STATE OF RHODE ISLAND

PUBLIC UTILITIES COMMISSION

IN RE: THE RHODE ISLAND DISTRIBUTED	:	
GENERATION BOARD'S RECOMMENDATIONS	:	
FOR THE 2024-2026 RENEWABLE ENERGY	:	DOCKET 23-44-REG
GROWTH PROGRAM YEAR	:	

Recommendations for the 2024-2026 Renewable Energy Growth Program Years

DISTRIBUTED-GENERATION BOARD
& OFFICE OF ENERGY RESOURCES

DECEMBER 20, 2023

TABLE OF CONTENTS

DISTRIBUTED GENERATION BOARD

RENEWABLE ENERGY GROWTH 2024-2026 PROGRAM YEAR RECOMMENDATIONS

Background

In accordance with R.I. Gen. Laws § 39-26.6-4(a)(1), the Distributed-Generation Board ("DG Board") hereby submits its recommendations for the 2024 through 2026 Renewable Energy Growth Program Years ("REG 2024-2026 PYs") to the Public Utilities Commission ("Commission" or "PUC"). The recommendations set forth herein for the three Program Year (PY) period from 2024 through 2026 (the duration of which was recommended by the DG Board by R.I. Gen. Laws § 39-26.6-12(b)) regarding classes, tariff term lengths, ceiling prices (and a related ceiling price adjustment mechanism over the 2024-2026 PY period), incentive-rate adders for certain eligible project types, and megawatt allocation plan were approved by the DG Board and endorsed by the Office of Energy Resources ("OER"). In accordance with R.I. Gen. Laws § 39-26.6-4(b), OER, in consultation with the DG Board, engaged Sustainable Energy Advantage, LLC ("SEA") to develop the above-described recommended ceiling prices, related ceiling price adjustment mechanism, and incentive-rate adders for review and approval by the DG Board and to provide other technical assistance regarding the Renewable Energy Growth ("REG") Program.

Goals and Objectives

The REG law was amended by the General Assembly during the 2023 legislative session[1]. The purposes of the REG Program are "to enable the state to meet its climate and resilience goals, including those established in the act on climate. This includes the goals to facilitate and promote installation of grid-connected generation of renewable energy; support and encourage development of distributed renewable energy generation systems while protecting important core forest areas essential to climate resilience and complying with Rhode Island's climate change mandates; reduce environmental impacts; reduce carbon emissions that contribute to climate

[1] Available at: http://webserver.rilin.state.ri.us/PublicLaws/law23/law23300.htm

change by encouraging the siting of renewable energy projects in the load zone of the electric distribution company and in preferred areas that have already been disturbed by industry or other uses; diversify the energy-generation sources within the load zone of the electric distribution company; stimulate economic development; and improve distribution-system resilience and reliability with the load zone of the electric distribution company." See R.I. Gen. Laws § 39-26.6-1.

Consistent with such purposes of the amended REG law, the anticipated outcomes for the REG 2024-2026 PYs are the following:

1. A diversified renewable energy program with a portion of the megawatt ("MW") capacity allocated to support each sector.
2. Economic development with the state's renewable energy market.
3. Maintaining consistent and predictable REG Program and capacity targets from year-to-year for both residential and commercial customer-focused and stand- alone generation renewable energy companies, allowing such companies to operate, maintain staffs and develop complex projects that may have potential multi-year lead times before submitting a proposal to Rhode Island Energy.
4. Increasing the supply of in-state renewable energy resources that are able (and/or eligible) to assist the State in reaching its Act on Climate and 100% Renewable Energy Standard by 2033 targets.
5. Improved alignment between Solar and Non-Solar energy projects and development on "preferred sites" (also per R.I. Gen. Laws. § 39-26.6-3).
6. The ceiling price adjustment mechanism during the three program years to make possible adjustments to lower the ceiling prices due to federal interest rate and other market condition dynamics.

Composition of the DG Board

Please see **Table 1** below for the composition of the DG Board as of the time that the recommendations set forth herein were approved.

Table 1 - DG Board Members

Name	Area of Representation
Chris Kearns	OER Commissionner (ex officio, non-voting)
Vacant	Rhode Island Energy (ex officio, non-voting)[2]
Karen Stewart	RI Commerce Corporation (ex officio, non-voting)
John McCann	Energy and regulation law
Harry Oakley	Large commercial/industrial users
Samuel J. Bradner	Small commercial/industrial users
Mark Kravitz	Residential users
Jennifer Hawkins	Low-income users
Vacant	Environmental issues pertaining to energy
Laura C.H. Bartsch (Chair)	Construction of renewable generation

[2] Following the sale of Narragansett Electric Co. to PPL Corporation, Ian Springsteel, the previous representative for Narragansett Electric (d/b/a at that time as National Grid), has left the Board. Though the role is being filled unofficially by Carrie Gill of Narragansett Electric Co. (d/b/a Rhode Island Energy), Dr. Gill's appointment has not been confirmed by the Rhode Island Senate, and thus the Rhode Island Energy seat on the Board is officially vacant.

Renewable Energy Classes and Tariff Term Lengths

Consistent with R.I. Gen. Laws § 39-26.6-3(15), § 39-26.6-4(a)(1), § 39-26.6-7(b), § 39-26.6-7(c), and R.I. Gen. Laws § 39-26.6-4(a)(1) please see **Table 2** below which contains the DG Board's recommendations for renewable energy classes and eligible system sizes for the REG 2024-2026 PY. The recommended classes and tariff terms are no different from those approved by the PUC for the 2023 PY.

Table 2 – Recommended Renewable Energy Classes and Tariff Lengths 2024-2026 PY

Renewable Energy Class	Eligible Size Range	Tariff Length
Small Solar I	<=15 kW_{DC}	15 Years
Small Solar II	>15-25 kW_{DC}	20 Years
Medium Solar	>25-250 kW_{DC}	20 Years
Commercial Solar I	>250-500 kW_{DC}	20 Years
Commercial Solar I – Community Remote Distributed Generation (CRDG)	>250-500 kW_{DC}	20 Years
Commercial Solar II	>500-1,000 kW_{DC}	20 Years
Commercial Solar II (CRDG)	>500-1,000 kW_{DC}	20 Years
Large Solar I	>1-<5 MW_{DC}	20 Years
Large Solar I (CRDG)	>1-<5 MW_{DC}	20 Years
Large Solar II	5 MW-<10 MW_{DC}	20 Years
Large Solar III	10-<15 MW_{DC}	20 Years
Large Solar IV	15-<39 MW_{DC}	20 Years
Wind	$\leq$ 5 MW_{AC}	20 Years
Wind (CRDG)	$\leq$ 5 MW_{AC}	20 Years
Anaerobic Digestion	$\leq$ 5 MW_{AC}	20 Years
Small Scale Hydropower	$\leq$ 5 MW_{AC}	20 Years

Ceiling Prices

Consistent with R.I. Gen. Laws § 39-26.6-5(d) and § 39-26.2-5, please see **Table 3** below, which contains the DG Board's recommendations for ceiling prices for the REG 2023 PY.

The differences between the approved ceiling prices for the 2023 PY and both potential sets of recommended ceiling prices for the 2024-2026 PY are illustrated in **Table 4** below. For additional information, please see the pre-filed testimony and schedules of Jim Kennerly and Tobin Armstrong.

Table 3 - Recommended Ceiling Prices (2024-2026 PYs, ¢/kWh)

Renewable Energy Class	**Eligible System Sizes**	**Ceiling Price (¢/kWh)[3]**		
		2024 PY	**2025 PY**	**2026 PY**
Small Solar I	<=15 kW_{DC}	36.45	34.65	33.95
Small Solar II	>15-25 kW_{DC}	33.15	31.95	31.35
Medium Solar	>25-250 kW_{DC}	34.35	33.45	33.25
Commercial Solar I	>250-500 kW_{DC}	29.35	28.55	28.35
Commercial Solar I (CRDG)	>250-500 kW_{DC}	32.25	31.45	31.25
Commercial Solar II	>500-1,000 kW_{DC}	24.45	23.75	23.55
Commercial Solar II (CRDG)	>500-1,000 kW_{DC}	27.35	26.65	26.35
Large Solar I	>1-<5 MW_{DC}	18.65	18.05	17.85
Large Solar I (CRDG)	>1-<5 MW_{DC}	21.35	20.75	20.52
Large Solar II	5-<10 MW_{DC}	18.05	17.45	17.25
Large Solar III	10-<15 MW_{DC}	18.45	17.85	17.75
Large Solar IV	15-<39 MW_{DC}	18.15	17.55	17.45
Wind	≤ 5 MW_{AC}	20.25	19.85	19.85
Wind (CRDG)	≤ 5 MW_{AC}	22.05	21.65	21.75
Anaerobic Digestion	≤ 5 MW_{AC}	19.05	18.95	19.05
Small Scale Hydroelectric	≤ 5 MW_{AC}	34.15	33.35	33.45

[3] Please note that prices shown for the 2025 and 2026 Program Year are subject to the Ceiling Price Adjustment Mechanism described both below and in the Direct Testimony of Jim Kennerly and Tobin Armstrong.

Table 4 - Comparison of Approved 2023 Program Year (PY) and Recommended 2024-2026 PY Prices (¢/kWh)

Renewable Energy Class	Eligible System Sizes	PUC Approved 2023 PY	Recommended 2024-2026 PY Prices[4]			% Change From 2023 PY[5]		
			2024 PY	2025 PY	2026 PY	2024 PY	2025 PY	2026 PY
Small Solar I	<=15 kW_{DC}	27.75	36.45	34.65	33.95	31%	25%	22%
Small Solar II	>15-25 kW_{DC}	26.15	33.15	31.95	31.35	27%	22%	20%
Medium Solar	>25-250 kW_{DC}	25.65	34.35	33.45	33.25	34%	30%	30%
Commercial Solar I	>250-500 kW_{DC}	22.05	29.35	28.55	28.35	33%	29%	29%
Commercial Solar I (CRDG)	>250-500 kW_{DC}	25.15	32.25	31.45	31.25	28%	25%	24%
Commercial Solar II	>500-1,000 kW_{DC}	10.05	24.45	23.75	23.55	28%	25%	24%
Commercial Solar II (CRDG)	>500-1,000 kW_{DC}	21.91	27.35	26.65	26.35	25%	22%	20%
Large Solar I	>1-<5 MW_{DC}	14.35	18.65	18.05	17.85	30%	26%	24%
Large Solar I (CRDG)	>1-<5 MW_{DC}	16.50	21.35	20.75	20.52	30%	26%	24%
Large Solar II	5-<10 MW_{DC}	N/A (New Class)	18.05	17.45	17.25	N/A (New Class)		
Large Solar III	10-<15 MW_{DC}	N/A (New Class)	18.45	17.85	17.75	N/A (New Class)		
Large Solar IV	15-<39 MW_{DC}	N/A (New Class)	18.15	17.55	17.45	N/A (New Class)		
Wind	$\leq$ 5 MW_{AC}	19.15	20.25	19.85	19.85	6%	4%	4%
Wind (CRDG)	$\leq$ 5 MW_{AC}	21.15	22.05	21.65	21.75	4%	2%	3%
Anaerobic Digestion	$\leq$ 5 MW_{AC}	31.95	19.05	18.95	19.05	1%	-2%	1%
Small Scale Hydroelectric	$\leq$ 5 MW_{AC}	19.05	34.15	33.35	33.45	7%	4%	5%

[4] Please note that prices shown for the 2025 and 2026 Program Year are subject to the Ceiling Price Adjustment Mechanism described both below and in the Direct Testimony of Jim Kennerly and Tobin Armstrong.
[5] Percentage change values represent values associated with initial proposed prices, and not with any proposed prices associated with changes resulting from the Ceiling Price Adjustment Mechanism.

Ceiling Price Adjustment Mechanism

To balance efforts to ensure that ceiling prices accurately reflect typical costs and development conditions while limiting the cost of the program to ratepayers, and consistent the definition of "ceiling price" in R.I. Gen. Laws § 39-26.6-3, the DG Board recommends that the PUC adopt a Ceiling Price Adjustment Mechanism. The purpose of this Mechanism is to balance a multi-year plan duration with ensuring that the most significant drivers in potential pricing volatility (namely, installed capital costs, interest rates on term debt, and potential future changes in state/federal policy requirements) can be addressed in a methodical and meaningful manner based on observable, objective, and understandable thresholds. If these thresholds are found to be met, the DG Board will recommend to the PUC that the prices be adjusted. Further details of this mechanism are described in the Direct Testimony of Jim Kennerly and Tobin Armstrong in support of this Report and Recommendations.

Incentive-Payment Adders for Renewable Energy Projects that "Require Remediation"

Consistent with R.I. Gen. Laws § 39-26.6-21, if an eligible projects is found to provide "an identifiable system benefit, reliability benefit, or cost savings to the distribution system…conservation benefit, or climate resilience benefit in that geographical area", either of "the electric distribution company, the board, or [OER] shall propose to include an incentive-payment adder to the bid price of any winning bidder that proposes a distributed-generation project in the preferred sites ***that require remediation*** [***emphasis added***]". Consultants to OER and the DG Board have identified a subset of Solar project types typically sited on "preferred sites" (as defined in R.I. Gen. Laws § 39-26.6-3) that require remediation that also confer system and reliability benefits, cost savings to the distribution system, and balance preserving the state's solar photovoltaic (PV) potential with compliance with new statutory requirements banning the development of projects on core forest parcels, recommend adoption of the incentive-payment adders for eligible landfill- and brownfield-sited projects as shown in Table 5 below.

Table 5 – Recommended Landfill and Brownfield/Superfund Adders (For 2024-2026 PYs)

Renewable Energy Class/ Project Size	**Eligible Project Size (MW_{DC})**	**Landfill Adder (¢/kWh)**		**Brownfield/ Superfund Adder (¢/kWh)**
		Final Recommended		***Final Recommended***
		(For Municipalities with funds to cap)	*(For Municipalities with no funds to cap)*	
All Solar Projects	<1 MW	4.3	8.0	3.6
Large Solar I	1-<5 MW	4.3	8.0	3.6
Large Solar II	5-<10 MW	3.6	7.8	2.9
Large Solar III	10-<15 MW	3.4	7.5	2.8
Large Solar IV	15-<39 MW	3.3	7.4	2.7

Megawatt Allocation Plan

Consistent with R.I. Gen. Laws § 39-26.6-12(c), please see Table 6 below, which contains the DG Board's recommended allocation plan for the REG 2024-2026 PY.

Table 6 - Recommended Megawatt Allocation Plan 2024-2026 PY

Renewable Energy Class	**Eligible System Sizes**	**MW_{DC} (2024 PY)**	**MW_{DC} (2025 PY)**	**MW_{DC} (2026 PY)**
Small Solar	<=25 kW_{DC}	9	10	12
Medium Solar	>25-250 kW_{DC}	5	7	9
Commercial Solar I	>250-500 kW_{DC}	7.5	9.5	11.5
Commercial Solar I (CRDG)	>250-500 kW_{DC}	0.5	0.5	0.5
Commercial Solar II	>500-1,000 kW_{DC}	10.5	11.5	12.5
Commercial Solar II (CRDG)	>500-1,000 kW_{DC}	1	1	1
Large Solar I	>1-<5 MW_{DC}	15	20	25
Large Solar I (CRDG)	>1-<5 MW_{DC}	5	5	5
Large Solar II	5 MW-<10 MW_{DC}	35	35	35
Large Solar III	10-<15 MW_{DC}	15	30	30
Large Solar IV	15-<39 MW_{DC}	0	0	40
Wind	$\leq$ 5 MW_{AC}	3	3	3
Wind CRDG	$\leq$ 5 MW_{AC}			
Anaerobic Digestion	$\leq$ 5 MW_{AC}	1	1	1
Small Scale Hydropower	$\leq$ 5 MW_{AC}			

Conclusion

After an extensive and transparent development process, the DG Board voted at its November 14, 2023, meeting to recommend the allocation plan and the proposed ceiling prices for the 2024-2026 PY.

The DG Board and OER respectfully request the PUC consider and approve the recommendations for the REG 2024-2026 PY.

DIRECT TESTIMONY OF JIM KENNERLY AND TOBIN ARMSTRONG, SUSTAINABLE ENERGY ADVANTAGE, LLC

I. INTRODUCTION

A. Witness Introduction

Q: Mr. Kennerly, can you please state your name and title?

A: My name is Jim Kennerly. I am a Director at Sustainable Energy Advantage, LLC ("SEA").

Q: Can you please provide your background related to renewable energy technologies?

A: I have thirteen years of experience with climate and energy policy and its impact on markets for clean energy technologies, and eleven years of professional experience related to renewable energy market and policy development. At SEA, I serve as a subject matter expert regarding distributed energy resource markets and policies. In addition to serving the Rhode Island Office of Energy Resources ("OER") and Distributed Generation Board ("DG Board"), our distributed energy team has undertaken custom consulting work for the Connecticut Green Bank (CGB), the Connecticut Public Utility Regulatory Authority (PURA), the Hawaii Public Utilities Commission (PUC), the Illinois Power Agency (IPA), the Maine Governor's Energy Office, the Maine PUC, the Massachusetts Attorney General's Office (AGO), the Massachusetts Clean Energy Center (MassCEC), the Massachusetts Department of Energy Resources (DOER), the New Jersey Board of Public Utilities (BPU), the New York State Energy Research and Development Authority (NYSERDA), the New Hampshire Office of Consumer Advocate (OCA), the Virginia State Corporation Commission (SCC), and not-for-profit entities such as the Clean Energy States Alliance (CESA), the Coalition for Community Solar Access (CCSA), the Natural Resources Council of Maine (NRCM), the Nature Conservancy, Vote Solar, as well as a wide variety of buy-side and sell-side solar and distributed energy market participants.

Prior to working at SEA, I was a Senior Policy Analyst at the North Carolina Clean Energy Technology Center (NCCETC) at North Carolina State University, where I served as the senior analyst for the energy policy team, which manages the Database of State Incentives for Renewables and Efficiency (DSIRE), and where I led the NCCETC's participation in a national technical assistance and research grant for the United States Department of Energy's SunShot Initiative. Prior to that, I was a Regulatory and Policy Analyst at the North Carolina Sustainable Energy Association, where I managed the organization's regulatory, legislative, and utility rates analysis.

I have a Master of Public Affairs degree from the Lyndon B. Johnson School of Public

Affairs at the University of Texas at Austin and a Bachelor of Arts in Politics with Honors from Oberlin College.

Q: Have you previously appeared before this Commission to provide testimony?

A: Yes. Each year since 2018, I have led SEA's support to OER and the Board related to the Renewable Energy Growth (REG) program and sponsored (or co-sponsored) the direct (and as needed, rebuttal) testimony filed by OER and the Board, regarding recommended Renewable Energy Growth (REG) program ceiling prices. I have also sponsored testimony in support of changes to the design of the program as requested, from time to time, by OER and the DG Board.

Q: Please indicate which aspects of the instant testimony you are sponsoring before this Commission.

A: I am sponsoring the testimony and Schedules contained or referred to in Section V (Recommended Duration of Program Plan and Ceiling Price Adjustment Mechanism), Section VIII (2024-2026 Megawatt Allocation Plan), and Section IX (Cost-Effectiveness of 2024-2026 Program Plan).

Q: Mr. Armstrong, could you please state your name, employer, and title?

A: My name is Tobin Armstrong. I am a Principal Analyst at SEA. I also lead the firm's distributed energy market modeling.

Q: What is your background related to renewable energy technologies?

A: I have nine years of experience related to renewable energy policy, and five years of professional experience with Distributed Generation (DG) related policy and quantitative analysis. At SEA, I lead the company's distributed generation market modeling, and have played a leading role in multiple quantitative analyses informing DG policy including benefit-cost analyses, variable revenue analysis, and analyses informing optimal incentive rates for renewable energy utilizing SEA's Cost of Renewable Energy Spreadsheet Tool (CREST) model.

I have a Master of Public Policy degree from the University of Massachusetts, Amherst and a Bachelor of Arts in Sustainable Energy Policy from the University of Massachusetts, Amherst.

Q: Have you previously appeared before this Commission to provide testimony?

A: Yes. During the 2023 ceiling price development process, I provided testimony in Docket 22-39-REG relating to SEA's methods and calculated ceiling prices. In addition, during the 2022 ceiling price development process I provided testimony in Docket 5202 relating to the production degradation inputs assumed in developing ceiling prices for the solar renewable energy classes.

Q: Please indicate which aspects of the instant testimony you are sponsoring before this Commission.

A: I am sponsoring the testimony and Schedules contained or referred to in Section II (Market Fundamentals), Section III (Statutory Changes Relevant to the Renewable Energy Growth Program), Section IV (Ceiling Price and Incentive Payment Adder Development Process), Section VI (Recommended Ceiling Prices), and Section VII (Recommended Incentive-Payment Adders).

B. SEA Background and Role Related to Renewable Energy Growth Program and Ceiling Price Development Process

Q: Could you please describe SEA's background related to renewable energy technologies?

A: SEA is a consulting advisory firm that has been a national leader in renewable energy policy analysis, market analysis and program design for over 20 years. In that time, SEA has supported the decision-making of more than two hundred (200) clients, including more than forty (40) governmental entities, through the analysis of renewable energy policy, strategy, finance, projects, and markets. SEA is known and respected widely as an independent analyst, a reputation earned through the firm's ability to identify and assess all stakeholder perspectives, conduct analysis that is objective and valuable to all affected and provide advice and recommendations that are in touch with market realities and dynamics.

Q: What role has SEA played in the development of the Renewable Energy Growth (REG) program?

A: SEA has served as a technical consultant to OER and, beginning in 201, to the DG Board in their implementation of the Distributed-Generation Standard Contracts Program ("DG Program"), R.I. Gen. Laws § 39-26.2-1 et seq., and the Renewable Energy Growth Program ("REG Program"), R.I. Gen. Laws § 39-26.6-1 et seq. SEA's role is to advise OER and the DG Board to make informed recommendations with respect to technology- and size-specific ceiling prices based on detailed research and analysis.

Q: What was SEA's role in the development of the proposed 2024-2026 REG program plan?

A: SEA was hired by OER and the DG Board to conduct detailed research and analysis of regional distributed renewable energy markets, collect additional insight through public meetings, written comments, and interviews, and then to recommend ceiling prices for each technology-, ownership- and size-specific class established by OER and the DG Board, as well as incentive-payment adders for certain project types. SEA also assisted OER and the DG Board in the development of the Megawatt Allocation Plan, and an evaluation of the cost-effectiveness of the Megawatt Allocation Plan and potential incentive-payment adders.

Q: Did SEA engage with the DPUC and their consultants during the development of the ceiling prices, and related assumptions?

A: Yes. The consulting team collaborated extensively with consultants to the DPUC and directly incorporated a significant degree of their suggested changes to the ceiling price and incentive-payment adder inputs.

Q: Are those recommendations reflected in the Report and Recommendations submitted to the Commission?

A: Yes.

Q: Are there any SEA recommendations that were not included in the Report and Recommendations?

A: No.

II. MARKET FUNDAMENTALS

A. Recent Trends in Northeast Regional Distributed Renewable Energy Market

Q: What are some of the global macroeconomic trends over the past few years, and how have they impacted the distributed energy resource markets?

A: Over the past two to three years, there have been a number or emergent trends that have, on net, increased the revenue requirements of renewable energy projects. During that time, it is broadly understood that the COVID-19 pandemic, and resulting disruptions to labor participation and industrial production, has limited the supply of materials critical to all scales of renewable energy projects and the workers necessary to deploy them. The limitations on the supply of parts and labor lead to price inflation for these goods and services that has not equilibrated to pre-pandemic levels. Distributed renewable energy projects are not immune from these sector-wide cost drivers.

Other global geopolitical developments that have raised costs for distributed renewable energy projects include the significant escalation of the war in Ukraine since February of 2022, as well as the expected sunset of the solar panel import duties grace period in June 2024.

Furthermore, the Federal Reserve has responded to inflation stemming from these disjunctive shifts in supply and demand for various goods (and from fiscal responses to the shocks created by the pandemic) by increasing the federal funds rate sharply relative to recent experience, which has increased the cost of U.S. Treasury securities, which serve as a key valuation yardstick for the "risk-free rate" of borrowing in the United States. This increase in the "risk-free rate" has led to an increase in the cost of capital for distributed renewable energy projects.

All these factors, taken together, have applied upward pressure to distributed renewable energy project costs of materials, labor, and financing. The increases in installed costs representing capital expenditures by solar developers are especially impactful, as capital costs are the largest single driver of the revenue requirement for a given renewable energy project.

Q: What are some of the regional distributed renewable energy market trends over the past few years, and how have they impacted distributed energy resource markets?

A: Concurrently with global and national trends, there are several more regional and Rhode Island-specific developments that also, on net, have increased the costs of deploying renewable energy projects. These include increasing scrutiny of project siting, particularly on sites that have historically been relatively low-cost (such as sites that require tree clearing and sites on current or historical agricultural land). This culminated with the enactment of Chapter 300 in June 2023. As described in more detail below, Chapter 300 prohibits REG projects from being sited in a "core forest" and mandates that certain larger projects must be located on a "preferred site." This fundamentally drives renewable energy development away from sites that are least cost due to land-use policy preferences of the State.

As further discussed in Section V below, contraction in the supply of eligible land for REG project siting has driven up the necessary land lease costs for third-party owned renewable energy projects when compared to previous REG program year ceiling price cycles. This is likely to be especially pronounced in the largest project size category, where the necessity of locating projects on preferred sites means that project sponsors are directly competing with other commercial and industrial uses of the land, raising the opportunity cost of hosting a REG project and therefore increasing the land lease payments required to secure the rights to the project footprint over the tariff term and potentially beyond.

Q: What has been the result of these recent cost increases on the REG program?

A: The results of recent Open Enrollments make clear that the cost increases experienced by projects in the development phase have outstripped the increases in recent REG ceiling prices, due to a mixture of data lag, methodological choices, changes in Rhode Island Energy's Electric Service Bulletin, and sharply rising interest rates.

B. <u>Interconnection Cost Trends</u>

Q: Prior to DG projects reaching the higher levels of saturation on the distribution system that Rhode Island is beginning to experience today, what was the typical cost of interconnection for DG customers?

A: Historically, under unsaturated distribution circuits DG interconnection costs have been moderate relative to other project capital costs. Typically, interconnection costs have been around $150/kW- $250/kW for the various solar Resource Classes, based on data from projects interconnecting in 2021 and 2022.

Q: How have interconnection costs changed as DG penetration increases?

A: As the headroom on a distribution circuit becomes more constrained, the marginal installed MWs on the circuit must, under a pure cost-caused allocation methodology, pay for expensive upgrades to the distribution, transmission, and substation infrastructure of transmission and distribution companies. Once this threshold is reached, DG projects must pay more substantial interconnection fees relative to the historical average for similar sized projects, often because of distribution group or transmission cluster study (commonly referred to as Affected System Operator (ASO) study) cost allocations. This trend is evident in states with high DG saturation on certain circuits, such as Massachusetts, where recent costs per kW for interconnection are now often over $500/kW (a cost to project owners equivalent to $2.5 million for a 5 MW project). These high allocated costs frequently drive attrition of projects in the group studies, further increasing the allocated cost per MW for interconnection, which in turn can drive further attrition. These historically high interconnection costs have led several districts (including Massachusetts[6] and, for certain resources, Maine[7,8]) to implement, or consider, interconnection

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[6] See the Massachusetts Department of Public Utilities' "Order on Provisional System Planning Program" issued in MA DPU Docket 20-75 on November 24, 2021. Available at: https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14232299

[7] See the Maine Public Utilities Commission's "Order Amending Rule and Statement of Factual and Policy Basis" issued in ME PUC Docket 2020-00004 on March 6, 2020. Available at: https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=105644&CaseNumber=2020-00004

[8] See the Maine Public Utilities Commission's "Order Adopting Rule and Statement of Factual and Policy Basis" issued in ME PUC Docket 2023-00103 on November 3, 2023. Available at: https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=121241&CaseNumber=2023-00103

cost sharing approaches in order to appropriately allocate the cost of system modifications that benefit non-interconnecting customers to all ratepayers. However, broad-scale cost sharing between developers and ratepayers for such common upgrades is not currently authorized in Rhode Island, and the results of the currently ongoing group studies are not publicly known.

Q: Even though these values are not publicly known at this time, does SEA believe, based on its market experience, that Rhode Island will reach similar levels of market and market-wide circuit penetration as in high-distributed renewable energy penetration states like Massachusetts and Maine?

A: Based on our experience and discussions with market participants, Rhode Island is likely to experience similar interconnection costs for distributed renewable energy projects as circuits become increasingly saturated. Though the first two rounds of ASO studies in Rhode Island did not yield such results, the third round of ASO study has not yet been released at the time of this testimony writing. However, based upon the experience of other jurisdictions with higher DG penetration, we expect allocated interconnection costs in Rhode Island to follow a similar trajectory to states with high levels of distributed renewable energy penetration soon.

As discussed in further detail later in this testimony, SEA used a mix of Rhode Island specific and regional interconnection cost data points from high-penetration DG states (including Massachusetts and Maine) to arrive at an input value for installed capital costs that more properly reflects what we see as a "new normal" for interconnection costs for projects greater than 1 MW_{DC}.

Q: How do DG interconnection costs affect REG program Ceiling Prices?

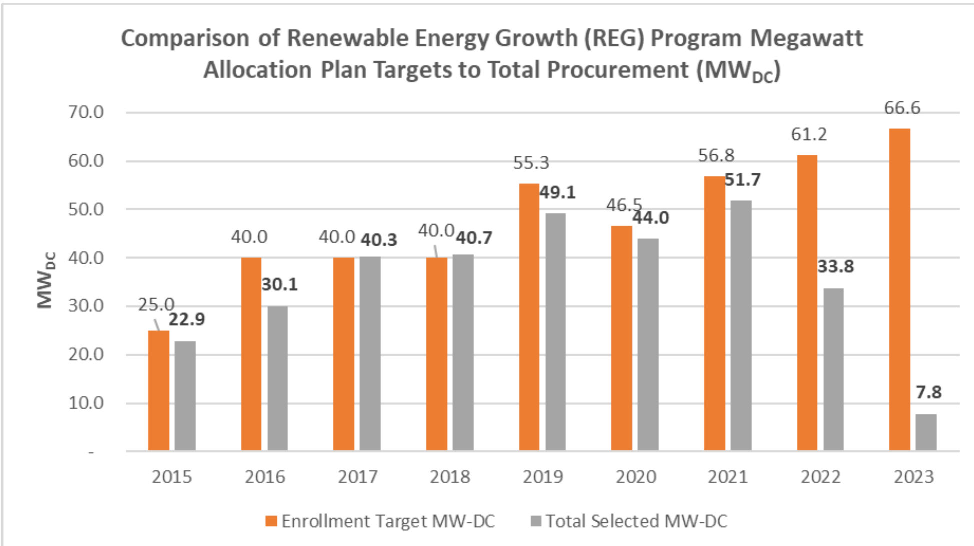
A: Interconnection costs borne by DG developers affect the overall capital costs of DG projects. Given that their value is functionally undiscounted on a net present value basis, upfront capital costs drive much of the levelized revenue requirement for REG projects. Per the R.I. Gen. Laws § 39-26.6-3, the Ceiling Prices "…should be a price that would allow a private owner to invest in a given project at a reasonable rate of return, based on recently reported and forecast information…." Therefore, the ceiling prices for DG resources should incorporate the projected interconnection costs in order to provide a reasonable rate of return based upon projects prices developers will likely face for the qualified projects. While this results in an increase in ceiling prices as compared to past years, fundamentally the ceiling prices are following the trends in the market over which no single stakeholder exercises complete control.

C. <u>Results Of Recent Open Enrollments</u>

Q: Has the REG program been successful in attracting bids and/or reservations for the capacity it offered?

A: The total capacity (both greater than and less than/equal to 25 kW_{DC}) procured under the REG program, relative to the amount of capacity sought, can be seen in SEA Figure 1 below.

SEA Figure 1 – Comparison of REG Program Target Capacity to Actual Selected/Procured Capacity



Q: During what period was the REG program successful in attracting bids and/or reservations for the capacity it offered?

A: From the 2015 to 2021 Program Year, the REG program was largely successful in its objective of attracting enough project developer interest to have almost all the capacity offered under the program reserved or selected. As shown in the chart, during program years 2015-2021, the program had procured 92% of its capacity target on an annual basis, with these values at or exceeding 100% in certain years.

Q: Since the 2021 Program Year, has the REG program been successful in attracting bids and/or reservations for the capacity it offered?

A: No. During the 2022 and 2023 program years, the total share of the capacity target enrolled has sharply declined in each year. Specifically, during the 2022 Program Year, capacity reserved or procured was equivalent to only 55% of the program capacity (33.79 MW_{DC} out of a target of 61.2 MW_{DC}), with more than half of this capacity going to Small Solar projects. As of December, of the current (2023) Program Year, only <u>12%</u> of the program's capacity (7.8 MW_{DC} out of a target of 66.62 MW_{DC}) has been procured. Unlike in the 2022 Program Year, Small Solar capacity only comprised a small fraction of the total capacity.

III. STATUTORY CHANGES RELEVANT TO THE RENEWABLE ENERGY GROWTH PROGRAM

Q: Have any statutory changes have been made to the statutes governing the REG program since the 2023 Program Year Ceiling Prices were approved?

A: Yes. During the 2023 legislative session, the Rhode Island General Assembly passed Chapter 300 of the 2023 Public Laws (hereafter referred to as Chapter 300).

Q: What changes did Chapter 300 make regarding project siting for the REG Program?

A: With regard to siting requirements, Chapter 300:

- Defines "core forest" as unfragmented forest blocks, across one or more parcels, which is at least 250 acres, unbroken by development, and at least 25 yards from a mapped road.
- Prohibits future REG (and certain net metering projects) from being sited on a "core forest" parcel.
- Limits forest clearing on core forest parcels to a maximum of 100,000 square feet of core forest, including for interconnection and/or development of a brownfield.
- Delegates "core forest"-related project eligibility questions to the director for the Rhode Island Department of Environmental Management (DEM) in a contested case; and
- Defines a "preferred site" for renewable energy as a location that has a prior development, such as, but not limited to, landfills, brownfields, parking lots, and all rooftops.

Q: What other changes did Chapter 300 make to the REG Program?

A: With regard to the REG program itself, Chapter 300:

- Expands the maximum procurement level per year in the REG program to "up to" 300 MW per year (from 40 MW), with a carve-out of 30 MW per year for projects less than 1 MW;
- Reconfigures and expands the REG DG sizes for Large Scale projects into four classes:
  - Greater than 1 MW but less than 5 MW;
  - Greater than 5 MW but less than 10 MW;
  - Greater than 10 MW but less than 15 MW;
  - Greater than 15 MW but less than 39 MW (but such projects must be located on preferred sites);
- Allows OER and the DG Board to propose capacity allocations and ceiling prices that may last for up to three years, and to revise ceiling prices based upon changes to federal or state tax credits, incentives, or other programs or trade tariffs that would affect the "calculation of a project's rate of return."

- Requires either of OER, the DG Board, or Rhode Island Energy, upon making certain findings, to propose incentive-payment adders for projects on sites requiring remediation, and propose disincentive subtractors for projects not located on preferred sites;
- Eliminates the carrying forward of unused or terminated capacity from program year to program year;
- Allows re-allocation of capacity between categories if there is an over-subscription in a certain category and OER, the DG Board, and Rhode Island Energy agree, but specifies that no reallocations may be made between the competitive and non-competitive pricing classes until the first open enrollment period in a year; and
- Forbids Rhode Island Energy from claiming remuneration for projects in the REG program.

IV. CEILING PRICE AND INCENTIVE-PAYMENT ADDER DEVELOPMENT PROCESS

A. Process Overview

Q: Please describe the process that SEA utilizes to develop recommended ceiling prices and incentive-payment adders.

A: Each year, SEA acts as a joint facilitator of a lengthy process to request, gather and analyze cost and performance data from current and prospective market participants and other interested parties. Throughout the process, SEA solicits empirical evidence from stakeholders regarding market trends and practices and offers multiple opportunities for interested parties to participate in public meetings and submit written comments, which are encouraged to address both general market observations and to respond directly to specific data requests and draft proposed ceiling price recommendations. SEA also conducts interviews with active market participants each year.

SEA incorporates all the intelligence gained from this market research into its modeling of Ceiling Prices, utilizing the National Renewable Energy Laboratory ("NREL") Cost of Renewable Energy Spreadsheet Tool ("CREST") model to generate recommended ceiling prices through multiple rounds of analysis. The process included four presentations to the DG Board and stakeholders. At the final presentation, the DG Board discussed and approved the recommendations proposed by SEA which are reflected in the Report and Recommendations.

During the process for developing the 2024-2026 program plan, SEA also utilized the above-described data- and stakeholder-driven process to develop proposed incentive-payment adders.

Q: When were the presentations made to the DG Board and stakeholders?

A: SEA presented its first draft of the recommended ceiling prices for all resource categories for projects *under* 5 MW_{DC} at a public meeting held by webinar on August 24, 2023, during which SEA reviewed the proposed inputs for its analysis and the results. SEA presented its first draft of the recommended ceiling prices for all resource categories for projects *over* 5 MW_{DC} as well as potential incentive-payment adders at a public meeting held by webinar on September 22, 2023. SEA presented its second draft inputs and results for all resource categories and incentive-payment adders at a public meeting held by webinar on October 24, 2023. SEA presented additional incentive-payment adder considerations at a public meeting held by webinar on November 6, 2023. The final ceiling price recommendations for all resource categories, recommended incentive-payment adders, and other recommended elements were presented at a DG Board public meeting held by webinar on November 14, 2023, where the prices were approved.

SEA's five presentations are provided as SEA Schedule 1, SEA Schedule 2, SEA Schedule 3, SEA Schedule 4, and SEA Schedule 5 (containing both the prices approved at the October 24 meeting and the technical corrections approved at the November 14 meeting), respectively.

Q: Are those presentations attached to the Report and Recommendations?

A: Yes.

Q: Are these presentations also posted online?

A: Yes, they are all available on OER's website related to the development of the instant (2024-2026 Program Year) plan.[9]

B. <u>Cost of Renewable Energy Spreadsheet Tool ("CREST")</u>

Q: Can you please explain the Cost of Renewable Energy Spreadsheet Tool ("CREST") model?

A: Yes. The CREST model is a discounted cash flow analysis tool published by the National

[9] See Rhode Island Office of Energy Resources. *Renewable Energy Growth Program Development Process for Potential 2024-2026 Program Year Filing*. Available at: https://energy.ri.gov/renewable-energy/wind/renewable-energy-growth-program-reg-program/REG-program-development-process-Potential-2024-2026-PY-filing

Renewable Energy Laboratory (NREL). SEA was the primary architect of the CREST model, which was developed under contract to NREL. The CREST model is available to the public without charge, and is fully transparent (that is, all formulas are visible to, and traceable by, all users). CREST was created 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 designed to calculate the cost of energy, or minimum revenue 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.[10] 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.

Q: Were the CREST models made available to stakeholders?

A: Yes. The CREST model is always available to the public. Any stakeholder may download a CREST model from NREL's website, without charge, and enter any number of different input configurations.

In addition, for the convenience of stakeholders, SEA provided a simplified copy of the CREST model it used in its analysis, complete with the inputs used to develop the recommended ceiling prices and incentive-payment adders. A copy of this model is included in SEA Schedule 6.

C. Stakeholder Engagement Process

Q: How many stakeholder comments were received in response to the formal data requests?

A: The number of responses to both the data request and survey (which can be found in SEA Schedule 7), including those obtained via interviews and follow-ups, are summarized in SEA Table 1 below:

SEA Table 1 – Stakeholder Engagement Summary

Stakeholder Category	Number of Responses Received
Solar	8
Solar Projects that "Require Remediation"	7
Non-Solar	1

[10] CREST calculates this after-tax rate of return on a "levered" basis, which means that the return on equity capital invested is a percentage that is intended to reflect a return net of assumed debt service payments.

Q: Please summarize the subject matter on which stakeholders commented. How were these comments incorporated into the process and ceiling price recommendations to the DG Board?

A: SEA received comments regarding three of the four eligible technologies (solar, wind, hydroelectric) from a combination of project developers, financiers, Rhode Island Energy and the DPUC. As during the 2023 program year stakeholder process and several prior year processes, SEA received no feedback from Anaerobic Digestion stakeholders. Throughout the process, SEA vetted all the stakeholder feedback and made more than a dozen adjustments to inputs or calculation methodologies as a direct result of stakeholder feedback where warranted.

Q: Are ceiling price or incentive-payment adder recommendations based exclusively on stakeholder input?

A: No. While stakeholder input is critical to understanding aspects of the project cost, financing and market landscape specific to Rhode Island, basing all aspects of the proposed ceiling prices on the self-reported assumptions of the entities seeking tariff compensation, particularly if inputs and comments are received from a limited number of project developers in a given technology or size category, would not be appropriate and would risk over-compensating project owners at the expense of ratepayers. Thus, the 2024-2026 recommended ceiling prices take other recent data sources (which are described and linked within SEA Schedule 1, SEA Schedule 2, SEA Schedule 3, SEA Schedule 4, and SEA Schedule 5) into account, particularly with respect to cost and financing trends, to incentivize the development of projects in Rhode Island that are price-competitive with similar projects throughout the region.

Q: Did OER allow SEA to have direct communication with the stakeholders on the development of the ceiling prices, including by email, phone calls and face to face meetings?

A: Yes. As in prior years, OER encouraged stakeholders to ask questions of SEA directly by phone, email, or in person. As a result, SEA attended stakeholder meetings, conducted phone calls, and exchanged emails with a range of participants on a range of topics.

Q: Did SEA, on behalf of OER and the DG Board, consider all the stakeholder feedback given in the development of recommended 2024-2026 ceiling prices and incentive-payment adders?

A: Yes. While we did not adopt every stakeholder suggestion, we solicited, carefully considered, and incorporated stakeholder feedback throughout the entire process. SEA's presentation of multiple draft ceiling prices, and associated explanation of changes in response to stakeholder feedback (which can be found attached to the Report and Recommendations), substantiates this consideration.

V. RECOMMENDED DURATION OF PROGRAM PLAN PERIOD AND CEILING PRICE ADJUSTMENT MECHANISM

A. Key Considerations

Q: During the ceiling price development process, did SEA request feedback from market participants regarding their desired potential duration of what became the recommended program plan period?

A: Yes, we did.

Q: In general, how would you characterize the feedback provided by market participants?

A: While only one market participant indicated his interest in Rhode Island continuing its historical offer ceiling prices and capacity allocations for the next program year only, most market participants supported (sometimes strongly) at least a 2-year, if not a 3-year pricing and capacity plan duration.

Q: Based on your experience, what core interests on the part of market participants do you believe informed this feedback?

A: All other factors held equal (and if expected project revenues are sufficient to yield market-rate returns), longer-term pricing and capacity allocation pathways tend to increase market participants' level of certainty that sufficient capacity will be available at attractive prices, and thus their confidence in that market, especially considering the substantial delays involved in completing distribution group studies and ASO studies.

B. Proposed Approach

Q: Did discussions with stakeholders during the ceiling price development process cause you to consider factors other than market participant certainty regarding the optimal duration of a potential set of ceiling prices and capacity allocation?

A: Yes, they did. During the ceiling price development process, OER wanted to pursue a mechanism to adjust the three-year program ceiling prices due to interest rate and other market condition dynamics likely to occur over the next two years that may benefit ratepayers. Both Rhode Island Energy (RIE) and the DPUC both expressed similar concerns that setting ceiling prices that could not change over three years based on changes in market conditions could potentially increase costs for ratepayers beyond what was necessary for developers to bid and bring projects successfully to commercial operation. RIE and DPUC also expressed support for a mechanism to adjust the ceiling prices.

Q: Do you believe that these concerns, as expressed by RIE and the DPUC, are reasonable and well-grounded?

A: Yes, we do, but we also believe this initial analysis only addresses part of the issue at hand. Specifically, there are not only downside risks for ratepayers, but also for market participants, associated with having ceiling prices fixed in part based on forecasted values alone. This is particularly true considering the poor performance of the Open Enrollments over the past two program years.

Q: How would SEA characterize the risk of not accounting for downside risks for market participants over a potential two- to three-year period?

A: Not accounting for this risk, we believe, also places the program at equal risk of failing to achieve its objectives during the duration of the program plan.

Q: How have OER and the Board proposed to mitigate this risk?

A: In order to ensure that prices remain flexible and consistent with key cost, policy, ratepayer costs and other market drivers while preserving a significant degree of market participant certainty, OER and the Board have proposed the inclusion of a Ceiling Price Adjustment Mechanism.

Q: In broad terms, how would this Ceiling Price Adjustment Mechanism work?

A: While the Mechanism would not affect 2024 Program Year ceiling prices, the operation of this Mechanism would result in changes in prices for the 2025 and 2026 Program Years based upon findings that any of the following minimum thresholds for price changes have been met:

- Major deviations (±10%) from SEA's forecasted installed capital cost inputs;
- Major deviations (± 50 basis points (bps)) in interest rate on term debt inputs from SEA's forecasted values; and

- Any changes in state or federal law, regulation or policy that have a direct, material, and mandatory impact on program design, cost, performance, and financing inputs for eligible REG projects, or upon any other factor that would change the expected rate of return for such projects.

Q: Of the substantial number of other inputs involved in calculating recommended ceiling prices, why have OER and the Board focused on upfront/installed capital costs and interest rates on term debt for inclusion in this mechanism?

A: SEA recommended that OER and the Board focus on changes to these input values because these values tend to be the most impactful of the annual ceiling price drivers that, based on recent experience, tend to be subject to the most significant degree of macroeconomic volatility. Furthermore, upfront capital cost is by far the most significant driver of the cost of any renewable energy project, given that this cost is the least discounted element of the project's revenue requirement, and because renewable energy projects have much more limited ongoing operating expenses when compared to traditional nuclear and fossil generation sources.

Q: Did OER and the Board place any limitations on the scope of changes to prices that are possible via this Mechanism?

A: Yes. To limit the scope of these changes and balance the preservation of a substantial degree of market participant certainty with the avoidance of upside and downside risk for both ratepayers and market participants, OER and the Board propose that these changes would be limited strictly to:

- The renewable energy class or classes to which the above-described changes would apply; ***and***
- The next Program Year.

If such changes would apply over multiple years (e.g., a change in law or policy assumed to be permanent in nature), we anticipate that these changes would be applied to the subsequent year. However, OER and the DG Board would propose that the change would not be made until the following year, to ensure the process of annual assessment (and targeted adjustment in the case that minimum thresholds of change in these specific inputs are met) is not interrupted.

C. Details of Ceiling Price Adjustment Mechanism

Q: What specific methodology do OER, and the Board propose to utilize to determine whether

the minimum threshold for changes in installed capital costs has been met, for either the 2025 or 2026 program years?

A: OER and the Board propose direct SEA, consistent with its historical practice when developing ceiling prices, to collect information on installed capital costs for Solar and Non-Solar projects in "the ISO-NE control area and northeast corridor"[11] that is reported to various state governments (including Rhode Island) and other national and/or private databases over the 12 months prior to October 1st of the calendar year prior to the next Program Year. As it did with the recommended 2024-2026 ceiling prices, SEA would then utilize this data to recalculate the input for installed capital costs by determining the average of the 50th and 75th percentile of both reported total project costs from state databases, as well as revealed total project costs from:

- Accepted bids from the previous two Renewable Energy Growth (REG) Open Enrollments; and
- Information on estimated total project costs for accepted bids from other private databases (such as EnergySage, a longtime source of revealed pricing data to SEA for projects less than or equal to 25 kW).

If, based on this information, SEA determines there is a ten percent (10%) or more deviation from the estimates of total project development costs utilized to calculate the 2025 or 2026 ceiling prices proposed in this filing for any given renewable energy class (or classes), SEA would recommend to OER and the DG Board that a change in the prices should be made for that renewable energy class (or classes). SEA anticipates also developing a data request to send to Non-Solar participants by the end of the third quarter of the calendar year prior to the start of the next program year, to ensure such pricing can be obtained if such information is not available in state or private databases.

Q: Does SEA anticipate any of this data would need to be collected from Rhode Island Energy?

A: Yes. To ensure that prices for the 2025 or 2026 program years appropriately account for accepted REG bids, SEA would, at minimum, need to collect the following from Rhode Island Energy:

- Total project development cost data from Rhode Island Energy from its first two Open Enrollments of the year;
- Interconnection cost data from Rhode Island Energy over the past 12-24 months; and

[11] OER and the Board propose that this activity would be conducted per the requirements of R.I.G.L. § 39-26.6-5(d)(1).

- Installed costs for REG Small Solar projects.

Q: **What specific methodology do OER, and the Board propose to utilize to determine whether the minimum threshold for changes in interest rates on term debt has been met for any given program year?**

A: To determine whether a change is necessary, SEA would start by calculating what the "risk-free" component of interest rates should be over typical renewable energy project debt tenors, prior to adding on a figure intended to represent the specific risk premium associated with renewable energy projects. To establish this "risk-free" value, SEA would calculate the average of the closing daily values of 10-year and 20-Year U.S. Treasury Yields between July 1 and September 30 of the calendar year prior to the Program Year in question (be it either the 2025 or the 2026 Program Year). Beyond establishing the 10-year and 20-year "risk-free" values, SEA would also create weighted averages of these values to derive 13-year and 15-year values, to match typical assumed debt tenors for various renewable energy projects and determine the effective "risk free rate" for these tenors. Once these "risk-free" values are established, SEA would then add on 325 bps (equivalent to 3.25%), the risk premium value used to calculate the interest rates on term debt input for the 2024 Program Year ceiling prices.

To determine if this value has deviated ±50 bps from the input values utilized in the ceiling prices initially recommended herein, SEA will compare these recalculated values by renewable energy class to the values utilized in the initial recommended ceiling prices contained in this filing. If difference between the two values is a deviation 50 basis points above or below the forecasted value for the year in question, SEA will recommend to OER and the Board that it should recommend change to the prices for renewable energy classes in which the minimum threshold has been met, and for the forthcoming year only.

Q: **How would SEA propose to change the values if the minimum threshold were met for a given renewable energy class?**

A: SEA would trend the recalculated value using a consensus forecast for Treasury yields, such as one derived from econforecasting.com. The trending would be undertaken, averaged, and factored into the ceiling price for the forthcoming year.

Q: **Does SEA anticipate any of the data needed to determine whether this interest rate-related threshold is met would need to be collected from Rhode Island Energy?**

A: No.

Q: What methodology does OER, and the Board propose to use to determine whether there have been changes in state or federal law, regulation or policy with a direct, material and mandatory impact on program design, cost, performance and financing inputs for eligible REG projects, or upon any other factor that would change the expected rate of return for such projects?

A: To determine whether a change is necessary, SEA would continue to monitor the market on behalf of OER and the Board and notify the board when any change in state or federal policy would result in a direct, material and mandatory impact on the cost, performance or financing assumptions, or anything else that would impact rates of return for projects of any size. If necessary, SEA would also issue data requests to market participants to understand the nature of the impact on said cost, performance and/or financing inputs.

D. Proposed Process for Price Adjustment (If Necessary)

Q: How do OER and the Board propose to effectuate a change to 2025 or 2026 ceiling prices based on SEA's recommendation?

A: Following SEA's recommendation, OER would propose to formally notify all stakeholders of an impending proposal of a change in either the 2025 or 2026 ceiling prices via OER's stakeholder email lists, along with SEA's list that it curates on OER and the Board's behalf. The notification would include the previously approved price for the affected renewable energy classes and show the value of the recalculated price for said classes based on the changes to the inputs described in the mechanism, as well as a description of what factors led to its change. OER would present the revised price for the DG Board's approval, and following the Board's approval, the revised price would be filed at the PUC for its requested approval ahead of the start of the next Program Year. Upon seeking the Board's approval, OER would also request that the Board grant leeway to OER to propose any changes to the prices based on any direct, material, and mandatory impacts of policy changes on ceiling prices that might occur after the Board's vote but prior to beginning of the next program year.

Q: Would OER and the Board make SEA available to consultants to the DPUC to discuss the proposed change, and for consultants to the DPUC to inspect the methodology and calculation upon which the proposed change was made?

A: Yes.

Q: Would OER and the Board also notify stakeholders if no changes were proposed to be made

following SEA's review of installed/upfront capital costs, interest rates on term debt and any potential policy changes with a direct, material, and mandatory impact?

A: Yes. The DPUC requested that this notification take place, and OER and the Board accepted it as reasonable and in the best interests of both ratepayers and market participants.

E. Reasonableness of Program Duration When Paired With Ceiling Price Adjustment Mechanism

Q: Assuming that the Ceiling Price Adjustment Mechanism discussed herein is adopted by the PUC, do you believe that a three-year plan will foster an enhanced degree of business and investment certainty for market participants in Rhode Island?

A: Yes. Based on our discussions with market participants over several years, a major driver of the decline in their confidence in REG is a lack of a clear understanding of how long prices will be in place, and if they change, how much they are likely to change. Therefore, we believe the plan, as proposed, balances cost-effectiveness with the promotion of business certainty and an understanding of how future prices might change.

Q: Did the DPUC comment on the concept of the recommended Ceiling Price Adjustment Mechanism?

A: Yes. As shown in their comments dated October 31, 2023 (which are included in SEA Schedule 8) the DPUC stated that they were "supportive of the potential triggers". Except for the portion that pertains to the measurement period for the interest rate trigger (which was extended to the length of the third quarter of the calendar year prior to the start of the next program year), the potential thresholds that the DPUC suggested they approved of are the same.

Q: Did Rhode Island Energy provide input into the development of the recommended Ceiling Price Adjustment Mechanism?

A: Yes, SEA made several changes minor technical changes to the initially proposed Mechanism in response to both the DPUC and the company's comments, which are described in SEA's final presentation of the prices to the DG Board in **SEA Schedule 5**. As shown in their tariff filing, the company has proposed adopting the Mechanism as proposed.

VI. RECOMMENDED RENEWABLE ENERGY CLASSES AND CEILING PRICES

A. Installed Cost Methodology

Q: Please describe the methodology your team utilizes when developing inputs for upfront capital costs for use in the CREST model for resources under 5 MW.

A: In general, we rely on various state databases in the Northeast region that provide regional installed cost data, combined with the self-reported installed cost figures provided by REG applicants in recent enrollment periods. Historically, SEA has aimed to incent projects that represent the lowest quartile of project costs, or in the case of the 2023 program year, an average of the lowest quartile and median costs, from other jurisdictions (save for New York, where Upstate build costs are typically much lower) to mitigate ratepayer costs.

Q: How did SEA alter its approach to calculating installed cost for projects greater than or equal to 25 kW (i.e., those subject to competitive procurement) during the 2024 ceiling price development process?

A: Given the 2022 and 2023 Program Year's atypically low participation thus far, we adjusted the cost quartiles for selected projects in the state databases used to derive assumed installed cost to enable the receipt of competitive, market-based bids representing projects likely to reach commercial operation. Specifically, we derived our installed cost inputs for all resources over 25 kW based on an average of median and 75^{th} percentile costs from state databases and REG bid values, as opposed to an average of median and 25^{th} percentile costs, as used during the 2023 Program Year ceiling price development process.

Consistent with the 2023 ceiling price development process, we computed year-on-year cost decline assumptions based on the National Renewable Energy Laboratory's (NREL's) Annual Technology Baseline (ATB) conservative case values (provided in SEA Schedule 9) to transform the 2023 installed cost figures derived via the methods discussed above into forecasted 2024 through 2026 installed cost figures. The installed cost inputs, by resource class, resulting from these methods, as compared to the installed cost inputs adopted during the 2022 program year ceiling price development process, are provided in SEA Schedule 5.

Q: **How did SEA alter its approach to calculating installed cost for projects less than 25 kW (i.e., those not subject to competitive procurement) during the 2024 ceiling price development process?**

A: Given the 2023 program year's atypically low participation thus far, we adjusted the cost quartiles for selected projects in the state databases used to derive assumed installed cost to enable a more competitive REG program offering relative to net metering. Specifically, we derived our installed cost inputs for all resources under 25 kW based on median costs from state databases, as opposed to an average of median and 25th percentile costs, as used during the 2023 Program Year ceiling price development process. For Small Solar projects less than or equal to 25 kW_{DC}, median values from these datasets, as opposed to an average of median and 75th percentile costs, were used to derive installed cost inputs, given that the price for small solar is administratively set, rather than competitively procured.

Q: Please describe the methodology your team utilizes when developing inputs for upfront capital costs for use in the CREST model for resources over 5 MW.

A: In order to derive upfront capital cost assumptions for resources over 5 MW, SEA conducted a bottom-up analysis of individual capital cost components. SEA utilized this approach, as opposed to the top-down regional database approach utilized for resources under 5 MW, given the lack of a robust sample size of region-specific, recent capital cost data for larger resources. As a starting point for the bottom-up capital cost inputs, SEA used inputs specific to each proxy project size assessed taken from NREL's Detailed Cost Analysis Model (DCAM),[12] which utilized an input set provided in NREL's Q1 2022 Solar and Storage Cost Benchmarking Report. Certain NREL-supplied inputs were refined or removed to reflect Rhode-Island specific consideration (e.g., higher interconnection costs, sales tax exemption for solar). These inputs were then further refined through three rounds of stakeholder feedback via targeted interviews to arrive at the values presented in the final recommended ceiling prices.

Q: What adjustments were made to the installed cost inputs derived through the aforementioned process?

A: SEA made three categories of adjustments to the installed cost inputs derived through the process discussed above to capture costs that were not assumed to be included in the base capital cost data. Specifically, SEA adjusted the installed cost assumptions to capture incremental costs associated with prevailing wage requirements, meter relocation costs, and interconnection.

Q: Please describe the adjustments made to installed cost inputs relating to prevailing wage.

A: Consistent our approach during the 2023 Program Year ceiling price development process, SEA applied incremental costs reflecting the prevailing wage requirements of the Inflation Reduction Act of 2022 for resources over 1 MW.[13] As discussed in SEA's 2023 Program Year testimony, stakeholder data suggested that the cost of meeting prevailing wage requirements was $57.50/$kW_{DC}$ for eligible Solar renewable energy class projects and $130/$kW_{DC}$

[12] See https://dcam.openei.org/
[13] See Public Law (P.L.) No. 117-169. Available at: https://www.congress.gov/bill/117th-congress/house-bill/5376/text

for eligible Wind renewable energy class projects. However, because certain data sources used to derive installed cost inputs representing projects commencing commercial operation in 2023 are now assumed to contain such costs, SEA adjusted the applicable added costs to apply to only data sources reflecting 2022 commercial operations. No adjustments were made to the prevailing wage costs assumed for wind, given the base capital cost data was not updated with 2023 data. No adjustments were made to the calculated capital costs of resources over 5 MW, as the DCAM model assumptions already included the cost of prevailing wage.

Q: How did SEA verify the incremental cost impact of prevailing wage requirements?

A: During the 2023 Program Year ceiling price development process, SEA collected labor cost data from multiple stakeholders which provided estimates of the incremental costs of complying with prevailing wage requirements. Such estimates included breakdowns of labor costs before and after prevailing wage requirements. SEA was able to benchmark labor estimates before prevailing wage requirements to labor costs contained in NREL’s Q1 2022 Solar and Storage Cost Benchmarking Report, which verified their reasonableness. Similarly, SEA was able to verify that the labor cost estimates provided by market participants after the enactment of prevailing wage requirements in the IRA based on Davis-Bacon rates published on the Federal System for Award Management webpage.

Q: Please describe the adjustments made to installed cost inputs relating to meter relocation.

A: SEA applied a fixed cost of $30,000 to Medium and Commercial I Solar renewable energy classes to account for the potential added cost of meter re-location for such facilities. As discussed in SEA’s first and third stakeholder meeting presentations (see SEA Schedule 1 and SEA Schedule 2, respectively), Rhode Island Energy’s Electric System Bulletin now contains requirements that customers upgrading their service must re-locate their meter outside of the building in question at the customer’s expense. Based on interviews with affected stakeholders, it is SEA’s understanding that such requirements impose significant costs on building-mounted projects to which the requirements might apply given service upgrades triggered by solar installation. As such, SEA applied a fixed upfront cost of $30,000 to the installed cost inputs for Medium and Commercial I Solar renewable energy classes. These estimates represented the low end of a very wide spectrum of estimates received regarding the cost of meter re-location, to provide appropriate headroom in the calculated ceiling price to accommodate certain meter relocation costs. However, of the limited response provided, the majority of respondents indicated that $30,000 was a more accurate estimate than the value supplied at the higher end (of $500,000).

Q: Please describe the adjustments made to installed cost inputs relating to interconnection.

A: SEA assumed that resources over 1 MW would incur interconnection costs of $493/kW. For resources over 5 MW, in which SEA conducted bottom-up component-level cost modeling, $493/kW was applied to the interconnection cost component. Although projects over 5 MW are more likely to be able to interconnect at the transmission level (which can result in lower interconnection costs on a per kW basis), all projects qualifying for REG must be interconnected at the distribution level per R.I. Gen. Laws § 39-26.6-3. As such, SEA assumed the same interconnection costs for all Large Solar renewable energy classes. For Large Solar I, which utilized state installed cost databases to derive “base” installed cost figures, an incremental $263/kW was applied to the base installed cost to represent the difference between the target interconnection cost of $493/kW and the assumed interconnection cost contained in the historic installed cost data of $230/kW. SEA calculated the assumed historic interconnection cost based on 2022 and 2023 Rhode Island Energy interconnection data, which demonstrated that the average historic interconnection cost for resources between one and five megawatts was $230/kW.

Q: Why did SEA determine that it was appropriate to assume incremental interconnection costs beyond the historic costs contained in state installed cost databases?

A: As discussed above in Section II, regional trends strongly suggest that New England states with high penetration of DG experience rapid increases in average interconnection costs, especially for larger facilities that are not sited close to load. Currently, there are ongoing Affected System Operator (ASO) interconnection cluster studies in Rhode Island, the latest of which is currently ongoing and implicates over 100 MW of solar projects. Previous ASO studies in Rhode Island did not determine that system upgrades were necessary to facilitate the interconnection of the DG under study. However, based on SEA’s regional experience, the ongoing study and future studies have a high likelihood of determining that system upgrades will be necessary to facilitate the interconnection of distributed renewable energy projects, as an increasingly saturated grid will require greater incremental system modifications to accommodate the safe interconnection of additional distributed renewable energy projects to the distribution system.

As an illustration of this phenomenon, Rhode Island Energy’s November 15th Paragraph 9 Monthly ASO Study Update reports that initial analysis for the ongoing ASO study identified issues relating to voltage, which is currently undergoing further study. In addition, Rhode Island Energy’s November 15th Paragraph 4 Monthly Report reports that an addition 35 substations (all affecting three or more distributed renewable energy project applications or more than 15 MW of DG capacity) have a potential need for an ASO study in the following 6 months, indicating that most future large DG facilities will be subject to such study, and potential resulting system upgrade costs, going forward.

Q: How did SEA calculate the assumed interconnection cost of $493/kW for resources over 1 MW?

A: SEA determined that the most appropriate and REG statute-reflective means to calculating interconnection costs was to take a regional approach reflecting the states (like Rhode Island) with both relatively high levels of DG penetration and (where possible) known and measurable interconnection costs that reflect the results of completed transmission and distribution studies. Specifically, SEA averaged interconnection costs from Massachusetts, Maine, and Rhode Island to derive the assumed interconnection cost of $493/kW for resources over 1 MW. Details specific to each state sampled are as follows:

- **Massachusetts:** SEA calculated the average dollar-per-kW interconnection cost resulting from the interconnection group studies currently included in the state's provisional cost allocation program. Because the program includes the potential for a portion of interconnection costs to be socialized, and no such program currently exists in Rhode Island, SEA utilized group study costs assuming no socialization in its calculations. The resulting weighted average interconnection was $700/kW. We note, however, that these represent primarily distribution-level costs, since the Massachusetts electric distribution companies have elected to not include certain transmission-side costs (e.g., costs associated with lines and transmission-side substation upgrades) in the program and, instead, fully socialize such costs. As such, most transmission-side costs are not reported on through the program, and thus were not considered in SEA's analysis. In addition, SEA's analysis does not include facility-specific interconnection costs at the site of each project. Given these limitations, SEA adopted an input of $750/kW, which likely represents a low-end estimate of the total interconnection costs that solar projects in Massachusetts would face under cost allocation methods similar to those utilized in Rhode Island.
- **Maine:** Maine does not currently have an interconnection cost allocation program like Massachusetts. As such, public data on interconnection costs is limited. However, SEA has formed estimates on typical interconnection costs in Maine through research calls with developers, calls with industry trade groups, and public stakeholder processes. The

data we collected through this process suggests that, for resources over 1 MW, typical interconnection costs in Maine are approximately $500/kW. This assumption was recently vetted and adopted through a public stakeholder process informing a 2022 benefit cost analysis on behalf of the Maine Public Utilities Commission.[14]

- **Rhode Island:** Rhode Island has yet to produce an interconnection group study resulting in system upgrade costs assessed to study participants. As such, SEA utilized the average historic interconnection costs for projects over 1 MW in 2022 and 2023, as provided through Rhode Island Energy's interconnection data, of $230/kW. Although it is SEA's assessment that the historic interconnection costs are unlikely to reflect expected future costs, data from Rhode Island was averaged into the sample to ensure that Rhode Island-specific data was included in SEA's calculation.

B. Financing Cost Methodology

Q: How did SEA alter its financing inputs during the 2024 ceiling price development process?

A: For 2024 PY prices, to calculate the modeled interest rate on term debt, SEA utilized the same approach as it used for the 2023 prices, which was to estimate the change in interest rates based on changes in the yield on 10- and 20-year US Treasuries, with adjustments to reflect technology-specific risk premiums. To calculate applicable inputs for the 2024, 2025 and 2026 Program Years, SEA utilized forecasted 10- and 20-year Treasury yields.

Q: Did SEA make any change to the equity assumptions?

A: No, we did not.

Q: What were the calculated interest rate inputs resulting from this approach?

A: The interest rates adopted for each Program Year and renewable energy class are provided in SEA Table 2.

SEA Table 2 – 2024-2026 Interest Rate on Term Debt Assumptions for REG-Eligible Projects

Renewable Energy Class	2023 PY (Approved)	2024 PY (Proposed)	2025 PY (Proposed)	2026 PY (Proposed)
Small Solar I	6.30%	7.63%	6.91%	6.97%
Small II	7.00%	7.49%	6.78%	6.84%

[14] See the Distributed Generation Stakeholder Group's Final Report to the Maine Legislature's Joint Standing Committee on Energy, Utilities and Technology (EUT), dated January 6, 2023. Available at: https://legislature.maine.gov/doc/9388

Medium	7.29%	7.60%	6.88%	6.95%
Commercial I (All)	7.29%	7.60%	6.88%	6.95%
Commercial II (All)	7.29%	7.60%	6.88%	6.95%
Large Solar (All)	7.34%	7.66%	6.96%	7.03%
Large II	N/A (New Class)	7.66%	6.96%	7.03%
Large III	N/A (New Class)	7.66%	6.96%	7.03%
Large IV	N/A (New Class)	7.66%	6.96%	7.03%
Wind	7.59%	7.90%	7.18%	7.25%
Small Scale Hydroelectric	7.59%	8.05%	7.32%	7.40%
Anaerobic Digestion	7.34%	7.66%	6.96%	7.03%

Q: Given the minimum and average debt service coverage requirements that projects must meet for debt providers to authorize the placement of debt, what is the maximum feasible percentage of debt the capital stack can sustain for each type of project?

A: The debt percentages adopted for each Program Year and renewable energy class are provided in

SEA Table *3.*

SEA Table 3 – Percentage Debt Assumptions for 2024-2026 Program Years

Renewable Energy Class	**2024 PY**	**2025 PY**	**2026 PY**
Small Solar I	51.00%	51.00%	51.00%
Small II	45.50%	45.50%	45.75%
Medium	47.00%	48.00%	48.00%
Commercial I (All)	46.50%	47.00%	47.00%
Commercial II (All)	46.00%	46.50%	46.50%
Large Solar I	44.50%	44.75%	44.75%
Large II	50.50%	50.75%	50.75%
Large III	54.00%	54.50%	54.50%
Large IV	54.00%	54.50%	54.50%
Wind	42.00%	42.75%	42.75%
Small Scale Hydroelectric	48.00%	48.50%	48.50%
Anaerobic Digestion	51.00%	51.00%	51.00%

Q: Did SEA consider changes to its assumptions regarding bonus depreciation for solar

projects during the 2024 Program Year ceiling price development process?

A: Yes. SEA considered changes to its assumptions regarding bonus depreciation as a component of its data request and survey. In addition, SEA conducted general market research through its broader market analytics consulting engagements to determine if factors influencing the ability for projects to claim bonus depreciation have changed.

Q: Did SEA ultimately determine that changes to its assumptions regarding bonus depreciation were warranted?

A: No, we did not.

Q: Why did SEA determine that no changes should be made to bonus depreciation assumptions?

A: Consistent with SEA's findings during the 2023 Program Year ceiling price development process, SEA determined that because bonus depreciation is a placed-in-service regime (rather than based on the year in which the project started construction), and because many projects have longer interconnection delays (often now approaching 2-3 years, or longer, from project qualification) it is unclear that bonus depreciation, if not extended beyond the end of 2026, would be something that would be possible for either tax or sponsor equity partners to claim.

In addition, SEA continues to lack sufficient data from market participants to determine whether the enhanced transferability provisions encourage financiers to start utilizing bonus depreciation to the benefit of REG-eligible projects.

Q: Did SEA discuss this determination with the DPUC?

A: Yes. The DPUC indicated during our meetings with them that they were generally comfortable with SEA's adopted approach, in part because the assumed timeline for REG projects participating in the 2024 through 2026 Program Year to be placed-in service would not result in any bonus depreciation available for Program Years 2025 and 2026, and minimal depreciation benefits in Program Year 2024.

C. <u>Operating Cost Methodology</u>

Q: What operating cost inputs did SEA revise during the 2024 ceiling price development process?

A: SEA revised site lease costs for Solar projects greater than 25 kW_{DC} and certain operating cost inputs for hydro facilities.

Q: Why did SEA revise site lease costs assumptions for resources over 25 kW_{DC}?

A: As discussed above, the enactment of Chapter 300 banned renewable energy development on core forests. Research calls with solar developers confirmed that most of the development prior to the enactment of Chapter 300 occurred on core forests. Development on forested parcels is expected to have, on average, lower site lease costs relative to non-forested areas. This is because non-forested areas suitable for development are suitable for a broad range of development activities, resulting in increased competition for available sites. In addition, our market research has revealed that owners of commercial and industrial-zoned land often expect a higher return for the use of their land relative to owners of agricultural or forested landowners, in part because of the increased demand for such sites. As such, SEA determined that it was appropriate to increase the assumed site lease costs (which previously reflected costs typical with development on forested land) to reflect the shift in development to non-forested areas.

For the Medium Solar resource class, which is often sited on rooftops, SEA increased its assumed land lease rate to reflect feedback from stakeholders active in this market segment that suggested the market rate for small commercial and industrial rooftops was higher than SEA's prior assumption. In response to this feedback, SEA took a midpoint of the prior values and the values suggested by stakeholders. The adopted input was then benchmarked against commercial rooftop lease costs provided by public databases which validated their reasonableness. Specific values adopted can be found in the appendix of SEA's final presentation to the DG Board (see SEA Schedule 5).

Q: How did SEA determine an appropriate adjustment to reflect the Chapter 300 ban on core forest development?

A: SEA received feedback from five market participants regarding the incremental costs of shifting development from core forests. SEA then benchmarked these estimates with commercial lease costs provided by public databases. Stakeholders active in developing projects over 5 MW_{DC} validated the reasonableness of these estimates via targeted surveys in terms of their applicability to larger renewable energy classes. The resulting inputs (which are detailed in SEA's first stakeholder presentation, provided in SEA Schedule 1) were then open to multiple rounds of stakeholder feedback via the first and second draft of ceiling price presentations, which did not yield comments in opposition to the assumptions.

Q: What operating cost inputs did SEA revise for hydro facilities?

A: SEA increased the assumed insurance costs and fixed operations and maintenance costs for hydro facilities by 10%. Specific values adopted can be found in the appendix of SEA's final presentation to the DG Board (see SEA Schedule 5).

Q: Why did SEA revise insurance costs for hydro facilities?

A: SEA received feedback from an active market participant developing hydro facilities suggesting that insurance costs and fixed operations and maintenance costs for hydro facilities had increased 10% relative to the previous values SEA assumed. SEA met with the participant to better understand the scope of cost increases and verified the reasonableness of the suggested inputs based on SEA's broader understanding of recent cost trends for renewables.

D. <u>Methodology for Development of Large Solar II-IV Inputs</u>

Q: For the Large Solar renewable energy classes established by Chapter 300, how did SEA determine appropriate proxy projects sizes?

A: Consistent with SEA's practice in prior program years, for Large Solar II and III, SEA set the proxy project size assumed in CREST modeling equal to the largest allowable capacity for each resource class. This approach follows guidance provided by the PUC in previous program year ceiling price development processes and reflects developers' tendency to size projects to the largest allowable capacity for each resource class to minimize costs on a per-unit basis.

For Large Solar IV (15 to <39 MW_{DC}), which is required to be sited on a "Preferred Site" per Chapter 300, SEA modeled the proxy project as a 20 MW project to reflect a more typical parcel size for such Preferred Sites. SEA's adopted proxy project size was based on an analysis of Synapse Energy Economics' *Solar Siting Opportunities for Rhode Island* Report results, which suggests that a majority of the preferred site parcels that can support solar development over 15 MW_{DC} have roughly 20 MW_{DC} of technical potential.[15] More specifically, the results demonstrate that only a single brownfield could support a project sized at greater than 20 MW_{DC}, suggesting sizing beyond this point would exclude a majority of total brownfield potential.

Q: For the Large Solar renewable energy classes established by Chapter 300, how did SEA determine appropriate operational cost inputs?

A: The consulting team surveyed market participants active in developing projects over 5

[15] See Synapse Energy Economics. *Solar Siting Opportunities in Rhode Island*. March 2021. Prepared for the Rhode Island Office of Energy Resources. Available at: https://www.synapse-energy.com/solar-siting-opportunities-rhode-island-0

MW_{DC} to better understand typical fixed operations and maintenance costs for such facilities. Stakeholders validated the reasonableness of SEA's assumed cost of $9.00/$kW_{DC}$-yr. This value was benchmarked against utility-scale solar operations and maintenance costs contained in NREL's 2022 Solar and Storage Cost Benchmarking Report, which validated its reasonableness. All other operational cost inputs for Large Solar II, III, and IV were assumed to be the same as Large Solar I, with the exception of site lease costs, which were adjusted to reflect that larger projects will require a larger parcel and thus a more expensive site lease. The underlying site lease cost per MW was identical across all Large Solar renewable energy classes. Project management costs, which are also expressed as total dollar per year, were not scaled with size in order to reflect economies of scale from managing larger projects. All the operational cost assumptions were then open to two rounds of stakeholder feedback via the first and second draft of ceiling price presentations, which did not yield comments in opposition to the assumptions. Adopted inputs can be found in the appendix to SEA's final presentation to the DG Board, provided in SEA Schedule 5.

Q: For the Large Solar renewable energy classes greater than 5 MW_{DC} established by Chapter 300, how did SEA determine appropriate performance inputs?

A: SEA assumed that performance inputs (e.g., capacity factor and production degradation rate) were identical across all renewable energy classes over 1 MW. As such, inputs utilized in the 2023 program year for Large Solar I were applied to Large Solar II, III, and IV. This approach was taken given that the factors influencing capacity factor and degradation rate are likely to be sufficiently similar across projects of this scale, assuming all projects are fixed tilt and located in the same state. SEA has assessed typical capacity factors and degradation rates in multiple analyses and has not identified clear improvements in performance within the range of capacities assessed.

Q: Relative to Large Solar I, what adjustments to financing inputs were made for the Large Solar II-IV renewable energy classes established by Chapter 300?

A: Resources over 5 MW_{AC} are unable to claim interconnection costs in the basis for Federal Investment Tax Credit (ITC) benefits.[16] Therefore, SEA did not include interconnection costs for Large Solar II, III, and IV in the total costs used to compute ITC benefits.

Q: What is the effect of not including interconnection costs in the ITC basis for Large Solar II-

[16] See 26 U.S.C. § 48(a)(8)(A)

IV?

A: Not including interconnection costs in the proxy projects' ITC basis for Large Solar II, III, and IV raises the calculated ceiling price by approximately 2 cents/kWh for Large Solar II-IV for all three years due to reduction in total eligible ITC value, relative to a case in which such costs were eligible for ITC treatment.

Q: How did SEA account for post-tariff revenue in its analysis?

A: Consistent with the ceiling prices selected by the Commission for the 2023 Program Year, SEA assumes that REG facilities, post-tariff, would be entitled to compensation for production at the applicable net metering rate. To reflect this, SEA incorporated a discounted post-tariff revenue stream into the CREST model starting after the end of the tariff term and continuing through the end of the project's useful life, provided that such discounted post-tariff revenue could cover project operational costs (e.g., was not resulting in losses that would increase the calculated ceiling price) post-tariff. Also consistent with the set of ceiling prices selected by the Commission for the 2023 Program Year, this revenue stream was based on a forecast of the applicable net metering rate, with a 40% discount applied to reflect the uncertainty regarding program availability and the applicable rate at the end of the tariff term. However, given that Chapter 300 now provides for virtual net metering credits at 80% of the full net metering rate, SEA applied a further discount of 20% to reflect that current law now provides discounted compensation relative to statute during the 2023 ceiling price development process.

Q: What adjustments to post-tariff revenue inputs were made for the Large Solar II-IV renewable energy classes?

A: Given that virtual net metering is available to resources up to 10 MW_{DC}, SEA determined that it was inappropriate to apply net metering revenue to Large Solar III and IV (which are modeled at a size of 15 MW_{DC} and 20 MW_{DC}, respectively) post tariff. SEA evaluated the application of un-discounted wholesale energy and REC revenue post-tariff and found that such revenue streams were insufficient to cover operating expenses post-tariff. As a result, extending the analysis period to include post tariff increased the modeled ceiling price. Given these findings, SEA determined that the approach that would minimize ceiling prices was to limit the analysis term to the tariff duration for Large Solar III and IV.

Q: What is the effect of removing post-tariff revenue for Large Solar III and IV?

A: The removal of post-tariff revenue for Large Solar III and IV raises ceiling prices approximately 1.2 cent/kWh Large Solar III and IV for all three years, relative to a case in which such resources were eligible for virtual net metering revenue post-tariff.

Q: What adjustments to post-tariff revenue inputs were made for the Medium Solar resource class?

A: The Medium Solar resource class, despite being eligible for net metering revenue post-tariff, was unable to cover operating expenses post-tariff based on the discounted net metering revenue assumed. As a result, extending the analysis period to include post tariff increased the modeled ceiling price. Given these findings, SEA determined that the approach that would minimize ceiling prices was to limit the analysis term to the tariff duration for Medium Solar.

E. Recommended Classes and Prices

Q: What are the recommended renewable energy classes and tariff terms for the 2024 through 2026 program year?

A: The recommended renewable energy classes and tariff terms for the 2024 through 2026 program year are provided below in SEA Table 4.

Q: What are the recommended ceiling prices for the 2024 through 2026 program year?

A: The recommended ceiling prices for the 2024 through 2026 program year, including a comparison to the prices approved for the 2023 program year and the percentage change between said prices, are provided below in SEA Table 5.

SEA Table 4 – Recommended 2024-2026 PY Renewable Energy Classes, Eligible and Modeled System Sizes and Tariff Terms

Renewable Energy Class	Eligible Size Range	Modeled Size (MW$_{DC}$)	Tariff Term
Small Solar I	<=15 kW$_{DC}$	5.8 kW	15 Years
Small Solar II	>15-25 kW$_{DC}$	25 kW	20 Years
Medium Solar	>25-250 kW$_{DC}$	250 kW	20 Years
Commercial Solar I	>250-500 kW$_{DC}$	500 kW	20 Years
Commercial Solar I – Community Remote Distributed Generation (CRDG)			
Commercial Solar II	>500-1,000 kW$_{DC}$	1 MW	20 Years
Commercial Solar II (CRDG)			
Large Solar I	>1-<5 MW$_{DC}$	5 MW	20 Years
Large Solar I (CRDG)			
Large Solar II	5 MW-<10 MW$_{DC}$	9.99 MW	20 Years
Large Solar III	10-<15 MW$_{DC}$	14.99 MW	20 Years
Large Solar IV	15-<39 MW$_{DC}$	20 MW	20 Years
Wind	$\leq$ 5 MW$_{AC}$	3 MW	20 Years
Wind (CRDG)			
Anaerobic Digestion	$\leq$ 5 MW$_{AC}$	750 kW	20 Years
Small Scale Hydropower		500 kW	

SEA Table 5 - Comparison of Approved 2023 Program Year (PY) and Recommended 2024-2026 PY Prices (¢/kWh)

Renewable Energy Class	**Eligible System Sizes**	**PUC Approved 2023 PY**	**Recommended 2024-2026 PY Prices**			**% Change From 2023 PY[17]**		
			2024 PY	**2025 PY**	**2026 PY**	**2024 PY**	**2025 PY**	**2026 PY**
Small Solar I	<=15 kW_{DC}	27.75	36.45	34.65	33.95	31%	25%	22%
Small Solar II	>15-25 kW_{DC}	26.15	33.15	31.95	31.35	27%	22%	20%
Medium Solar	>25-250 kW_{DC}	25.65	34.35	33.45	33.25	34%	30%	30%
Commercial Solar I	>250-500 kW_{DC}	22.05	29.35	28.55	28.35	33%	29%	29%
Commercial Solar I (CRDG)	>250-500 kW_{DC}	25.15	32.25	31.45	31.25	28%	25%	24%
Commercial Solar II	>500-1,000 kW_{DC}	10.05	24.45	23.75	23.55	28%	25%	24%
Commercial Solar II (CRDG)	>500-1,000 kW_{DC}	21.91	27.35	26.65	26.35	25%	22%	20%
Large Solar I	>1-<5 MW_{DC}	14.35	18.65	18.05	17.85	30%	26%	24%
Large Solar I (CRDG)	>1-<5 MW_{DC}	16.50	21.35	20.75	20.52	30%	26%	24%
Large Solar II	5-<10 MW_{DC}	N/A (New Class)	18.05	17.45	17.25	N/A (New Class)		
Large Solar III	10-<15 MW_{DC}	N/A (New Class)	18.45	17.85	17.75	N/A (New Class)		
Large Solar IV	15-<39 MW_{DC}	N/A (New Class)	18.15	17.55	17.45	N/A (New Class)		
Wind	$\leq$ 5 MW_{AC}	19.15	20.25	19.85	19.85	6%	4%	4%
Wind (CRDG)	$\leq$ 5 MW_{AC}	21.15	22.05	21.65	21.75	4%	2%	3%
Anaerobic Digestion	$\leq$ 5 MW_{AC}	19.05	19.25	18.95	19.05	1%	-2%	1%
Small Scale Hydroelectric	$\leq$ 5 MW_{AC}	31.95	34.15	33.35	33.45	7%	4%	5%

[17] Percentage change values represent values associated with the prices as currently recommended, and not with any proposed prices associated with changes resulting from the Ceiling Price Adjustment Mechanism described in this testimony.

Q: Does SEA believe that the importance of both policy objectives and cost-effectiveness were considered in its analysis and recommendations?

A: Yes. SEA believes that the recommended ceiling prices represent an effective balance among all the policy objectives of Rhode Island law.

Q: Does SEA believe that the ceiling price development process used for the 2024 through 2026 REG program was consistent with all prior years in which the PUC has approved the Ceiling Prices?

A: Yes.

Q: Will SEA, as it has in prior years, make appropriate adjustments to the ceiling prices if there are intervening changes in federal tax, trade or other policies that affect the economics of REG-eligible projects?

A: Yes.

VII. RECOMMENDED INCENTIVE-PAYMENT ADDERS FOR SELECTED PROJECTS IN SOLAR RENEWABLE ENERGY CLASSES

A. Recommended Incentive-Payment Adder Categories

Q: What categories of incentive-payment adders for projects requiring remediation is the Board proposing?

A: The Board proposes the adoption of incentive-payment adders for brownfield, Superfund, and landfill sites. The same adder would be available for the brownfield and Superfund-sited projects.

Q: Did SEA consult with the Department of Environmental Management in making these determinations?

A: Yes, SEA met with the Department of Environmental Management (DEM) multiple times to discuss its recommended incentive-payment adder categories. DEM confirmed that the brownfields, superfund sites, or landfills represent the most typical siting options that would be eligible for an incentive-payment adder pursuant to Chapter 300.

Q: What additional guidance relating to incentive-payment adder categories did DEM provide SEA with?

A: DEM noted that landfills that have already been capped are unlikely to qualify as "requiring remediation," as the capping of a landfill is the primary remediation activity required for the site to be suitable for development. DEM also noted that several municipalities possess inactive landfills but lack funds to finance the remediation and capping of such landfills.

Q: How do OER and the Board propose to address issues relating to landfill incentive-payment adder eligibility?

A: Given DEM's guidance, OER and the Board determined that it was appropriate to calculate two potential incentive-payment adders for landfill projects.

First, a full adder was calculated that was designed to cover incremental costs associated with both the capping of a landfill and the installation and maintenance of a solar project on a capped landfill. Second, a reduced adder was calculated that was designed to cover incremental costs associated with only the installation and maintenance of a solar project on a capped landfill, but not the costs associated with the capping of a landfill. SEA determined the calculation of two adder options was appropriate because, based on DEM's guidance, it appears that the cost responsibility for the funding of capping a landfill will vary by case.

Specifically, Rhode Island Energy suggested that, in cases in which an existing party is responsible for the funding of landfill capping, the reduced adder be applied such that such costs are not shifted to ratepayers via the incentive-payment adder. If, however, a municipality can attest that there is no party responsible for funding such capping and that sufficient funds for such remediation activities do not currently exist, it would be appropriate to apply the full adder to fund the capping of the landfill and enable the development of the site. These suggestions were adopted by OER and the Board.

Q: Did SEA model incentive-payment adders specific to certain renewable energy classes?

A: Yes. SEA modeled incentive-payment adders applicable only to the Large Solar I-IV renewable energy classes.

Q: Why where those renewable energy classes selected?

A: The Board and OER chose to focus on these renewable energy classes because a majority of development on preferred sites occurs at scales greater than 1 MW_{DC}. In addition, most of the technical potential for landfills, brownfields, and superfund sites is made of up sites with technical potential levels greater than 1 MW_{DC}, as reported in Synapse Energy Economics' *Solar Siting Opportunities for Rhode Island* Report.

Q: How do OER and the Board recommend projects under 1 MW_{DC} be compensated if they are eligible for an incentive-payment adder?

A: OER and the Board recommend that projects under 1 MW_{DC} that qualify for an incentive-payment adder be given an incentive-payment adder equal to the applicable incentive-payment adder for the Large Solar I resource class. This approach is recommended given that the calculated adder value for Large Solar I resources could potentially be viable for projects under 1

MW_{DC} and (as discussed further in Section IX) has a strong chance of still being cost-effective under the Rhode Island Test.

B. Incremental Cost Methodology

Q: What methodology did your team utilize when developing inputs for the incremental costs associated with development on sites requiring remediation use in the CREST model?

A: To develop inputs relating to the incremental costs of development on projects requiring remediation, SEA started with collecting recent regional cost data obtained through other various engagements, including through the recent benefit-cost analysis assessing Rhode Island's distributed generation policies completed in partnership with OER. Using this data, SEA calculated a set of proposed inputs specific to landfill and brownfield projects relating to incremental capital and operating costs. These proposed inputs were then used to solicit feedback via targeted interviews with developers active in developing such projects. The resulting inputs, adjusted to account for the feedback received, were then open to two rounds of public comment via SEA's first and second draft ceiling price presentations. Initial, first draft, second draft, and final inputs are available in the appendix to SEA's final presentation to the DG Board (see SEA Schedule 5).

In general, stakeholder feedback validated the reasonableness of SEA's proposed inputs, resulting in modest revisions to the proposed inputs relative to the adopted inputs. In instances in which stakeholders provided alternative inputs, SEA used its expert judgment to assess the reasonableness of the recommended changes. If the recommended changes were deemed reasonable, SEA took a conservative approach in which the average recommended value was averaged against SEA's prior assumptions, reflecting the large sample size of cost quotes informing SEA's initial proposed inputs and SEA's desire to limit costs modeled where reasonable.

Q: Were the adopted values consistent with incremental cost figures assumed in prior analyses conducted by SEA?

A: Yes. The adopted values were similar to (though not identical to) those assumed in previous analysis assessing the incremental costs of development on landfills and brownfields. The only exception to this finding is costs associated with capping landfills, which was not considered in previous analyses.

Q: Did SEA assume that brownfield projects would qualify for 10% bonus ITC in its adder calculations?

A: No. Although some brownfield projects will be able to qualify for a 10% ITC bonus as an "energy community" under the IRA, the ability to do so will be limited to certain brownfields meeting federal criteria, rather than the full class of brownfields. Thus, assuming ITC bonus in the calculation of an applicable brownfield adder is likely to render the adder unworkable for projects unable to qualify for ITC bonus.

Q: How did SEA assess the costs of capping landfills?

A: SEA conducted a literature review to understand the typical range of costs incurred from capping a landfill. SEA determined that the cost of capping a landfill is typically between \$100,000/acre and \$300,000/acre but can be as high as \$500,000/acre. SEA adopted an incremental cost of \$150,000/acre, which translates to a total cost of \$570/kW based on capacity density assumptions provided by NREL. A detailed description of the review's findings is available on slide 6 of SEA's fourth stakeholder presentation (see SEA Schedule 4).

Q: What measures did SEA take to limit costs associated with the full landfill adder?

A: SEA chose to adopt a cost input relating to capping landfills that was on the low side of the ranges contained in the literature. SEA selected such a value to limit the ratepayer impact of a resulting adder (if ultimately adopted) and to reflect the likelihood that some portion of landfill capping costs may still be covered by municipalities who would want to attract solar development to fund a significant portion of landfill capping costs.

Q: Did SEA calculate an incentive-payment adder specific to Superfund sites?

No. According to our research, and discussions with stakeholders, development on Superfund sites is less common as compared to development on landfill and brownfield sites resulting in a lack of regional data on such development.

Q: How do OER and the Board recommend projects sited on Superfund sites be compensated under an incentive-payment adder for projects requiring remediation?

A: OER and the Board recommend projects qualifying for an incentive-payment adder that are sited on Superfund sites be given an adder equivalent to the calculated brownfield incentive-payment adder applicable to its rate class.

Q: Is SEA concerned that applying the calculated brownfield adder to superfund sites could result in overcompensation of superfund sites relative to the incremental costs associated with such development?

A: No. Our consultations with DEM confirmed that the costs associated with remediating superfund sites are often higher than the costs associated with remediating brownfield sites. As such, OER and the Board determined, based on SEA's recommendation, that this recommended approach did not result in significant risk of overcompensating Superfund projects relative to the incremental costs associated with such development.

C. <u>Recommended Incentive-Payment Adder Values</u>

Q: What are the recommended incentive-payment adders for the 2024 through 2026 program year?

A: The recommended incentive-payment adders for the 2024 through 2026 program year are provided below in SEA Table 6.

SEA Table 6 - Recommended Landfill and Brownfield/Superfund Adders (For 2024-2026 PYs)

Renewable Energy Class/ Project Size	Eligible Project Size (MW_{DC})	Landfill Adder (¢/kWh)		Brownfield/ Superfund Adder (¢/kWh)
		Final Recommended		***Final Recommended***
		(For Municipalities with funds to cap)	*(For Municipalities with no funds to cap)*	
Solar	<1 MW	4.3	8.0	3.6
Large Solar I	1-<5 MW	4.3	8.0	3.6
Large Solar II	5-<10 MW	3.6	7.8	2.9
Large Solar III	10-<15 MW	3.4	7.5	2.8
Large Solar IV	15-<39 MW	3.3	7.4	2.7

Q: Would the recommended incentive-payment adders apply for all Program Years under consideration?

A: Yes.

Q: Are the incentive-payment adders consistent with the adder values adopted by regional programs for similar siting types?

A: Overall, yes. The resulting brownfield and reduced landfill adders are similar to those adopted in the Solar Massachusetts Renewable Target (SMART) Program, which are approximately 3-4 cents/kWh. The full landfill adder calculated is in excess of these values but contains costs that are not reflected in regional adders given Rhode Island’s focus on sites “requiring remediation.” As such, a comparison of the full landfill adder to regional landfill adder values is not an apples-to-apples comparison.

VIII. RECOMMENDED 2024-2026 PROGRAM YEAR MEGAWATT ALLOCATION PLAN

A. SEA Role in Development of Megawatt Allocation Plan

Q: Has SEA previously sponsored testimony in support of the REG Megawatt Allocation Plan before the Public Utilities Commission?

A: No, this is our first time doing so.

Q: How did SEA come to assist with this task?

A: During the decade-plus period in which SEA has assisted OER with developing recommended ceiling prices and (on occasion) "public policy adders," OER requested no support from SEA in developing the Megawatt Allocation Plan (hereafter referred to as "Plan" or "the Plan"). However, during the first half of 2023, and prior to the enactment of Chapter 300, SEA was engaged by OER to undertake a prospective evaluation of potential changes to Rhode Island's distributed renewable energy programs utilizing the Benefit-Cost Framework developed in conjunction with interested stakeholders and approved by the PUC in RIPUC Docket 4600 for use thereafter. Following the conclusion of this support, and the enactment of Chapter 300, OER requested that SEA assist it with developing a two- to three-year Megawatt Allocation Plan. The requested scope of SEA's assistance also included analyzing the benefits and costs of any Plan that would be ultimately filed with the PUC.

B. Recommended Megawatt Allocation Plan for 2024-2026 Program Year

Q: What is OER and the DG Board's proposed Megawatt Allocation Plan?

A: OER and the Board's proposed Megawatt Allocation Plan by program year is shown in SEA Table 7 below.

SEA Table 7 – OER and DG Board Recommended Megawatt Allocation Plan (2024-2026 Program Years)

Renewable Energy Class	Size Bin (DC)	Final Recommended Annual Allocation (MW)		
		2024	**2025**	**2026**
Small Solar	<=25 kW	9	10	12
Medium Solar	>25-250 kW	5	7	9
Commercial Solar I	>250-500 kW	7.5	9.5	11.5
Commercial Solar I CRDG	>250-500 kW	0.5	0.5	0.5
Commercial Solar II	>500 kW-1 MW	10.5	11.5	12.5
Commercial Solar II CRDG	>500 kW-1 MW	1	1	1
Large Solar I	1-<5 MW	15	20	25
Large Solar I CRDG	1-<5 MW	5	5	5
Large Solar II	5-9.99 MW	35	35	35
Large Solar III	10-14.99 MW	15	30	30
Large Solar IV	15-38.99 MW	0	0	40
Wind	<=5 MW	3	3	3
Wind CRDG				
Small Scale Hydro	<=5 MW	1	1	1
Anaerobic Digestion (AD)				
Total	**All**	**107.5**	**133.5**	**185.5**

Q: With the plan shown in SEA Table 7 above, are OER and the Board requesting procurement of the full 300 MW per year it is statutorily permitted to propose on an annual basis for procurement under the new REG law?

A: No, they are not.

Q: What, in fact, were OER's key objectives in developing the Megawatt Allocation Plan?

A: OER directed SEA to propose and analyze capacity allocations that considered the relative direct cost to ratepayers of the Plan, as well as the availability of capacity presently in Rhode Island Energy's interconnection queue that would be eligible to bid during the 2024, 2025 and 2026 Program Years.

Q: How does the recommended Plan account for the relative direct costs to ratepayers?

A: OER requested that SEA analyze the relative cost-effectiveness of the combined ceiling prices, and recommended incentive-payment adders utilizing the Rhode Island Test (which, as noted later in this testimony, considers a hybrid ratepayer/societal perspective).

Q: Do you believe that the recommended Plan accomplishes this objective?

A: Yes. As we will show in the benefit-cost analysis sections of this testimony, when combined with the recommended ceiling prices (which decline over the recommended three-year period), we believe the Plan accomplishes this objective.

Q: Do you believe that the relative backloading of capacity in the recommended Plan is also consistent with the state of projects in Rhode Island Energy's interconnection queue?

A: Yes. In general, interconnection study timelines have increased substantially as an increasing number of projects greater than 1 MW (whether measured in DC or AC) have entered the company's queue. Therefore, we believe there are clear synergies between the proposed backloaded structure and the realities of project development in a time of significant interconnection queue delays.

Q: How did SEA account for the availability of capacity in Rhode Island Energy's interconnection queue that would be eligible to bid during the period of the recommended Plan?

A: In order to ensure that the Plan reflects realistic volumes of capacity greater than or equal to 1 MW in the interconnection queue likely to be eligible to bid during the years in question, SEA, on behalf of OER, propagated a data request to Rhode Island Energy during July/August 2023 requesting an accounting of capacity by size range in its distribution interconnection queue. A summary of this accounting by size bin is contained in SEA Table 8 and SEA Table 9.

SEA Table 8 - Total Capacity (MW_{AC}) of Solar Projects Intending to Bid Into REG Program by Interconnection (IC) Process Milestone and Size Bin (Excluding Withdrawn, Terminated, and Connected Projects)

IC Process Milestone	Preapplication	Application	Screening	Study	Witness Test	Conditional Approval	Design	Supp. Review	Construction	Meter Install.	Completion Documents	Hold
Large Solar IV (15-<39 MW)	[redacted]											
Large Solar III (10-<15 MW)	[redacted]											
Large Solar II (5-<10MW)	[redacted]											
Large Solar I (1-<5MW)	[redacted]											
Commercial Solar I/II (>250-<1,000 kW)	[redacted]											
Medium Solar (>25-250kW)	[redacted]											
Small Solar (<=25kW)	[redacted]											

SEA Table 9 - Total Capacity (MW_{AC}) of Solar Projects Intending to Participate in Net Metering/Virtual Net Metering Program by IC Process Milestone and Size Bin (Excluding Withdrawn, Terminated, and Connected Projects)

IC Process Milestone	Preapplication	Application	Screening	Study	Witness Test	Conditional Approval	Design	Supp. Review	Construction	Meter Install.	Completion Documents	Hold
Large Solar IV (15-<39 MW)	[redacted]											
Large Solar III (10-<15 MW)	[redacted]											
Large Solar II (5-<10MW)	[redacted]											
Large Solar I (1-<5MW)	[redacted]											
Commercial Solar I/II (>250-<1,000 kW)	[redacted]											
Medium Solar (>25-250kW)	[redacted]											
Small Solar (<=25kW)	[redacted]											

Q: Based on the dataset provided by Rhode Island Energy, what were SEA's initial findings regarding Solar projects in the company's interconnection queue less than or equal to 1 MW_{AC}?

A: In general, SEA limited its analysis of the interconnection queue for the purpose of recommending various capacity allocations by renewable energy class for projects greater than or equal to 1 MW_{AC}. We took this step for two reasons:

- Projects greater than or equal to 1 MW_{AC} are subject to the greatest degree of interconnection scrutiny and delays, given that both Rhode Island Energy and the Affected System Operator (ASO) must extensively analyze them; and
- Projects less than or equal to 1 MW_{AC} tend to emerge from the interconnection process much more quickly than those larger than 1 MW_{AC} ,because the level of analysis required by Rhode Island Energy personnel to ensure a given project larger than 1 MW_{AC} can be safely interconnected to the distribution system is substantially greater than for smaller projects. Therefore, absent significant further restrictions or requirements for interconnection of projects, SEA assumes that these projects will emerge from the process on an ongoing basis, and thus do not factor as significantly into setting a multi-year capacity allocation as projects in multi-month or year distribution and/or transmission studies.

Q: What were SEA's initial findings based on its assessment of capacity contained in the data supplied by Rhode Island Energy?

A: We initially found that, although there was a substantial amount of intended Large Solar I capacity that would likely to be eligible to bid during 2024-2026 program years, it was initially unclear based on the data received from Rhode Island Energy how much Large Solar II-IV capacity was truly active and/or viable for potential bidding during those years. Our hesitation regarding these categories arose from the lack of a clear queue entry date for Large Solar II and III projects that appeared (at the time) to be early in the study process. Therefore, given the press of business, as well as SEA's assessment that capacity designated as intending to participate in virtual net metering would be unlikely to switch to the REG program, OER initially determined that no capacity should be included in the Large Solar II, Large Solar III or Large Solar IV categories for the 2024 program year, and would instead aim to procure such capacity in the final year or two years of the proposed Plan period.

Q: Did OER determine that it was reasonable to include capacity in the Large Solar II-IV renewable energy classes in the recommended Plan for the 2024 Program Year?

A: Yes. During October 2023, Rhode Island Energy indicated to SEA that its ongoing Affected System Operator study would be concluding soon enough that a certain amount of capacity would likely be eligible to execute an interconnection service agreement (ISA) and thus be eligible to bid in Open Enrollments during the 2024 program year. The specific (and de-identified) projects the company indicated to SEA would likely be eligible are contained in SEA Table 10 below.

Utilizing this information, SEA recommended to OER that it could conservatively assume up to half this capacity might bid into the Open Enrollments during the 2024 program year, with the remainder likely to bid in the two years thereafter.

SEA Table 10 - Supplemental List of REG Projects from Rhode Island Energy Interconnection Queue

De-Identified Project	kW_{AC}	MW_{AC}	kW_{DC} Estimate (Assumes 1.3 DC-AC Ratio)	MW_{DC} Estimate (Assumes 1.3 DC-AC Ratio)	SEA-Assessed Megawatt Allocation Plan Category
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q: Did OER accept this recommendation?

A: Yes, they did.

IX. COST-EFFECTIVENESS OF 2024-2026 PROGRAM YEAR PLAN

A. <u>Identification of Benefits Under R.I. Gen. Laws § 39-26.6-22</u>

Q: Did SEA evaluate the benefits and costs of the recommended 2024-2026 REG program plan?

A: Yes, we did.

Q: Could SEA please provide the benefit categories calculated and included in this BCA, a description of said benefits, the specific methodology utilized for calculating the benefits, and the source for the benefit values?

A: Yes, please see SEA Schedule 10 for this information.

Q: Are any of the benefits shown in SEA Schedule 10 "identifiable system benefit(s)" as described in R.I.G.L. § 39-26.6-22?

A: Yes. In the instant analysis, the categories of benefit identifiable as system benefits consistent with R.I.G.L. § 39-26.6-22 (as well as with the categories at the "Power System Level" approved in the Docket 4600 Report and Order) include:

- Avoided Energy (which includes avoided environmental compliance cost with standards for limiting greenhouse gas (GHG) and nitrogen oxide (NOx) emissions, a separate category that falls under "Power System Level");
- Energy Demand Reduction-Induced Price Effects (DRIPE);
- Electric-Gas and Electric-Gas-Electric Cross-DRIPE;
- Avoided (Generation) Capacity;
- Capacity DRIPE;
- Avoided Transmission Capacity; and
- REC Value.

Q: Do any of the benefits shown in SEA Schedule 10 constitute a "reliability benefit" as described in R.I.G.L. § 39-26.6-22?

A: Yes. Reliability benefits are included as part of this analysis.

Q: Are avoided distribution costs (described as "cost savings to the distribution system" in R.I.G.L. § 39-26.6-22) quantified in this analysis?

A: No, they are not, because even though all REG projects are front-of-meter resources that are connected to the distribution system, SEA assumes that much of the potential capacity in the proposed Megawatt Allocation Plan will be connected to relatively solar-saturated circuits that require system modifications for safe interconnection to the distribution system.

Q: Despite their not being quantified in the instant analysis, does SEA believe these benefits are likely to exist for some REG projects?

A: Yes, we do. Given that this value is usually quite small for projects not paired with energy storage (the latter of which describes all Solar projects in the REG program that SEA knows of), as a simplification measure, no distribution benefits were calculated for Solar projects. Though we acknowledge that it is likely that these benefits exist, they are highly location specific.

Q: Do any of the benefits shown in SEA Schedule 10 constitute a "conservation benefit" as described in R.I.G.L. § 39-26.6-22?

A: Yes. In the instant analysis, the categories of benefit identifiable as conservation benefits consistent with R.I.G.L. § 39-26.6-22 include the non-carbon value of ecosystem services associated with water supply, water quality, flood and storm damage mitigation, wildlife habitat and air pollution removal provided by conserved open space.[18] In the instant analysis, they are applied only to projects sited on landfills and brownfields, since such parcels are not assumed to provide similar ecosystem services. These values are also consistent with the "Conservation and Community Benefits" category included in the "Societal Level" strata of benefits and costs approved in the Docket 4600 Report and Order.

Q: Does SEA believe there are other possible benefits that could be considered "conservation benefit(s)" under R.I.G.L. § 39-26.6-22 associated with the projects it is proposing adders for?

A: Yes. As we have illustrated in prior REG proceedings before this Commission, siting

[18] See KD Schedule 1 – 2020 Program Year Carport Solar Pilot Program Evaluation Report, as filed to accompany the Report and Recommendations for the 2021 REG Program Year in Docket 5088. Available at: https://ripuc.ri.gov/eventsactions/docket/5088%20RE%20Growth%202021%20-%20NGrid%20&%20DGBoard/KD%20Schedule%201%20-%20REDACTED%202020_REG_Carport_Pilot_Evaluation_Report.pdf, and JG Schedule 4 - Carport Adder and Benefit-Cost Analysis, Revised November 2021, as filed to accompany the Report and Recommendations for the 2022 Program Year. Available at: https://ripuc.ri.gov/eventsactions/docket/JG%20Schedule%204%20-%20RI_REG_Carport_Adder_Final_Updated_November%202021.pdf

projects on disturbed parcels have other conservation-related benefits, including the avoided loss of property value associated with developing projects on greenfield parcels.[19] We have not quantified it here in part because it was not sufficiently clear to our team without further investigation that property values in proximity to brownfield and landfill parcels would have a similar degree of avoided loss of value as for properties abutting greenfield parcels.

Q: Did SEA include avoided carbon sequestration values associated with avoided forest loss?

A: No. As noted above, given that the carbon sequestration values estimated by SEA during the Evaluation process reflected values associated with both carbon-related benefits from avoided forest loss, we no longer believe it is reasonable to include such values. This is because the baseline has now been changed by the enactment of Chapter 300 to eliminate most solar development on forested parcels.

Q: Per R.I.G.L. § 39-26.6-22, do OER and the Board find that this analysis justifies a finding of the required types of benefits within the load zone of Rhode Island Energy for proposing incentive-payment adders?

A: Yes. The instant analysis identifies and quantifies, per R.I.G.L. § 39-26.6-22, not only system and reliability benefits, but also conservation benefits. Furthermore, and though we have not quantified them herein, our team has also identified the likely existence of other benefits, including cost savings to the distribution system as well as other conservation-related benefits.

B. Detailed Cost-Effectiveness Methodology

Q: What was the basis for this cost-effectiveness evaluation?

A: SEA utilized the Rhode Island Test, as derived from the Benefit-Cost Framework included in the Stakeholder Report accepted by the PUC in its Report and Order issued July 31, 2017.[20]

Q: How would you describe the scope of the benefit-cost analysis (BCA) conducted by SEA?

A: The scope of SEA's analysis is limited to the net present value per MW_{DC} of the benefits and costs of projects in the recommended Solar renewable energy classes from the 2024-2026 Program Year, assuming the capacity in these classes reaches commercial operation based on

[19] See Footnote 18
[20] See PUC Report and Order No. 22851, Issued July 31, 2017. Available at: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/4600-NGrid-Ord22851_7-31-17.pdf

SEA's understanding (from market participants) of typical project development timeframes.

Q: Why does SEA believe that a net benefits per MW_{DC} perspective is the appropriate means of assessing the cost-effectiveness of the recommended Plan?

A: We believe this approach is most appropriate for two reasons. First, as discussed earlier in this testimony, actual procurement volumes may not match the Plan's overall allocations. Second, the actual procured volumes associated with the Plan can change based on market conditions during the Plan period. Therefore, an absolute estimate of the net benefits/costs of the Plan based on a single allocation would likely represent illusory precision.

Q: What are the assumed project development timeframes that your team inferred from consultations with market participants?

A: Our analysis assumes Small Solar projects less than or equal to 25 kW_{DC} will reach commercial operation the same year as the given program year, that Medium and Commercial Solar projects will reach commercial operation two years after selection, and that Large Solar projects of all kinds will reach commercial operation no fewer than four years after selection.

Q: Do you believe that the limitation in the scope of the BCA to only Solar renewable energy classes in the Plan undermines its representativeness of the benefits and costs of the filing?

A: No. Solar projects comprise nearly the entirety of the Megawatt Allocation Plan, and therefore will comprise almost the entirety of the capacity from the Plan that reaches commercial operation.

Q: Per the requirements of the above-described Report and Order, can you please describe the perspective utilized in the BCA?

A: Yes. The Rhode Island Test represents a hybrid perspective of both participating and non-participating ratepayers, as well as society at large. Even though the costs quantified in our analysis are fully borne by both ratepayers participating and not participating in the REG program (given that REG participants still receive full requirements service from Rhode Island Energy), the benefits accounted for in this analysis accrue directly and indirectly to beneficiaries of differing perspectives. More specifically, some of the benefits employed in the analysis are directly monetized by both participating and non-participating Rhode Island ratepayers, while others are indirectly monetized, or monetized by society at large.

Q: Regarding the instant BCA, has SEA taken steps to "address uncertainty and the appropriate adjustments for less than comprehensive data"?

A: Yes, we believe we have, within the instant BCA's bounded scope. We have utilized Avoided Energy Supply Cost in New England 2021 study (AESC 2021) data, which is an accepted as a high-quality source for benefit-cost analysis data (including as a basis for BCA calculations for Rhode Island Energy's various energy efficiency programs). Given the robust approach taken by the Synapse Energy Economics team[21] in completing this analysis, we believe that many well-vetted assumptions are included herein.

Q: Could you please briefly describe AESC 2021?

A: Yes. The AESC is an analysis conducted once every three years as a means of establishing a wide variety of benefits associated with distributed energy resources (DERs) and demand-side management/energy efficiency programs and measures. The AESC's development is overseen by electric distribution companies (including Rhode Island Energy), state energy offices and other regulators, as well as select other stakeholders. The most recent completed version was released in May 2021.

Q: Did SEA maximize its use of the most recent AESC analysis from 2021? If so, why?

A: Yes, we did. This is because the AESC is a carefully vetted, resource-neutral analysis conducted using a sizable number of potential future baseline scenarios against which programs can be compared.

Q: Which baseline scenario from AESC 2021 did SEA utilize for the instant BCA, and why?

A: SEA utilized AESC 2021's "All-In Climate Policy" scenario as the baseline scenario for this analysis. We believed that this baseline is reasonable, given that it was designed as a "projection of expected energy prices, capacity prices, and other price series in a future with ambitious climate policies," including high levels of load growth from electrification and deep decarbonization of the power system. Based on stakeholder feedback from prior ceiling price development processes that suggested our forecasts did not consider enough price suppression based on high levels of renewable energy penetration, we believed that of all the scenarios, a scenario in which high levels of renewable energy were assumed was the best fit.

Q: Has SEA previously utilized this methodology for calculating the benefits and costs of distributed renewable energy programs in Rhode Island?

A: Yes, we have. During the spring of 2023, SEA undertook an Evaluation of Rhode Island

[21] For full disclosure, SEA participated in the development of the AESC 2021 analysis as a subcontractor to Synapse Energy Economics, providing renewable energy buildout and REC/CEC price estimates. SEA is also playing a similar role on the Synapse team for the ongoing development of AESC 2024.

Distributed Generation Policies on behalf of OER, through which we also used the Rhode Island Test to evaluate the prospective benefits and costs of various distributed renewable energy projects across multiple policies, assuming said policies were to be changed and/or expanded.[22]

Q: How does the methodology for the instant BCA differ from the one developed as part of the Evaluation process this spring?

A: Relative to the "Alternative REG" case from the "Evaluation" process, in which REG was expanded to include low-income customers, the BCA categories in the instant analysis differ in the following ways:

- Low-income benefits are excluded (since no REG capacity is known at this time to directly benefit low-income customers, and no changes were ultimately made by Chapter 300 to functionally incentivize low-income customer participation in REG);
- Avoided forest loss benefits were excluded, given that Chapter 300 bans development on core forest parcels. As a result, the baseline has now been adjusted to eliminate most solar development on forested parcels; and
- Multiple input values were updated, including:
    - An update to the ceiling prices for 2024-2026 (to match the recommended values for the three-year period);
    - Updated economic development benefits inputs to reflect revised capital and operating cost inputs consistent with those assumed during the 2024-2026 ceiling price development process;
    - Updated project performance inputs to ensure consistency with capacity factors and production degradation inputs assumed in CREST modeling; and
    - Updated REC prices based on SEA's Renewable Energy Market Outlook (REMO) delivered in July 2023 (known as 2023-2).

Q: Could you please describe the cost categories calculated included in this BCA?

A: Yes. For the BCA pertaining to the Megawatt Allocation Plan and proposed prices, the costs are equivalent to 1) the assumed procured value of (rather than the ceiling prices associated with) REG projects procured during the 2024-2026 program year period, and 2) the assumed administrative costs associated with the REG program.

[22] See OER's page hosting the analysis associated with the Evaluation effort here: https://energy.ri.gov/resources/major-initiatives/evaluation-rhode-island-distributed-generation-policies

Q: From which perspective are these costs experienced?

A: As noted in prior responses, participating and non-participating ratepayers alike experience these costs, since participating REG customers must still pay for full requirements service.

Q: How does SEA differentiate the assumed procured value from the ceiling price value?

A: The assumed procured value of REG projects, as described herein, is equivalent to the recommended ceiling prices, *less* the historical procured value for REG projects for the five-program year period covering the 2017 to the 2021 program years. According to our analysis of projects procured during this period, this value was equivalent to 9.5% less than the ceiling price value for projects greater than or equal to 25 kW.[23]

Q: Why did SEA select this five-year period, rather than a five-year period that includes program years 2022 or 2023?

A: We selected the five-year period in question because the 2022 Program Year was the first year in which the REG program Open Enrollments began to show acute and concerning signs of unhealthy competition, including very low procurement volumes and accepted bid values that were very close to the potential ceiling price, which suggests a high probability that the prices were insufficient to attract bids from developers reflecting healthy competition.

Q: How did SEA estimate administrative costs?

A: To estimate the annual value of administrative expenses for Rhode Island Energy in administering the REG program, SEA utilized the information contained in the annual Renewable Energy Growth Program Factor Filing. According to this filing, the estimated costs for Program Year ending March 31, 2023 were $1.18 million.[24]

C. Cost-Effectiveness Results: Ceiling Prices and Megawatt Allocation Plan

Q: What were the overall results of the benefit-cost analysis for Solar projects in the

[23] SEA originally calculated this five-year value as part of its support to the Maine Governor's Energy Office (GEO) and Distributed Generation Stakeholder Group (DGSG) as part of a team led by Synapse Energy Economics (Synapse) conducting a benefit-cost analysis of a successor to the Net Energy Billing (NEB) program on behalf of GEO and the DGSG. For more details, please see the DGSG's final report to the Joint Standing Committee on Energy, Utilities and Technology (EUT), dated January 6, 2023: https://legislature.maine.gov/doc/9388
[24] See Rhode Island Energy 2022 Renewable Energy Growth Program Factor Filing (June 30, 2022). Available at: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2022-07/22-04-RIE-REGReconci_06-30-22.pdf

recommended Plan?

A: The overall results for the benefit-cost results associated with the recommended Plan, and weighted based on the Plan's capacity allocations, can be found in SEA Table 11 below.

SEA Table 11 - Capacity-Weighted Benefit-Cost Ratio By Size Threshold (2024-2026 PY Weighting Period)

Program Years	**2024-2026**
Capacity-Weighted BCR per MW Allocated <=1 MW	0.93
Capacity-Weighted BCR per MW Allocated >1 MW	1.51
Capacity-Weighted BCR per MW Allocated Capacity (All MW)	**1.34**

Q: How do these annual results break down by projects less than or equal to 1 MW_{DC}, relative to those that are for projects greater than 1 MW_{DC}?

A: The benefit-cost results associated with those relative sizes for eligible projects, weighted based on the capacity allocations contained in the recommended Plan, can be found in SEA Table 12 below.

SEA Table 12 – Annual Capacity-Weighted BCR by Year and Size Threshold (Annual Weighting Period)[25]

Program Year	**2024**	**2025**	**2026**
Annual Capacity-Weighted BCR per MW Allocated <=1 MW	0.89	0.92	0.98
Annual Capacity-Weighted BCR per MW Allocated >1 MW	1.24	1.42	1.70
Annual Capacity-Weighted BCR per MW Allocated (All MW)	1.13	1.13	1.14

Q: What were the detailed results of the benefit-cost analysis for the Megawatt Allocation Plan by renewable energy class and year of the recommended Plan?

A: The benefit-cost results associated with each capacity allocation by renewable energy class by year of the recommended Plan can be found in SEA Table 13 below.

[25] We note that the annual capacity weighted BCRs shown in SEA Table 12 are lower than those shown in SEA Table 11 because the weighting in this instance only accounts for the weighting within the program year, rather than across all of the capacity proposed over the three-year duration of the Megawatt Allocation Plan.

SEA Table 13 – Proposed MW$_{DC}$, NPV of Total Benefits and Costs per MW and BCR by Renewable Energy Class and REG Program Year

Renewable Energy Class	**2024 Program Year**				**2025 Program Year**				**2026 Program Year**			
	Proposed MW$_{DC}$	*Total Benefits/ MW (NPV)*	*Total Costs/ MW (NPV)*	**BCR**	*Proposed MW$_{DC}$*	*Total Benefits/ MW (NPV)*	*Total Costs/ MW (NPV)*	**BCR**	*Proposed MW$_{DC}$*	*Total Benefits/ MW (NPV)*	*Total Costs/ MW (NPV)*	**BCR**
Small Solar I	9.0	$4,188,876	$4,652,107	**0.90**	10.0	$4,045,679	$4,293,566	**0.94**	12.0	$3,940,366	$4,084,299	**0.96**
Small Solar II		$4,313,407	$4,578,244	**0.94**		$4,173,891	$4,283,995	**0.97**		$4,188,483	$4,081,111	**1.03**
Medium Solar	5.0	$3,667,496	$5,032,334	**0.73**	7.0	$3,607,107	$4,757,750	**0.76**	9.0	$3,758,734	$4,591,556	**0.82**
Commercial Solar I	7.5	$3,587,122	$4,299,825	**0.83**	9.5	$3,529,054	$4,060,800	**0.87**	11.5	$3,682,969	$3,914,906	**0.94**
Commercial Solar I CRDG	0.5	$3,828,934	$4,724,680	**0.81**	0.5	$3,763,824	$4,473,281	**0.84**	0.5	$3,910,900	$4,315,373	**0.91**
Commercial Solar II	10.5	$3,498,321	$3,581,967	**0.98**	11.5	$3,442,840	$3,378,074	**1.02**	12.5	$3,599,266	$3,252,065	**1.11**
Commercial Solar II CRDG	1.0	$3,785,156	$4,144,042	**0.91**	1.0	$3,721,321	$3,920,368	**0.95**	1.0	$3,869,635	$3,763,336	**1.03**
Large Solar I	15.0	$3,489,733	$2,731,303	**1.28**	20.0	$3,779,358	$2,566,439	**1.47**	25.0	$4,338,352	$2,464,080	**1.76**
Large Solar I CRDG	5.0	$3,818,570	$3,140,998	**1.22**	5.0	$4,051,911	$2,950,339	**1.37**	5.0	$4,602,966	$2,833,692	**1.62**
Large Solar II	35.0	$3,283,934	$2,643,432	**1.24**	35.0	$3,532,847	$2,481,128	**1.42**	35.0	$4,099,020	$2,381,254	**1.72**
Large Solar III	15.0	$3,258,670	$2,702,013	**1.21**	30.0	$3,508,320	$2,538,002	**1.38**	30.0	$4,075,207	$2,450,275	**1.66**
Large Solar IV	0.0	$3,233,407	$2,658,077	**1.22**	0.0	$3,483,792	$2,495,347	**1.40**	40.0	$4,051,394	$2,408,862	**1.68**

Q: Can SEA provide a detailed breakdown of the benefits by category of quantified benefit for all the cases and years of the analysis pertaining to the Megawatt Allocation Plan?

A: Yes, this information is contained in SEA Schedule 11**.**

Q: Are all the resource types in the various renewable energy classes modeled to be cost-effective in all the years of the recommended Plan?

A: No, they are not. As shown in SEA Table 13, several of the allocations for project less than or equal to 1 MW_{DC} include have BCRs less than 1.0 for at least one year.

Q: If so, then why do OER and the Board recommend allocations to these categories?

A: R.I.G.L. § 39-26.6-12A(c) requires that a minimum of 30 MW "shall be reserved" for projects less than 1 MW_{DC}, With these allocations included, the Megawatt Allocation Plan is still cost-effective, with an overall 2024-2026 BCR of 1.34, as measured using the PUC's Benefit-Cost Framework.

D. <u>Cost-Effectiveness Results: Incentive-Payment Adders</u>

Q: Did SEA undertake an analysis to quantify the benefits and costs associated with the adoption of incentive-payment adders for projects greater than 1 MW_{AC} (for which incentive-payment adders were initially designed)?

A: Yes, we did.

Q: Can SEA provide a detailed breakdown of the benefits by category of quantified benefit for all the cases and years of the analysis pertaining to the Solar classes greater than 1 MW_{DC} for which incentive-payment adders were initially designed?

A: Yes, this information is also contained in SEA Schedule 11

Q: What were the benefit-cost analysis results by program year for Solar projects sited on brownfield parcels that can earn an incentive-payment adder pursuant to R.I.G.L. § 39-26.6-22?

A: The results of the benefit-cost results associated with offering incentive-payment adders to projects in the Large Solar classes that are sited on brownfields can be found in SEA Table 14 below.

SEA Table 14 – Benefit Cost Ratios For Recommended Brownfield/Superfund Adder Values for Large Solar Renewable Energy Classes

Renewable Energy Class	Incentive-Payment Adder by Renewable Energy Class (Brownfield/Superfund, ¢/kWh)	2024 PY BCR	2025 PY BCR	2026 PY BCR
Large Solar I	3.6	1.14	1.29	1.50
Large Solar II	3.4	1.09	1.24	1.41
Large Solar III	3.2	1.07	1.22	1.40
Large Solar IV	3.2	1.08	1.23	1.43

Q: Has this Commission previously approved adder values based in part on these specific values?

A: Yes. As we have illustrated in prior REG proceedings before this Commission, siting projects on disturbed parcels has other conservation-related benefits. To quantify the benefits associated with open space preservation SEA used an identical input to that assumed in its analysis in Docket 5202.

Q: Does SEA believe these results justify adoption of the recommended brownfield incentive-payment adder values for Solar projects greater than 1 MW_{DC}?

A: Yes. As discussed in Subsection A, brownfield projects confer both quantified and unquantified system, reliability and conservation benefits within the State of Rhode Island (and thus the load zone of Rhode Island Energy), a necessary prerequisite of R.I.G.L. § 39-26.6-22 for proposing incentive-payment adders. Our analysis found that for all Solar projects greater than 1 MW_{DC} sited on brownfields, the benefits, as measured using the as measured using the Rhode Island Test based on the Benefit-Cost Framework promulgated by this Commission and utilized in the context of evaluating expenditures related to energy efficiency and other programs, are expected to outweigh the costs of said projects over the proposed 2024, 2025 and 2026 Program Years, even in the absence (given the ban on siting on "core forest" parcels) of any explicit forest loss-related benefits.

Q: What were the annual benefit-cost analysis results for Solar projects sited on landfill parcels that do not require the full cost of capping of the landfill itself that can earn an incentive-payment adder pursuant to R.I.G.L. § 39-26.6-22?

A: The benefit-cost results associated with offering incentive-payment adders to projects in the Large Solar classes that are sited on brownfields can be found in SEA Table 15 below.

SEA Table 15 – Benefit Cost Ratios For Recommended Landfill Adder Values for Projects in Large Solar Renewable Energy Classes Not Requiring Full Cost of Physical Capping of Landfill

Renewable Energy Class	Incentive-Payment Adder by Renewable Energy Class (Landfill Projects Not Requiring Full Cost of Physical Capping, ¢/kWh)	2024 PY BCR	2025 PY BCR	2026 PY BCR
Large Solar I	4.3	1.12	1.26	1.46
Large Solar II	3.6	1.09	1.24	1.45
Large Solar III	3.4	1.07	1.22	1.42
Large Solar IV	3.3	1.08	1.23	1.44

Q: Does SEA believe these results justify adoption of the recommended landfill incentive-payment adder values for Solar projects greater than 1 MW_{DC} that do not require the full cost of physically capping the landfill?

A: Yes. As discussed in Subsection A, landfill projects that do not require the full cost of physically capping the landfill projects confer both quantified and unquantified system, reliability and conservation benefits within the State of Rhode Island (and thus the load zone of Rhode Island Energy), a necessary prerequisite of R.I.G.L. § 39-26.6-22 for proposing incentive-payment adders. Our analysis found that for all Solar projects greater than 1 MW_{DC} sited on landfill parcels not requiring the full cost of capping the landfill, the benefits, as measured using the as measured using the Rhode Island Test based on the Benefit-Cost Framework promulgated by this Commission and utilized in the context of evaluating expenditures related to energy efficiency and other programs, are expected to outweigh the costs of said projects over the proposed 2024, 2025 and 2026 Program Years, even in the absence (given the ban on siting on "core forest" parcels) of any explicit forest loss-related benefits.

Q: Does SEA also believe these results justify allowing projects less than or equal to 1 MW_{DC} to access the recommended incentive-payment adder values for Large Solar I projects on landfills that do not require the full cost of physically capping the landfill?

A: Yes, and for the same reasons that we recommend allowing brownfield projects less than or equal to 1 MW_{DC} to access the incentive-payment adder value for Large Solar I projects on such parcels.

Q: What were the annual benefit-cost analysis results for Solar projects sited on landfill parcels that do not require the full cost of capping the landfill itself, that can earn an incentive-payment adder pursuant to R.I.G.L. § 39-26.6-22?

A: The results of the benefit-cost results associated with offering incentive-payment adders to projects in the Large Solar classes that are sited on landfills that required the full cost of capping said landfill can be found in SEA Table 16 below.

SEA Table 16 – Benefit Cost Ratios For Recommended Landfill Adder Values for Large Solar Renewable Energy Classes

Renewable Energy Class	Incentive-Payment Adder by Renewable Energy Class (Landfill Projects Requiring Full Cost of Physical Capping, ¢/kWh)	2024 PY BCR	2025 PY BCR	2026 PY BCR
Large Solar I	8.0	0.92	1.14	1.31
Large Solar II	7.8	0.96	1.08	1.26
Large Solar III	7.5	0.95	1.07	1.24
Large Solar IV	7.4	0.96	1.08	1.25

Q: Does SEA believe these results justify adoption of the recommended landfill incentive-payment adder values for Solar projects greater than 1 MW_{DC} that require the full cost of physically capping the landfill?

A: Yes. As discussed in Subsection A, these projects confer both quantified and unquantified system, reliability, and conservation benefits within the State of Rhode Island (and thus the load zone of Rhode Island Energy), a necessary prerequisite of R.I.G.L. § 39-26.6-22 for proposing incentive-payment adders. Our analysis found that for all Solar projects greater than 1 MW_{DC} sited on brownfields, the benefits, as measured using the as measured using the Rhode Island Test based on the Benefit-Cost Framework promulgated by this Commission and utilized in the context of evaluating expenditures related to energy efficiency and other programs, are expected to outweigh the costs of said projects over the proposed 2025 and 2026 Program Years, even in the absence (given the ban on siting on "core forest" parcels) of any explicit forest loss-related benefits.

Q: Does this conclude your testimony?

A: Yes, it does.

SEA Schedule 1 – Presentation for Public Stakeholder Meeting No. 1 (Aug. 14, 2023)

See file named 'SEA Schedule 1 – Presentation for Public Stakeholder Meeting No. 1 (Aug. 14, 2023).pdf'

SEA Schedule 2 – Presentation for Public Stakeholder Meeting No. 2 (Sept. 22, 2023)

See file named 'SEA Schedule 2 – Presentation for Public Stakeholder Meeting No. 2 (Sept. 22, 2023).pdf'

SEA Schedule 3 – Presentation for Public Stakeholder Meeting No. 3 (Oct. 24, 2023)

See file named 'SEA Schedule 3 – Presentation for Public Stakeholder Meeting No. 3 (Oct. 24, 2023).pdf'

SEA Schedule 4 – Presentation for Public Stakeholder Meeting No. 4 (Nov. 6, 2023)

See file named 'SEA Schedule 4 – Presentation for Public Stakeholder Meeting No. 4 (Nov. 6, 2023).pdf'

SEA Schedule 5 – Presentation for DG Board Meeting (Nov. 14, 2023)

See file named 'SEA Schedule 5 – Presentation for DG Board Meeting (Nov. 14, 2023).pdf'

SEA Schedule 6 – Public-Facing CREST Model

See file named 'SEA Schedule 6 – Public-Facing CREST Model.xlsm'

SEA Schedule 7 – Stakeholder Data Request and Survey

See file named 'SEA Schedule 7 – Stakeholder Data Request and Survey.pdf'

SEA Schedule 8 – Stakeholder Comments

See file named 'SEA Schedule 8 – Stakeholder Comments.pdf'

SEA Schedule 9 – NREL ATB Conservative Installed Cost Index

See file named 'SEA Schedule 9 – NREL ATB Conservative Installed Cost Index.xlsx'

SEA Schedule 10 – REG 2024-2026 BCA - Benefits Methodology

See file named 'SEA Schedule 10 – REG 2024-2026 BCA - *Benefits Methodology.docx'*

SEA Schedule 11 – REG 2024-2026 BCA - Component Benefit Calculations

See file named 'SEA Schedule 11 – REG 2024-2026 BCA - Component Benefit Calculations.xlsx'