and 5 provide the results of these analyses; Section 6 presents a straw proposal for a successor program design, along with the economic analysis of that proposal;[12]

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https://www.maine.gov/energy/sites/maine.gov.energy/files/inline-files/Interim%20Report%20of%20the%20Distributed%20Generation%20Stakeholder%20Group_Dec%2031%202021.pdf.

[11] *See id.,* p. 5.

[12] The straw proposal evaluated in Section 6 of this report is generally consistent with the "LD 936 Successor Program Framework" proposed by the DGSG in November 2022 for public feedback.

Section 7 discusses the results of economic analyses when battery storage is added to solar photovoltaics (PV); Section 8 presents the results of several sensitivities as requested by the DGSG; Section 9 presents the results of our macroeconomic analysis of the straw proposal; and, finally, Section 10 discusses our primary conclusions.

2. SUCCESSOR PROGRAM DESIGNS

2.1. Overview

When designing DG programs, there are a wide variety of issues and features that must be considered.[13] The design must provide sufficient incentive to fund projects, minimize costs, and maximize the benefits of renewable DG. Our work focused on the most important factors that drive the costs of DG programs, which we presented to the DGSG and incorporated feedback to inform the program designs modeled in this study. Table 1 summarizes the primary design features selected, discussed in further detail in the following sections. For context, these are compared with the Original Tariff Program in the table. The alternate compensation mechanism established by LD 634, which provides a fixed tariff rate subject to a 2.25% annual escalator, is not reflected in the table.

[13] A more extensive list of issues and features is discussed in the SEA team's presentation delivered to the DGSG on September 20, 2022, and can be found at: https://www.maine.gov/energy/sites/maine.gov.energy/files/inline-files/Workshop-2-%20SEA%20Sucessor%20Program%20Slides_FINAL_FOR%20PRESENTATION_9202022.pdf.

Table 1. Comparison of Successor Program Options with Original NEB Tariff Program

Program Type	Original NEB Tariff Program[14] (P.L. 2019, Ch. 478)	Successor Option #1: Fixed Future Payments	Successor Option #2: Moderate Hedge	Successor Option #3: Wholesale PPA
Eligible Project Size Range	Less than 5 MW_{AC}	1-5 MW_{AC}		
Eligible Offtakers/Participants	Commercial and institutional customers	"Identified residential, commercial and institutional customers" (per P.L. 2021 Ch. 390)		N/A (No specific offtakers)
Prioritization of Resources Meeting Policy Objectives	None (Eligible projects are not differentiated)	Successor options modeled utilizing a specific set of eligible project resource blocks (described in Section 2)		
Attributes Titled to Electric Distribution Company (EDC)	Energy*	Energy*	Energy and RECs*	
Price-Setting Mechanism	EDC Billing Determinants (SOS + 75% of T&D rate)	Competitive procurement (can be either (a) a one-time procurement ahead of a standard offer program or (b) annual procurements)		
Compensation Term (Years)	20 years			
Compensation Approach	Variable	Fixed (can be flat rate in nominal terms, or escalating at known rate)		
Benefits Provided to Offtakers	Bill credits			None (No specific offtakers)
Cost Shifting Potential	Yes (Bill credits result in lost EDC revenue)			No (Program costs recovered from all customers)
Bill Credit Creation Interval	Monthly			N/A (No specific offtakers)
Type of Bill Credit Utilized	Monetary (at NEB/other contract rate)	Monetary (at unspecified other rate)		N/A (No specific offtakers)
Bill Credit "Cash Out" Term	12 months			N/A (No specific offtakers)

**The gains from the resale of these attributes are assumed to accrue to the ratepayers of the EDCs purchasing the attributes produced by eligible projects*

2.2. Key Program Design Features Impacting the Benefits, Costs, and Rate Impacts of DG Programs

Eligible Project Size Range

The Original Tariff Program is limited to project sizes of 2-5 MW. Based on feedback from the DGSG, our team assumes that a successor program would allow projects from 1 MW_{AC} capacity to qualify. Further, we assumed that smaller projects (1 MW) would be behind the meter (BTM), co-located with a

[14] Additional modifications have been made to the original NEB program per LD 634, establishing a fixed tariff rate subject to a 2.25% inflator, which is not reflected in the table above.

commercial building or facility, because this is likely the most economical application of DG projects of this size.

Smaller capacity projects yield higher resource costs than larger projects because the costs of solar projects generally decline as they increase in capacity due to economies of scale. Meanwhile, projects located BTM to serve on-site load increase diversity in terms of project deployment alternatives.[15] This was deemed an acceptable tradeoff to the DGSG, at least for modeling assumption purposes.

Attribute Purchaser/Attributes Purchased

Other key DG cost drivers include (1) the attribute purchaser—which entity can (or must, under the program design) purchase attributes procured from wholesale markets (e.g., wholesale energy, renewable energy credits (RECs), and wholesale capacity) and (2) the attributes purchased—which of these attributes are purchased by the selected entity. Primarily, these program design elements affect project financing costs, as explained below.

Attribute Purchaser

We initially evaluated several potential entities that can theoretically purchase market attributes: electric distribution companies (or EDCs - Central Maine Power and Versant Power), the State of Maine, and other market participants or third parties. The attribute purchaser's creditworthiness has a significant impact on the project's cost of capital. Loans to more creditworthy offtakers[16] (such as an EDC or the State of Maine) are considered low-risk investments from the perspective of project financiers. On the other hand, third parties such as load-serving entities or other private companies, are generally considered riskier and therefore have higher costs of capital.[17] Furthermore, third-party purchases of RECs eliminate monetary benefits that could otherwise be passed on to electric ratepayers.

The DGSG broadly agreed that a DG successor program should seek to drive down financing costs and monetize benefits on market attributes for the benefit of ratepayers. However, the GEO and stakeholders concluded the State of Maine was not in a position to serve as such a purchaser. Based on these considerations, it was decided that all successor options should be modeled assuming EDCs will purchase DG project market attributes, and that these benefits would be conferred to ratepayers.

Attributes Purchased

The program design choice regarding which attributes are purchased has significant ramifications for both ratepayers and the owners of eligible projects. In the case of a more limited transfer of attributes (i.e., where a small portion of potential revenues are purchased by the EDC, with the remainder going to

[15] We assume BTM projects have a larger impact on avoided utility system benefits than front of the meter projects due to their ability to directly reduce load impacts on distribution circuits.
[16] The terms "offtaker" and "participant" are used interchangeably in this report.
[17] Based on metrics commonly used by financing entities to evaluate projects.

project owners), project owners can privately monetize gains, but they also bear the associated risk of market prices. In a limited transfer case, the EDCs would also be able to avoid the financial risks (and administrative costs) associated with monetizing attributes, but the EDCs would be unable to sell attributes to offset the cost of the program to their ratepayers. On the other hand, cases where more attributes will be purchased at preset compensation rates significantly lower the risk and cost of DG installations.

Feedback on this issue from the DGSG was twofold. First, parties generally agreed that energy and Renewable Energy Certificate (REC) monetization should be the responsibility of the EDCs. Second, the EDCs were concerned about the risks and feasibility of monetizing capacity values. Based on this feedback, the only attributes considered for the successor program options were energy or a combination of both energy and RECs. We assume none of the relevant parties monetize capacity via the Forward Capacity Market (FCM).

Prioritization of DG Resources that Serve Statutory Public Policy Objectives and Overlap with the Inflation Reduction Act

LD 936 requires that the DG Stakeholder Group prioritize distributed generation that is sited to

- limit impacts by being located on previously developed or impacted land, including areas covered by impervious surfaces, reclaimed gravel pits, capped landfills or brownfield sites as defined by the Department of Environmental Protection;
- serve load within a low-income to moderate-income community;
- directly serve customer load; or
- optimize grid performance or serve a non-wires alternative function.[18]

Historically, projects with incremental land use and/or siting value, directly serving load, or serving low- and/or middle-income (LMI) communities have tended to incur incremental costs in excess of the costs of a ground-mounted project sited on a greenfield parcel of land, generally the cheapest option for solar PV. However, on August 16, 2022, the federal government passed the Inflation Reduction Act ("IRA" or "Act") of 2022.[19] The IRA is highly relevant to the site selection of DG resources because it provides a

[18] We note that such direct prioritization is not explicitly featured in the original NEB tariff program developed pursuant to P.L. 2019, c. 478. Furthermore, the DGSG's Interim Report (issued December 31, 2021) also indicated stakeholder consensus around using the program to encourage deployment of energy storage, a subject discussed later in this report. See P.L. 2019, c. 478 here: https://legislature.maine.gov/legis/bills/bills_129th/chapters/PUBLIC478.asp

[19] See 26 U.S.C. § 48(a)(14) and 26 U.S.C. § 48E(a)(3)(a) for more information regarding bonus credits for "energy communities" and 26 U.S.C. § 48(e) and 26 U.S.C. § 48E(h) for more information about bonus credits for "low-income communities" and "disadvantaged communities." It is important to note that the exact details regarding eligibility and implementation of the various bonus credits rely on forthcoming guidance from the Internal Revenue Service that is not yet available.

bonus federal Investment Tax Credit (ITC) and a successor Clean Energy Incentive Credit (CEIC) for certain projects sited in “energy communities”, or serving “low-income” and/or “disadvantaged communities” as defined and/or limited by the Act.[20] Furthermore, the Act allows all projects less than or equal to 5 MW_{AC} to include transmission and distribution interconnection costs in the project’s ITC or CEIC basis. As a result, these bonus credit values are now set to substantially offset (if not fully outweigh) the incremental direct costs of these resources relative to greenfield, ground-mounted projects.

We received feedback from the DGSG that the successor program options should, where possible, make use of IRA credits in a way that balances the minimization of the cost of the program with the encouragement of resource diversity.

Eligible Project Benefit Offtakers/Participants

Another key driver of costs is the degree to which projects are assumed to contract with specific offtakers. For the purpose of analyzing potential NEB successor programs, LD 936[21] defines the term “distributed generation project” as projects with “identified residential, commercial and institutional customers and includes, but is not limited to, net energy billing arrangement projects.” This represents an expansion from previous definitions.

The program design feature of identifying offtakers has consequences for the costs of the resources procured, namely,

- additional capital costs for customer acquisition (e.g., locating and successfully enrolling a pool of customers prior to commercial operation);
- incremental ongoing operating costs for customer care and management following the commencement of commercial operations; and
- the cost of providing a discount to the offtaker.

On the other hand, including offtakers in program design can help achieve certain policy goals in addition to the deployment of renewable energy. For example, program designs can promote equity by ensuring low-income residential customers receive a higher share of program financial benefits (i.e. bill credits) compared with other customer groups, since these customers are disproportionately burdened by the regressive nature of energy costs. However, such program designs come with tradeoffs in costs and efficiency, which impact non-participants, discussed further below.

The DGSG was not unified on how to address this issue for modeling purposes. Several stakeholders opposed including the “identified residential, commercial and institutional customers”[22] specified in LD

[20] LD 936, Section 4.

[21] *Ibid.*

[22] *Ibid*.

936 in modeling of potential successor program designs. On the other hand, other stakeholders expressed the desire to promote equity by allowing some portion of LMI customers to participate directly in a successor program.

Based on this feedback from the DGSG, the modeling included several alternatives: some deployment with identified offtakers and one alternative with no offtakers (see Table 1). This allows for an economic comparison of various alternatives as Maine weighs successor program options.

Compensation Approach

The commercial and industrial (C&I) tariff NEB programs currently in place allow projects that meet certain initial time-based cutoffs to receive variable compensation, while the remainder receive fixed compensation. The variable compensation approach provides revenue to project owners that is based on the standard offer service rate in place at any given time, plus 75 percent of the applicable transmission and distribution billing determinants in place at any given time, while the projects that do not meet these time-based cutoffs will receive a fixed Year 1 compensation value (based on the 2020 standard offer service rate) plus a fixed escalation rate of 2.25 percent. The Maine Public Utility Commission (PUC) reports that roughly 250 MW of projects fulfilled requirements to qualify for the initial variable tariff rate (around 25 percent of total capacity), [23] suggesting that most of the capacity (around 75 percent) will be paid a fixed rate of compensation.[24]

Programs that utilize fixed compensation rates (or those that include pre-determined escalation rates) generally reduce project risk, thus lowering the cost of capital and compensation required to develop a project. On the other hand, variable rates, all other factors held equal, increase the financier's perceived project risk, thereby increasing the cost of capital and thus the level of compensation required.

Other considerations include the fact that a fixed payment structure allows ratepayers to benefit if market energy prices increase. If energy prices decrease relative to expectations, there can be negative impacts on ratepayers that may not be fully offset by attribute resales offsetting the cost of the program, or even the reduction in the cost of capital passed through in the form of lower compensation

[23] We estimate that approximately 900-950 MW of total capacity will reach commercial operation. Note that our estimate of 25 percent variable compensation should be treated as a maximum upper bound. Given the current number of projects subject to potentially expensive and time-consuming transmission and distribution interconnection studies, it is likely that a significant portion of the 250 MW of variable rate projects qualified under the PUC's rules will not reach commercial operation.

[24] See Maine Public Utilities Commission docket 2022-00185, available at: https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=117290&CaseNumber=2022-00185.

payments.[25] On the other hand, payments that are variable and not fixed do not provide a hedge to ratepayers since they are less predictable.

The DGSG appeared to be in general agreement that a fixed compensation approach was desirable, and was likely necessary following the original program, to mitigate costs and risks to ratepayers, while also providing project financiers with a sufficient degree of certainty to mitigate the perceived project risk. However, some stakeholders suggested using a fixed escalator (rather than a fully fixed value on a nominal basis).

Compensation Term

The compensation term also impacts project costs. Longer incentive terms tend to reduce the required compensation amount and limit the near-term rate impacts, though they also increase the time ratepayers must fund project installations. That said, long compensation terms reduce the need for developers to earn market revenues in later years, reducing financing risk.

Based on these factors, the DGSG was in general agreement that a 20-year compensation term should be assumed (equal to the maximum allowable term allowed under statute). This was modeled for all successor program options.

Bill Credits

Whether and how to structure bill credits affects program costs and the distribution of benefits among ratepayers. In coordination with the DGSG, we modeled several options where participation was considered and bill credits were analyzed to inform the relative costs and benefits of applying bill credits. These credits were assumed to expire after one year (as is typical in regional net metering programs), at which time any remaining monetary compensation would be paid to the offtaker at a rate lower than the retail rate to minimize ongoing debt carried forward in the form of bill credits.

Compensation Price-Setting Mechanism

The final program element that has a direct impact on our analysis is the price-setting mechanism used to determine the project's compensation rate. For certain projects under the current NEB programs, prices are effectively set via the EDCs' rates that are in place at the time the system generates

[25] It is important to note that it is also possible for a program design that incorporates a fixed (or otherwise fully predictable) escalation rate to also provide hedge value to ratepayers, so long as the escalation rate is calibrated to be lower than the expected rate of increase for customer rates. We further note a fixed-but-escalating structure could also better accommodate the combination of debt service payments and project operating expenses over time (the latter of which tends to increase at around 2-3 percent per year). However, these changes still can have an impact on the relative cost-effectiveness of the program, given that such an approach would result in rising rates over time (rather than flat rates).

electricity. Other prices are based on EDC rates at a fixed point in time, escalated into the future (see above).

Project developers value the fact that the current NEB approach relies on retail electric rates, which tend to be significantly higher than the cost to deploy projects. However, this approach is sub-optimal from a ratepayer perspective because the program cannot capture the benefit of future reductions in solar PV costs (and/or solar PV paired with energy storage) nor the advantages of competitive bidding processes.

Certain stakeholders in the DGSG preferred declining- or adjustable-block pricing in which the compensation rate can either decline or be adjusted (manually or automatically) based on market conditions.[26] Additionally, some suggested the use of a one-time competitive procurement to set the price for a standard offer program for the balance of the program capacity. Meanwhile, others suggested that the program be based on annual competitive procurements.

Based on the majority of DGSG feedback, we assumed in our modeling that all the successor options would utilize competitive procurement processes or at least engage in a form of price discovery such that pricing would match competitive bidding.

2.3. Core Successor Program Options Evaluated

In this section, we describe the three successor program options ultimately modeled as part of the first (screening) phase in order to reflect the DGSG deliberations discussed in the preceding sections.

Common Attributes Shared by All Successor Program Options

All three successor program options modeled in the initial screening phase have the following program attributes in common:

- An eligible project size range of no less than 1 MW_{AC} to no greater than 5 MW_{AC}
- A uniform set of proxy project resource blocks, which are intended to capture a diverse array of projects that are expected to have distinct cost profiles;[27]
- A fixed compensation approach, in which compensation is assumed to be a fixed value on a nominal basis throughout the term of the contract or tariff

[26] For an example of such an approach, see: 225 CMR 20.00: Solar Massachusetts Renewable Target (SMART) Program available here: https://www.mass.gov/doc/225-cmr-20-solar-massachusetts-renewable-target-smart-program-0/download

[27] Resource block selections are not meant to represent the actual program mix, or imply that modeled resources are preferred from a public policy perspective. Rather, different resource blocks were chosen to model a diversity of project types that achieve policy goals (e.g., serving LMI customers), or are more economical (e.g., due to IRA bonus tax credits), or both.

- A compensation term (for the applicable tariff or contract) of 20 years
- Compensation rates set via either a one-time competitive procurement, or an ongoing, semi-annual set of competitive procurements

Successor Program Option #1: Fixed Future Payments

This option is intended to represent a program that is limited in the degree of market attributes purchased by the EDC. In this case, we assume only wholesale energy attributes are monetized. To represent this difference, the projects under this policy option are assumed to have a slightly higher cost of capital, and thus slightly higher costs to the developer. Furthermore, and unlike successor program Option #3 (Wholesale PPA), Option #1 assumes that all projects will have their production assigned to identified offtakers that receive a fixed bill credit, depending on which kind of customer they are. Details regarding the bill credits applied to the eligible project types are described in the Appendix.

Successor Program Option #2: Moderate Hedge

Similar to Option #1 (and unlike Option #3), Successor Option #2 assumes that all projects have identified offtakers and a similar fixed bill credit value. However, the main purpose of this case is to represent a program in which all project benefits are assigned to identified offtakers; wholesale energy attributes and RECs are purchased at a fixed price, as in Option #3.

Successor Program Option #3: Wholesale PPA

Finally, Option #3 is intended to combine a case in which all of the cost-reducing features of Option #2 (an EDC purchaser of both energy and RECs) with the further cost-reducing attribute of including no projects with identified offtakers.[28] As such, this case represents a program in which all projects would be procured directly by the EDCs, with no need for bill credits or offtakers (along with their required capital and operating costs, plus offtaker discount) of any kind.

2.4. Initial Determination of Eligible Successor Program Capacity

Per statute, the MW target for the NEB successor is calculated as seven percent of load, less any development from the initial NEB program in excess of the 750 MW program target. The equation for deriving this value is shown below[29]:

[28] Though it is unclear if this option, if adopted as modeled as the successor to the current NEB programs, is compliant with the terms of P.L. 2021, Ch. 390 (LD 936), GEO and the DGSG indicated their interest in understanding of the results of such a case as a means to understand and bound the impact of allowing projects without identified offtakers to be eligible.

[29] The specific values utilized for 2030 statewide load, the expected capacity factors (in alternating current (AC)) for the current program and potential successor program options, and the consulting team's current estimate for final capacity reaching commercial operation from the current NEB programs can be found in the Appendix.

$$\frac{(2030\ Statewide\ Load * 7\%) - \left(Final\ Current\ NEB\ MW > 750 * \ Capacity\ Factor_{AC} * \ 8760_{hrs/yr}\right)}{Wtd.Av.\ \ AC\ Cap.Factor_{NEB\ Successor} \big/ 8760_{hrs/yr}}$$

This results in a total program size of **558 MW** for successor program Options #1-#2 (Fixed Future Payments and Moderate Hedge, respectively), and **564 MW** for successor program Option #3 (Wholesale PPA). The small differences between the program types can mainly be ascribed to the minute differences in weighted average capacity factors for each successor option, as well as the capacity allocation between various DG resource blocks utilized in the modeling of the three successor program options (the development of which is described in the next subsection).

2.5. Eligible Distributed Generation Resource Blocks/Modeling Approach

In response to both LD 936 and the findings of the Interim Report, we developed a set of resource blocks, intentionally chosen to balance various public policy objectives that increase the technological, locational, and offtaker-based diversity, with the cost of the projects.[30]

For successor program Options 1-2, our team proposed six specific resource blocks. As discussed in Section 2.3 above, under these policy options, all projects are assumed to have identified offtakers (residential, commercial, and/or institutional) per LD 936. Therefore, in addition to assuming discounts for the offtaker/project host for BTM 1 MW_{AC} projects, all FTM 5 MW_{AC} projects under these policy options are assumed to be shared solar projects, and thus require upfront customer acquisition costs (treated in modeling like upfront capital costs) and ongoing customer care and management cost (treated in modeling like operating expenses).

As also noted in Section 2.3, under successor program Option #3, all projects are assumed to sell directly to the utility, and would thus have no residential, commercial, or industrial offtakers (requiring no offtaker discounts or added capital or operating expenses associated with acquiring or maintaining offtakers). Furthermore, two specific resource blocks defined by the project that had 50 percent of their production assigned to LMI customers were removed from this case (one that was eligible for a bonus ITC or CEIC credit of up to 20 percent, and one that was not) because Option #3 was designed to model projects with identified offtakers.

To estimate the compensation required for these resource blocks for each case, we utilized a version of the Cost of Renewable Energy Spreadsheet Tool (CREST) developed by SEA, originally for the National Renewable Energy Laboratory (NREL). The CREST model was customized to utilize the cost, performance, financing, and tax assumptions specific to projects developed in the state of Maine. The model is described in Appendix Section A.2 and additional specific assumptions utilized are described in detail in the Appendix.

[30] Please note that the resource blocks utilized in either the screening analysis or the sensitivities associated with the hybrid program design (described later in this report) are not intended to be interpreted as the actual resources expected or preferred in the successor program.

Table 2. Successor Program Options 1 and 2: Characteristics by Resource Block

Project Size (AC)	Configuration/Location	Offtaker Type(s)	ITC (IRA Base + Bonus)	Capacity (MW_{AC})
1 MW	Behind the Meter (BTM): (C&I)	Host Customer	30% (30% + 0%)	93 MW
5 MW	Front of Meter (FTM): Any	50% Res, 50% C&I	30% (30% + 0%)	93 MW
	FTM: Any	50% LMI, 25% Res, 25% C&I	40% (30% + 10%)	93 MW
	FTM: Brownfield/Energy Community"	50% Res, 50% C&I	40% (30% + 10%)	93 MW
	FTM: "Low Income (LI) Community"	50% Res, 50% C&I	40% (30% + 10%)	93 MW
	FTM: "LI Benefit"	50% LMI, 25% Res, 25% C&I	40% (30% + 10%)	93 MW
Program Total				558 MW

Table 3. Successor Program Options 1 and 2: Annual Capacity by Resource Block

Project Size (AC)	Configuration/Location	2024 (2027 COD)	2025 (2028 COD)	2026 (2029 COD)	2027 (2030 COD)	2028 (2031 COD)
1 MW	BTM: C&I	19	19	19	19	19
5 MW	FTM: Any	19	19	19	19	19
	FTM: Any	19	19	19	19	19
	FTM: Brownfield/Energy Community"	19	19	19	19	19
	FTM: "LI Community"	19	19	19	19	19
	FTM: "LI Benefit"	19	19	19	19	19
Annual Total		112	112	112	112	112

Table 4. Successor Program Option 3: Resource Blocks, Tax Treatment, and Modeled Capacity

Project Size (AC)	Configuration/Location	Offtaker Type(s)	IRA Bonus ITC %	Capacity (MW_{AC})
1 MW	BTM: C&I	All Customers (No specific offtaker)	0%	141
5 MW	FTM: Any		0%	141
	FTM: Brownfield/Energy Community"		10%	141
	FTM: "LI Community"		10%	141
Program Total				564

Table 5. Successor Program Option 3: Annual Capacity (MW_{AC}) by Resource Block for

Project Size (AC)	Configuration/Location	2024 (2027 COD)	2025 (2028 COD)	2026 (2029 COD)	2027 (2030 COD)	2028 (2031 COD)
1 MW	BTM: C&I	28	28	28	28	28
5 MW	FTM: Any	28	28	28	28	28
	FTM: Brownfield/Energy Community"	28	28	28	28	28
	FTM: "LI Community"	28	28	28	28	28
	Annual Total	113	113	113	113	113

3. Economic Assessment Methods

3.1. Overview

This section provides a general overview and discussion of the economic analyses of successor programs. More details about the methodology, as well as the values used and the assumptions made, are provided in the Appendix to this report. We provide the results of the analyses discussed here in the ensuing sections.

We evaluated potential successor programs using analytical frameworks that are often employed in the energy utility sector—(1) benefit-cost analysis and (2) rate, bill, and participation analysis. We provide an overview of these methodologies in the ensuing sections, as well as the specific inputs and assumptions used to evaluate potential successor DG programs.

3.2. Benefit-Cost Analysis

As stated in the National Energy Screening Project's *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resource* (NESP), BCAs "involve a systematic approach for assessing the cost-effectiveness of investments by consistently and comprehensively comparing the benefits and costs of individual or multiple types of DERs with each other."[31] The BCA results presented here allow stakeholders in Maine to quantitatively evaluate potential DER successor programs that achieve a variety of clean energy and equity-related goals. In short, these tests allow stakeholders to compare the projected benefits with the costs of potential successor programs on an "apples to apples" basis. The

[31] National Energy Screening Project. 2020. *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*. E4TheFuture, Synapse Energy Economics, Energy Futures Group, ICF, Pace Energy and Climate Center, Schiller Consulting, Smart Electric Power Alliance. (NESP), p. i.

end result of a BCA is a benefit-cost ratio (BCR) for each program and an estimate of "net benefits"—benefits minus costs.[32]

There are several cost-effectiveness tests traditionally used to evaluate programs from different stakeholder perspectives: [33]

- Utility Cost Test (UCT), also known as the Program Administrator Cost Test (PACT), which includes the benefits and costs experienced by the utility system.
- Total Resource Cost (TRC) Test, which includes the benefits and costs experienced by the utility system, plus benefits and costs to host customers.
- Societal Cost Test (SCT), which includes the benefits and costs experienced by society.
- Participant Cost Test (PCT), which includes the benefits and costs experienced by host customers. This test supports program design and host customer investment decisions.
- Rate Impact Measure (RIM) Test, which indicates whether rates are likely to increase or decrease as a result of DER investments, and therefore primarily represents the perspective of non-host customers

Benefit-Cost Test to Evaluate Maine's DG Successor Programs—The "Maine Test"

The traditional tests described above do not necessarily account for the specific policy goals of any one state, including Maine. In these cases, the NESP recommends establishing a jurisdiction-specific test that does reflect the applicable energy policy goals of the jurisdiction, as guided by statutes, regulations, commission orders, and stakeholder input. Any such test should adhere to fundamental BCA principles and should represent the "regulatory perspective," which is meant to represent the views of legislators, commissioners, and other relevant decision-makers.

Figure 2 presents the perspectives that are used to determine the traditional cost-effectiveness tests and compares these to the regulatory perspective.

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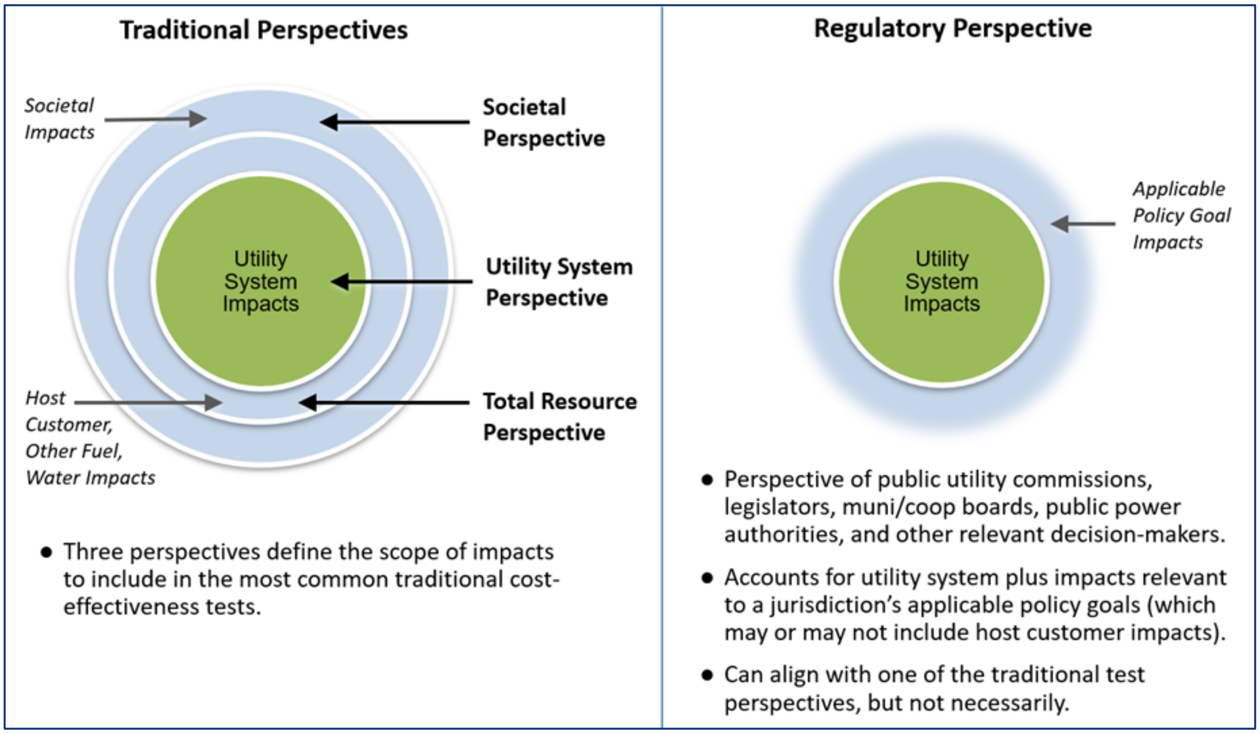
[32] All results are presented in constant 2022 dollars and discounted to account for the time value of money.
[33] NESP 2020, p. 3-1.

Figure 2. Cost-effectiveness Test Perspectives



Source: NESP, p. 3-3.

The NESP also provides a step-by-step process for how to determine a jurisdiction-specific test. These steps are described in Figure 3.

Figure 3. Process for Determining the Primary Benefit-cost Test

STEP 1 **Articulate Applicable Policy Goals**
Articulate the jurisdiction's applicable policy goals related to DERs.

STEP 2 **Include All Utility System Impacts**
Identify and include the full range of utility system impacts in the primary test.

STEP 3 **Decide Which Non-Utility System Impacts to Include**
Identify those non-utility system impacts to include in the primary test based on applicable policy goals identified in Step 1:

STEP 4 **Ensure that Benefits and Costs are Properly Addressed**
Ensure that the impacts identified in Steps 2 and 3 are properly addressed, where:
- Benefits and costs are treated symmetrically;
- Relevant and material impacts are included, even if hard to quantify;
- Benefits and costs are not double-counted; and
- Benefits and costs are treated consistently across DER types

STEP 5 **Establish Transparent Documentation**
Establish comprehensive, transparent documentation and reporting, whereby:
- The process used to determine the primary test is fully documented; and
- Reporting requirements for presenting assumptions and results are developed.

Source: Synapse Presentation at the 8/31/22 DGSG meeting, slide 14, https://www.maine.gov/energy/studies-reports-working-groups/current-studies-working-groups/dg-stakeholder-group.

These steps were used to determine a BCA test that is appropriate for evaluating the successor DG programs. We refer to this test as the Maine Test. Synapse and SEA presented a straw proposal for the Maine Test to the DGSG at the August 31, 2022, stakeholder meeting.[34] Through an iterative process including written feedback from DGSG participants, the group decided on a set of benefits to include as part of the Maine Test, which includes utility system impacts and the primary societal impacts of DG. The test does not include all the potential benefits of DG, many of which are difficult to quantify or do not easily lend themselves to inclusion in a traditional BCA framework.[35] The benefits and costs selected for evaluation by the DGSG are shown in Table 6, in conjunction with the method and source of the information utilized by Synapse and SEA to calculate each benefit or cost.

[34] Synapse Presentation at the August 31, 2022 DGSG meeting, slide 26, https://www.maine.gov/energy/studies-reports-working-groups/current-studies-working-groups/dg-stakeholder-group.

[35] These include, but are not limited to, public health benefits, macroeconomic effects, energy security, energy equity, and resilience benefits. These were nevertheless presented in the straw proposal to the DGSG.

Table 6. Benefits and Costs Included in the Maine Test

Type of Impact	Impact	Benefit or Cost?	Method
Generation	Avoided Energy Cost	Benefit	AESC 2021
	Avoided Capacity Cost	Benefit	AESC 2021
	Avoided Environmental Compliance	Benefit	AESC 2021
	Avoided RPS Compliance Costs	Benefit	AESC 2021
	Market Price Effects ("DRIPE")	Benefit	AESC 2021
Transmission	Avoided PTF Costs	Benefit	Efficiency Maine assumptions
	Avoided Non-PTF Costs	Benefit	Efficiency Maine assumptions – only applied to BTM
Distribution	Avoided Distribution Costs	Benefit	Efficiency Maine assumptions – only applied to BTM
General	Renewable Energy Credit Prices	Benefit	Sustainable Energy Advantage (SEA) "CREST" Model
	DG Costs	Cost	Based on program design and total cost from SEA "CREST" Model
	Program Administration Costs	Cost	Input from utilities ($600,000 for first 5 years, $300,000 for remaining generation period)
Societal	Avoided CO_2	Benefit	AESC 2021
	Avoided NOx	Benefit	AESC 2021

Table 7 provides brief definitions for the benefits listed above. See Appendix Section A.3 for more details. For full definitions, methodologies, and resources, see the Methods, Tools, and Resources (MTR) manual published by the National Energy Screening Project (NESP).[36]

[36] *Ibid.*

Table 7. Definitions of Benefits Included in the Maine Test

Impact	Definition
Utility system benefits	
Avoided energy costs	Avoided fuel and operating costs associated with producing or procuring energy.
Avoided capacity costs	Avoided cost of building or procuring capacity to meet the peak demand of the generation system.
Avoided environmental compliance costs	The avoided cost of complying with environmental requirements for air emissions or other environmental factors.
Avoided RPS compliance costs	The avoided cost of complying with a renewable portfolio standard (RPS) or similar policy such as clean energy standards (CES) or clean peak standards (CPS).
Market price effects/demand reduction induced price effects (DRIPE)	The price reduction effect in competitive wholesale electricity markets price impacts from reducing system demand or increasing low-cost supply.
Avoided transmission costs	The avoided (or increased) cost of upgrading the transmission system to safely and reliably transfer electricity between regions. This avoided cost applies if the DERs passively defers investments by reducing load during transmission peak periods or if the DER is strategically placed to avoid transmission investments and is operated for that purpose. Alternatively, DERs can increase costs on the transmission system by adding new load.
Avoided distribution costs	The avoided (or increased) cost of upgrading the distribution system (including substations) to transfer electricity in local electric grids. If peak demand exceeds capacity of a circuit, it will require investments to increase distribution capacity to a level that preserves safety and reliability. Similar to transmission avoided costs, DERs can passively or actively reduce strain on the distribution system. Alternatively, DERs can increase costs by adding new load.
REC revenue	Revenue from selling renewable energy certificates (RECs). RECs are credits designed to represent the clean energy attributes of renewable energy generation.
Societal benefits	
Greenhouse gas (GHG) emissions impacts	The benefit associated with reducing GHG emissions because of DERs. GHGs are created during fossil fuel-based energy production, transmission, and distribution. DERs that produce clean energy can avoid GHG emissions from other sources. In the BCA, this impact represents the avoided societal cost of GHG emissions.

Using the sources of data shown above, described in further detail in the ensuing subsections, we calculated the avoided costs (used interchangeably with "benefits") of each program by multiplying the estimated level of generation (in MWh) for aggregated time periods by the expected price or value (in $/MWh) in the applicable time period. We aggregated hourly time periods across each year for energy "peak" (8 am-11 pm) and "off-peak" hours (11 pm-7 am) for each season (winter and summer), according to designations of these periods by ISO-NE. Generation capacity, transmission, and distribution avoided costs were calculated by multiplying the maximum output (in kW per year) during the most expensive hours on the electric grid by the dollar values of each avoided cost (in $/kW-year) for those benefit categories. See the Appendix for a further discussion of these benefit categories.

Costs for program administration were fixed in each year, as indicated in the table, while the cost of renewable generation is calculated by multiplying SEA's estimated cost per megawatt hour (MWh) by the generation profile of solar during each time period described above.

The ensuing sections discuss the primary sources of data used to calculate the results of the Maine Test for potential successor programs—the Avoided Energy Supply Components (AESC) Study and Efficiency Maine, and SEA's modeling of DG costs.

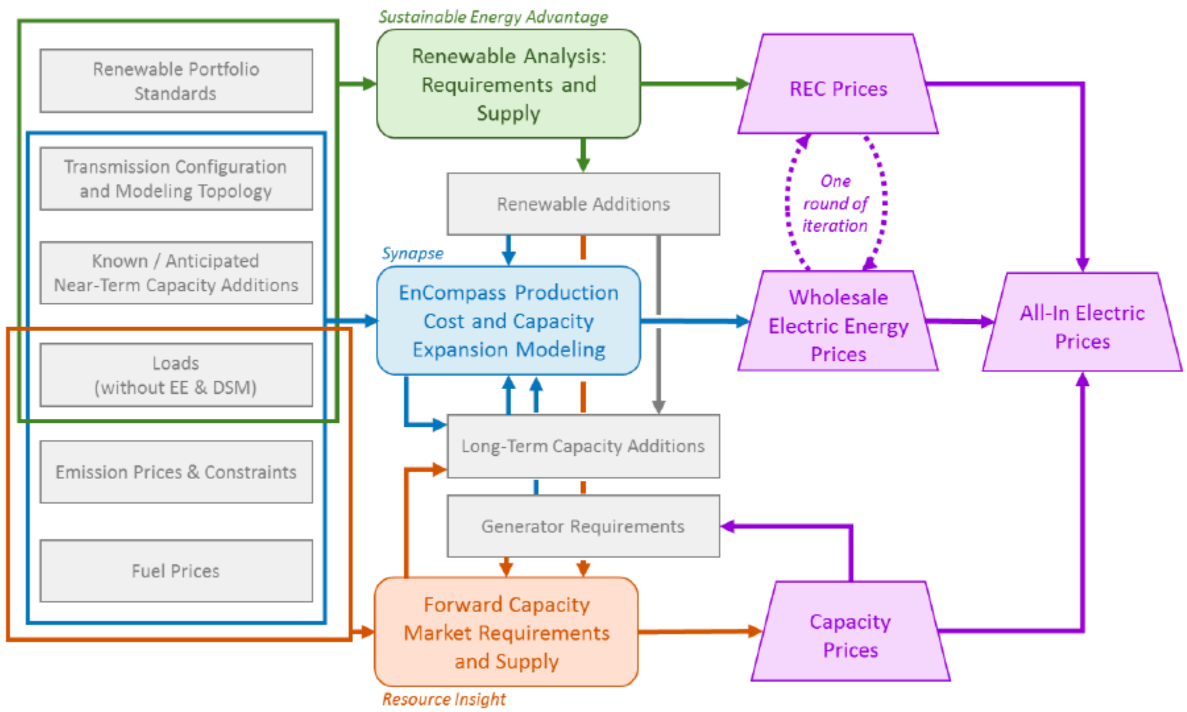
Avoided Energy Supply Components (AESC) Study and Efficiency Maine

The AESC is a triannual publication used by utilities, commissions, and other stakeholders to evaluate the economic impacts of energy efficiency programs in New England. The 2021 study was developed by Synapse and a group of subcontractors. The analysis presented here utilizes the "All-in Climate Policy" scenario included in the AESC, which "models a future with ambitious levels of energy efficiency, building electrification, and transportation electrification, as well as a policy which achieves 90 percent clean energy regionwide by 2035. As a result, it can be interpreted not as an avoided cost, but as a projection of expected energy prices, capacity prices, and other price series in a future with ambitious climate policies." [37]

Electric price forecasts are developed with production cost/capacity-expansion modeling of the New England electric system to forecast load, generator dispatch, and long-term capacity additions. The AESC relies on a variety of models, inputs, and assumptions, depicted below.

[37] Synapse et al. 2021. *Avoided Energy Supply Components in New England: 2021 Report,* Amended May 14, 2021, p. 294.

Figure 4. AESC 2021 Modeling Schematic



Source: Synapse et al., 2021 AESC Study, Amended May 14, 2021, p. 66, https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf.

In a scenario with increased DG, avoided costs can be calculated by multiplying the market price in each time period by the expected generation, which serves to reduce load on the bulk electric system.

The "Efficiency Maine" source referenced in Table 6 refers to a supplement to the AESC that estimates avoided transmission and distribution costs specific to the state of Maine—as opposed to New England—pursuant to a separate contract between the Efficiency Maine Trust (EMT) and Synapse.[38] The analysis is consistent with the methodology described in the AESC but utilizes specific data provided by Central Maine Power (CMP) as a proxy for the state of Maine.

The analysis utilizes data provided by CMP of forecast transmission and distribution (T&D) capital costs, as well as load profiles, to create a range of potential avoided T&D cost values.[39] We selected the mid-point of this range for this study, and we conduct sensitivities for this assumption in Section 8.1.

[38] Efficiency Maine Trust is the energy efficiency program administrator in Maine. Any assumptions cited as consistent with EMT refer specifically to its 2020-2022 Plan filing, available at: https://www.efficiencymaine.com/triennial-plan-iv/.

[39] AESC 2021. p. 260-261.

Cost of Renewable Energy Spreadsheet Tool (CREST) Model

The CREST model is a cash flow analysis tool published by the National Renewable Energy Laboratory (NREL). SEA was the primary architect of the CREST model, which SEA developed under contract to NREL. SEA developed CREST to help policymakers develop cost-based renewable energy incentives and has been peer reviewed by both public and private sector market participants. The model is a transparent tool that allows the user to modify inputs and assumptions. It is designed to calculate the cost of energy, or minimum compensation per unit of production, necessary for the modeled project to cover its expenses, service its debt obligations (if any), and meet its equity investors' assumed minimum required after-tax rate of return.[40]

As noted in Section 2, we developed a series of cost, performance, and financing inputs intended to be regionally representative (and, where possible, state-specific) conditions for development of distributed generation projects. Furthermore, we sought feedback on a draft set of cost, performance, and financing assumptions for both solar PV and co-located energy storage from the DGSG. The final inputs (described in the Appendix) reflect assumptions that have been vetted and adjusted after they were shared with market participants to ensure accuracy.

3.3. Rate, Bill, and Participation Analysis

Background

As described in the NESP, rate, bill, and participation analyses (RBPA) indicate "the extent to which DER investments might lead to distributional equity or cost allocation concerns."[41] RBPAs are considered separately from BCAs, as they provide different information regarding the financial impact of programs on ratepayers. The differences between BCAs and RBPAs are described in the Table 8.

[40] CREST was developed in Microsoft Excel, so it offers the user a high degree of flexibility and transparency, including full comprehension of the underlying equations and model logic.

[41] NESP, p. xxii.

Table 8. Purpose of Cost-effectiveness Analysis versus Rate Impact Analysis

Key Considerations	Cost-Effectiveness Analysis	Rate Impact Analysis
Answers the question:	*Which utility DER investments are expected to have benefits that exceed costs?* Cost-effectiveness indicates the extent to which different utility investments will reduce utility costs and achieve other policy goals, regardless of how the benefits and costs are distributed across different customers.	*How much will utility DER investments impact rates for one group of customers compared to another?* [42]
Results of the analysis are expressed as:	Present value of revenue requirements, benefit-cost ratios, and net benefits. These metrics are important for regulators and other stakeholders to understand cost-effectiveness but do not provide any information relevant to rate impacts.	Long-term impacts on rates (in ȼ/kWh or percent changes to rates) or in terms of long-term bill impacts (in $ per month or percent changes to bills). These metrics are important for regulators and other stakeholders to understand rate impacts but do little to inform benefit-cost analyses.

Source: NESP, p. xxii.

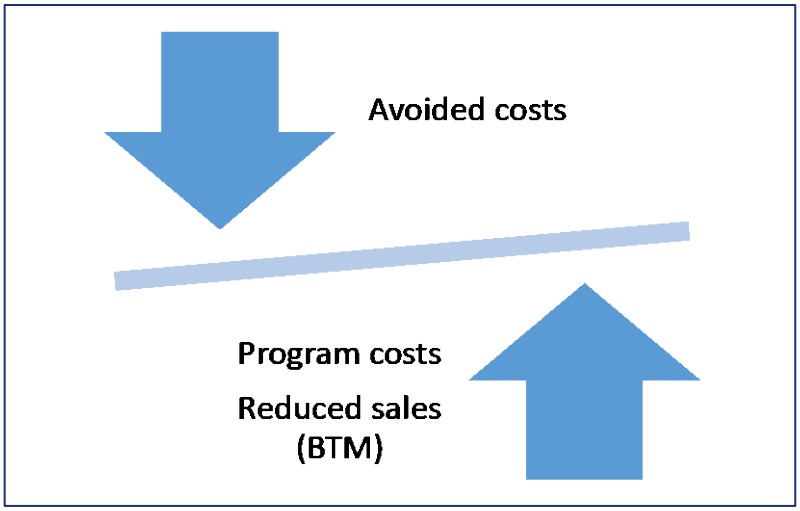
In addition to distributional impacts, RBPAs provide aggregate rate and bill impacts for all ratepayers. This is the only data provided in cases where there are no participants (i.e., all ratepayers pay for a program and no particular group of customers receives a preferential subsidy).

In general, RBPAs flow directly from data inputs and modeling results from the BCA. Avoided costs exert downward pressure on rates, while program costs and reduced sales from DERs[43] exert upward pressure on rates.

[42] Fully understanding the impacts across different customers requires a comparison of the bill impacts on host customers versus the bill impacts of other customers. (See Appendix).

[43] Only DER generation related to BTM sales are assumed to exert upward pressure on rates due to "lost sales" effectively revenue requirements that must be collected from non-participating ratepayers.

Figure 5. BCA Elements and Rate Impacts



Bill impacts flow directly from rate impacts but provide additional information with regard to the long-term monetary impact of programs under evaluation. Bill impacts are the same as rate impacts for those customers that do not experience any energy savings or bill credits. Customers that participate in programs where they experience energy savings or bill credits will see more favorable bill impacts than rate impacts.

Finally, participation estimates provide the number of program beneficiaries relative to the total population of customers. This offers information on the population of customers that directly benefit from a program, where applicable.

Rate, Bill, and Participation Analyses Conducted to Evaluate Maine's DG Successor Programs

As discussed above, the assumptions for RBPAs flow directly from the program designs (discussed in Section 2) and the BCA inputs and methodology (discussed above). Rate impacts are driven by the utility system costs and benefits, including the generation, transmission, distribution, and general impacts presented in Table 6. Societal impacts, such as reduced GHG or NO_X emissions, do not impact rates because these costs are not borne by the utility or included in utility rates.

To determine the potential impacts of the successor programs on electric rates, we developed rate forecasts[44] using data from CMP and Versant Power, the states' two investor-owned utilities (IOUs), as well as input from the DGSG. These consisted of forecasted revenue requirements in each year, divided by expected load, over the assumed lifetime of the successor program (20 years from the first year of production). We then calculated the effect on rates by subtracting any program benefits (e.g., REC revenue) that would decrease rates and adding program costs that would increase rates to the

[44] Rate forecasts were developed using long-term averages and are not intended to capture effects of specific events, either in the in the short-, medium-, or long-term. The forecasts are intended for BCA and rate impact assessment purposes and do not represent any entity's expectations about actual future outcomes.

forecasted revenue requirement in each year. This allowed for an annual average estimate of electric rates with and without the program, the difference of which is the rate impact of the successor program. It is important to note that these rate forecasts are used solely for modeling purposes and do not reflect any one view in particular.

We determined bill and participant impacts by multiplying the annual rate impacts from the program by annual estimated average energy consumption per customer at both CMP and Versant. Depending on the program design under evaluation, a bill credit was then applied for participants, the cost of which was assumed to be borne by non-participants, resulting in differential bill impacts for these two groups, where applicable.

4. Results of the Benefit-Cost Analysis

4.1. Successor Program Resource Costs

Table 9 shows the cost per megawatt-hour to finance, develop, and operate each resource block throughout the life of the project, for each successor program. These costs incorporate available federal tax incentives, namely those offered by the recently passed Inflation Reduction Act (IRA), which reduces costs of installing and operating renewable technologies.

The results displayed below assume the project qualifies for participation in the year listed, and begins operation three years later, with the lag due to development timelines including factors such as permitting, financing, and interconnection queue times typical of these sorts of projects. The costs for each program and technology block decline over time to account for improved economies as the technologies become more commercially available and widely adopted.

Table 9: Project cost by successor program option and resource block in nominal dollars ($/MWh)

Option	Block	Program Enrollment Year				
		2024	2025	2026	2027	2028
Fixed Future Price	Roof Mounted	194	185	176	170	165
	Ground Mount	166	158	152	147	143
	Ground: LMI Offtakers	182	175	167	163	158
	Ground: Brownfield & LMI Location	167	160	153	149	145
	Ground: LMI Offtakers & LMI Location	167	159	153	149	145
	Ground: LMI Offtakers & LMI Benefit	149	143	138	134	131
Moderate Hedge	Roof Mounted	185	175	167	163	157
	Ground Mount	172	164	157	153	149
	Ground: LMI Offtakers	191	182	176	172	167
	Ground: Brownfield & LMI Location	182	175	169	164	161
	Ground: LMI Offtakers & LMI Location	164	157	151	147	143
	Ground: LMI Offtakers & LMI Benefit	160	154	149	146	142
Wholesale PPA	Roof Mounted	171	161	154	149	143
	Ground Mount	131	125	118	114	110
	Ground: LMI Offtakers	N/A	N/A	N/A	N/A	N/A
	Ground: Brownfield & LMI Location	140	133	127	122	119
	Ground: LMI Offtakers & LMI Location	118	112	106	103	99
	Ground: LMI Offtakers & LMI Benefit	N/A	N/A	N/A	N/A	N/A

We derived the cost inputs to the BCA from SEA's CREST model, shown in Table 9 above. We then converted these nominal dollars to 2022 present value dollars, using a nominal discount rate, to put them in the same dollar terms as the rest of the costs and benefits in the BCA (see the Appendix).

The key findings from this analysis are as follows:

- ***Financing Risk Mitigation Impact by Policy Option and Block:*** Renewable DG projects have several attributes that can be assigned to either the developer or the utility procuring the power, including energy, capacity, and REC attributes. Developers see the attributes of renewable DG projects as risky because it is difficult to predict what these attributes will be worth for the life of the DG project or contract. Projects with more risk to developers require higher financing costs and thus higher overall project costs, while projects with less risk to developers have lower financing costs and thus lower overall project costs.

- ***Offtaker Impact:*** The costs of recruiting and servicing offtakers, i.e., direct participants, which increases overall costs.

- ***Bonus IRA Investment Tax Credit:*** The bonus IRA credits have a major impact on costs for qualifying resources. For example, the 10 percent bonus "energy communities" credit substantially reduces the cost of projects sited on a qualifying brownfield.

- ***Relative Project Size/Scale Impacts by Block:*** The CREST analysis confirms that larger capacity projects have lower costs. Nevertheless, and despite the IRA's allowance to include interconnection costs in the project's investment credit basis, the difference is not as significant as it once was. This is in part due to the substantially higher interconnection costs associated with 5 MW_{AC} projects.

4.2. Successor Program Benefits

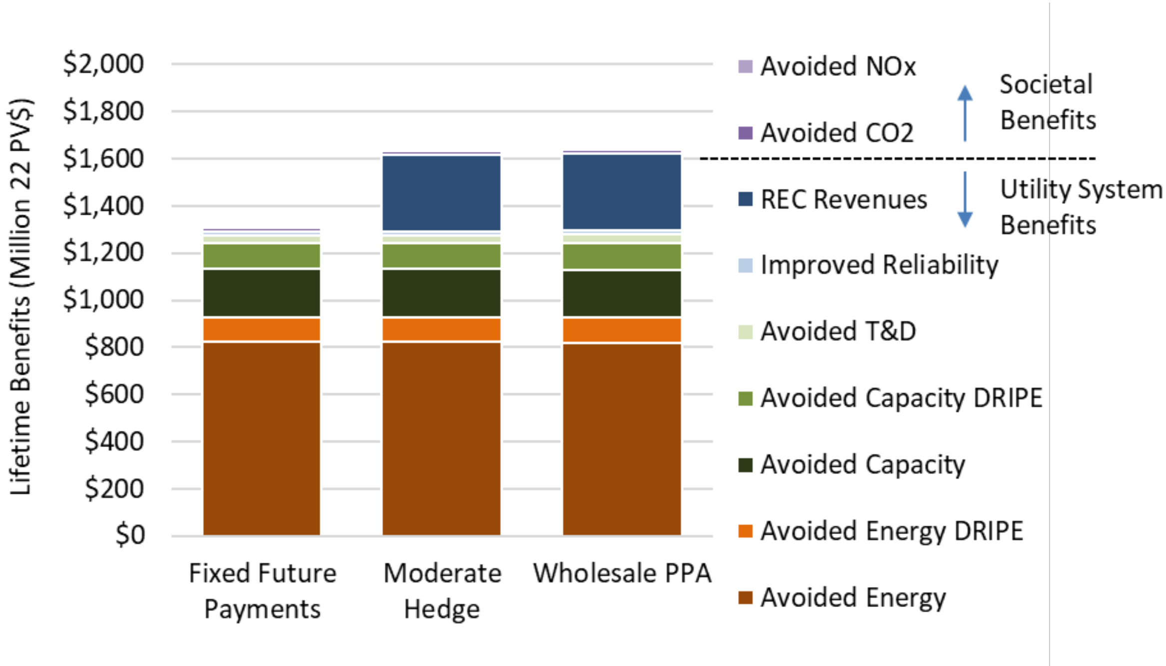
The BCA benefits fall into two categories: utility system benefits and societal benefits. Utility system benefits, which include avoided energy and energy DRIPE costs, avoided capacity and capacity DRIPE costs, avoided T&D costs, improved reliability, and REC revenue, have a monetary value to the utility, and ultimately, ratepayers. Societal benefits, including reduced CO_2 and NO_X emissions, do not have a direct monetary benefit to the utility or ratepayers, but the societal benefits are monetized in order to allow for a direct comparison with the other monetary impacts. These benefits are defined in Appendix Section A.3

Figure 6 displays the benefits for each successor program, broken out by the benefit categories described above. The total lifetime benefits for each program are between $1.3 billion and $1.7 billion.

Key findings from this graph include the following:

- These benefits are generally consistent across the three programs (except for the REC benefits) because we assumed that each program would include the same set of resource blocks. We made this assumption to allow for consistent, direct comparisons across the successor program options.
- For each program, avoided energy benefits are the largest single benefit.
- For the Fixed Future Payments program, the RECs are assigned to the developers. Therefore, the REC benefits cannot be attributed to this program because (a) the developer can sell the RECs to load serving entities for use in complying with other state's renewable portfolio standards, and (b) the revenues obtained from selling those RECs would flow to the developers and not Maine electricity customers. This assignment of RECs to the developers represents the largest difference in benefits among the three program designs.
- For the Moderate Hedge and the Wholesale PPA programs, the REC revenues are the second largest benefit after avoided energy.

Figure 6. Lifetime benefits for each successor program

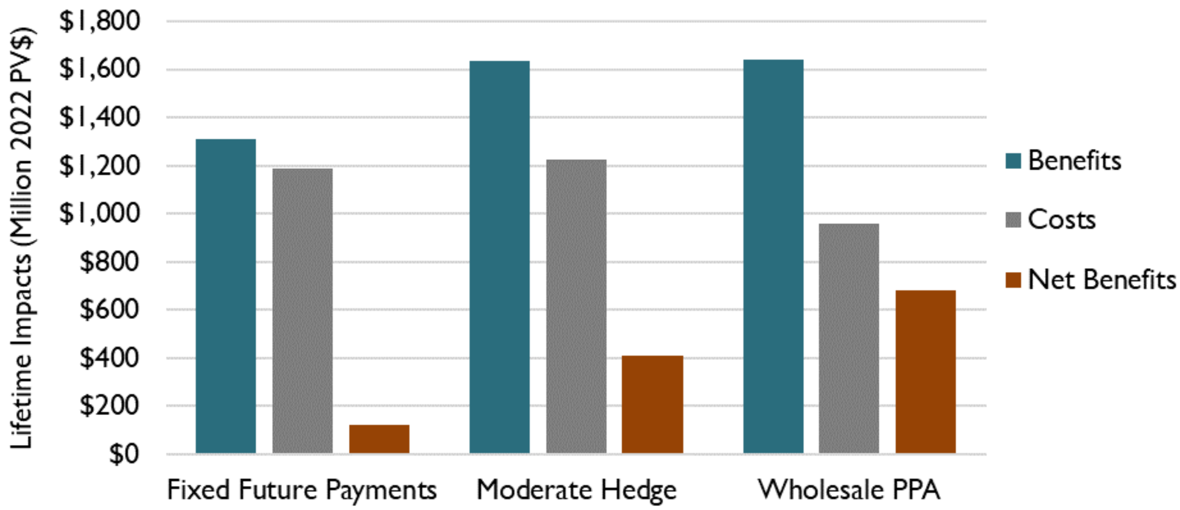


Our analysis does account for the benefits associated with avoided NO_X and GHG emissions, even though these benefits do not appear in Figure 6. There is an important relationship between the value of RECs and the societal benefits of renewable generation. In our analysis, we subtracted out the value of RECs from the societal benefits to avoid double counting RECs, which represent the above-market value of renewable generation, including societal impacts. A full discussion of the interaction between societal benefits and RECs can be found in the Appendix.

4.3. Successor Program Cost-Effectiveness Results

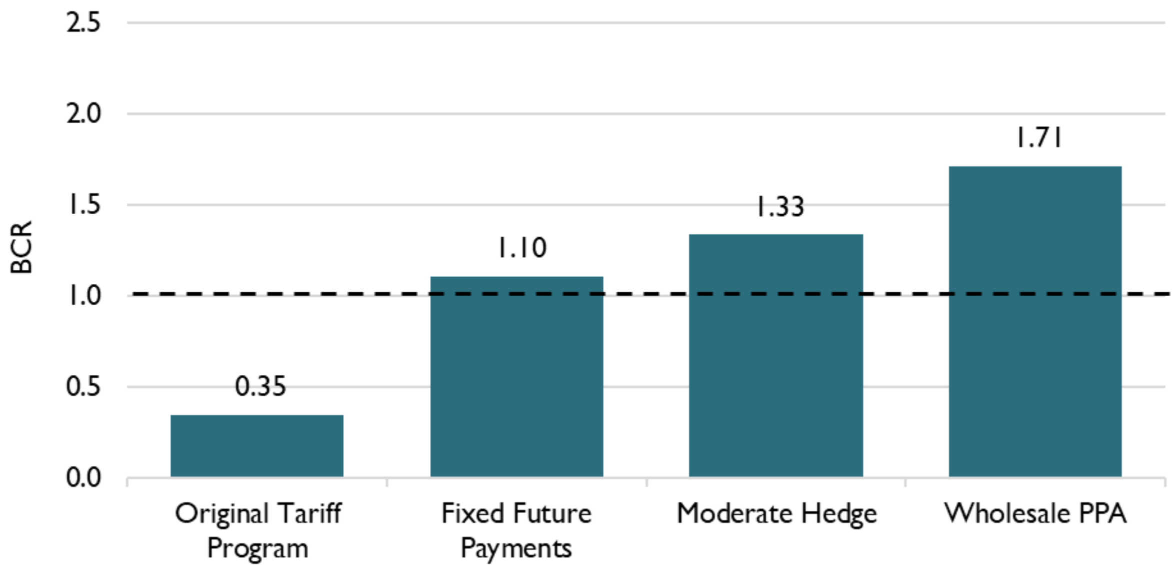
Each of the successor programs we modeled were cost-effective, meaning the modeled benefits exceeded the costs, indicated by a BCR that is greater than one. Figure 7 displays the benefits, costs, and net benefits (benefits minus costs) for each program. As discussed in the prior sections, the benefits are highest for the Moderate Hedge and Wholesale PPA programs due to the inclusion of REC revenue. The Moderate Hedge Program has the highest costs followed closely by the Fixed Future Payments Program. Accordingly, the Wholesale PPA Program has the highest net benefits ($690 million), followed by the Moderate Hedge Program ($415 million), and lastly the Fixed Future Payments Program ($130 million).

Figure 7. Lifetime benefits, costs, and net benefits for each successor program



The BCRs for each successor program are displayed in Figure 8. We also present the BCR of the Original Tariff Program for comparison purposes. The Wholesale PPA Program has the highest BCR at 1.71, followed by the Moderate Hedge Program at 1.33, and then the Fixed Future Payments program at 1.10. Unlike the three successor program options modeled here, the Original Tariff Program is not cost-effective, with a BCR of 0.35. This is primarily due to the program costs, which were originally determined by linking payments to retail rates, which were reformed by legislation passed in 2022. We discuss modeling assumptions for the Original Tariff Program in the Appendix.

Figure 8. BCRs by program



5. Results of the Rate, Bill, and Participation Analysis

5.1. Rate Impact Results

We used the program costs and benefits shown in Section 4 to quantify the impacts of each successor program option on electric rates. DG programs apply both upward pressure on rates because of program costs and cost shifts (in some cases), and downward pressure on rates due to program benefits that impact rates. To calculate the net result, we broke out the rates forecasts from CMP and Versant into the following components: generation, transmission, distribution, and other. For the purposes of this analysis, we used average rates across all customer classes, separately for CMP and Versant.

For costs, we modeled a separate program charge in addition to the components above that included the technology implementation costs and the program administration costs.

For benefits, we calculated the impact of the avoided costs on each existing rate. Table 10 shows the avoided costs that reduce rates and the corresponding rate component that is reduced.

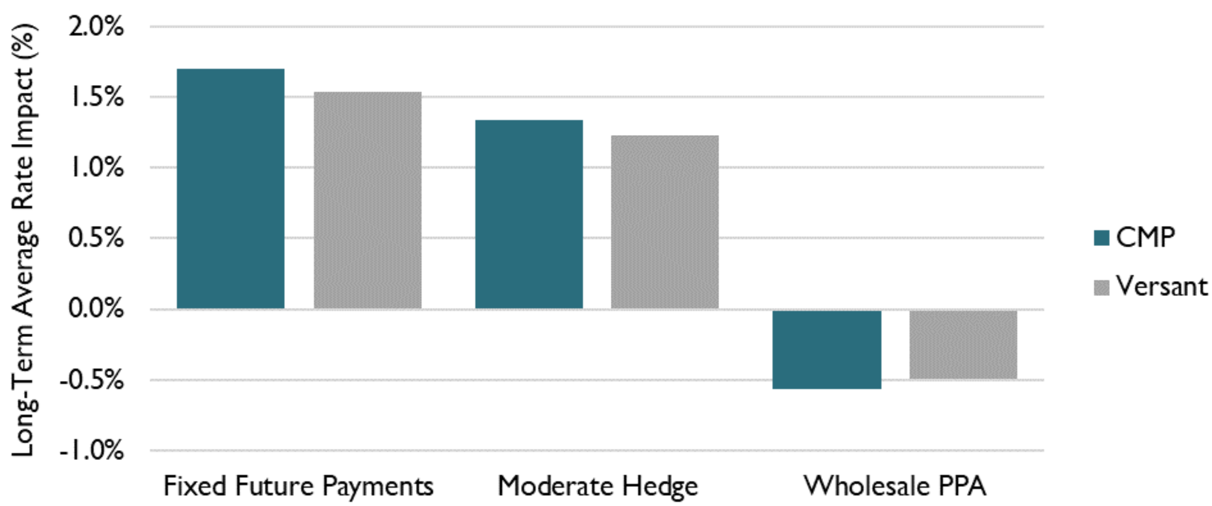
Table 10. Avoided costs impact on customer rates

Impacted Rate	Avoided Cost
Generation	• Price suppression effects (energy and capacity DRIPE) • Reliability • REC revenue • Avoided energy (Wholesale PPA Program only)
Transmission	• Avoided PTF • Avoided non-PTF transmission (BTM only)
Distribution	• Avoided distribution (BTM only)
Other	• None

We present the results of our analysis in Figure 9, which displays the long-term average rate impact of the three successor programs, for CMP and Versant. The long-term average rate impact represents the difference between electricity rates under the successor DG program relative to electricity rates in a reference case without the successor program, on average over the entire study period.

The Fixed Future Payment Program and the Moderate Hedge Program result in a modest rate *increase* while the Wholesale PPA Program results in a modest rate *decrease*. The Fixed Future Payments Program increases rates by 1.6 percent on average and the Moderate Hedge Program increases rates by 1.2 percent on average (with only slightly varied results between CMP and Versant). Meanwhile, the Wholesale PPA Program reduces rates by 0.5 percent on average.

Figure 9: Long-term average rate impact



The primary explanation for the variance between the Fixed Future Payments and the Moderate Hedge program versus the Wholesale PPA Program is the first two program options have program offtakers who experience the avoided energy costs as bill savings. Since offtakers receive energy savings directly, cannot claim avoided energy costs as rate-reducing benefits. The third program option shown above, Wholesale PPA, does not have any offtakers, thus allowing all ratepayers to experience the avoided energy benefits. In this case, rates go down slightly for all customers on average.

5.2. Bill Impact Results

Bill impacts are based on three factors: the change in rates (shown above), bill credits, and the average energy billed per customer. We calculated participant and non-participant bill impacts by estimating the average energy cost billed per customer and subtracting participant benefits from this group's bills. We note that *rates* do not change between participants and non-participants, but bills do because participants (i.e., offtakers) receive bill credits, for those programs that include offtakers.

Table 11 summarizes the bill impacts for non-participants and participants, respectively, by program option. For the Fixed Future Payments and Moderate Hedge programs, non-participants will see long-term average bill increases of roughly $2.00 per month, while the participants will see bill reductions of roughly $5.00 per month. The Wholesale PPA Program, where there are no offtakers, will likely reduce all customers' bills by roughly $0.75 per month.

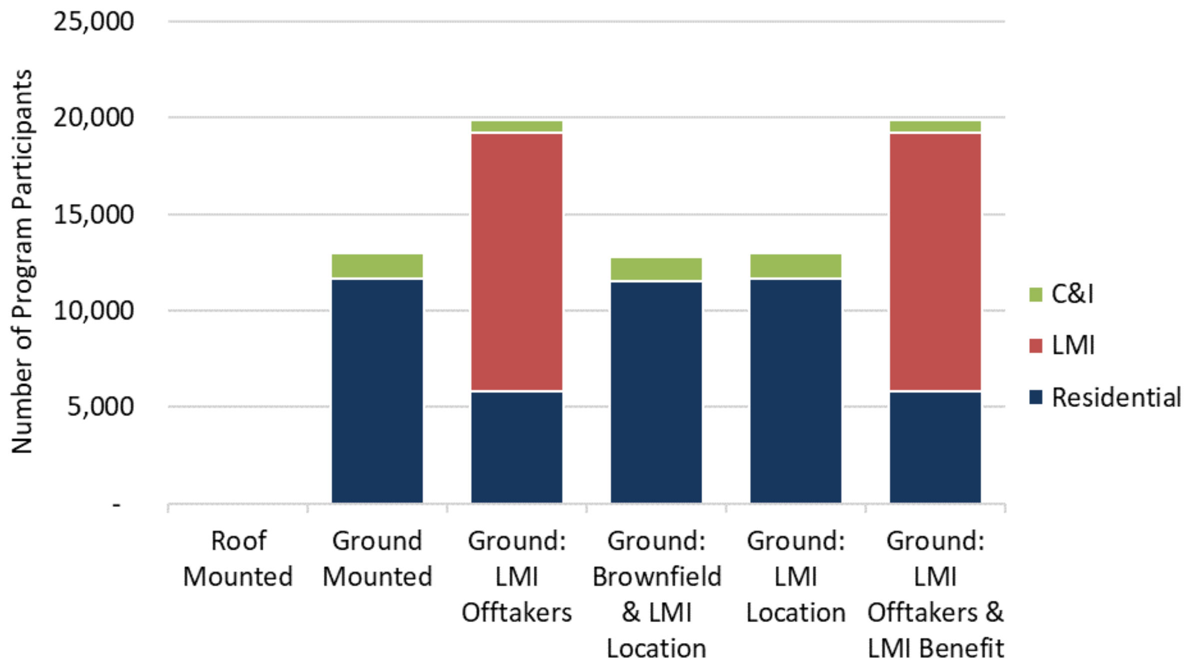
Table 11: Summary of participant and non-participant bill impacts – average residential customers ($ per month)

Program	Non-Participants		Participants	
	CMP	Versant	CMP	Versant
Fixed Future Payments	$2.43	$2.23	-$5.16	-$4.41
Moderate Hedge	$1.91	$1.78	-$5.67	-$4.86
Wholesale PPA	-$0.81	-$0.71	There are no offtakers	

5.3. Participation Results

The following figure summarizes the number of participants by resource block, estimated by calculating the total generation for each participant block and dividing by average energy consumption per customer.[45] Note that LMI customers are a subset of the residential customer class.

Figure 10: Participants by Resource Block

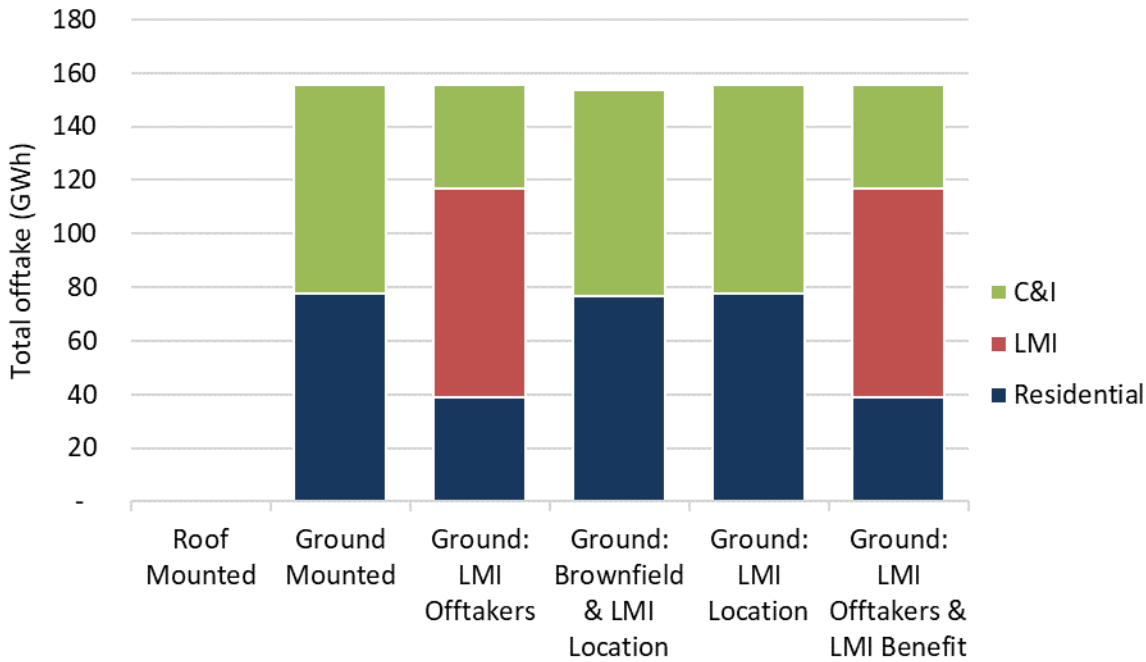


In total, our modeled programs assume approximately 46,600 residential, 27,000 LMI, and 5,400 C&I customers. This represents about 7.4 percent of total residential (including LMI) customers, and the same percentage of total C&I customers at CMP and Versant.[46] Figure 11 presents the same information as above but on an energy basis, representing the total amount of energy by customer block. This is estimated by multiplying the total number of customers by their average energy use.

[45] See Appendix Section A.3.

[46] U.S. Energy Information Administration. 2022. "Electric Sales, Revenue, and Average Price." Tables 6 and 7. Available at: https://www.eia.gov/electricity/sales_revenue_price/. In 2021, CMP and Versant had 503,190 and 126,991 residential customers respectively; and 49,671 and 22,865 C&I customers, respectively.

Figure 11: Total energy offtake by resource block



Since C&I customers use more energy than residential, they receive a higher proportion of participation benefits on an energy basis.

6. Working Group "Hybrid" Program

6.1. Working Group Hybrid

Based on the results of the BCAs and RBPAs for the program options discussed in Sections 4 and 5, several key findings emerged from our analysis that were reflected in discussions with the DGSG. These include the following:

- Programs that assign the REC attributes to the utility result in in both lower costs and greater benefits.
- Limiting the number of direct offtakers results in lower overall ratepayer costs and greater net benefits.
- The wholesale PPA approach to procuring large DG resources eliminates cost shifting and results in rate and bill reductions for all customers.

- The IRA confers substantial benefits for projects that serve LMI customers, and allows projects sited on brownfields to be competitive with similarly situated non-brownfield (e.g., greenfield) projects.

In light of these findings and statutory requirements regarding program design, a "hybrid" of Options 2 and 3 (described above) was preferred by the working group and allowed for additional modeling options such as investigating the impact of pairing battery storage with solar, discussed in Section 7.

For the Hybrid Case we included five of the original six resource blocks. The only block that was excluded was the resource block that included a 5 MW project, located anywhere, with a minimum of 50 percent LMI offtakers, because a wholesale PPA approach does not include any offtakers. Based on the mix of assumed resources, we estimated the total capacity for the program to be 560 MW.

Based on feedback and discussion with the DGSG, we assumed 30 percent of deployed capacity would have offtakers and the remaining 70 percent would be procured using the wholesale PPA approach. The key facets of the Hybrid Case, including the applicable resource blocks and total capacity by block and year, are included in the tables below.

Table 12. Hybrid Program Characteristics by Resource Block

Project Size (AC)	Project Type/Location	Offtakers	ITC (Base + Bonus) %	Capacity (MW_{AC})
1 MW	BTM: C&I	Host customer	30% (30% + 0%)	84
5 MW	FTM: Any	All Customers (No Specific Offtakers)	30% (30% + 0%)	131
	FTM: Brownfield/ "Energy Community"	All Customers (No Specific Offtakers)	40% (30% + 10%)	131
	FTM: "Low Income (LI) Community"	All Customers (No Specific Offtakers)	40% (30% + 10%)	131
	FTM: "LI Benefit"	50% LMI, 25% Res, 25% C&I	50% (30% + 20%)	84
Totals	-----	-----	-----	560

Table 13. Hybrid Program Annual Capacity (MW_{AC}) by Resource Block

Project Size (AC)	Project Type/Location	2024 (2027 COD)	2025 (2028 COD)	2026 (2029 COD)	2027 (2030 COD)	2028 (2031 COD)
1 MW	BTM: C&I	16.8	16.8	16.8	16.8	16.8
5 MW	FTM: Any	26.1	26.1	26.1	26.1	26.1
	FTM: Brownfield / "Energy Community"	26.1	26.1	26.1	26.1	26.1
	FTM: "LI Community"	26.1	26.1	26.1	26.1	26.1
	FTM: "LI Benefit"	16.8	16.8	16.8	16.8	16.8
Annual Total		112	112	112	112	112

6.2. Hybrid Program Resource Costs

The DG cost results for the Hybrid Case are provided in the table below. These are derived from the CREST model, which is described in Section 3.2. The results displayed below assume the project qualifies for participation in the year listed, and begins operation three years later, with the lag due to development timelines including factors such as permitting, financing, and interconnection queue times typical of these sorts of projects.

Table 14. Hybrid Program Project Cost Comparison by Resource Block

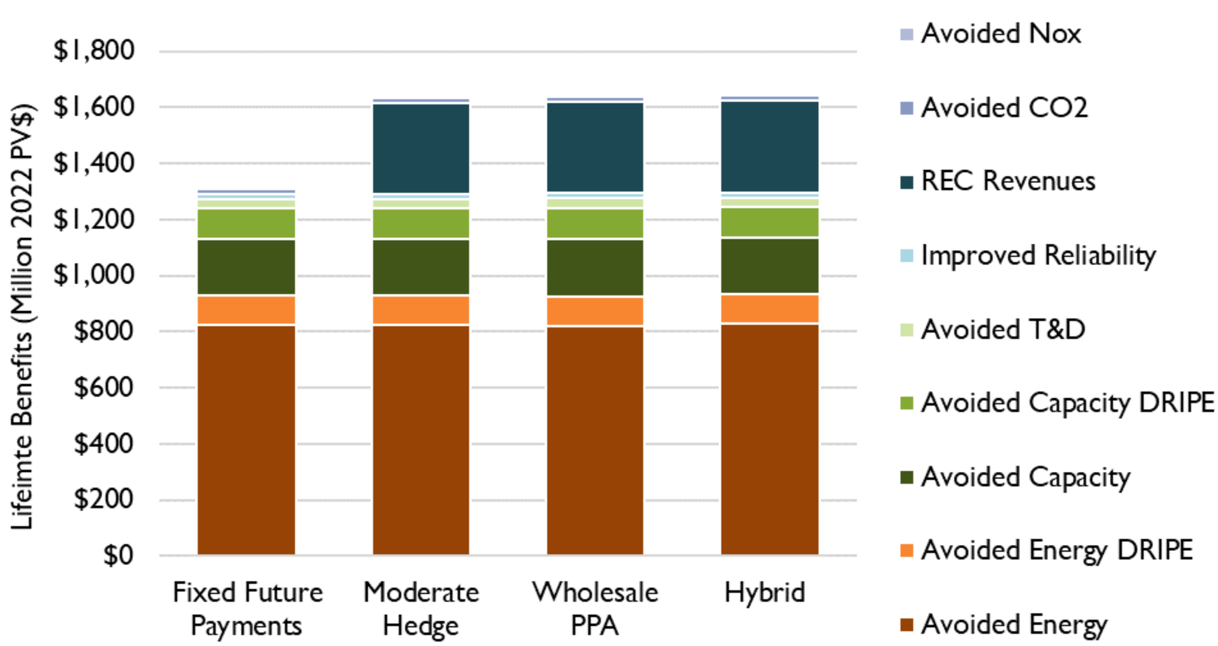
	Project Cost (Nominal $/MWh)				
Procurement/Enrollment Year	**2024**	**2025**	**2026**	**2027**	**2028**
Roof Mounted (Hedged Energy and RECs)	185	175	167	163	157
Ground Mount (Wholesale PPA)	131	125	118	114	110
Ground: Brownfield (Wholesale PPA)	140	133	127	122	119
Ground: LMI Location (Wholesale PPA)	118	112	106	103	99
Ground: LMI Offtakers & LMI Benefit (Hedged Energy and RECs)	160	154	149	146	142

A comparison of nominal dollars, shown above, and present value real dollars, used in the BCA modeling, can be found in the Appendix.

6.3. Hybrid Program Benefits

The estimated benefits for the Working Group Hybrid Program are presented in Figure 12 alongside the three successor program options for comparison purposes. The Hybrid Program has nearly identical benefits to the Moderate Hedge and Wholesale PPA programs.

Figure 12. Lifetime benefits for the Hybrid Program



6.4. Hybrid Program Cost-Effectiveness

Figure 13 presents the lifetime benefits, costs, and net benefits for the Hybrid Program alongside the original three successor program options. The Hybrid Program most closely resembles the Wholesale PPA Program, but with slightly higher costs for reasons stated above. The Hybrid Program has net benefits of $660 million, as compared with the Wholesale PPA Program with net benefits of $690 million.

Figure 13. Lifetime benefits, costs, and net benefits for the Hybrid Program

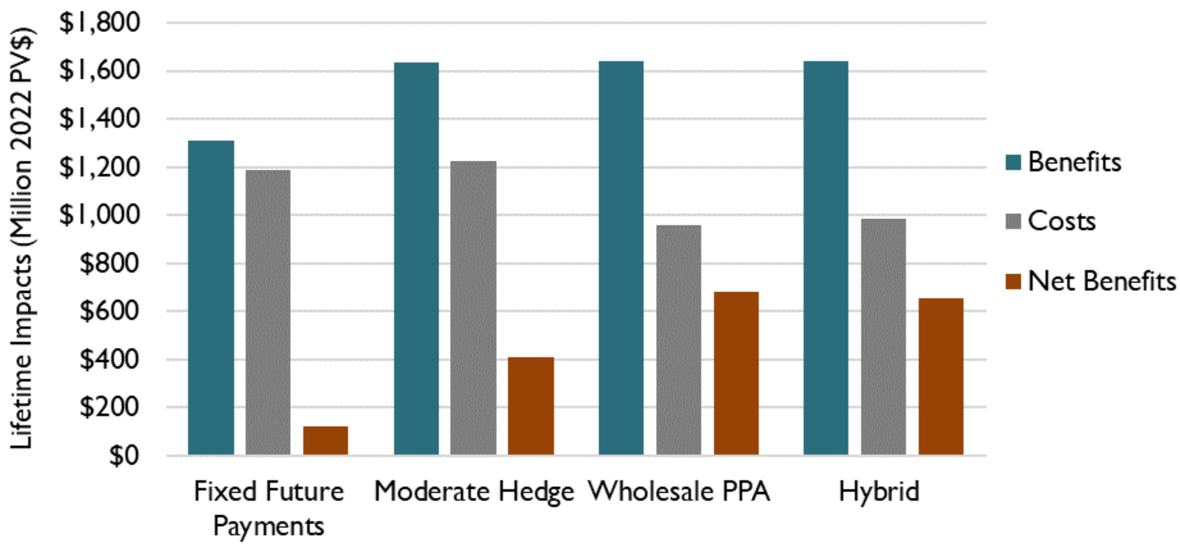
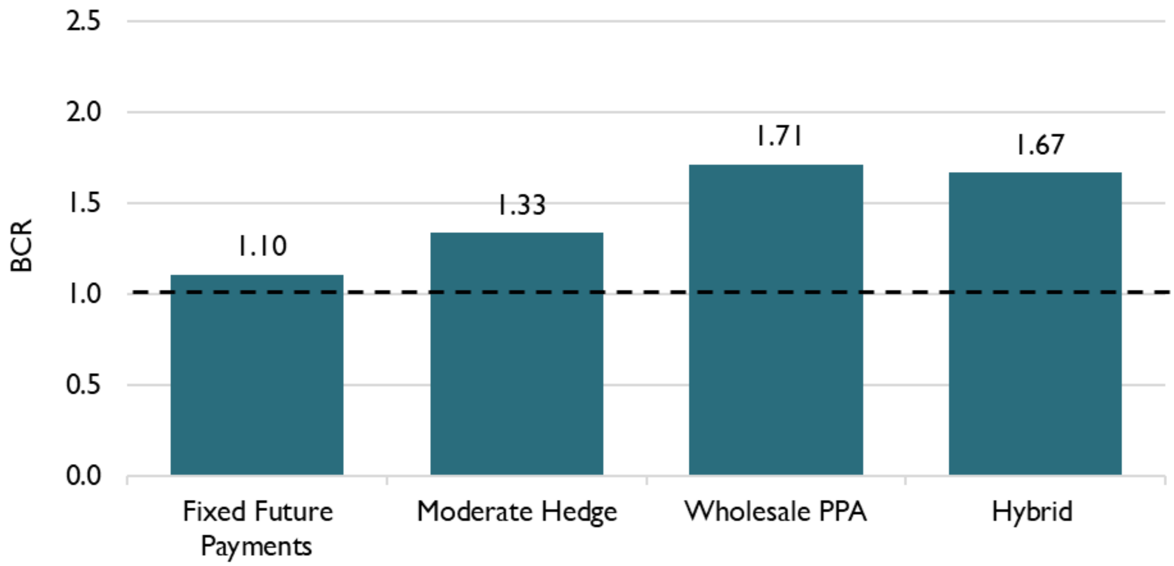


Figure 14 displays the BCR for the Hybrid Program alongside the three other successor program options modeled here. Following the same pattern as net benefits, the Hybrid Program most closely resembles the Wholesale PPA Program but has a slightly lower BCA of 1.67 as compared to the Wholesale PPA Program, which has a BCA of 1.71.

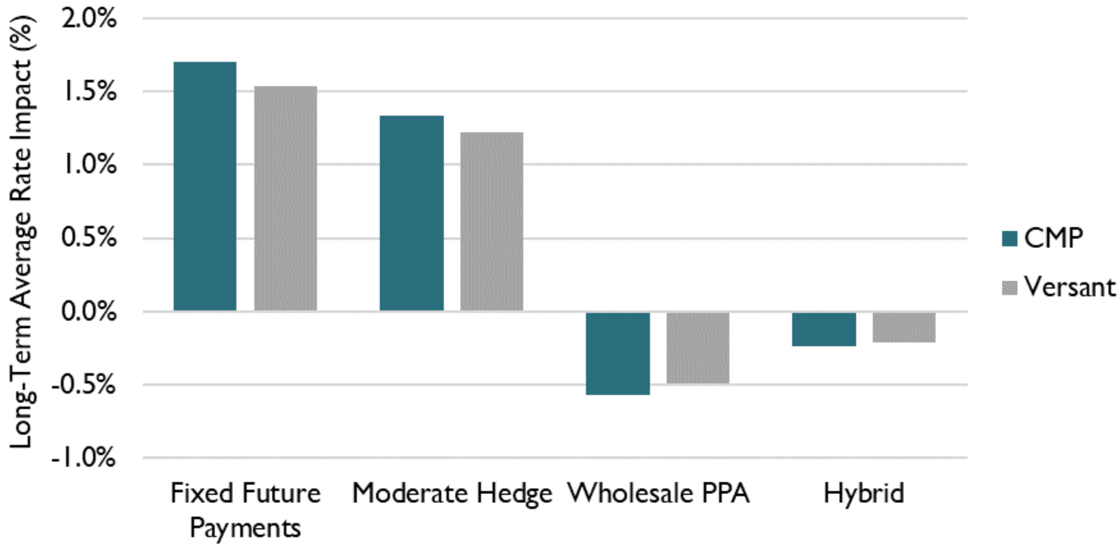
Figure 14. Benefit-Cost Ratios for the Hybrid and other programs



6.5. Hybrid Program Rate and Bill Impact Results

Following the same trend as the BCA results, the Hybrid Program closely aligns with the Wholesale PPA's rate impacts, resulting in a long-term average rate decrease for all customers. The impact is slightly less for the Hybrid Program, however, with an average rate impact of -0.2 percent compared to the Wholesale PPA programs -0.5 percent rate impact.

Figure 15: Long-term average rate impacts for Hybrid and other programs



The bill impacts for the Hybrid Program follow suit, achieving similar results to the Wholesale PPA Program. A non-participant in the Hybrid Program will see an average $0.30 decrease in their monthly bill, compared to the $0.75 decrease in the Wholesale PPA Case. Program participants see a greater bill decrease than participants in the Fixed Future Payments and Moderate Hedge programs because rates are lower to begin with, as opposed to competing with the rate increase from those programs.

Table 15: Summary of participant and non-participant bill impacts for Hybrid and other programs—average residential customers ($ per month)

Program Option	Non-Participants		Participants	
	CMP	Versant	CMP	Versant
Fixed Future Payments	$2.43	$2.23	-$5.16	-$4.41
Moderate Hedge	$1.91	$1.78	-$5.67	-$4.86
Wholesale PPA	-$0.81	-$0.71	There are no offtakers	
Hybrid	-$0.35	-$0.31	-$7.93	-$6.95

7. Distributed Storage

In its Interim Report, the DGSG stated that a primary objective for a successor program is to “(r)ecognize the expected increasing opportunities for energy storage” and “maximiz(e) the value of energy storage deployments."[47] In addition, LD 936 requires consideration of "net energy billing arrangements paired with energy storage" in the development of a NEB successor program. With continued interest by the DGSG we modeled the impacts of incorporating storage with the solar PV hybrid case.

7.1. Considerations and Assumptions for Energy Storage

At a meeting of the DGSG, Synapse and SEA presented a series of critical considerations in designing a storage incentive mechanism, including (1) the incentive design and (2) the storage dispatch strategy.

Incentive design considerations may incorporate one or more of the following features:

- **Lump-sum Incentive:** Under such a design, projects may be eligible for an upfront incentive that is not performance-based. However, a design like this often includes requirements to dispatch in certain ways such as during specific high-value periods.[48]
- **Performance-Based Incentive:** A performance-based incentive is a traditional option in which performance/discharge during certain high-value periods is required to earn compensation.[49]
- **Renewable Energy Incentive Adder:** A less traditional incentive design is to tie compensation with the production from a paired renewable energy system, which may or may not be subject to certain daily, weekly, monthly, or annual dispatch requirements.[50]

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[47] Interim Report of the Distributed Generation Stakeholder Group, 12/31/21, p. 13, https://www.maine.gov/energy/sites/maine.gov.energy/files/inline-files/Interim%20Report%20of%20the%20Distributed%20Generation%20Stakeholder%20Group_Dec%2031%202021.pdf.

[48] A relevant example of such a program is the CT Energy Storage Solutions program. More information about this program is available at: https://energystoragect.com/

[49] Relevant examples of a performance-based storage incentive include the Connected Solutions programs sponsored and managed by the EDCs in Massachusetts and Rhode Island.

[50] A relevant example of such an approach is the Energy Storage Adder available under the Solar Massachusetts Renewable Target (SMART) Program. Find more information on SMART program guidelines (including guidelines for energy storage participation) here: https://www.mass.gov/info-details/solar-massachusetts-renewable-target-smart-program#program-guidelines-. Find more information on the SMART Program generally here: https://masmartsolar.com/learn.php#resources.

Related to the incentive structure, the assumed dispatch strategy has critical implications for the types of benefits that storage is likely to yield. Dispatch strategies include:

- **Defined Periods:** Under this approach, eligible projects must regularly discharge (or be incented to discharge) during defined periods.[51]
- **Event-Based Dispatch:** An event-based approach requires discharge in response to events called by a program administrator. This is a typical approach in demand response programs for which energy storage resources are eligible (including, but not limited to, the EDC-run Connected Solutions programs in Massachusetts and Rhode Island).
- **EDC Control:** Under this approach, the EDC retains control of the storage technology. This approach is sometimes referred to as a tolling agreement and has some similarities to a non-wires alternative.[52]

Based on the goal of modeling a program design that would be broadly applicable to any successor program that includes storage, we made several assumptions that are broadly consistent with a number of different incentive designs and dispatch strategies that seek to minimize costs and maximize benefits of battery installations:

1. Batteries are sized to capture "clipped" solar energy, which is energy that is usually not exported to the grid due to difference in size between the solar panels and inverter. This results in a 25 percent solar-to-storage capacity ratio.[53]
2. Batteries would be dispatched to reduce the New England generation peak demand. There will be smaller impacts on the transmission and distribution peak demands to the extent that they are coincident with the generation peak demand.
3. Batteries would be dispatched at least during peak hours in the summer (3 pm-7 pm), thus requiring a 4-hour duration.

Additional characteristics of battery storage systems (BSS) are provided in Table 16 below.

[51] A relevant example of a program that incentivizes discharge during defined periods is the Massachusetts Clean Peak Energy Standard, which requires dispatch during certain Seasonal Peak Periods. See 225 CMR 21.00 for the regulations associated with this program, available at: https://www.mass.gov/doc/225-cmr-21-clean-peak-energy-portfolio-standard-cps/download

[52] A relevant example of such a program is Green Mountain Power's Bring Your Own Device (BYOD) program.

[53] For example, a 1,300 kW_{DC} solar paired with 325 kW_{DC} storage.

Table 16. Energy Storage Cost and Size Characteristics

	Unit	ESS Co-Located with 1 MW_{AC} PV Project	ESS Co-Located with 5 MW_{AC} PV Project
PV Capacity	kW_{DC}	1,300	6,500
Storage Capacity	kW_{DC}	325	1,625
Duration	Hours	4	4
Upfront Capital Cost	Nominal $	$1,080,950	$3,473,438
	Nominal $/kWh	$832	$534
Operating Expenses	Nominal $/yr	$7,472	$24,292

7.2. Distributed Storage Costs

We modeled the impacts of pairing battery storage systems (BSS) with solar in each of the resource blocks in the Hybrid Program described above. The impacts of adding BSS to the cost of DG resources are shown in Table 17 below for each of the resource blocks included in the Hybrid Program.

Based on annual solar production profiles and other assumptions described above, we were able to model the assumed dispatch of storage for every hour over the course of a year. This allowed us to calculate the cost of adding BSS to solar PV projects on a dollar per MWh basis, shown below.

The results displayed below assume the project qualifies for participation in the first program year, 2024, and begins operation in 2027, with the lag due to development timelines including factors such as permitting, financing, and interconnection queue times typical of these sorts of projects.

Table 17: Project cost for Hybrid and Hybrid plus storage program by resource block in nominal dollars ($/MWh)

Option	Block	Project Cost				
		Nominal $/MWh				
	Program Enrollment Year	2024	2025	2026	2027	2028
Hybrid	Roof Mounted (Hedged Energy and RECs)	185	175	167	163	157
	Ground Mount (Wholesale PPA)	131	125	118	114	110
	Ground: Brownfield (Wholesale PPA)	140	133	127	122	119
	Ground: LMI Location (Wholesale PPA)	118	112	106	103	99
	Ground: LMI Offtakers & LMI Benefit (Hedged Energy and RECs)	160	154	149	146	142
Hybrid + Storage	Roof Mounted (Hedged Energy and RECs)	256	239	225	217	209
	Ground Mount (Wholesale PPA)	164	152	144	139	134
	Ground: Brownfield (Wholesale PPA)	169	158	151	146	140
	Ground: LMI Location (Wholesale PPA)	146	137	130	125	120
	Ground: LMI Offtakers & LMI Benefit (Hedged Energy and RECs)	185	177	170	166	161

A comparison of nominal dollars, shown above, and present value real dollars, used in the BCA modeling, can be found in the Appendix.

7.3. Distributed Storage Benefits

Unlike stand-alone solar PV projects, most benefits of storage are capacity-related: avoided capacity costs, capacity DRIPE, and avoided T&D. The extent to which storage will deliver these benefits is highly contingent upon how it is dispatched and other considerations. For example, storage is theoretically capable of helping avoid or defer distribution system investments. However, if a particular incentive design incents projects to engage in a dispatch strategy centered around energy arbitrage or discharging during generation system peaks, this may not coincide with the ability to serve needs on the distribution system.[54] Furthermore, an EDC may not recognize the ability of storage (or other system resources) to serve a distribution system need unless it controls the asset directly. Therefore, it is plausible that no significant avoided T&D cost would occur if solar and storage systems are owned and operated by project developers responding to wholesale market price signals, which is the most common project design.

Based on these considerations and our assumptions above, we assumed storage captures the following percentage amounts of benefits in each respective category:

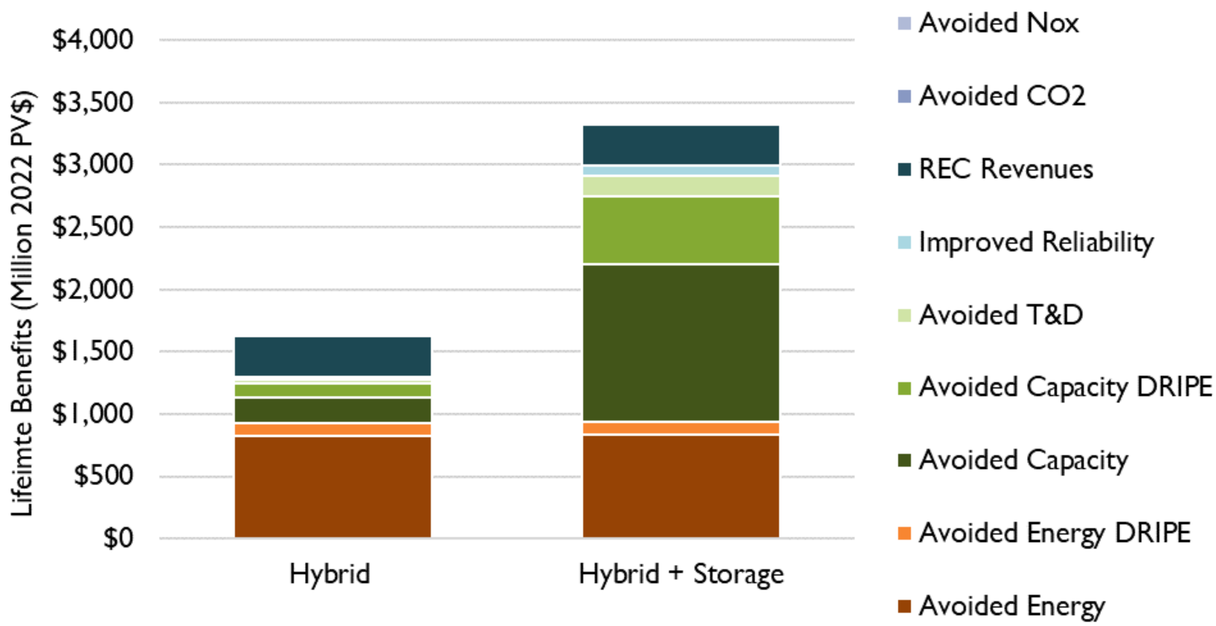
- Avoided generation (capacity and capacity DRIPE): 90 percent
- Avoided transmission: 20 percent
- Avoided distribution: 10 percent

The range of policy design options discussed above have a significant effect on these values, though we find these assumptions are reasonable to assess the benefits of adding storage to a successor DG program in Maine.

The inclusion of energy storage has a dramatic impact on the benefits that accrue to the Hybrid Case. Overall, these benefits increase by nearly 100 percent, primarily due to greater avoided capacity and avoided capacity DRIPE benefits, which account for 89 percent of the difference between the two cases. This is based on the assumed dispatch of storage during ISO- NE’s peak load, described in the Appendix.

[54] In addition, realizing certain benefits may require changes in how EDCs and ISO-NE model the impacts of storage.

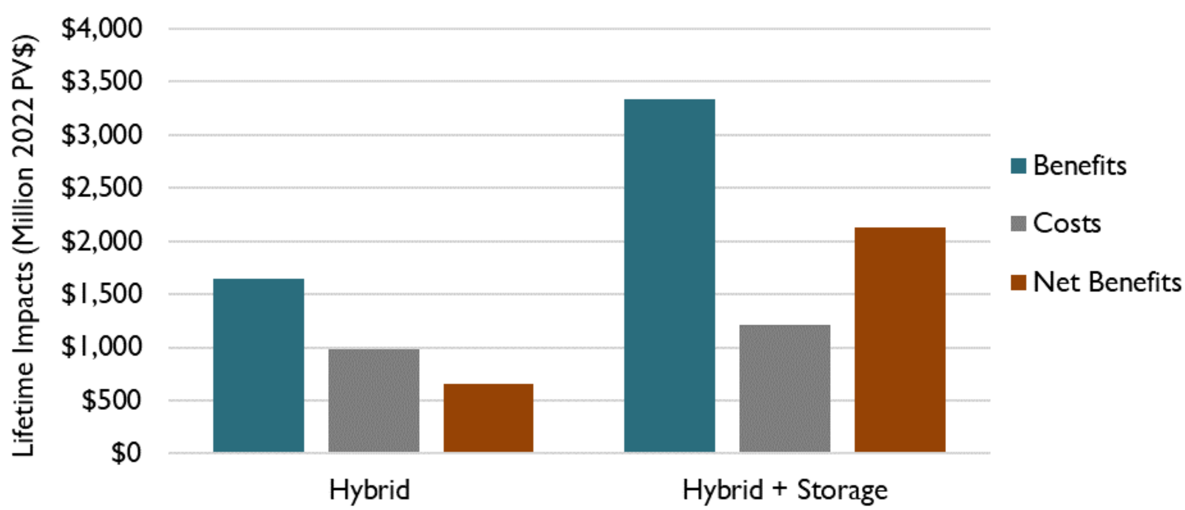
Figure 16. Benefits of Hybrid and Hybrid + Storage Program



7.4. Distributed Storage Cost-effectiveness

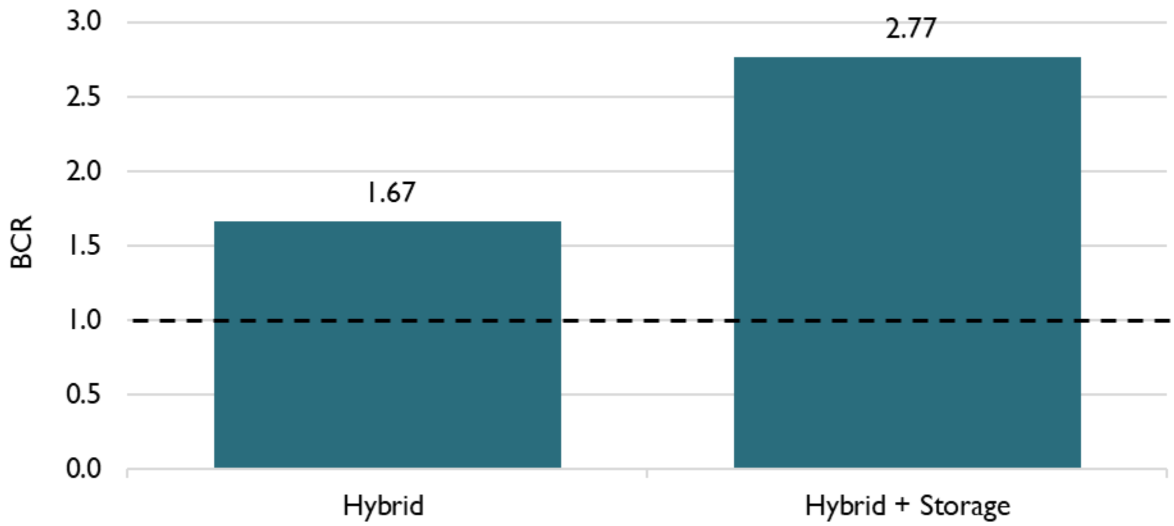
Figure 17 presents the lifetime benefits, costs, and net benefits for the Hybrid Program with and without storage. The Hybrid plus Storage program has modestly higher costs than the Hybrid program (22 percent increase) and significantly higher benefits (103 percent increase). This results in a Hybrid plus Storage program with net benefits exceeding $2 billion, compared to $660 million without storage (in present value 2022 dollars).

Figure 17. Benefits, Costs, and Net Benefits of Hybrid and Hybrid + Storage Program



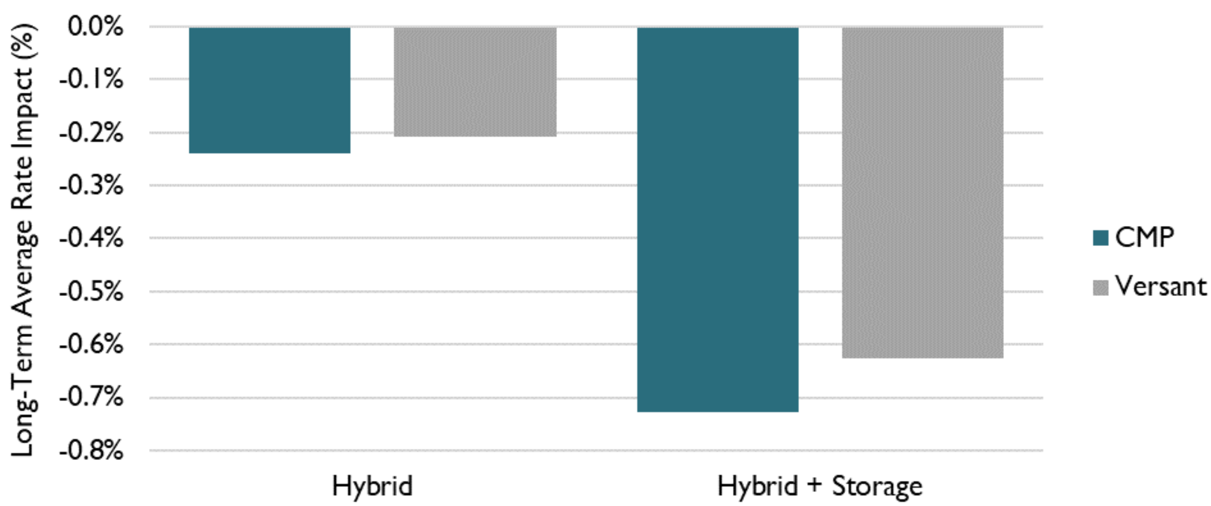
Consistent with the figure above, the increase in costs to deploy storage are sufficiently outweighed by the increase in benefits, demonstrated by the BCR's for the two options shown below.

Figure 18. Benefit Cost Ratios of Hybrid and Hybrid + Storage Case



The same pattern can be seen for long-term rate and bill impacts. The Hybrid + Storage Case results in greater rate reductions than the Hybrid case due to the increased capacity benefits.

Figure 19: Long-term average rate impact for Hybrid and Hybrid + Storage



Similarly, the bill impacts for both non-participants and participants are also minimal.

Table 18: Summary of participant and non-participant bill impacts for Hybrid and Hybrid + Storage– average residential customers ($ per month)

Program	Non-Participants		Participants	
	CMP	Versant	CMP	Versant
Hybrid	-$0.35	-$0.31	-$7.93	-$6.95
Hybrid + Storage	-$1.03	-$0.91	-$8.62	-$7.55

8. SENSITIVITIES

We performed sensitivities on two variables within the BCA: avoided T&D costs and the discount rate. The reason these two variables were selected for sensitivities are described in more detail below. We present the impact of our sensitivities for the Hybrid Program.

8.1. Avoided Transmission and Distribution Costs Sensitivities

Rationale for Sensitivity

Synapse conducted a sensitivity of the avoided T&D costs assumptions used in the BCA. Avoided T&D costs are the diminished need for new or updated poles and wires to support the electric grid. This benefit can interact with DERs in variable ways. For instance, traditional energy efficiency reduces system load while it operates, meaning less energy flows through the electric grid and there is a lessened need for T&D investments. Meanwhile, solar DG produces, rather than reduces, energy. In certain contexts, this can alleviate strain on the electric grid by providing power to remote areas or areas with energy bottlenecks. Similarly, solar DG can be installed behind the meter, reducing consumption in the same way that energy efficiency does.

In other instances, solar DG can put *additional* strain on the electric grid. In Maine, these cost to upgrade T&D infrastructure are assumed by the developer (and included within our cost results).

The presence of this benefit depends on several variables, including the location, size, and configuration (BTM versus FTM) of the solar DG. We performed a sensitivity off the Hybrid Program to quantify the impacts of avoided T&D benefits given the complexity of the issue.

Assumptions

The Hybrid and Original Successor Program options assume that, at the coincident peak hour, all resource blocks reduce PTF costs while only the single BTM resource block produces additional avoided T&D benefits.[55] The values used in the base case are consistent with EMT's 2021 BC model. For a high

[55] See the Appendix for information on how coincident peak load is calculated.

sensitivity, we assumed avoided T&D costs were 50 percent higher than for energy efficiency. For a low sensitivity, we assumed no avoided T&D costs. See Table 19 for the avoided T&D cost sensitivity assumptions. Note that this sensitivity does not modify the T&D cost to the developer captured by the CREST model.

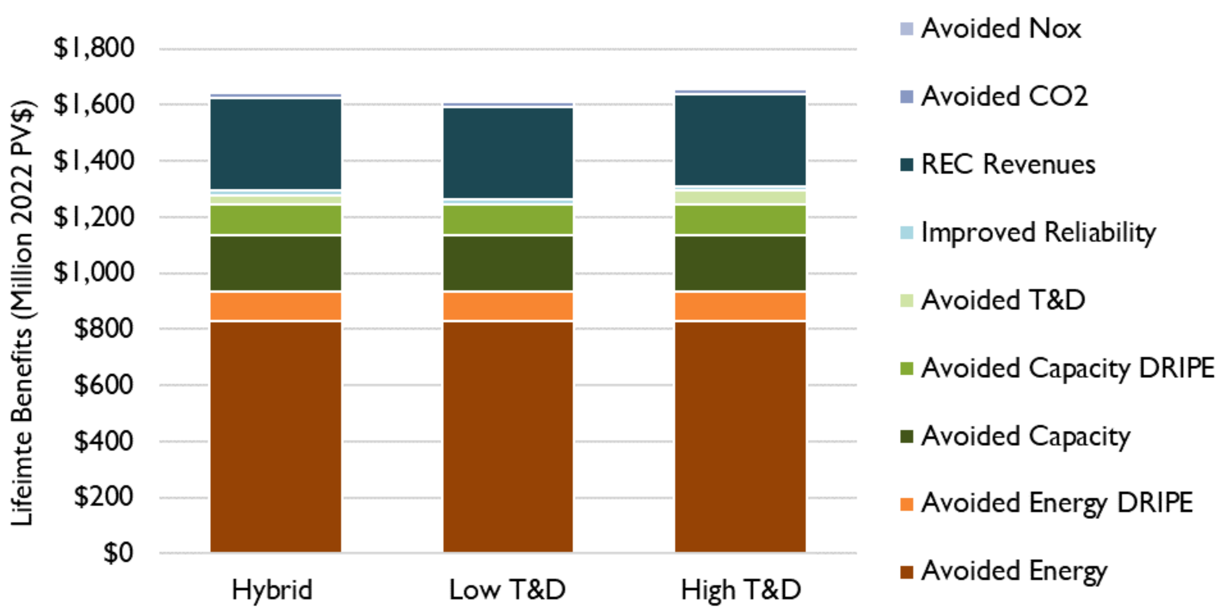
Table 19. Avoided T&D cost sensitivity assumptions

Units	Metric	Low T&D	Base case	High T&D
BTM ($/kW per year)	Distribution	$0	$250	$375
	Non-PTF transmission	$0	$40	$60
	Non-PTF other	$0	$20	$30
BTM & FTM ($/kW per year)	Maine PTF	$0	$97	$146

Results

The results of this sensitivity show that variations in avoided T&D assumptions have minimal impact on the total program benefits. Figure 20 shows the lifetime benefits of the base case, the low avoided T&D costs sensitivity, and the high avoided T&D cost sensitivity. In the low avoided T&D cost sensitivity, the total benefits are lower by $32 million. In the high avoided T&D cost sensitivity, the total benefits are higher by $16 million. Total benefits change less than 2 percent after modifying this variable.

Figure 20. Lifetime benefits of avoided T&D cost sensitivity.



We present the remaining BCA results in Figure 21 and Figure 22. Given there is no change in costs as a result of this sensitivity, both figures show minimal impact.

Figure 21. Lifetime benefits, costs, and net benefits of avoided T&D cost sensitivity

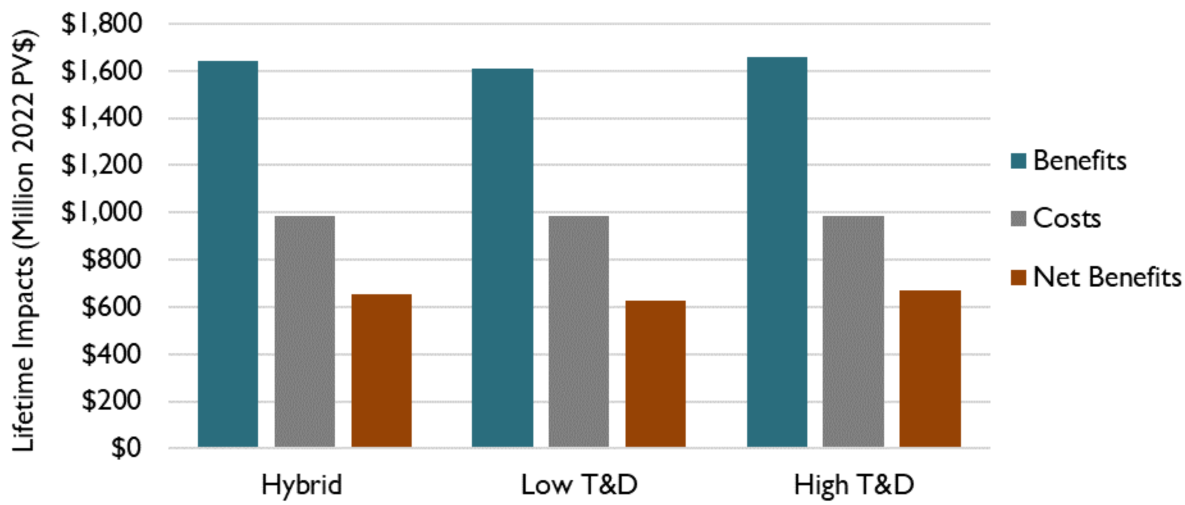
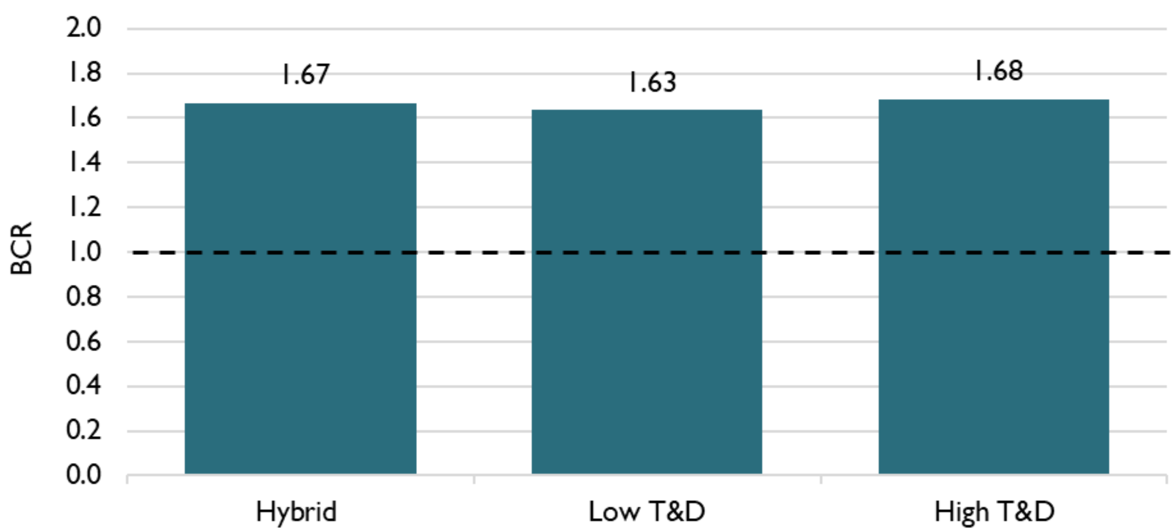
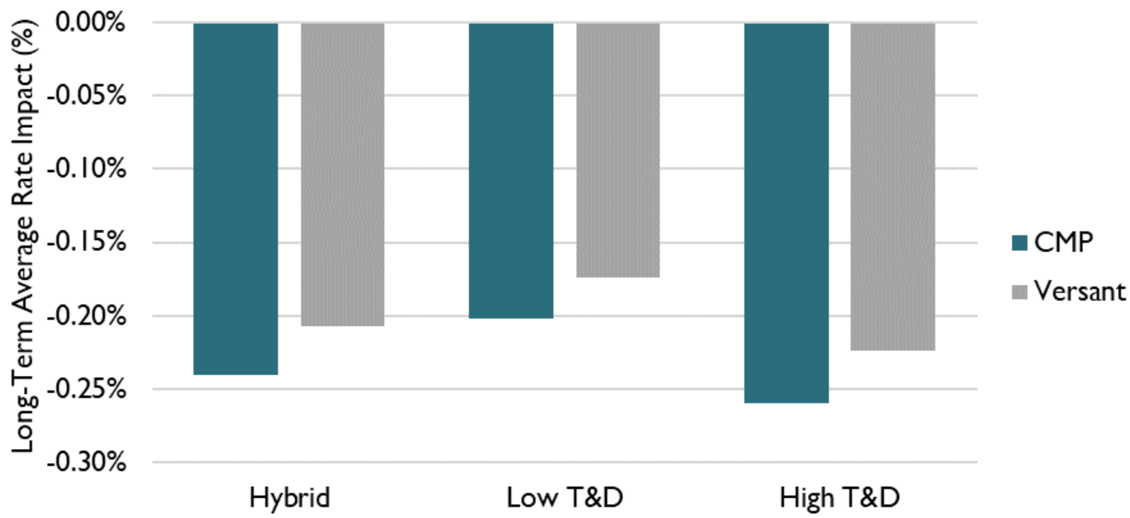


Figure 22. BCRs of avoided T&D cost sensitivity



As was the case with the benefits and costs, the rate and bill impacts of this sensitivity are minute. Figure 23 shows the long-term average rate impact for the Hybrid Program and the sensitivities for low and high avoided T&D costs.

Figure 23: Long-term average rate impact of avoided T&D cost sensitivity



Similarly, the bill impacts for both non-participants and participants are also minimal.

Table 20: Summary of participant and non-participant bill impacts for T&D sensitivity – average residential customers ($ per month)

Program	Non-Participants		Participants	
	CMP	Versant	CMP	Versant
Hybrid	-$0.35	-$0.31	-$7.93	-$6.95
Low T&D	-$0.29	-$0.26	-$7.88	-$6.90
High T&D	-$0.38	-$0.33	-$7.96	-$6.98

8.2. Discount Rate Sensitivities

Rationale for Sensitivity

Real discount rates are used in BCAs to reflect the time-value of money. A high discount rate will make present dollars more valuable than future dollars, emphasizing the short-term impact of costs and benefits. A low discount rate will weight future dollars more equally to present day dollars, giving greater emphasis to long-term impacts. The discount rate is a policy choice. This sensitivity allows for varying time preferences.

The discount rate is applied to all future streams of costs and benefits.

Assumptions

The Hybrid Program "Base Case," or standard modeling assumptions driving the benefits and cost results shown above, uses a 2.8 percent real discount rate. This value is consistent with EMT's 2021 BC model. As displayed in Table 21, the low case assumes a discount rate of 1.6 percent, and the high case assumes a discount rate of 4.0 percent. This represents a reasonable range of potential discount rates for this type of analysis.

Table 21. Discount rate sensitivity assumptions

	Low DR	Base Case	High DR
Discount Rate (% Real)	1.6%	2.8%	4.0%

All programs and sensitivities are provided in constant 2022 dollars.

Results

As noted above, modifying the discount rate impacts the value of benefits in the future. Given our choice to discount all dollars back to 2022 present value, and the fact that the program costs and benefits do not start until 2027, even the earliest years of our analysis are impacted by this choice. The deviations between the discount rate sensitivities only increase over the study period. To provide one example, Figure 24 displays the impact the discount rate has on avoided energy costs across the study period. This trend is mirrored with all costs and benefits.

Figure 24. Impacts of real discount rates on avoided energy costs

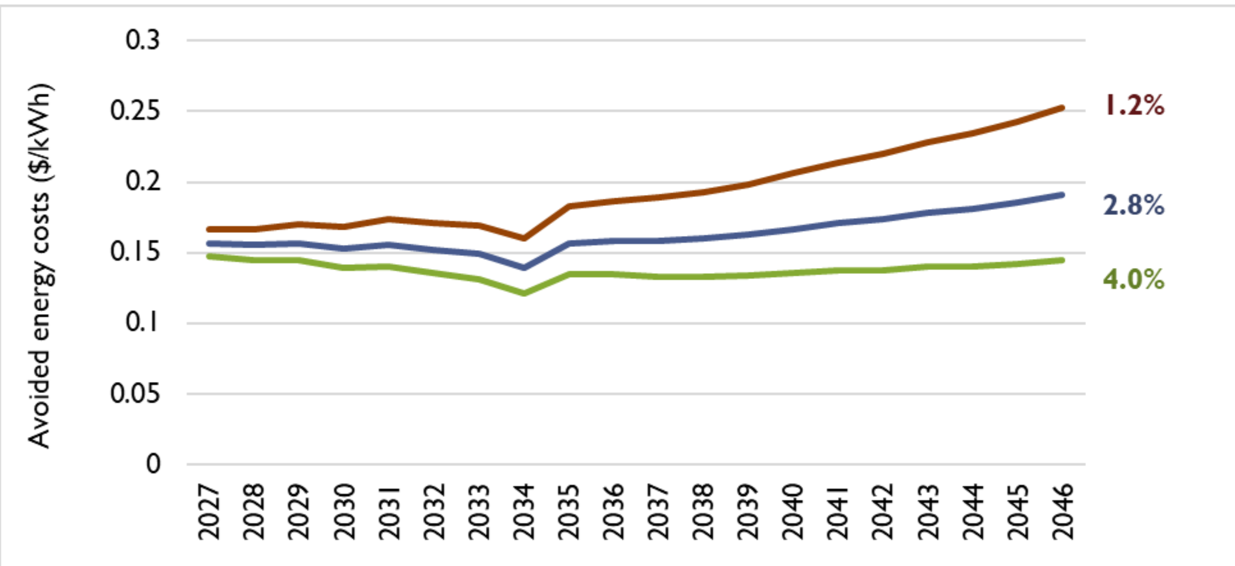
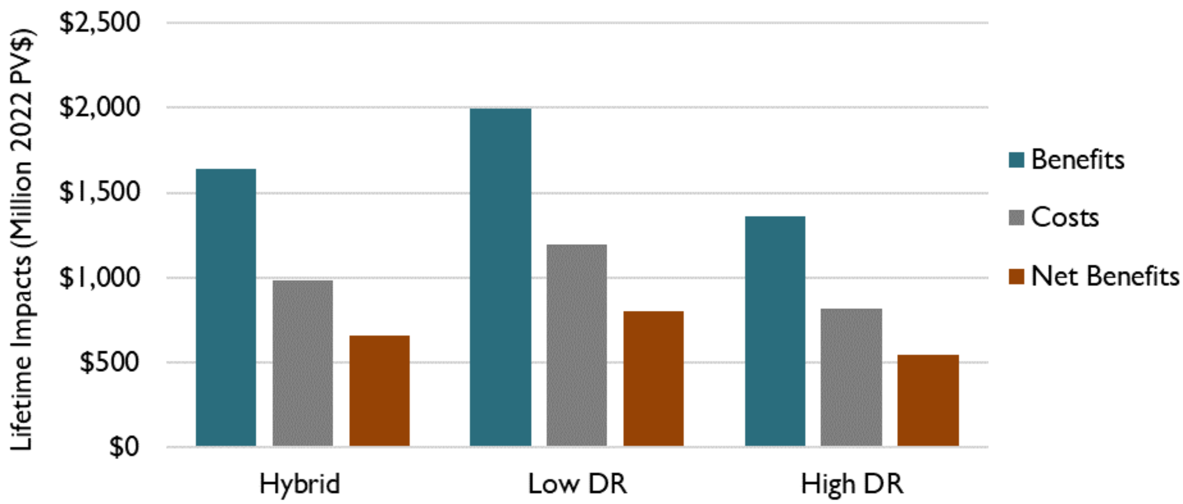


Figure 25 shows the lifetime benefits, costs, and net benefits for the Hybrid Program, the low discount rate, and the high discount rate sensitivities. Following the pattern shown in the figure above, the low discount rate sensitivity has the highest benefits, highest costs, and highest net benefits. This rate values future benefits more than the base case. Correspondingly, the high discount rate sensitivity has the lowest benefits, lowest costs, and lowest net benefits.

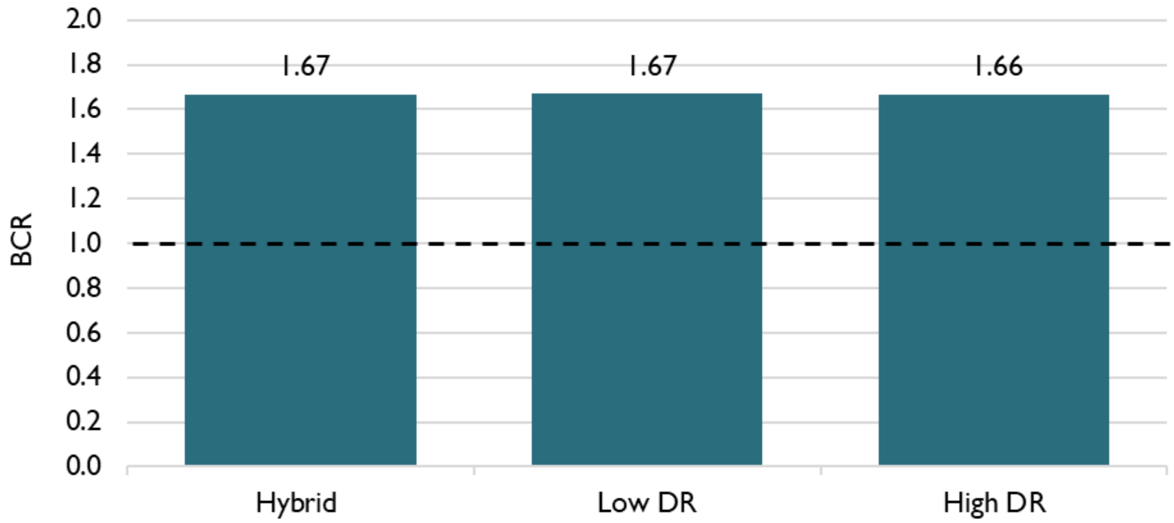
Figure 25. Lifetime benefits, costs, and net benefits of discount rate sensitivity



Under our modeling assumptions for these programs, where the developers are paid a constant amount each year over the life of the program, the costs and benefits occur relatively consistently throughout the life of the system (rather than being frontloaded or backloaded). As a consequence, the modified discount rate impacts costs and benefits evenly, and the BCR remains more or less unchanged.[56]

[56] The slightly lower BCR for the High DR sensitivity is because administrative cost were frontloaded rather than spread evenly throughout the study period. Discount rates have a larger impact on long-term costs than short-term costs, causing a slight imbalance.

Figure 26. BCRs of discount rate sensitivity



The change in discount rate has no impact on the RBPA. This is because a BCA and an RBPA have fundamentally different purposes. A BCA is a decision-making tool that accounts for policy choices as defined by a group of stakeholders (see Section 3.2). One of these policy choices is how much to weight the near-term costs and benefits against the long-term costs and benefits; this weighting is achieved through a discount rate. Meanwhile, the RBPA shows the actual impacts on customers throughout the life of the program. It is not a decision making tool that accounts for policy choices, but instead is meant to project customer impacts using the best available assumptions.

9. Job Impacts

The Maine Test includes the consideration of macroeconomic impacts of the successor DG program. We estimated the macroeconomic impacts of the straw proposal (i.e., the Hybrid Program). We used IMPLAN, an industry standard input-output model, to estimate these macroeconomic impacts.[57]

There are many ways to measure macroeconomic impacts. We report changes in each of the following indicators to measure the economic impacts of the program:

[57] For more information, see "How IMPLAN Works" available at: https://support.implan.com/hc/en-us/articles/360038285254-How-IMPLAN-Works#:~:text=IMPLAN%20is%20an%20I%2DO%20modeling,past%20or%20existing%20economic%20activity.

- *Job-years.* This indicator provides the employment impacts from the hybrid scenario within Maine. A job-year is equivalent to full-time employment for one person for one year (e.g., five job-years could be five jobs for one year or one job for five years).

- *Income*: This indicator provides the income impacts from the scenario and includes income received by all individuals, businesses, and households in Maine.

- *State Gross Domestic Product* (GDP): This indicator provides the overall economic impact of the scenario within the state. GDP reflects the total value added within Maine across all goods and services.

Our analysis also accounts for the three different ways that investments can lead to macroeconomic impacts:

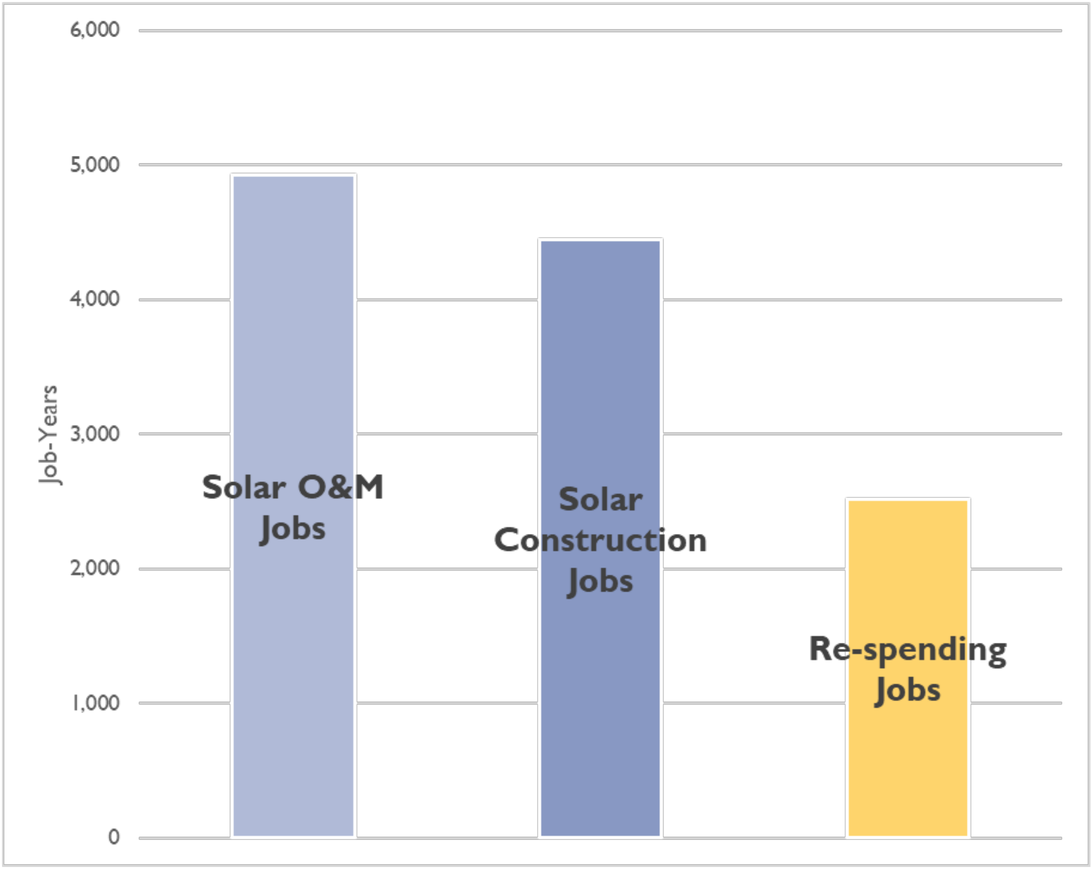
1. *Direct Impacts*. The economic activity created from direct investments in the DG equipment and services during the implementation phase.

2. *Indirect Impacts*. The economic activity created by firms in the supply chains that provide products and services to firms in the direct impacts category.

3. *Induced Impacts*. The economic activity created through the respending of the wage earnings of the newly hired workers who have gained employment as a result of the direct or indirect impacts.

In addition to spending by the utilities, DG developers, and others, customer respending effects can also affect macroeconomic activity. These effects occur when customers save money on their electric bills and spend that freed-up money in the local economy. If utility programs cause an average reduction in bills, customer respending will result in increased macroeconomic impacts, and *vice versa*. The customer respending effects can produce direct, indirect, and induced impacts.

Figure 27. Modeled employment impacts from the Hybrid Program (Job-Years)



Like most utility programs, the successor DG program will lead to both macroeconomic gains and losses. The gains will result from the increased economic activity associated with installing and operating the DG resources. The losses will result from reduced economic activity associated with the costs avoided by the DG resources, such as avoided generation, transmission, and distribution costs. Our analysis accounts for the *net* macroeconomic impacts of the successor DG program, which subtracts the macroeconomic losses from the macroeconomic gains.

The macroeconomic gains and losses will occur partly in Maine and partly in other states or provinces. The results we present below are the impacts that affect only Maine.

9.1. Results

We estimate that the Hybrid Program will result in net macroeconomic benefits for Maine. This includes a net gain of about 11,734 job-years over the entire period, an increase of about $585 million in income, and growth in state GDP equal to approximately $1.36 billion. Further, our analysis indicates that each new job would provide the employee an income of just under $50,000 per year.

These positive impacts are driven by two factors. First, much of the *increased* macroeconomic activity from this program, driven by the investment in solar construction and operations and maintenance, will occur in Maine, while much of the *reduced* macroeconomic activity, driven by avoided generation and transmission costs, will occur outside of Maine.[58] Second, the Hybrid Program is expected to result in significant bill savings for Maine residents and businesses. These bill savings will result in respending effects that will lead to significant local economic activity.

Note that the monetary macroeconomic impacts, such as the $1.36 billion increase in state GDP, should not be added to the monetary results of the benefit-cost analysis presented in other chapters. The costs and the benefits of the BCA can significantly overlap with those of the macroeconomic analysis and adding the monetary impacts together can result in significant double-counting. These macroeconomic results nonetheless represent real benefits to the Maine economy. We recommend that they be considered alongside the BCA results, while recognizing that they cannot be added together.

10. CONCLUSIONS

Based on the results of the BCAs and RBPAs presented above, we conclude the following:

1. Successor DG programs can be designed to provide significant net benefits to all utility customers on average.
2. Successor DG programs can be designed to provide long-term average *reductions* in rates – thereby eliminating any cost-shifting among customers.
3. Successor DG Programs can pay developers significantly less than retail rates and still encourage deployment of DG resources.
4. Successor DG programs can use competitive bidding processes and/or administratively set prices based on contemporaneous price information that incorporate future learning curves to drive down costs of renewable energy procurement.
5. Successor DG programs that provide developers with fixed prices over time will significantly reduce the cost of these program relative to those that provide increasing prices over time.
6. Larger capacity solar projects are less expensive per unit than smaller capacity projects.
7. There are tradeoffs between policy goals and costs of successor program implementation, but provisions of the Inflation Reduction Act help to balance the scales in some instances by

[58]Our assumption concerning the extent of avoided spending impacts that would be experienced in Maine versus other states was based upon modeling results from EPA's Avoided Emissions and Generation Tool (AVERT). AVERT is available at: https://www.epa.gov/statelocalenergy/avoided-emissions-and-generation-tool-avert.

encouraging LMI participation and siting of clean energy on brownfield sites and certain other federally incentivized locations.

8. There are tradeoffs between the number of direct beneficiaries (offtakers) in a program and the financial impacts faced by non-participants. The more program participants, the higher the rate and bill impacts for non-participants, and vice-versa.

    - Despite these tradeoffs, it is possible to design a program with direct participants that is nearly as cost-effective as a program with no direct beneficiaries.

9. If given proper dispatch incentives, battery storage can be deployed in conjunction with solar PV at incremental costs that are significantly less than incremental benefits.

APPENDIX

A.1 General Modeling Assumptions

There are several general modeling assumptions that impact the calculation of costs and benefits, shown below in Table A1. These include the discount rate, compensation term, and time lag between when a project qualifies to participate in the program and when the project begins. These assumptions are applied consistently within the BCA. The RBPA adopts these assumptions as well. However, the RBPA does not adopt the discount rate, as it is only appropriate to forecast rates in nominal terms.

Table A1. General modeling assumptions

Metric	Value	Source
Real discount rate (Base Case)	2.80%	EMT 2020-2022 Plan BC Model
Compensation term	20 years	Consistent with Original Tariff Program
Enrollment to implementation time lag	3 years	Industry knowledge from SEA

Synapse selected a real discount rate of 2.80 percent for consistency with energy efficiency programs administered by EMT. We determined this was a reasonable value to balance the importance of present-day investments with future benefits. We conducted a sensitivity analysis of the discount rate and other variables with high of uncertainty to examine the effect on overall results. See Section 8.2.

The compensation term is the period over which costs are incurred and benefits accrue. We selected a term length of 20 years for consistency with the Original Tariff Program and our judgement that this is a reasonable program length for solar DG installations.

Based on current market developments and our knowledge of interconnection queues in the region, we assumed a 3-year lag between program enrollment and the start of the compensation term, or when the facility begins producing energy. This lag accounts for siting, development, and delays associated with the interconnection process.

Within the BCA, all costs and benefits are stated in present value 2022 dollars. This means that any nominal, future-year costs or benefits are deflated to constant 2022 dollars using factors from the Energy Information Administration (EIA)'s Annual Energy Outlook 2022,[59] and then discounted with a real discount rate of 2.8 percent in the base case, shown above. The deflation rate accounts for expected inflation across the economy in each year, while the real discount rate accounts for the time-value of money, uncertainty in future estimates, intergenerational equity issues, and other factors that

[59] EIA. 2022. *Annual Energy Outlook*. "Table 20. Macroeconomic Indicators: Consumer Price Index for All Urban Customers." Available at: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=18-AEO2022&cases=ref2022&sourcekey=0

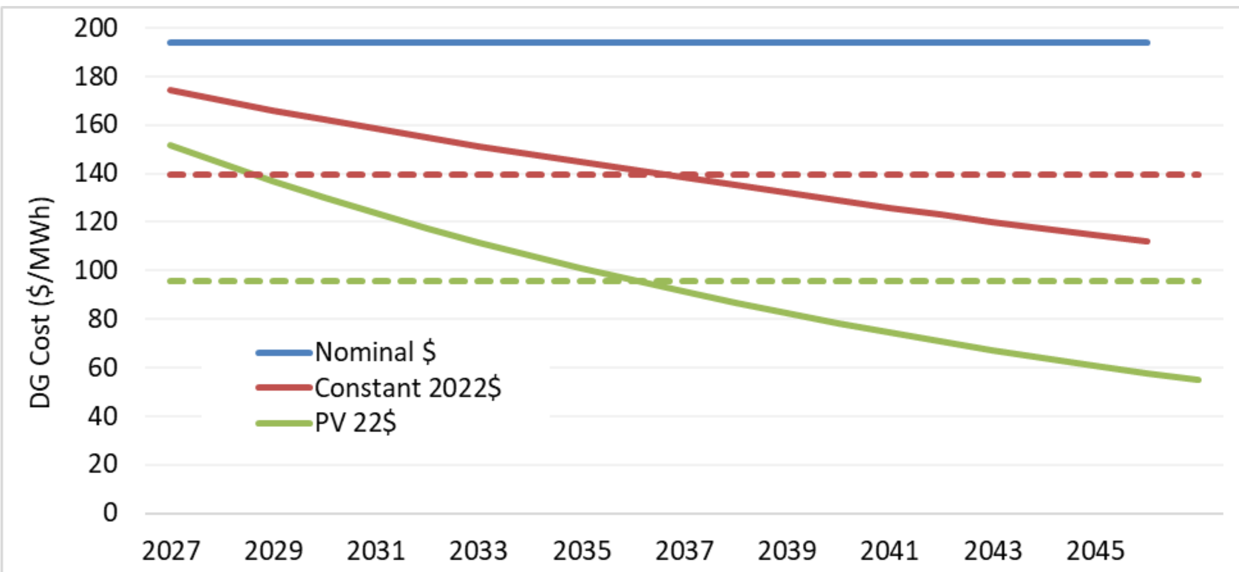
are additional to inflation considerations. We use a relatively low real discount rate because that is consistent with the goal of our BCA, which is to identify DG program designs and resources that meet the ultimate goal of providing low-cost, clean, reliable energy to all customers over a short, medium, and long-term planning horizon.

Below is an example of a calculation that converts 2027 nominal dollars to 2022 real dollars:

$$\begin{aligned}2022\ real\ dollars\\ &= 2027\ nominal\ dollars * 2027\ to\ 2022\ deflation\ rate\\ &* (1 + real\ discount\ rate)^{2022-2027}\end{aligned}$$

Figure A1 below shows the distinct impacts of inflation and discounting. The blue line shows nominal dollars (no inflation adjustments or discounting). The red solid line shows constant $2022 (inflation adjustments only). The green solid line shows present value (PV) $2022 (inflation adjustments and discounting). The dotted lines represent the average across the time period for constant dollars and PV dollars, respectively.

Figure A1. Nominal, constant, and present value dollars



A.2 Cost of Renewable Energy Model and Other Cost Assumptions

Cost of Renewable Energy Spreadsheet Tool (CREST) Model

The CREST model is a cash flow analysis tool published by NREL, developed under contract by SEA. The model is a transparent tool that allows the user to modify inputs and assumptions. It is designed to calculate the cost of energy, or minimum compensation per unit of production, necessary for the modeled project to cover its expenses, service its debt obligations (if any), and meet its equity investors' assumed minimum required after-tax rate of return.[60]

Methodology for Representing Impacts of Competitive Bidding in Resource Cost Estimates

Assuming no collusion, competitive bidding is considered to produce the lowest-cost outcomes for resource procurement when compared to administratively set prices. To estimate the impact of competition in Maine, we used a regional example from Rhode Island. Namely, in the Rhode Island Renewable Energy Growth (REG) program, a comparison between the administratively-set ceiling price for various renewable energy classes and the as-bid prices for projects suggests that these prices tend to be around 9.5 percent below the ceiling price. To represent the impact of competition, we therefore reduced the levelized cost outputs of our CREST model by 9.5 percent. In reality, the impact of competition on prices will vary depending on the number of competitors, the size of procurements, and other factors.

Project Cost and Performance Assumptions

We developed a wide array of solar PV and PV plus energy storage-related inputs based on regionally representative (and where available, Maine-specific) development conditions. We describe these inputs, assumptions, and their sources below.

Solar PV – Project Installed Capital/Operating Cost and Performance Assumptions

- ***Installed Capital Cost Estimates:***
    - *1 MW_{AC} Projects:* Averages of median and 25th percentile values from state databases in the Northeast region and actual as-bid values for projects submitting bids in 2022 Rhode Island Renewable Energy Growth (REG) Open Enrollments.[61]
    - *5 MW_{AC} Projects:* An average of the median and 25th percentile value of several different Northeast regional statewide databases.[62]

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[60] CREST was developed in Microsoft Excel, so it offers the user a high degree of flexibility and transparency, including full comprehension of the underlying equations and model logic.

[61] For more information on the state databases in the Northeast region and the general approach to calculating such installed cost values, see SEA Schedules 1, 2 and 3 to the *Distributed Generation Board's Report and Recommendations for Renewable Energy Classes and Eligible System Sizes for the RE Growth Program Year 2023* (filed on November 16, 2022, in R.I. Public Utilities Commission (PUC) Docket 22-REG-39 by the Rhode Island Distributed Generation Board and Office of Energy Resources (OER)), available at: https://ripuc.ri.gov/Docket-22-39-REG

[62] We note that installed capital costs for these projects do not include observations from REG 2022 Open Enrollment accepted bids because, as of this writing, no bids have been received for solar projects between 1-5 MW_{DC} during the current program year. However, these state database assumptions were recently adjusted to account for market conditions in which costs have risen sharply between 2021 and 2022, for projects in development ahead of closing a PPA deal in 2023.

- ***Interconnection Cost Estimates:*** Stakeholders reported expected costs around \$400/kW_{DC}, which SEA views as reasonable. Given this, SEA applied a \$150/kW_{DC} interconnection premium to the average regional installed cost data of \$250/kW_{DC} for 5 MW_{AC} projects. The 1 MW_{AC} project modeled was assumed behind-the-meter and did not receive any interconnection premium above regional average interconnection costs.

- ***Incremental Cost of Meeting Federal/State Prevailing Wage Requirements for Eligible Projects:*** With the passage of the IRA and P.L. 2022, c. 705,[63] all renewable energy projects that are 1 MW_{AC} and larger in Maine and that wish to receive incentives and tax credits consistent with the financing assumptions in this analysis must pay Davis-Bacon prevailing wages to project laborers.[64] Based on discussions with regional market participants, the incremental cost of meeting these requirements was assumed to be approximately \$57.50/kW_{DC} in nominal 2022 dollars. To adjust these values to reflect 2024-2028 market conditions, this incremental installed cost value was adjusted for inflation over the period.[65]

- ***Assumed Year-on-Year Change in Installed Capital Costs:*** We assumed that Installed capital costs would decline for all resource blocks through 2030, based on an average of the NREL Annual Technology Baseline (ATB) 2022 Moderate and Conservative cases (approximately 3 percent per year). We determined that this blended average was likely to be most representative of an environment in which project cost reductions were more broadly offset in the near-to-medium term by cost increases (including supply chain realignments from Asia to North America) than was typical during the 2010s. We benchmarked this value utilizing publicly available information on average, medium- and longer-term all-in solar PV engineering, procurement, and construction (EPC) prices from Wood Mackenzie.[66]

- ***Sources of Incremental Capital Cost Values and Operating Expense Values for Various Resource Blocks:*** The incremental capital cost values for brownfield projects, shared solar projects, shared solar projects serving LMI customers, and operating expense assumptions (including incremental operating expense assumptions for certain

[63] In May 2022, LD 1969 – An Act Concerning Equity in Renewable Energy Projects and Workforce Development, became law as P.L. 2022, c. 705. Starting January 1, 2023, Chapter 705 requires that “assisted projects” pay all construction workers the prevailing rate for wages and benefits as determined by the Maine Bureau of Labor Standards. The law defines assisted projects as renewable energy projects greater than 2 MW in size for which an RFP is initiated after January 1, 2023, and that receive state certification for RECs, PPA payments, grants, or loans from the state of Maine. The definition of assisted project excludes projects participating in NEB and projects for which the PUC has approved a term sheet on or before June 29, 2021. Find more information on LD 1969 here: https://legislature.maine.gov/bills/display_ps.asp?snum=130&paper=HP1464&PID=1456

[64] U.S. Department of Labor. 2022. “Prevailing Wage and the Inflation Reduction Act”. Available at: https://www.dol.gov/agencies/whd/IRA#:~:text=The%20prevailing%20wage%20provisions%20of%20the%20Inflation%20Reduction%20Act%20state,with%20the%20Davis%2DBacon%20Act.

[65] U.S. Energy Information Administration. 2022. *2022 Annual Energy Outlook,* Table 20 (Macroeconomic Indicators). Available at: https://www.eia.gov/outlooks/aeo/.

[66] Wood Mackenzie. 2022. *Is the end of high US solar system prices in sight?* Available at: https://www.woodmac.com/news/opinion/is-the-end-of-high-us-solar-system-prices-in-sight/.

brownfield and shared solar projects) represent a mix of values derived from SEA's confidential discussions with market participants in the New England region.

- ***Bill Credit Expenses:*** For the Successor Program Options that involved customer offtake (Policy Options 1-2), SEA included bill credit costs in its CREST analysis. For Policy Options 1-2, a fixed bill credit was applied (1.5¢/kWh for non-LMI, 2.5¢/kWh for LMI offtake). Stakeholders were surveyed for typical bill credit discounts (expressed as a percent of retail rates) which were used to benchmark the fixed bill credits adopted for Policy Options 1-2. Policy Option 3 included no customer offtake, and thus did not have any bill credit expenses included.

- ***Assumed Year-on-Year Change in Operating Costs:*** We chose to conservatively assume no year-on-year changes in year one operating costs over time (e.g., for projects enrolling in different program years), opting to keep this value flat in light of rapidly changing dynamics in these sectors. While it is possible (even potentially likely) that certain operating expense values (such as the starting value for land or site leases per acre) could change, the typical asking price for a lease is highly site- and host-dependent, and thus subject to a highly opaque set of price dynamics and an unclear overall trajectory for new projects over time.

- ***DC-AC Ratio:*** We assumed all projects met a direct current (DC) to alternating current (AC) ratio of 1.3. This ratio corresponds to a 1.3 MW_{DC} and 6.5 MW_{DC} modeled project, to produce 1 MW_{AC} and 5 MW_{AC} projects. Capacity factors represent the output assumptions for projects sized to assumed AC-based limits.[67]

- ***Assumed Project Location/Production:*** We sourced project related performance assumptions from the National Renewable Energy Laboratory's PVWatts database, and derived them based on an assumed location in Bangor, ME.[68] We selected Bangor due to its proximity to the center of the state.

  We utilized actual regional production data to adjust PVWatts outputs for real-world project performance, which resulted in the capacity factors shown in Table A2 below.

- ***Production Improvement Assumptions Over Time:*** We assumed that capacity factors for new projects improve by 1 percent per year for each year of the project enrollment period (2024-2028). As an example, if the Year 1 capacity factor assumption for 2024 qualified projects is equal to 13.8 percent, the 2025 assumption will be 14.0 percent, and so on.

- ***Annual Production Degradation Assumptions:*** Based on a project-level production analysis of Massachusetts solar projects, we assumed an annual production degradation

[67] We acknowledge that, in the case of projects with co-located energy storage, it is possible for the storage to capture the clipped energy associated with oversizing the PV system, which thus allows for projects to be built at sizes well in excess of the 6.5 MWDC nameplate project utilized in this analysis (and thus could reduce costs by increasing system scale). However, for analytical simplicity (e.g., in order to avoid revisiting all of the PV capital cost assumptions), the team utilizes a 1.3 ratio for both PV-only and PV plus storage projects.

[68] NREL. 2022. *PVWatts Calculator.* Available at: https://pvwatts.nrel.gov/

rate of 0.8 percent per year for 1 MW_{AC} projects, and 0.5 percent per year for 5 MW_{AC} projects.

- ***Term of Analysis:*** SEA limited the term of the CREST analysis to the duration of the tariff to ensure that the modeled project is able to meet its return-on-investment requirements within the duration of the tariff. As such, post-tariff revenue was not considered in this analysis.

All of the solar PV-specific cost and performance assumptions utilized in the CREST analysis of the various NEB successor program options are contained in the table below.

Table A2. Solar PV Cost and Performance Assumptions Included in CREST Analysis of NEB Successor Program Options

	Unit	Large Commercial Roof Mounted	Large Ground Mount	Large Ground Mount (LMI)	Large Ground Mount (Brownfield/ Other Energy Community)	Large Ground Mount (Located in Low-Inc./Disad. Community)	Large Ground Mount ("Low Income Benefit")
Rated Size	kW_{AC}	1000	5000	5000	5000	5000	5000
DC-AC Ratio	#	1.3	1.3	1.3	1.3	1.3	1.3
Modeled Size	kW_{DC}	1300	6500	6500	6500	6500	6500
Capacity Factor	%	12.23%	13.82%	13.82%	13.63%	13.82%	13.82%
Annual Degradation	%	0.8%	0.5%	0.5%	0.5%	0.5%	0.5%
Useful Life (Years)	Years	20	20	20	20	20	20
Expected 2023 Base Project Cost (Incl. Interconnection)	$/kW_{DC}$	$2,116	$1,960	$1,960	$1,960	$1,960	$1,960
Expected 2023 Incremental IRA Prevailing Wage Requirement Cost	$/kW_{DC}$	$57.50	$57.50	$57.50	$57.50	$57.50	$57.50
Expected 2023 Incremental Shared Solar Installed Capital Cost*	$/kW_{DC}$	N/A	$100	N/A	$100	$100	N/A
Incremental LMI Shared Solar Installed Capital Cost*	$/kW_{DC}$	N/A	N/A	$150	N/A	N/A	$150
Expected 2023 Incremental Brownfield Installed Capital Cost	$/kW_{DC}$	N/A	N/A	N/A	$330	N/A	N/A
Expected 2023 Total Project Cost (Incl. Interconnection)	$/kW_{DC}$	$2,174	$2,118	$2,168	$2,448	$2,118	$2,168
Assumed Offtaker Discount to Retail Rate*	$/kWh	$0.015	$0.015	$0.025	$0.015	$0.015	$0.025
Expected 2023 Base Fixed O&M	$/kW_{DC}-yr	$13.83	$11.00	$11.00	$12.76	$11.00	$11.00
Expected 2023 Incremental Shared Solar O&M*	$/kW_{DC}-yr	N/A	$22.00	$22.00	$22.00	$22.00	$22.00
Expected 2023 Total Fixed O&M	$/kW_{DC}-yr	$13.83	$33.00	$39.60	$38.28	$39.60	$39.60

	Unit	Large Commercial Roof Mounted	Large Ground Mount	Large Ground Mount (LMI)	Large Ground Mount (Brownfield/ Other Energy Community)	Large Ground Mount (Located in Low-Inc./Disad. Community)	Large Ground Mount ("Low Income Benefit")
Expected 2023 Insurance	% of Total Costs	0.63%	0.57%	0.60%	0.66%	0.60%	0.60%
Expected 2023 Total Project Management Cost	$/yr	$4,400	$20,000	$20,000	$21,400	$20,000	$20,000
Expected 2023 Total Site Lease	$/yr	$12,300	$30,000	$32,700	$30,600	$30,000	$32,700
Property Tax/PILOT	$/yr	$0	$0	$0	$0	$0	$0
O&M Escalation/yr	%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Non-O&M Escalation/yr	%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

**The team did not apply costs relating to shared solar customer acquisition, management, and bill credits for Policy Option 4 (Wholesale PPA).*

Paired BSS–Incremental Performance/Dispatch Assumptions

- ***BSS Coupling and Assumed Losses:*** Based on proprietary analyses previously accomplished by SEA, we assumed that paired battery storage systems (BSS) were DC-coupled and had a round-trip efficiency of approximately 89 percent.

- ***Minimum Reserve Levels:*** We assumed that eligible projects with paired BSS would maintain a minimum 10 percent of total capacity in reserve at any time. This is in order to provide for emergency situations, as well as to minimize excessive wear and tear on the battery.

- ***Discharge Optimization:*** Discharge of the assumed BSS focused on two objectives: (1) capturing otherwise clipped output from PV for later discharge and (2) discharging during specified hours. SEA's proprietary dispatch model assumed 75 percent of potential clipped PV energy would be captured, a step intended to simulate imperfect foresight, and a need to ensure that the battery can be fully charged before event windows began. The specific hours of events in which performance was required were 3 pm to 8 pm during non-holiday weekdays in June, July, and August, which is based on the event windows for the CT Energy Storage Solutions program.

- ***Charging Period:*** Charging to replenish the battery's capacity occurs between midnight and 5 am (generally low-cost periods when solar is unavailable).

- ***System Benefits of Paired ESS:*** The benefits of pairing PV with co-located energy storage are highly sensitive to ultimate program design and resulting dispatch. Based on the assumptions utilized in this analysis, we determined that the following values were reasonable to assume for calculating benefits under the Maine Test:

    - Avoided generation (capacity and capacity DRIPE): 90 percent

    - Avoided transmission expenses: 20 percent

    - Avoided distribution expenses: 10 percent

Financing Assumptions

<u>Solar PV</u>

- ***Project Ownership Structure:*** The team assumed that all projects were owned by third parties that pay state and federal corporate tax.

- ***Federal ITC/CEIC Eligibility:*** Projects were assumed to be eligible under federal tax code provisions of the ITC for projects that either begin construction prior to December 31, 2024, as well as the availability of the successor Clean Energy Investment Credit (CEIC) for projects that are placed in service no earlier than January 1, 2025.

- ***Debt Fraction and Minimum Coverage Ratio:*** The share of debt in the project's capital stack is held constant over the 2024-2028 analysis term and is sized to meet an average debt service coverage ratio (DSCR) of 1.25.

- ***Debt Term:*** Project debt terms vary based on the degree of hedged revenue (ranging from 10 years for least hedged policy cases, to 15 for most hedged cases). We assumed terms that are based on an offer of debt for a portfolio of projects, rather than a single project with its financial risks viewed in isolation, which generally lowers financing costs.

- ***Interest Rate on Term Debt:*** We assumed interest rates calculated based on averages of 10- and 20-year Treasury note values on October 10, 2022, plus a risk premium of 325 basis points.

- ***Tax Equity Assumptions:*** We assumed tax equity investors take the most valuable share of the projects. We therefore assumed tax equity investors constitute a larger share of the projects' capital financing. Projects with bonus ITC/CEIC values include larger tax equity shares of total equity than projects eligible for smaller tax credits.

- ***State and Federal Tax Rates:*** All applicable Maine tax rates are assumed, and all applicable federal corporate taxes are assumed to be paid.

Energy Storage

- ***Financing Assumption Parity Between PV-Only and PV-Plus-Storage Resources:*** Based on discussions with market participants, our team assumed that solar plus storage projects have the same financial terms as solar PV projects in the context of a program where most of the project's revenue is hedged (the Hybrid Program).

Table A3. Project Financing Assumptions

Year	***2024***	***2025***	***2026***	***2027***	***2028***
Statutory ITC/ CEIC Value (%)*	• Large Rooftop/Ground Mount (No Project Offtaker/Siting Bonus from IRA): **30% ITC/CEIC** • Large Ground Mount (Brownfield/Energy Community or Sited in LI/Disad. Comm.): **40% ITC/CEIC** • Large Ground Mount (LI Benefit Projects): **50% ITC/CEIC**				
Debt %^	• Projects Monetizing 30% ITC/: **47%-52%** • Projects Monetizing 40% Investment Credit: **40%-44%** • Projects Monetizing 50% Investment Credit: **34%-36%**				
Debt Tenor^	For All Projects: **10-15 years**				
Interest Rate on Term Debt %†	**6.7%-6.8%**	**6.1%-6.2%**	**5.5%-5.6%**	**5.5%-5.6%**	**5.5%-5.6%**
Lender's Fee*	For All Projects: **2%**				
Sponsor/Tax Equity Split*	• Projects Monetizing 30% ITC/CEIC: **25%/75%** • Projects Monetizing 40% ITC/CEIC: **17.5%/82.5%** • Projects Monetizing 50% ITC/CEIC: **10%/90%**				
Sponsor/Tax Equity After-Tax IRRs (Levered)*	• Tax Equity IRR (All Projects): **9.5%** • Sponsor Equity IRR (All Projects): **11%**				
Consolidated After-Tax Equity IRR (Levered)^	• Projects Monetizing 30% ITC/CEIC: **9.88%-10.88%** • Projects Monetizing 40% ITC/CEIC: **9.77%-10.77%** • Projects Monetizing 50% ITC/CEIC: **9.65%-10.65%**				
Depreciation	For All Projects: **5-Year MACRS (no bonus depreciation)**				

**Value held constant across all years.*

^Value held constant across all years. The lowest end values represent policy cases with low/no hedged attribute revenue expectations, with values increasing as more revenue is hedged.

†The lowest end values represent policy cases with low/no hedged attribute revenue expectations (and shorter debt terms), with values increasing as more revenue is hedged (and longer debt terms are assumed). The assumed trajectory of interest rates is informed by federal funds rate expectations over the medium- and long-term, which drive pricing of 10- and 20-year Treasury note values.

Table A4 displays the final project costs from the CREST model for all program options in nominal terms and in real, present value dollars.

Table A4. CREST model outputs converted to real 2022$

Option	Block	Project Cost									
		Nominal $/MWh					PV 2022$/MWh				
	Program Enrollment Year	2024	2025	2026	2027	2028	2024	2025	2026	2027	2028
Fixed Future Price	Roof Mounted	194	185	176	170	165	98	86	76	68	61
	Ground Mount	166	158	152	147	143	84	73	65	59	53
	Ground: LMI Offtakers	182	175	167	163	158	92	81	72	65	58
	Ground: Brownfield & LMI Location	167	160	153	149	145	84	74	66	59	53
	Ground: LMI Offtakers & LMI Location	167	159	153	149	145	84	74	66	59	53
	Ground: LMI Offtakers & LMI Benefit	149	143	138	134	131	75	67	60	53	48
Moderate Hedge	Roof Mounted	185	175	167	163	157	93	82	72	65	58
	Ground Mount	172	164	157	153	149	86	76	68	61	55
	Ground: LMI Offtakers	191	182	176	172	167	96	85	76	68	61
	Ground: Brownfield & LMI Location	182	175	169	164	161	92	82	73	65	59
	Ground: LMI Offtakers & LMI Location	164	157	151	147	143	82	73	65	58	53
	Ground: LMI Offtakers & LMI Benefit	160	154	149	146	142	81	72	64	58	52
Wholesale PPA	Roof Mounted	171	161	154	149	143	86	75	66	59	53
	Ground Mount	131	125	118	114	110	66	58	51	45	40
	Ground: LMI Offtakers	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Ground: Brownfield & LMI Location	140	133	127	122	119	70	62	54	49	44
	Ground: LMI Offtakers & LMI Location	118	112	106	103	99	59	52	46	41	36

Option	Block	Project Cost									
		Nominal $/MWh					PV 2022$/MWh				
	Program Enrollment Year	2024	2025	2026	2027	2028	2024	2025	2026	2027	2028
	Ground: LMI Offtakers & LMI Benefit	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Hybrid	Roof Mounted (Hedged Energy and RECs)	185	175	167	163	157	93	82	72	65	58
	Ground Mount (Wholesale PPA)	131	125	118	114	110	66	58	51	45	40
	Ground: Brownfield (Wholesale PPA)	140	133	127	122	119	70	62	54	49	44
	Ground: LMI Location (Wholesale PPA)	118	112	106	103	99	59	52	46	41	36
	Ground: LMI Offtakers & LMI Benefit (Hedged Energy and RECs)	160	154	149	146	142	81	72	64	58	52
Hybrid + Storage	Roof Mounted (Hedged Energy and RECs)	256	239	225	217	209	129	111	97	86	77
	Ground Mount (Wholesale PPA)	164	152	144	139	134	82	71	62	55	49
	Ground: Brownfield (Wholesale PPA)	169	158	151	146	140	85	73	65	58	51
	Ground: LMI Location (Wholesale PPA)	146	137	130	125	120	73	64	56	50	44
	Ground: LMI Offtakers & LMI Benefit (Hedged Energy and RECs)	185	177	170	166	161	93	82	73	66	59

In addition to the project costs shown in Table A4, we included annual administrative costs of $600,000 (real 2022$) for the first 5 enrollment years (2024–2028) and $300,000 annually through the final year of compensation term (2050). This estimate is based on data from an information request to the DGSG dated October 7, 2022.

Modeling assumptions for Original Tariff Programs

Synapse modeled the Original Tariff Program cost using the same general modeling assumptions as the three successor program options described above. The only difference in modeling was how we calculated program costs. Unlike the three successor programs, the Original Tariff Program tied program incentives to utility rates. The costs were not an output from the CREST model. The incentives to developers were calculated based on projected rates at the percentages shown in Table A5.

Table A5. Compensation percent by rate component

Rate component	Compensation percent
Generation	100%
Transmission	75%
Distribution	75%
Riders	75%

The methodology we used to forecast rates is described in Section A.4. The only difference is for the Original Tariff Program costs, we used the Small General Service (SGS) rate rather than an average rate across all rate classes. The SGS is the rate from which the Original Tariff Program bases compensation. This approach resulted in the costs per unit of energy produced shown in Table A6.

Table A6. Original tariff program

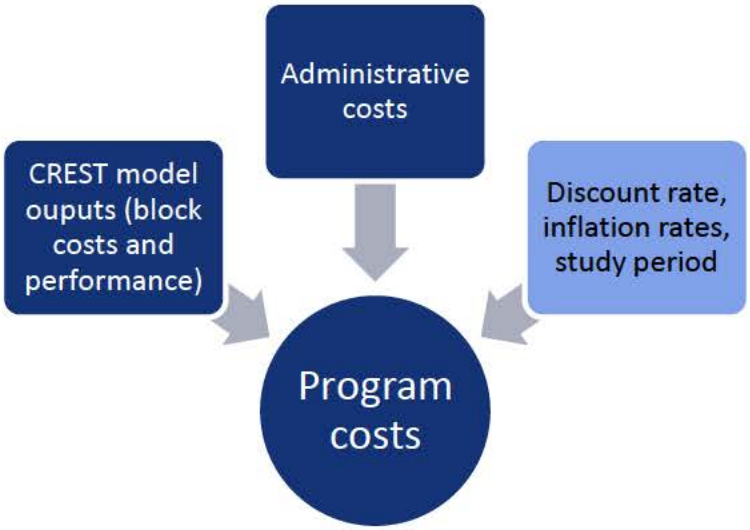
Project start	Incentive Cost real 2022$/MWh
2027	222
2028	220
2029	219
2030	217
2031	216

A.3 Benefit Cost Analysis Methodology

Treatment of Costs in BCA

The cost inputs are integrated into the BCA as displayed in Figure A2. The inputs include the CREST model results from SEA, the annual administrative cost estimates based on feedback from the DGSG, and the general modeling assumptions implemented throughout this analysis.

Figure A2. BCA program cost inputs



The CREST model outputs project costs per energy generated ($/MWh) as well as the rated generation capacity by block. To convert the costs per energy generated into total project costs ($), we take the following approach:

$$Project\ costs\ (\$) = Block\ cost(\$/MWh) * compensation\ term(years) * annual\ generation\ (kWh)/1000$$

where,

$$Annual\ generation\ (kWh) = Maximum\ output(kW) * capacity\ factor(\%) * 8760(hours)$$

Maximum output (kW) is derived from annual (8,760 hours) solar and solar plus storage performance curves.

Benefit Definitions

The following avoided costs definitions are from the Methods, Tools, and Resources (MTR) manual published by the National Energy Screening Project (NESP)[69]:

[69] NESP, 2022.

- ***Avoided energy costs:*** Energy generation costs consist of the fuel and variable O&M costs from the production or procurement of energy (i.e., kWh) from generation resources. Energy generation costs can vary significantly by season and time of day. In general, DERs will (a) create energy generation benefits when they reduce the amount of electricity utilities need to produce or procure in order to meet load, or (b) create energy generation costs if they require higher levels of energy generation. An exception to this occurs during periods of negative pricing whereby consuming grid energy (e.g., storage or electric vehicle charging) results in a benefit and curtailing grid energy consumption results in a cost.[70]

- ***Avoided capacity costs:*** Generation capacity is the amount of installed capacity (i.e., kW) required to meet the forecasted peak load, which typically includes an additional reserve margin. A utility will either need to build generation capacity or procure it (for instance through bilateral contracts or wholesale market purchases) to ensure it has sufficient generation capacity to meet its planning requirement. If a DER results in a net decrease in load (e.g., from energy efficiency savings, curtailment through demand response, PV generation, injections from storage) during the system peak, the utility will experience benefits in the form of lower generation capacity needs. Consequently, DERs can impact generation capacity by inducing the retirement of generators and marginally changing the mixture of generators that would have otherwise been built. Alternatively, if a DER results in a net increase in load (such as with electrification) during the system peak, the utility will incur additional generation capacity costs.[71]

- ***Avoided environmental compliance costs:*** There are many environmental requirements that impact the electric utility system. Utilities experience environmental compliance impacts and pass them on to all customers through revenue requirements and rates. In many cases, DERs will help to reduce the costs of environmental requirements by reducing air emissions and other environmental impacts of electricity generation, transmission, and distribution. In some cases, DERs might increase the costs of environmental requirements, for example if they create a net increase in GHG or criteria pollutant emissions.[72]

- ***Avoided RPS compliance costs:*** In jurisdictions that have adopted a renewable portfolio standard (RPS) or similar regulatory mechanisms like clean energy standards (CES) or clean peak standards (CPS), DERs can impact the cost of compliance. DERs can reduce compliance costs either by reducing the target by virtue of lowering overall electricity demand or increasing the level of qualified renewable or clean energy generation. Alternatively, if a DER has the effect of increasing electricity demand (e.g., electrification) it will require additional renewable purchases and therefore increase the compliance costs of meeting the standard.[73]

[70] *See id.*, p. 14
[71] *See id.*, p. 24–25
[72] *See id.*, p. 48
[73] *See id.*, p. 36

- ***Market price effects/demand reduction induced price effects (DRIPE):*** In jurisdictions with competitive wholesale electricity markets, wholesale market prices are a function of the demand of buyers and the marginal costs of suppliers at any given instant. When DERs reduce (or increase) the demand for electricity, they reduce (or increase) the wholesale market prices. This change creates benefits (or costs) for all customers participating in the wholesale market at that time. This effect is sometimes referred to as demand reduction induced price effect (DRIPE). DERs can impact wholesale market prices either in the form of demand (e.g., distributed solar PV treated as a utility load modifier) or supply (e.g., demand response participation directly in the wholesale market). This impact typically lasts for only a short period before the market adjusts to the new supply/demand balance.[74]

- ***Avoided transmission costs:*** Transmission capacity refers to the availability of the electric transmission system to transport electricity in a safe and reliable manner. In areas with insufficient transmission capacity available to support transmission of lowest-cost electricity, there will be transmission congestion costs due to the need to utilize higher-cost generation to avoid the transmission constraint. A DER's impact on transmission capacity depends on its load impact profile during the times coincident with the transmission peaks. If a DER increases load at the time of the transmission system peak, it will result in added costs. Alternatively, if a DER reduces load at the time of the transmission system peak, it will result in reduced costs. DERs may reduce transmission capacity costs in two ways:

    - DERs may passively defer needed transmission capacity investments if their operation for other purposes (e.g., host customer bill management) results in lower load at the same time the transmission facilities are at their peak. In these instances, the DERs may be attributed with a system-wide average for the transmission capacity benefit provided.

    - DERs may actively defer transmission capacity needs as part of a geographically targeted non-wires alternative (NWA). The value of active deferrals is typically based on the actual deferral value of the avoided transmission project (i.e., the costs avoided if the wires investment is deferred for a certain number of years). There is often a minimum cost threshold for transmission projects to be considered for an NWA; therefore, the value of active deferrals is typically higher than that of passive deferrals. Some ISOs/RTOs allow for wholesale market participants to trade fixed transmission rights to help them manage transmission congestion costs. Some DERs might be able to create benefits by reducing transmission congestion and costs of fixed transmission rights. Costs of fixed transmission rights are typically included in wholesale energy market prices and therefore may not need to be included as a separate impact.[75]

- ***Avoided distribution costs:*** Distribution capacity refers to substation and distribution line infrastructure necessary to meet customer electric demand, and as such the impact

[74] *See id.*, p. 40

[75] *See id.*, p. 60–61

will depend on the cost associated with the specific type of distribution infrastructure being affected. If peak demand exceeds capacity of a circuit, it will require investments to increase distribution capacity to a level that preserves safety and reliability. The net effect of DERs on distribution capacity depends on their load impact profiles during the distribution system peaks. DERs can either actively or passively help defer or eliminate the cost of needed investments by reducing net load during peak hours. With respect to passive benefits, a DER may have the effect of reducing net load despite operating for some other purpose (e.g., host customer bill management). For active deferrals, a utility may incentivize DERs through pricing, programs, or procurements to provide distribution capacity benefits. Alternatively, DERs might increase distribution capacity costs if the local distribution system does not have sufficient hosting capacity (i.e., if a given feeder cannot accommodate more DERs without impacting system operation under existing control and infrastructure configurations). For example, if a DER consumes electricity from the grid during times of the distribution peak load or injects electricity onto the grid during times of minimum load (and therefore creates voltage issues) it would have the effect of creating a cost to invest in the necessary distribution infrastructure to avoid these issues. Distribution capacity impacts can be calculated for the electric system on average or on a location-specific basis.

- ***Greenhouse gas emissions impacts***: Greenhouse gases include carbon dioxide, methane, nitrous oxide, and fluorinated gases. GHG emissions are created from a variety of sources, including production, transmission, and distribution of both electricity and natural gas; industrial processes; heating of commercial and residential buildings; and transportation. Societal impacts should be accounted for in a jurisdiction's BCA to the extent they are relevant to the jurisdiction's energy policy goals, consistent with NESP 2020 guidance. Some DER types, such as distributed PV, can reduce GHG emissions by reducing the production and consumption of fossil fuels. Other DER types, such as building electrification and electric vehicles, can increase GHG emissions from electricity generation but reduce GHG emissions by reducing the consumption of other fuels such as gas or gasoline. For these latter DER types, it is important to account for net impact of increased and decreased emissions.[76]

  In this study we only include the impacts of CO_2 and NO_x.

The REC revenue is not an avoided cost but a source of revenue specific to renewable energy projects:

- ***REC revenue:*** Renewable energy certificates (RECs) are credits designed to represent the clean energy attributes of renewable energy generation. One REC is generated for every megawatt-hour of energy produced. RECs are bought and sold in the renewable energy market, either for compliance with a particular policy (e.g. RPS) or voluntarily.[77] For

[76] *See id.*, p. 139–140

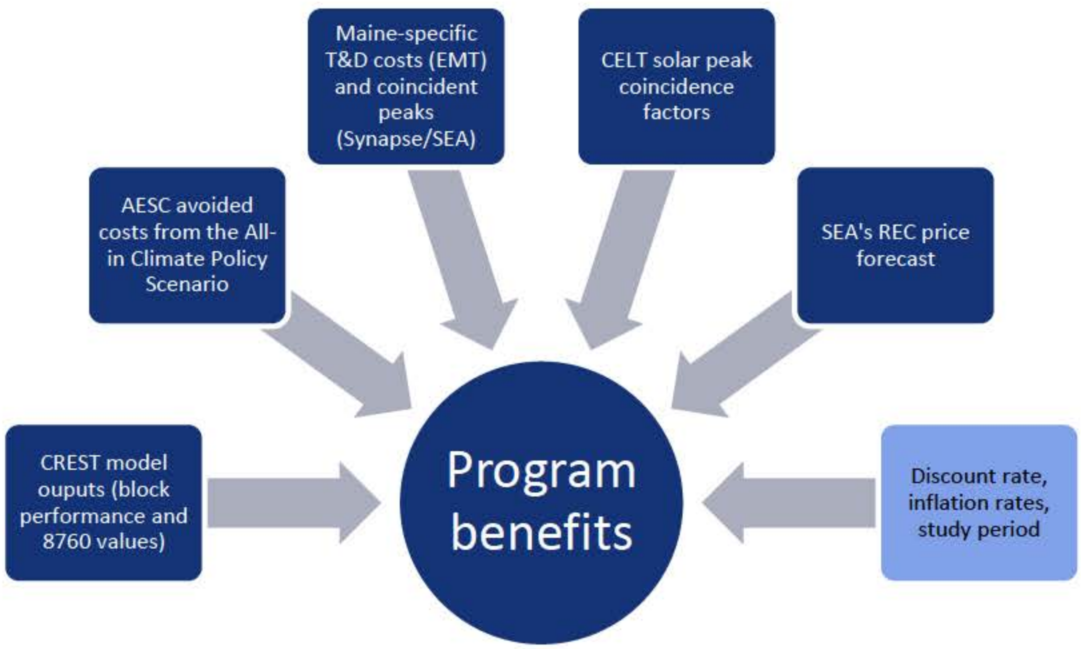
[77] U.S. Environmental Protection Agency. 2022. "U.S. Renewable Electricity Market." Available at: https://www.epa.gov/green-power-markets/us-renewable-electricity-market#:~:text=Electricity%20service%20providers%20use%20renewable,certain%20types%20of%20renewable%20energy.

entities that generate RECs but do not have to comply with renewable energy policy, RECs can be sold as a source of revenue.

Treatment of Benefits in BCA

The benefit inputs are integrated into the BCA as displayed in Figure A3. The inputs include the CREST model results from SEA, the avoided costs from AESC and EMT, the solar peak coincidence factors from the CELT report, the REC price forecast from SEA, and the general modeling assumptions implemented throughout this analysis.

Figure A3. BCA program benefit inputs



We use the CREST-developed resource curves to calculate total annual kWh, detailed in the cost section above. We also calculate the percent of generation during the four aggregate time periods per AESC summer peak, summer off-peak, winter peak, winter off-peak—and the maximum output using the annual generation provided by the CREST model.

Avoided Cost Assumptions

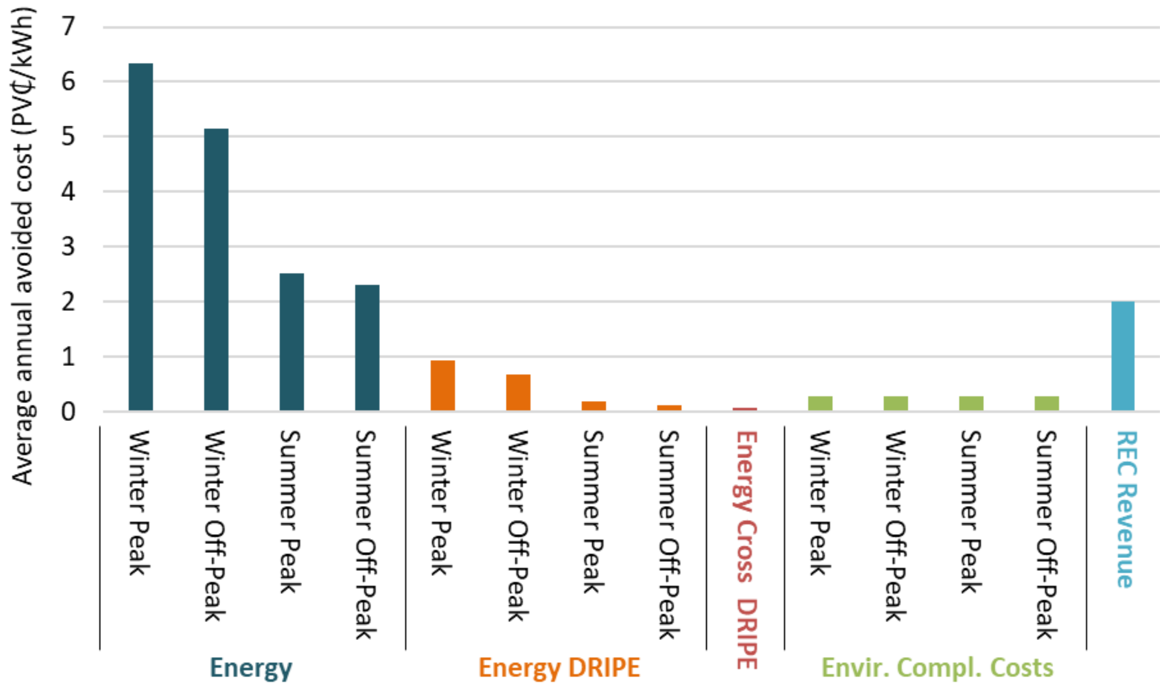
Table A7 summarizes the benefits included in the Maine Test resulting from discussions with the DGSG and their accompanying sources.

Table A7. Benefits included in the Maine Test

Type of Impact	Impact	Benefit or Cost?	Method
Generation	Avoided Energy Cost	Benefit	AESC 2021
	Avoided Capacity Cost	Benefit	AESC 2021
	Avoided Environmental Compliance	Benefit	AESC 2021
	Avoided RPS Compliance Costs	Benefit	AESC 2021
	Market Price Effects ("DRIPE")	Benefit	AESC 2021
Transmission	Avoided PTF Costs	Benefit	Efficiency Maine assumptions
	Avoided Non-PTF Costs	Benefit	Efficiency Maine assumptions – only applied to BTM
Distribution	Avoided Distribution Costs	Benefit	Efficiency Maine assumptions – only applied to BTM
General	Renewable Energy Credit Prices	Benefit	Sustainable Energy Advantage (SEA) "CREST" Model
	DG Costs	Cost	Based on program design and total cost from SEA "CREST" Model
	Program Administration Costs	Cost	Input from utilities ($600,000 for first 5 years, $300,000 for remaining generation period)
Societal	Avoided CO_2	Benefit	AESC 2021
	Avoided NOx	Benefit	AESC 2021

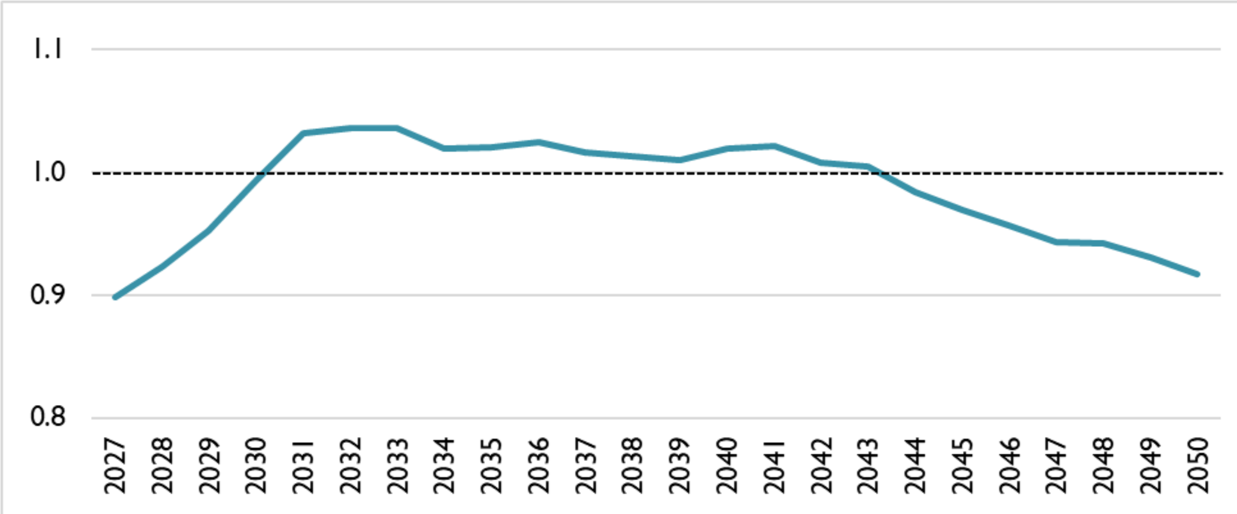
Figure A4 shows the average annual value per unit of energy production (₵/kWh) of each utility system for the avoided costs of energy. Avoided energy costs are the largest benefit, followed by RECs, avoided energy DRIPE, avoided environmental compliance costs, and, lastly, avoided cross-DRIPE costs. These benefit categories are defined above.

Figure A4. Lifetime avoided costs of energy-based benefits (PV¢/kWh)



Except for REC revenue, discussed below, the values in the chart above are from AESC 2021 with one minor adjustment. We modified one subset of the AESC values slightly to reflect near-term high gas prices. The avoided energy generation costs are predominantly based on gas prices, so we made the simplifying assumption that avoided costs would scale linearly with gas costs. We updated the avoided costs using EIA's AEO 2022 gas price forecast. We calculated the percent difference in prices compared to AEO 2020 (a primary source for AESC 2021) to determine an appropriate multiplication factor with which to adjust gas prices. As seen in Figure A5, only minor adjustments were needed for our study period.

Figure A5. Multiplication factors to adjust avoided energy generation costs



For avoided costs that are broken into the four time periods, we take a weighted average based on the percentage of generation during each period. These costs per unit of energy are multiplied by the annual energy generation of each resource. Table A8**Error! Reference source not found.** shows the energy generation in the four time periods for a standalone PV system and a PV system paired with storage. The table shows that the storage system increases the percentage of energy generated during the summer peak period (when electricity prices are at their highest) by 3-5 percent, based on our modeling assumptions. This minor shift of energy production across periods increases avoided energy costs for the PV plus storage scenario by less than 1 percent, but has a dramatic effect on avoided capacity values, since these values occur during a minority of hours in the year but entail very high system costs.

Table A8. PV energy generation profiles with and without storage

Resource	Without Storage				With Storage			
	Summer Peak Energy	Summer Off-Peak Energy	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Winter Peak Energy	Winter Off-Peak Energy
Ground Mounted 5 MW AC	*26%*	*13%*	*42%*	*26%*	*29%*	*9%*	*42%*	*20%*
Rooftop 1 MW AC	*28%*	*14%*	*38%*	*28%*	*33%*	*10%*	*39%*	*19%*
Brownfield 5 MW AC	*26%*	*13%*	*42%*	*26%*	*29%*	*9%*	*42%*	*20%*

RECs are the only energy-based avoided cost not from AESC. Class I REC prices are forecast using SEA's proprietary New England Renewable Energy Market Outlook (REMO) and Solar Market Study (SMS) models. Within REMO, Sustainable Energy Advantage can define forecasts for both near-term and long-term project buildout and REC pricing.

Near-term renewable builds (through 2030) are defined as projects under development that are in the advanced stages of permitting and have either identified long-term power purchasers or an alternative path to securing financing. These projects are subject to customized, probabilistic adjustments to account for deployment timing and likelihood of achieving commercial operation. The near-term REC price forecasts are a function of existing Renewable Portfolio Standard (RPS)-certified renewable energy supplies, near-term renewable builds, regional RPS demand, alternative compliance payment (ACP) levels in each market, and other dynamic factors. Such factors include banking, borrowing, imports, and discretional curtailment of renewable energy.

The long-term REC price forecasts (i.e., after 2030) are based on a supply curve analysis that considers technical potential, resource cost, and market value of production over the study period. These factors are used to identify the marginal, REC price-setting resource for each year in which new renewable energy builds are called upon. The long-term REC price forecast is estimated to be the marginal cost of entry for each year, meaning the premium requirement for the most expensive renewable generation unit deployed for a given year.[78]

We derived peak load-based avoided costs from costs during the highest demand period of the year—historically occurring in the summer. ISO-NE produces the Capacity, Energy, Loads, and Transmission (CELT) forecast annually, which approximates the overlap of BTM solar generation with the summer peak, displayed in Table A9. We assumed these factors can be applied to FTM solar generation indiscriminately, and that the factor in 2030 (the final year of the CELT report) can be applied to the remainder of the study period. These derating factors include uncertainty of future solar development, assumed degradation in solar panels over time, and solar-driven shifts in grid peaks.[79] We multiply each capacity-based avoided cost by the factors in the table below to account for this effect.

[78] AESC 2021. p.65.

[79] ISO-New England. 2022. *2022 CELT Report 2022-2031 Forecast Report of Capacity, Energy, Loads, and Transmission,* Table 3.2. available at: https://www.iso-ne.com/static-assets/documents/2022/04/2022_celt_report.xlsx

Table A9. 2022 CELT solar peak coincidence factors by year

Year	Solar Peak Coincidence Factor
2027	21.2%
2028	20.3%
2029	19.4%
2030	18.6%
2031	*18.6%*
2032	*18.6%*
2033	*18.6%*
2034	*18.6%*
2035	*18.6%*
2036	*18.6%*
2037	*18.6%*
2038	*18.6%*
2039	*18.6%*
2040	*18.6%*
2041	*18.6%*
2042	*18.6%*
2043	*18.6%*
2044	*18.6%*
2045	*18.6%*
2046	*18.6%*
2047	*18.6%*
2048	*18.6%*
2049	*18.6%*
2050	*18.6%*

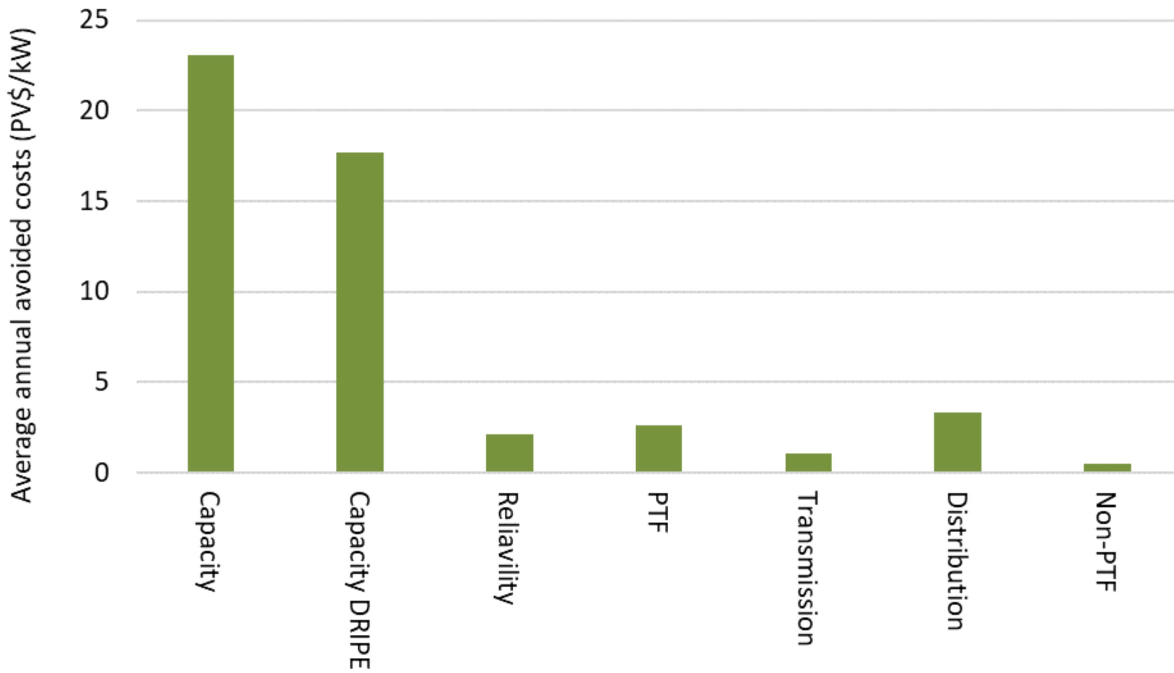
The hour when the generation capacity system is most constrained (peak load) is often not the same as the hour when the transmission and distribution systems are most constrained. To account for this discrepancy, we apply the following “derate factors” to the avoided T&D costs to represent that the T&D peaks are not fully coincident with the capacity system peak. The factors shown in Table A10 reduce the AESC T&D avoided costs *additionally* to the values shown in the table above.

Table A10. T&D coincident peak derating

System	Coincident peak derating
Transmission	20%
Distribution	10%

Figure A6 displays the peak load-based avoided costs after they have been multiplied by the factors in Table A9 and Table A10, where appropriate. Avoided capacity costs are the largest benefit, followed by avoided capacity DRIPE costs, avoided distribution costs, avoided PTF costs, improved reliability, avoided transmission costs, and, lastly, avoided non-PTF costs. For detailed definitions for each of these benefits, please see above.[80] As explained earlier in the report, in all program iterations, we assumed capacity is not bid into the FCM.

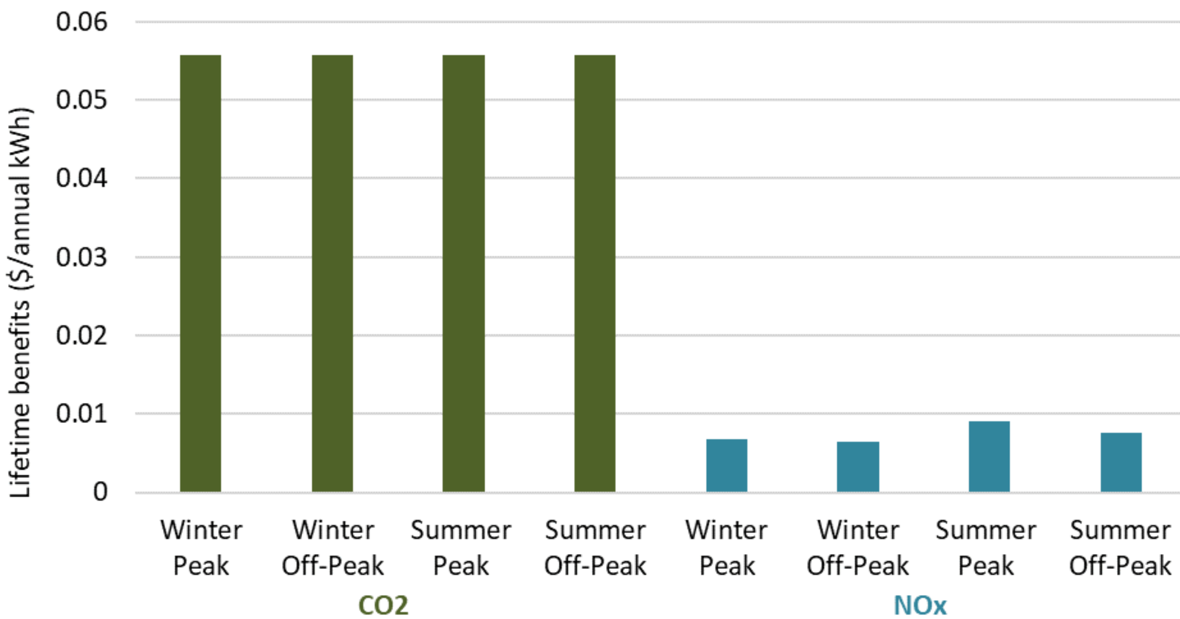
Figure A6. Lifetime avoided costs of peak load-based benefits (PV$/kW)



As described previously, the Maine Test includes the societal benefits of GHGs, including CO_2 and NO_x. AESC publishes benefits per energy produced for these two GHGs. Figure A7 displays the lifetime benefits by costing period used in our analysis.

[80] AESC 2021.

Figure A7. Lifetime benefits from avoided CO_2 and NOx



While the total societal benefits are calculated by the model, the full value is not included within the BCA due to the relationship between the value of RECs and the societal benefits of renewable generation. In our analysis, we subtracted out the value of RECs from the societal benefits to avoid double counting.

RECs represent the above-market value of renewable generation. They theoretically represent several societal benefits of renewable resources, including GHG benefits, other environmental benefits, job benefits, and more. In general, these societal benefits are the reasons that legislatures establish renewable portfolio standards. Consequently, there is some overlap between RECs and broader societal benefits captured by a social cost of carbon value, which represents the marginal cost of a ton of carbon dioxide on society (or the marginal benefit to society of avoiding the release of a ton of carbon dioxide).

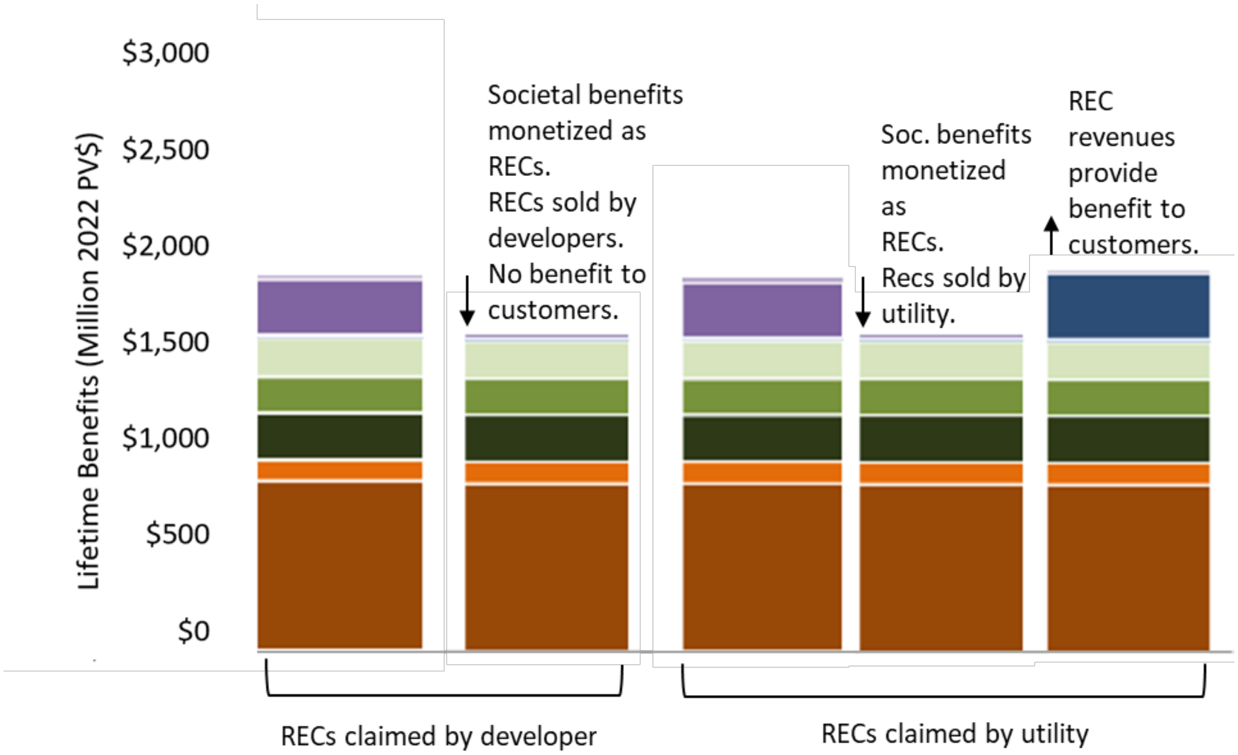
The monetary value of RECs, however, is not based on the societal benefits that renewable resources offer. RECs are created as a market mechanism to support the Maine RPS. The value of RECs is based upon the supply and demand for renewable resources, where the demand is created by the Maine RPS target plus demand for RECs in neighboring New England states. The societal benefits that are partly represented in RECs are valued in an entirely different way. For example, the environmental benefits are estimated using the societal damage cost of the pollutant of concern. Similarly, job benefits are typically estimated using a model of how different resource investments will flow through the local economy, which is not incorporated into our BCA framework.

In sum, RECs represent a portion of the societal benefits of renewable resources but not all of those benefits. For this reason, it is important to subtract out the value of REC revenues from the total societal benefits to identify the *net* societal benefits that would occur from the renewable programs after accounting for the societal benefits represented by the RECs.

Figure A8 shows how we treat this interaction in our model. In the Fixed Future Payment program, RECs are maintained by the developer, who we assumed will sell them to a buyer who will claim the environmental benefits of the program. This buyer may not even be located in Maine. For that reason, we reduced the total societal benefits by the value of the RECs as a conservative assumption to ensure no double-counting in our analysis. For the remaining successor programs we modeled, the utility claims the RECs generated by the program. We assumed the utility will sell the RECs, which will turn the environmental benefits into a monetary influx for ratepayers. To eliminate the risk of double counting benefits for these programs, we similarly subtract the REC revenue from the societal benefits.

In this analysis, the value of REC revenues is, coincidentally, very close to the monetary value of GHG emissions. When the value of RECs is subtracted from the monetary value of GHG emissions, the net societal benefit is very small, as indicated in the small lavender block at the top of each bar in Figure A8.

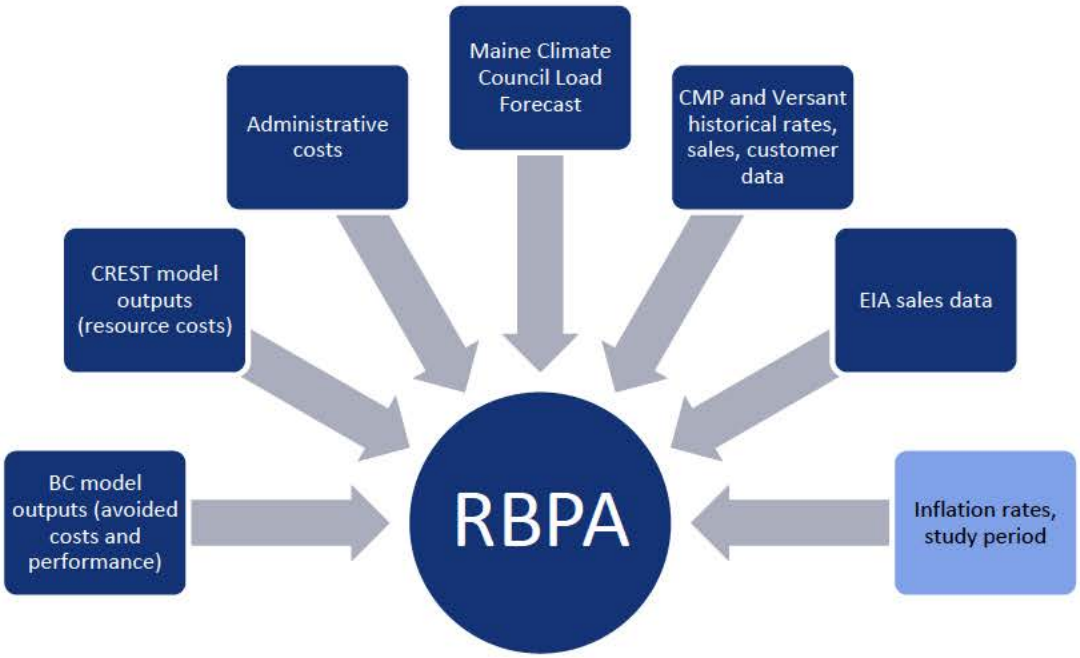
Figure A8. Interaction between societal benefits and RECs



A.4 Rate, Bill, and Participant Analysis Modeling Assumptions

The inputs that informed the Rate, Bill, and Participation Analysis (RBPA) modeling are shown in Figure A9**Error! Reference source not found.** below. The inputs include BCA results, CREST inputs from SEA, administrative costs, the load forecast developed for the Maine Climate Council, and utility-specific rate and cost data provided by CMP and Versant Power, EIA sales data, and the general modeling assumptions implemented throughout this analysis.

Figure A9: RBPA program inputs



A key input to the RBPA was the electric rate forecast for our study period. We developed the electric rate forecast with input from the Stakeholder Group, including recommendations for the supply and delivery portions of the rates. The basis of our analysis was the existing utility-specific rates. Representatives for CMP and Versant then provided input on escalation rates for the transmission and distribution components, consistent with recent proceedings before the Maine PUC. The escalation assumptions for stranded assets, conservation, and standard offer service were proposed by the project team and presented to the DGSG. The following table presents the escalation rates used to develop the electric rate forecast for each utility.

Table A11: Real escalation rates used to develop the electric rate forecast for each utility

Rate Component	Escalation Rate	
	CMP	**Versant**
Transmission and Distribution	2023: 6.1% 2024: 1.9% 2025: 1.4% 2026: 1.3% 2027 and on: 1.2%	2023: 2.3% (T) and 29.45% (D) 2024: 1.9% 2025: 1.4% 2026: 1.3% 2027 and on: 1.2%
Stranded Assets	2023: $0.02 and escalates at 2% per year	
Conservation, etc.	Remains same as 2022 value	
Standard Offer Service	Escalated based on AESC energy market price forecasts	

The forecasts shown below are for system-average electric rates. The rate forecasts used for this analysis are presented in Rate forecasts were developed using long-term averages and are not intended to capture effects of specific events, either in the in the short-, medium-, or long-term. The forecasts are intended for BCA and rate impact assessment purposes and do not represent any entity's expectations about actual future outcomes.

Figure A10. and Figure A11 below.

Rate forecasts were developed using long-term averages and are not intended to capture effects of specific events, either in the in the short-, medium-, or long-term. The forecasts are intended for BCA and rate impact assessment purposes and do not represent any entity's expectations about actual future outcomes.

Figure A10. Rate Forecasts for CMP used in the RBPA

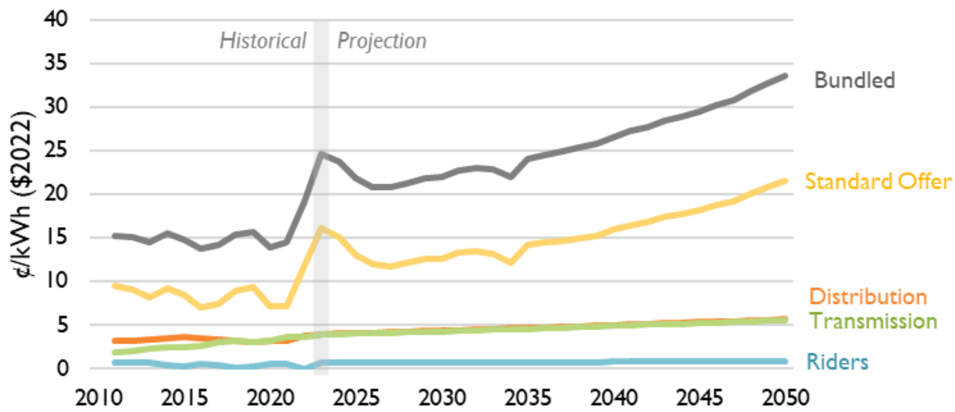
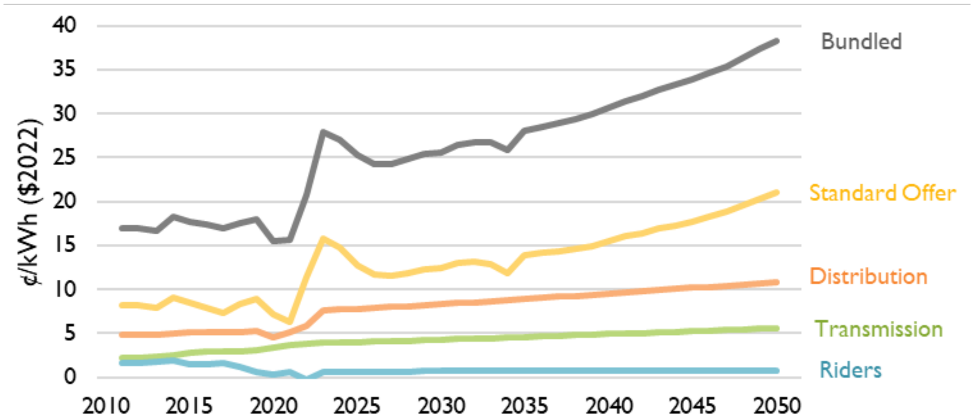
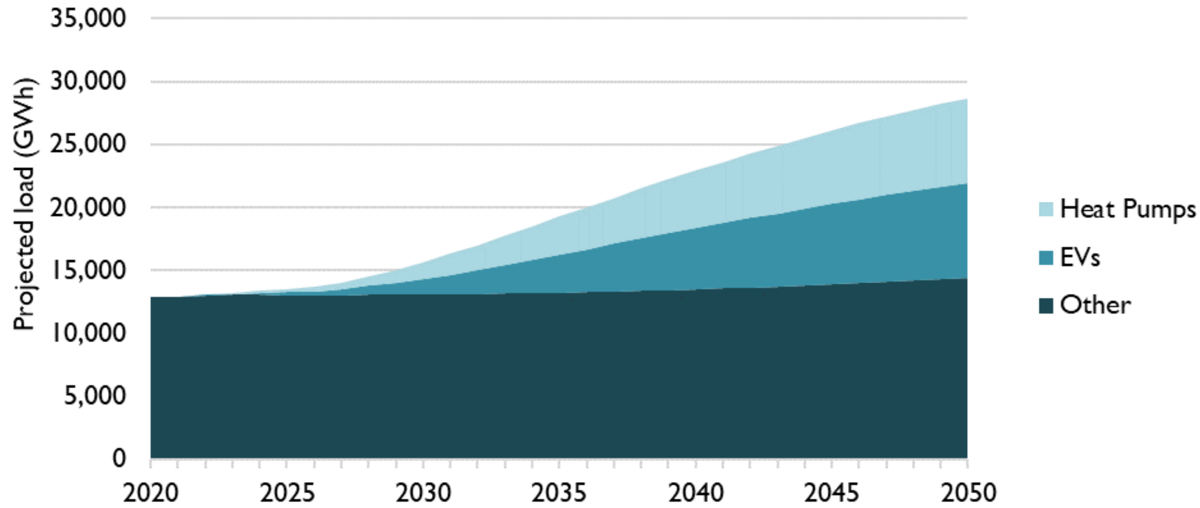


Figure A11. Rate Forecasts for Versant Used in the RBPA



The rates shown above were used to represent the base-case scenario with no DG program at all. We used these rates and the load forecast developed by Synapse for the Maine Climate Council to determine the utilities' expected revenue requirement for each year. This load forecast is presented in Figure A12 below. The forecast includes increases to load from electrification technologies (i.e., heat pumps and electric vehicles (EVs)). The forecast indicates load in Maine will double by 2050 due to the addition of these technologies as a core strategy for curbing climate change.

Figure A12. Maine load forecast



Benefits from the BCA are another key input for the RBPA. The table below shows the benefits that impact rates by program option. These vary due to whether there are participants (offtakers) in the program design, in particular for the avoided energy value.

Table A12: Benefits that have an impact on rates by program option

	Program 1	**Program 2**	**Program 3**	**Program 4**	**Program 5**
Benefits	Original Tariff Program	Fixed Future Payments	Moderate Hedge	Wholesale PPA	Hybrid Program
Transmission	Yes	Yes	Yes	Yes	Yes
Distribution	Yes	Yes	Yes	Yes	Yes
Price Suppression	Yes	Yes	Yes	Yes	Yes
Reliability	Yes	Yes	Yes	Yes	Yes
RECs	No	No	Yes	Yes	Yes
Electric Energy	No	No	No	Yes	Yes*

** Only the energy benefits for resource blocks associated with Program Option 4 are included.*

We determined each program's impact on rates using the following methodology:

1. Calculate the pre-program revenue requirement for each rate component (i.e., generation, transmission, distribution, and other) by multiplying the forecasted rate by the forecasted load.

2. Subtract the program-induced avoided costs from the rate-specific revenue requirement to calculate a post-program revenue requirement. The avoided costs that impact each rate component are displayed in the table A13.

3. Calculate the post-program rates by dividing the post-program revenue requirement by the forecasted load (adjusting for any program-induced BTM load reductions).

4. Include a program-specific charge which aggregates all program costs and divides it by the forecasted load (once again, adjusting for any program-induced BTM load reductions).

Table A13. Avoided costs that impact rates

Impacted rate	Avoided Cost
Generation	• Price suppression effects (energy and capacity DRIPE) • Reliability • REC revenue • Avoided energy (Wholesale PPA program only)
Transmission	• Avoided PTF • Avoided non-PTF transmission (BTM only)
Distribution	• Avoided distribution (BTM only)
Other	• None

For inputs that represented the state of Maine as a whole (i.e., the load forecast and program costs and benefits) rather than utility-specific inputs, we allocated the totals between utilities using sales data from EIA's 861 form from 2021.[81] The allocations between the utilities are as follows:

- CMP: 79 percent
- Versant: 17 percent
- Other (not included): 4 percent

We calculated bill impacts for nonparticipants using these electric rates multiplied by the average customer electric consumption shown in Table A14**Error! Reference source not found.**.[82]

Table A14. Average Annual Electric Consumption by Customer Sector for Each Utility (kWh/year)

Customer Sector	CMP	Versant
Residential	6,831	5,987
Residential LMI*	5,943	5,208
Commercial	70,676	32,868

** Assumes LMI customers use 13 percent less electricity than other residential customers.*

The rates and electric consumption above allowed us to determine the bill impact for non-participants. For program participants, we needed to establish the expected bill credit that they would see because of

[81] U.S. Energy Information Administration. 2021. *Form EIA-861.* "Sales to ultimate customers." Available at: https://www.eia.gov/electricity/d ata/eia861/

[82] is based on Synapse's analysis of CMP's 2020 Annual Report and Versant Power's Compliance Filing in MPUC 2022-00154.

the avoided utility costs. We assumed that bill credits for program participants are applied to 90 percent of total consumption, at a compensation rate equal to 10 percent of the retail generation rate (1.50 cents per kilowatt-hour).[83] For example, if a program participant consumes 1,000 kWh, their bill credit would be 900 kWh times 1.50 cents/kWh, equal to $13.50. This results in an overall bill reduction for program participants, as the bill credit outweighs the rate increase due to the DG program for the participating customer.

To determine the number of participants for each program and resource block, we divided each resource block's total annual energy output by the average customer's energy consumption (multiplied by 90 percent to account for the 90 percent coverage previously stated.) We used the offtaker structure as defined in Table 2 in the main body of this report and the average energy consumption shown in Table A14 above to determine program participants by customer type (residential, commercial).

[83] 90 percent of expected consumption is a widely utilized assumption to ensure bill credits are not over-allocated to participants and thus unused or wasted.