STATE OF RHODE ISLAND

PUBLIC UTILITIES COMMISSION

IN RE: THE RHODE ISLAND DISTRIBUTED	:	
GENERATION BOARD’S RECOMMENDATIONS	:	
FOR THE 2025 RENEWABLE ENERGY	:	DOCKET 24-50-REG
GROWTH PROGRAM YEAR	:	

Recommendations for the 2025 Renewable Energy Growth Program Year

DISTRIBUTED-GENERATION BOARD & OFFICE OF ENERGY RESOURCES

NOVEMBER 22, 2024

TABLE OF CONTENTS

DISTRIBUTED-GENERATION BOARD
RENEWABLE ENERGY GROWTH 2025 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 2025 Renewable Energy Growth ("REG") Program Years ("PYs") to the Public Utilities Commission ("Commission" or "PUC"). The recommendations set forth herein for the 2025 PY represent the following:

- Proposed (administratively-set) prices for Small Solar I and II renewable energy classes;
- A proposed pilot program proposal for the 2025-2026 PY period for incentive-rate adders for eligible Solar projects sited on brownfields requiring remediation; and
- A proposed Megawatt Allocation Plan for the 2025 PY.

In accordance with R.I. Gen. Laws § 39-26.6-4(b), the Office of Energy Resources ("OER"), in consultation with the DG Board, engaged Sustainable Energy Advantage, LLC ("SEA") to develop the above-described recommended ceiling prices, brownfield pilot program proposal for incentive-rate adders, and Megawatt Allocation Plan for review and approval by the DG Board for the Renewable Energy Growth ("REG") Program.

The recommendations were approved by the DG Board at its November 4 meeting and are endorsed by the OER.

Goals and Objectives

The REG law was amended by the General Assembly in 2023[1]. As amended, 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 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.[2]

Consistent with such purposes of the amended REG law, the anticipated outcomes for the REG 2025 PY 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. 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 ("RI Energy");
4. Increased 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; and
5. Improved alignment between REG projects and development on "preferred sites" (also per R.I. Gen. Laws. § 39-26.6-3).

[1] Available at: http://webserver.rilin.state.ri.us/PublicLaws/law23/law23300.htm
[2] See R.I. Gen. Laws § 39-26.6-1.

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)
Dr. Carrie Gill	RI Energy (ex officio, non-voting)
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
Hayley Kenyon	Residential users
Mark Kravatz	Low-income users
Angela Tuoni	Environmental issues pertaining to energy
Laura C.H. Bartsch (Chair)	Construction of renewable generation

Small Solar Classes, Tariff Term Lengths and Ceiling Prices

Below are the DG Board's recommendations for small solar classes and eligible system sizes for the REG 2025 PY.

The DG Board respectfully recommends that the PUC approve new Small Solar I and II ceiling prices (of 34.55 ¢/kWh and 33.35 ¢/kWh, respectively) for the 2025 PY. Therefore, and consistent with R.I. Gen. Laws § 39-26.6-5(d) and § 39-26.2-5, please see **Table 2** below, which contains the DG Board's recommendations for Small Solar I and II ceiling prices for the REG 2025 PY.

Table 2 – Recommended Small Solar I and II Ceiling Prices (2025 PYs, ¢/kWh)

Renewable Energy Class	Eligible System Sizes	Tariff Length	Ceiling Price (¢/kWh, 2025 PY)

Small Solar I	<=15 kW_{DC}	15 Years	34.55
Small Solar II	>15-25 kW_{DC}	20 Years	33.35

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 [DG 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."

In Docket No. 23-44-REG, the DG Board proposed a series of adders for landfill and brownfield projects that "require remediation" pursuant to R.I. Gen. Laws § 39-26.6-21. In its Report and Order in that docket, the PUC rejected the proposed incentive-payment adders but permitted the DG Board to propose an alternative to the rejected proposal no fewer than 105 days prior to its effective date.

Pursuant to this PUC directive, the DG Board respectfully recommends approval of a pilot program proposal intended to incent projects sited on brownfields that "require remediation." To this end, consultants to OER and the DG Board have identified a subset of Solar project types typically sited on brownfields (which qualify as "preferred sites" under R.I. Gen. Laws § 39-26.6-3) that require remediation, but also confer conservation, 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. The proposed pilot program is described in the direct testimony of Tobin Armstrong and Jim Kennerly, consultants to OER and the DG Board.

In sum, the DG Board recommends the adoption of a pilot program for the 2025 and 2026 program years to offer incentive-payment adders for eligible brownfield-sited projects as shown in **Table 3** below. OER and the DG Board are not pursuing an incentive-payment adder unique to landfills.

Table 3 – Recommended Brownfield Adders Under Proposed 2025 and 2026 PY Pilot Program

Renewable Energy Class	Eligible Project Size (MW_{DC})	Recommended Pilot Program MW_{DC} by Class	Final Recommended Brownfield Remediation Adder (¢/kWh)
Large Solar I	1-<5 MW	10	1.6
Large Solar II	5-<10 MW	10	

Megawatt Allocation Plan

The DG Board respectfully recommends the PUC adopt the recommended Megawatt Allocation Plan, which includes both a Plan A and Plan B contingent on the outcome of RI Energy's third Affected System Operator study ("ASO#3"), as shown in Table 4 below. Plan A refers to the DG Board's recommended plan in the case that RI Energy *can* finalize ASO#3 results, including any required re-studies, by forty-five (45) days prior to the anticipated opening of the Third Open Enrollment window for the 2025 Program Year. Plan B refers to the DG Board's recommended plan in the case that RI Energy *cannot* finalize ASO#3 results forty-five (45) days prior to the anticipated opening of the Third Open Enrollment window for the 2025 Program Year. Plan B includes reduced capacity in the Large Solar renewable energy classes, reflecting that the availability of eligible projects in such renewable energy classes is contingent on the conclusion of ASO#3. Under either plan, capacity available in the Large Solar renewable energy classes would only be available under the Third Open Enrollment to maximize competitive dynamics as well as the time for ASO#3 to conclude.

Consistent with R.I. Gen. Laws § 39-26.6-12(c), please see **Table 4** below, which contains the DG Board's recommended allocation plans for the REG 2025 PY.

Table 4 - Recommended Megawatt Allocation Plan for the 2025 Program Year (PY)

Renewable Energy Class	Eligible System Sizes	PUC Approved 2024 MW Allocation Plan	"Plan A" MW_{DC} (2025 PY)	"Plan B" MW_{DC} (2025 PY)
Small Solar	<=25 kW_{DC}	9	9	9
Medium Solar	>25-250 kW_{DC}	5	7	7
Commercial Solar I	>250-500 kW_{DC}	7.5	9.5	9.5
Commercial Solar I (CRDG)	>250-500 kW_{DC}	0.5	0.5	0.5
Commercial Solar II	>500 kW-1 MW_{DC}	10.5	11.5	11.5

Commercial Solar II (CRDG)	>500 kW-1 MW_{DC}	1	1	1
Large Solar I	>1-<5 MW_{DC}	15	**20**	**10**
Large Solar I (CRDG)	>1-<5 MW_{DC}	5	5	5
Large Solar II	5 MW-<10 MW_{DC}	35	**30**	**0**
Large Solar III	10-<15 MW_{DC}	15	**15**	**0**
Large Solar IV	15-<39 MW_{DC}	0	0	0
Wind	≤ 5 MW_{AC}	3	3	3
Wind CRDG	≤ 5 MW_{AC}			
Anaerobic Digestion	≤ 5 MW_{AC}	1	1	1
Small Scale Hydropower	≤ 5 MW_{AC}			
Total		**107.5**	**112.50**	**57.50**

Conclusion

After a thorough and transparent development process, the DG Board voted at its November 4, 2024, meeting to recommend the allocation plan, proposed Small Solar I and II ceiling prices for the 2025 PY and the two-year pilot program incentive-payment adder for projects sited on brownfields requiring remediation. The DG Board and OER respectfully request the PUC consider and approve the recommendations for the REG 2025 PY.

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

I. INTRODUCTION

A. Witness Introduction

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

A: My name is Tobin Armstrong. I am a Consultant at Sustainable Energy Advantage, LLC (“SEA”). I lead the firm’s distributed energy market modeling. During the 2025 Renewable Energy Growth (“REG”) Program Year (“PY”) ceiling price development process, I led SEA’s support to the Office of Energy Resources (“OER”) and the Distributed-Generation Board (“DG Board”).

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

A: I have ten years of experience related to renewable energy policy, and six years of professional experience with distributed generation (“DG”) related policy and quantitative analysis. At SEA, I lead the company’s DG 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 the National Renewable Energy Laboratory (“NREL”) Cost of Renewable Energy Spreadsheet Tool (“CREST”) model (developed by SEA under contract to NREL).

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 and 2024 ceiling price development process, I provided testimony in Docket 22-39-REG and 23-44-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: Mr. Kennerly, can you please state your name, employer, and title?

A: My name is Jim Kennerly. I am a Director at SEA, and for the 2025 PY process, I served as a senior adviser to Mr. Armstrong and contributed to the development of the plan.

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

A: I have fourteen 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.

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. From 2018 (for the 2019 PY) to 2024 (for the 2024 PY), I led SEA's support to OER and the DG Board related to the REG program and sponsored (or co-sponsored) the direct and, as needed, rebuttal testimony filed by OER and the DG Board regarding recommended 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.

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.

In addition to serving OER and the DG Board, our distributed energy team has undertaken custom consulting work for the Connecticut Green Bank, the Connecticut Public Utility Regulatory Authority, the Hawaii Public Utilities Commission, the Illinois Power Agency, the Maine Governor's Energy Office, the Maine Public Utilities Commission, the Massachusetts Attorney General's Office, the Massachusetts Clean Energy Center, the Massachusetts Department of Energy Resources, the New Jersey Board of Public Utilities, the New York State Energy Research and Development Authority, the New Hampshire Office of Consumer Advocate, the Virginia State Corporation Commission, not-for-profit entities such as the Clean Energy States Alliance, the Coalition for Community Solar Access, the Natural Resources Council of Maine, the Nature Conservancy, Vote Solar, as well as a wide variety of buy-side and sell-side solar and distributed energy market participants.

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 2015, to both OER and 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 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 2025 PY REG plan?

A: OER and the DG Board hired SEA 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 the Small Solar I and II renewable energy classes, 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 proposed pilot program for incentive-payment adders for solar projects sited on brownfields that "require remediation."

Q: Did SEA engage with the Division of Public Utilities and Carriers ("DPUC") and their consultants during the development of the ceiling prices, and related assumptions?

A: Yes. SEA reached out to the DPUC to inquire if the DPUC would like to discuss the proposed program plan with SEA and received numerous sets of helpful comments from the DPUC which were incorporated into the Small Solar ceiling prices and incentive-payment adder design.

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

A: Yes.

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

A: No.

II. SMALL SOLAR CEILING PRICE AND INCENTIVE-PAYMENT ADDER DEVELOPMENT PROCESS

A. Process Overview

Q: Please describe the process that SEA utilizes to develop recommended Small Solar 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 NREL CREST model to generate recommended ceiling prices through multiple rounds of analysis. The process included three 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 2025 program plan, SEA also utilized the above-described data- and stakeholder-driven process. SEA's research focused specifically on Small Solar I and II, given that the PUC approved ceiling prices for program years 2024-2026 for all larger resources in Docket 23-44-REG. SEA presented one draft of prices at a stakeholder session on October 16, 2024, prior to finalizing recommendations for the DG Board's vote in November. In addition, SEA and OER held a solar stakeholder meeting on September 10th, 2024 to discuss research and solicit stakeholder feedback and data regarding the development of proposed incentive-payment adders for the two-year pilot program.

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

A: SEA presented its initial research regarding proposed incentive-payment adders at a solar stakeholder meeting held virtually on September 10, 2024, during which SEA reviewed the proposed inputs for its analysis and the results. SEA presented its first draft of the recommended prices for Small Solar I and II well as updates regarding potential incentive-payment adders at a solar stakeholder meeting held virtually on October 16, 2024. The final price recommendations for Small Solar I and II, recommended incentive-payment adders for the two-year pilot program, and recommended 2025 Megawatt Allocation Plan were presented at a DG Board public meeting r on November 4, 2024, where the recommendations were approved.

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

A: Yes. SEA's three presentations are provided as **SEA Schedule 1**, **SEA Schedule 2**, and **SEA Schedule 3** , respectively.

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 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.[3] 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: Was the CREST model 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 it used to develop the first draft ceiling prices for Small Solar I and II.

C. <u>Stakeholder Engagement Process</u>

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

A: SEA received four responses to the data request and survey from members of the solar industry (which can be found in **SEA Schedule 5**), including those obtained via interviews and follow-ups. In addition, SEA received multiple rounds of comments from RI Energy and the DPUC regarding the program plan.

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

A: SEA received comments regarding Small Solar I and II solar capital, financing, and operating expenses from solar industry members. SEA received various comments from RI Energy and the DPUC regarding its price calculation methods, and analysis in support of the 2025 Megawatt Allocation plan and proposed brownfield remediation incentive-payment adder pilot program (described in more detail later in this testimony).

Throughout the process, SEA vetted all the stakeholder feedback and made several adjustments to inputs, calculation methodologies, and program design elements as a direct result of stakeholder feedback where warranted.

---

[3] 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: Are the Small Solar 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 2025 PY recommended ceiling prices for Small Solar I and II take other recent data sources (which are described and linked within **SEA Schedule 1**, **SEA Schedule 2**, and **SEA Schedule 3**) 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 participants on a range of topics.

Q: Did OER and the DG Board, as assisted by SEA, consider all the stakeholder feedback given in the development of recommended 2025 Small Solar ceiling prices and the proposed two-year pilot program for 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 draft prices, and associated explanation of changes in response to stakeholder feedback (which can be found attached to the Report and Recommendations), substantiates this consideration.

III. RECOMMENDED SMALL SOLAR CEILING PRICES

A. <u>Installed Cost Methodology</u>

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

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. Consistent with the 2024 ceiling price development process and given the 2024 program year's atypically low participation thus far, we continued to derive our installed cost inputs for all resources under 25 kW based on median costs from state databases.

In addition, 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 (described in **SEA Schedule 2**) to transform the 2023 and 2024 installed cost figures derived via the methods discussed above into forecasted 2025 installed cost figures. These cost declines were then offset by forecasted inflation provided by the Energy Information Administration's 2023 Annual Energy Outlook (utilizing the All-Urban Consumer Price Index). The installed cost inputs, by resource class, resulting from these methods, as compared to the installed cost inputs adopted during the 2024 program year ceiling price development process, are provided in **SEA Schedule 2**.

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

A: For Small Solar I and II, SEA made one adjustment to the installed cost inputs derived through the process discussed in the previous answer to capture incremental labor costs that were not assumed to be included in the base capital cost data.

Q: Why were adjustments to installed cost data relating to labor costs necessary?

A: During the 2023 legislative session, the Rhode Island General Assembly passed HB 7015 and SB 2120, both titled An Act Relating to Businesses and Professions – Electricians. HB 7015 and SB 2120 require a licensed electrician to perform all the installation and maintenance of solar racking, among other elements. SEA and OER understand that these new requirements will have an impact on labor costs for Rhode Island solar projects.

Q: Please describe the adjustments made to installed cost inputs relating to the new labor law requirements.

A: Given the law's recent enactment and Rhode Island-specific impact, the law's impact on labor costs would not be reflected in installed cost data reported in neighboring states and would not yet be contained in any Rhode Island-specific installed cost figures reported in 2023 or 2024. To address this, SEA applied an incremental $30/kW to the installed cost figures derived from state databases to reflect the incremental cost of the new labor law requirements.

Q: How did SEA verify the incremental cost impact of the new labor law requirements?

A: Stakeholders responding to SEA's data request and survey reported a wide range of expected costs from the new labor requirements, including estimates as high as a doubling of labor costs. To verify a reasonable range of costs, SEA conducted desktop research to substantiate industry-supplied estimates of the cost impact leveraging residential solar labor cost estimates provided by NREL in its Q1 2023 Solar and Storage Cost Benchmarking Report.[4] SEA's analysis resulted in incremental cost estimates ranging from $20/kW to $40/kW. SEA conducted follow-up outreach to industry members to further understand expected cost impacts, which substantiated incremental cost impacts ranging from $30/kW to $40/kW. As such, SEA adopted $30/kW as both the mid-point of its internal estimate, as well as the low-point of industry member estimates.

Q: Did SEA receive comments from stakeholders regarding other aspects of its installed cost calculations? If so, what where they?

A: Yes. RI Energy recommended that SEA utilize the lowest quartile costs, or average of the lowest quartile and median costs, instead of the median costs. In addition, RI Energy Recommended that SEA adjust its average cost calculations to account for data sources with limited sample size (see RI Energy's October 24 Comments, **SEA Schedule 5**).

Q: Did SEA revise its calculations in light of these comments? Why or why not?

A: While SEA understands that the Small Solar I and II classes have administratively set prices and are not subject to competitive bidding, SEA determined that it would be inappropriate and out of step with market realities to calculate costs based on lowest quartile costs in light of the limited volume of Small Solar I and II uptake in Program Years 2023 and 2024, as well as lingering concerns regarding durable cost increases experienced by the solar industry following the COVID-19 pandemic.

With respect to the recommendation that SEA adjust its average cost calculations to account for data sources with limited sample size, SEA combined two Rhode Island-specific datapoints for the purpose of calculating the region-wide average installed cost figure adopted in modeling. In conducting cost analysis, SEA must balance the desire to rely on data sources containing robust sample sizes with the need to include Rhode Island-specific data which may be more reflective of state-specific costs. In general, Rhode Island-specific data is more limited in sample size. Simply weighing each data source based on sample size would result in a disproportionate emphasize on states like New York which may mask Rhode Island-specific cost factors. However, in this instance, SEA determined that it was appropriate to combine two data

[4] Available at: https://www.nrel.gov/docs/fy23osti/87303.pdf

sources (specifically, the 2024 RI Small REF and 2024 RI Small REG sources) due to limited sample sizes to de-emphasize their individual influence over the final adopted installed cost input.

B. Operating Cost Methodology

Q: Did SEA revise any inputs relating to Small Solar I and II operating costs relative to the inputs utilized in the 2024-2026 Program Year development process?

A: No.

Q: Did SEA receive comments from stakeholders recommending a revision in Small Solar I and II operating cost assumptions?

A: Yes. An industry member recommended that SEA increase its assumed costs relating to insurance, in addition to increasing the operating cost escalation rate assumed in modeling.

Q: Did SEA ultimately recommend this approach to OER and the DG Board?

A: No. Though SEA requested additional data from industry members to substantiate the claims following receipt of the recommendation, SEA did not receive additional data from any industry members. Furthermore, SEA is not aware of any broad change in industry practice to substantiate including such costs in Small Solar I and II prices.

C. Financing Cost Methodology

Q: Did SEA alter the proposed financing inputs for 2025 PY ceiling prices for Small Solar I and II projects?

A: Yes, SEA changed its approach to calculating the interest rate on term debt inputs for Small Solar I and II projects, while eliminating the lender fee for said projects.

Q: Please describe the alterations made to these interest rates on term debt for Small Solar I and II projects.

A: For the 2025 PY prices, SEA moved away from calculating interest rate on term debt input values for Small Solar I and II based on values quoted to financiers of larger projects (which assume an approach based on 10- and 20-year U.S. Treasuries plus a risk premium) and towards an approach that considers the typical rates offered to residential and small commercial customers seeking solar PV-specific loan products. To accomplish this switch away from a more traditional project finance approach while preserving the forward-looking nature of the potential rate, SEA has utilized data from UMass Five Credit Union, a lender known to be active in New England host-owned solar project finance that publishes its solar loan offers, but subtracted 50 basis points to account for expectations that changes in Federal Reserve Bank interest rates would ultimately flow through to the offers extended by UMass Five and other market participants.[5]

Q: Please describe the alterations made to lender fees for Small Solar I and II projects.

A: SEA has removed the assumed lender fee from these calculations, since it has come to SEA's attention that such values are not consistently utilized by all financiers in this space and vary more significantly than we initially realized based on the credit quality of the borrower. As such, SEA has adopted an interest rate that assumes no lender fee, in significant part because the public offer utilized by UMass Five does not assume or require the payment of a lender fee

Q: Did SEA attempt to benchmark the UMass Five public values (including those that did not include a lender fee) with any other relevant market information?

A: Yes, we did. SEA received a confidential rate sheet from a non-UMass Five financing partner to a Small Solar market participant, which provided interest rate values with and without a lender fee, and for customers of varying levels of creditworthiness. The interest rate values for the debt term utilized in the analysis (10 years for both Small Solar I and II) that did not assume payment of an upfront lender fee were very similar to the interest rates offered by UMass Five.

Q: Why does SEA believe these changes are important to make for Small Solar I and II projects in particular?

A: With regard to interest rates on term debt, SEA believes these changes are necessary because it remains SEA's understanding that it is typical for host-owned Small Solar I and II projects (the dominant ownership type in the REG program) to be financed via boutique/specific solar loan products.[6] While SEA has previously attempted to account for the fact that host-owned projects tend to be financed by solar loans by incorporating market participant feedback on our interest rate estimates plus our dealer fees, it has come to our attention that offers for solar loans to borrowers can be more effectively (and publicly) sourced from the solar loan providers themselves. Furthermore, the cap on financing in such public offers allows for calculating interest rates for projects at Small Solar I and II proxy sizes.

---

[5] The current UMass Five offer is available at https://umassfive.coop/personal/loans/sustainability/mysolar.

[6] When referring to a "traditional project financing approach", we mean the development of an interest rate on term debt value comprised of a risk-free value (based on current and forecasted U.S. Treasuries) plus a risk premium (for Solar and Non-Solar projects greater than 25 kW_{DC}, this risk premium is assumed to be between 325 and 350 basis points (bps).

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

A: The interest rates adopted for each Program Year and renewable energy class are provided in **SEA Table 1**.

SEA Table 1 – 2025 PY Interest Rate on Term Debt Assumptions for REG-Eligible Projects

Renewable Energy Class	Interest Rate on Term Debt		Lender Fee	
	23-44-REG	***Recommended***	***23-44-REG***	***Recommended***
Small Solar I	6.91%	8.38%	2.3%	0.0%
Small Solar II	6.78%		4.2%	

Q: Did SEA also move to unify the debt tenor assumptions between Small Solar I and II projects?

A: Yes, SEA changed the assumed debt tenor for Small Solar I to be 10 years (rather than 13). SEA recommends prices that include this change in order to match the tenor to the UMass Five-offered tenor of 10 years, and to reflect information gleaned from market participants that borrowers financing Small Solar I and II tend to seek shorter-tenor debt financing if possible (and do not tend to prefer different tenors between renewable energy classes, as has been indicated based on information from industry sources in the past).

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 2**. For Small Solar I, the difference in percentage debt is driven by the change in the tenor and the change in interest rate on term debt itself, whereas the difference for Small Solar II is driven solely by the change in the interest rate on term debt.

SEA Table 2 – Small Solar I and II Percentage Debt Assumptions for 2025 Program Year

Renewable Energy Class	Percentage Debt (2025 PY)	
	23-44-REG	***DG Board Recommended***
Small Solar I	51.00%	43.4%
Small Solar II	45.50%	45.2%

Q: Did SEA make any changes to its equity assumptions for Small Solar I and II?

A: No, we did not. SEA continues to assume a 7 percent (%) equity internal rate of return

(IRR) for Small Solar I projects, and a 12% IRR for Small Solar II projects, since it is SEA's understanding that these rates remain as appropriate metrics of the "opportunity cost" of capital for residential and small commercial customers. In the case of Small Solar I (which primarily are owned by residential customers), 7% is specifically intended as an approximation for the annualized long-term return on the Standard and Poor's (S&P) 500. In the case of Small Solar II (which are primarily owned by corporations), 12% is specifically intended as an approximation for the "hurdle rate" such corporations use for considering how to allocate their cash equity.

Q: Did SEA implement changes to assumptions regarding bonus depreciation for solar projects during the 2025 Program Year ceiling price development process?

A: No. Our team remains confident (as it was during the development of the 2024-2026 PY period prices for projects larger than 25 kW_{DC}) that no such projects bidding into Open Enrollments during the 2025 program year will be able to access bonus depreciation, given that, at this time, no Congressional action has been taken to date to extend such treatment beyond projects reaching commercial operation in 2026. Furthermore, our understanding remains that tax equity investors continue to prioritize spreading their tax equity across the largest number of projects possible, rather than concentrating more of such equity into individual projects, which leads them to de-emphasize the use of bonus depreciation for "typical" projects.

D. Recommended Classes and Prices

Q: What are the recommended Small Solar classes, modeled proxy system sizes, tariff terms and ceiling prices for the 2025 program year?

A: The recommended renewable energy classes, modeled proxy system sizes, tariff terms, and ceiling prices for the 2025 program year are shown in **SEA Table 3** below and are unchanged from those approved by the PUC in Docket 23-44-REG. Though the Small Solar I and II prices are newly-proposed, SEA notes that all prices for resources over 25 kW are unchanged from the values approved for those classes by the PUC for the in Docket 23-44-REG.[7]

[7] As a reminder, in Docket 23-44-REG, the PUC did not approve the Small Solar I and II ceiling prices for the 2025 and 2026 PYs proposed in that docket, instead opting to have OER and the DG Board propose them anew for each of the 2025 and 2026 PYs in separate dockets. The instant docket is the first such docket during the current three-year plan period.

SEA Table 3 – Recommended 2025 PY Renewable Energy Classes, Eligible and Modeled System Sizes, Tariff Terms, and Ceiling Prices (Incl. Comparison to Initially-Approved 2025 PY Approved Prices)

Renewable Energy Class	Eligible Size Range	Modeled Size	Tariff Term	PUC Approved 2025 PY	Recommended 2025 PY
Small Solar I	≤15 kW_{DC}	5.8 kW	15 Years	N/A	**34.55**
Small Solar II	>15-25 kW_{DC}	25 kW	20 Years	N/A	**33.35**

Q: Does SEA believe that the recommended Small Solar ceiling prices for the 2025 PY effectively balance cost-effectiveness with the other REG program policy objectives in Rhode Island statute?

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

Q: Q: Will SEA, as it has in prior years, make appropriate adjustments to the ceiling prices prior to April 1, 2025, if there are intervening changes in federal tax, trade or other policies that affect the economics of REG-eligible projects?

A: Yes. With the re-election of former President Trump on November 5, 2024, it is SEA's understanding that it is possible that certain changes to federal tax policy and/or trade tariffs (including tariffs with a direct potential impact on REG-eligible projects) could be made prior to the start of the 2025 PY. SEA plans to work closely with OER and the DG Board to track such changes and their potential impact on the 2025 PY program plan.

IV. RECOMMENDED TWO-YEAR INCENTIVE-PAYMENT ADDERS PILOT PROGRAM FOR BROWNFIELD REMEDIATION PROJECTS IN SELECTED SOLAR RENEWABLE ENERGY CLASSES

A. Scope of Analysis

Q: What did SEA's analysis in support of an updated Incentive-Payment Adder Pilot consider?

A: Per the PUC's written Order in Docket 23-44-REG, SEA's analysis considered the following aspects of the incentive-payment adder pilot:

- Incentive level
- Incentive format (e.g., ¢/kWh, fixed grant, dollars per acre, or an adder based on actual remediation costs)

- Program duration and size
- Eligible land types and renewable energy classes
- Alignment with other sources of state or federal funding, with particular attention paid to the Renewable Energy Fund ("REF") Brownfield incentives, Rhode Island Infrastructure Bank ("RIIB") Brownfields Revolving Loan Fund, the Brownfields Remediation and Economic Development Fund administered by the Department of Environmental Management ("DEM"), and the federal Investment Tax Credit ("ITC") Bonus for Energy Communities which includes incentive for Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") eligible brownfields.
- Implementation details

Q: Did SEA's research focus on the incremental costs of projects eligible for the incentive-payment adder?

A: No, inputs relating to the incremental costs of development on projects requiring remediation were researched in depth during the 2024-2026 ceiling price development process in Docket 23-44-REG. Accordingly, although SEA welcomed stakeholder comments and additional data pertaining to the incremental costs of such projects, such costs were not the focus of SEA's analysis.

Q: Does SEA anticipate that the incremental costs of projects eligible for the incentive-payment adder would have meaningfully changed since SEA's research was conducted?

A: No, SEA expects that such costs have not meaningfully changed.

Q: What did SEA's research process entail?

A: SEA first conducted general research on state and federal incentives that could be leveraged by adder-eligible projects participating in REG. Next, SEA conducted a series of interviews with DEM, RIIB, and Commerce Rhode Island's ("Commerce RI") Renewable Energy Fund (REF) to better understand if each source of funding could reasonably be leveraged for adder-eligible projects participating in REG. SEA presented initial findings to stakeholders and solicited feedback on its determinations as well as a number of incentive design questions (e.g., format of the incentive) at its September 10 stakeholder meeting (see **SEA Schedule 1**). SEA then provided responses to feedback received at its October 16 stakeholder meeting (see **SEA Schedule 2**), and welcomed further comment on any issues discussed. Throughout the process, SEA received comments from RI Energy and the DPUC. SEA did not receive written comments from industry members.

B. Discussion of Findings

Q: During the 2024-2026 program development process in Docket 23-44-REG, what categories of incentive-payment adder did the DG Board propose?

A: OER and the DG Board proposed incentive-payment adders for projects cited on brownfields and Superfund sites and a separate incentive-payment adder for projects sited on landfills. SEA provided adder values unique to each renewable energy class.

Q: For the updated incentive-payment adder proposal, what categories of incentive-payment adders do OER and the DG Board recommend?

A: OER and the DG Board recommend the adoption of a single incentive-payment adder of 1.6 ¢/kWh limited to brownfields only for Large Solar I and II. After careful consideration, OER determined that focus on brownfields adder was desirable for several reasons. As such, OER will not be pursuing an adder specific to landfills.

First, brownfield projects are expected (at present) to qualify for bonus federal tax credits, as discussed in detail below, which can reduce the cost to ratepayers. Second, discussions with DEM suggest that a large portion of capped landfills have already installed solar PV projects. Lastly, the statutory requirements that adders apply only to projects on parcels that "require remediation" limits eligibility to uncapped landfills. During the 2024-2026 program development process in Docket 23-44-REG, OER determined that an incentive-payment adder sufficient to cover the cost of capping a landfill was unreasonably expensive.

Q: Under the proposed incentive-payment adder pilot, could a landfill or superfund site that also qualifies as a brownfield receive the brownfield adder?

A: Yes. Any site that qualifies as a brownfield requiring remediation, subject to the expert determination of DEM, could qualify for the adder.

Q: Did stakeholders provide comments on the recommended adder value?

A: Yes. In its comments filed following SEA's October 16 stakeholder session (see **SEA Schedule 5**), the DPUC recommended that OER utilize a single adder value for projects in both eligible renewable energy classes and set the incentive-payment adder equal to the lower of the two calculated values. The DPUC also inquired as to why the calculated Large Solar II incentive-payment adder was higher than the Large Solar I incentive-payment adder.

Q: What was OER and the DG Board's reasoning in recommending a single adder value for both Large Solar I and II?

A: SEA's analysis found that the appropriate incentive-payment adder value specific to Large Solar I was 1.3 ¢/kWh and that the appropriate value specific to Large Solar II was 1.6

¢/kWh. OER and the DG Board determined that if the goal is to propose a single adder value for both classes, that single value should be equal to the higher of the two values to ensure the proposed incentive-payment adder was sufficient to support development at either scale while adhering to the principle discussed by the PUC at its April 29 Open Meeting that larger renewable energy classes should not receive compensation higher than smaller classes.

Q: Why is the calculated Large Solar II incentive-payment adder higher than the Large Solar I incentive-payment adder?

A: Projects larger than 5 MW are not eligible to include their interconnection costs in the basis for the calculation of federal ITC incentives. As such, Large Solar II projects receive reduced Year 1 tax benefits (the year in which the ITC is monetized by the project). Given that SEA applied a 10% ITC bonus to modeled brownfield projects, this decision resulted in larger Year 1 tax benefits relative to the project’s total installed costs for Large Solar I projects as compared to Large Solar II projects. The increase in federal tax benefits for Large Solar I was sufficient to outweigh the economies of scale benefits realized by Large Solar II with respect to the incremental costs of development on a brownfield requiring remediation. As such, the calculated Large Solar II incentive-payment adder was higher than the Large Solar I incentive-payment adder.

Q: What did OER and the DG Board decide with respect to the incentive-payment adder pilot duration?

A: OER and the DG Board determined that a pilot program lasting two program years was optimal given that it would make the adder available for a sufficient period to allow developers to react to its availability and bid into the program with adder-eligible projects). This duration was supported by the DPUC in its comments filed following SEA’s September 10 stakeholder meeting (see **SEA Schedule 5**SEA Schedule 1). SEA notes that this was the pilot duration that OER intended to propose in its original pilot program proposed in Docket 23-44-REG, however OER expressed the duration as “18 months” in its letter following hearings. For clarity, OER is now expressing the duration in terms of total program years.

Q: Why were those renewable energy classes selected?

A: Most of the 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: With respect to the incentive-payment adder pilot capacity allocation, what were SEA’s findings?

A: Consistent with the original incentive-payment adder proposal considered in Docket 23-44-REG, a 10 megawatt allocation to each of Large Solar I and II was optimal.

Q: Would capacity under the incentive-payment adder pilot function as a carve-out from other REG program capacity?

A: No. Under the proposed incentive-payment adder pilot, capacity available under the pilot would not be set aside from the total capacity offered for a given renewable energy class. As such, adder-eligible projects would be competing for program awards alongside non-adder-eligible projects to maximize competitive dynamics.

Q: In conducting its analysis, did SEA consider if Large Solar I and Large Solar II projects could reasonably qualify for the adder during the recommended two-year pilot period?

A: Yes. Given long timelines to complete interconnection study for a majority of Large Solar I and II projects, SEA engaged with RI Energy and DEM to determine if projects in the current interconnection pipeline could qualify for the proposed incentive-payment adder. DEM determined, based on a list of Large Solar I and II projects in RI Energy's third Affected System Operator study ("ASO#3"), that multiple projects were located on parcels that were potentially eligible for the proposed incentive-payment adder. SEA verified that there were sufficient projects flagged by DEM to utilize the proposed pilot program's capacity.

Q: Q: With respect to the ability of REG adder-eligible projects to leverage other sources of state or federal funding, what were SEA's findings?

A: SEA's findings, organized by funding source, are described below:

- **<u>REF Brownfields Incentives</u>:** REG projects are currently ineligible for funding through the REF program. As a general matter, SEA's research was focused on how third-party funding sources *under current rules* could be leveraged for an REG adder, given the difficulty and uncertainty related to potential changes to program rules for a pilot proposed to commence in 2025. As a result, SEA determined that REG funds could not be considered in the adder pilot development. Despite this, SEA did discuss the potential for program rule changes to allow REF funds to be leveraged for an incentive-payment adder under REG to inform future policy discussions. Discussion with the REF revealed that revising program rules to allow REG projects to qualify would require changing (or creating exemptions for) other projects requirements (namely around metering), as REF and REG projects face different and sometimes conflicting requirements. In addition, the REF and OER expressed significant concerns with the limited pool of funding available under the REF, which is sized to support predominately small commercial projects, being drained by the application of such funds to Large Solar I and II REG projects. These concerns are articulated in Commerce RI's letter (see **SEA Schedule 6**).

- **<u>RIIB Brownfields Revolving Loan Fund:</u>** SEA's discussions with RIIB revealed that the Brownfield Revolving Loan Fund currently has no funding available. Although RIIB expects it will receive funding via the U.S. Environmental Protection Agency's ("EPA") Greenhouse Gas Reduction Fund, such funding is earmarked for projects on already-remediated brownfields. As such, these funds would not be applicable to adder-eligible projects witch, per Chapter 300, must be cited on parcels requiring remediation.
- **<u>DEM Brownfield Remediation and Economic Development Fund:</u>** SEA's discussions with DEM confirmed that REG-eligible projects could, in theory, qualify for funding through DEM's Brownfields Remediation and Economic Development Fund. However, several factors make it highly unlikely that an REG-eligible project would be awarded funding. Fund applications are scored by the DEM Review Committee based upon several criteria, including economic impact, beneficial environmental impact, benefits to the local community, and readiness to proceed with the project. In general, it was DEM's assessment that typical ground-mounted solar projects cited on brownfields would not score competitively in certain categories. Furthermore, DEM reported that, historically, program awards are highly competitive, with only one third of applicants receiving awards each funding cycle. Given this, SEA determined that it was not reasonable to assume that an adder-eligible REG project could qualify for DEM funds. DEM confirmed that, historically, no ground-mounted solar project had been awarded funds through the Brownfields Remediation and Economic Development Fund. However, SEA views information collection as an important aspect of the pilot program. As such, and in line with recommendations made by the RI Energy in their October 17 comments (see **SEA Schedule 5**), OER recommends that RI Energy collect information via the REG program application regarding a bidder's plans to pursue third-party funding, and that DEM provide records regarding any renewable projects selected through brownfields Remediation and Economic Development Fund to RI Energy.
- **<u>Internal Revenue Code Section 48/48E ITC Bonuses for Energy Communities</u>:** The Inflation Reduction Act of 2022 provides 10% ITC bonuses for projects sited in "energy communities," including CERCLA eligible brownfield. Discussion with DEM and review of Sections 48 and 48E of the Internal Revenue Code confirmed that brownfields in Rhode Island are expected to be predominantly CERCLA eligible. Although certain exclusions apply, given the limited scale of adder pilot, it is unlikely that the availability of bonus ITC-eligible sites will be the constraining factor. Given this, SEA determined

that it was appropriate to apply a 10% ITC bonus to the calculation of cost-based adder values such that the incentive-payment adder pilot would contain incentive levels appropriate for ITC bonus-eligible projects.

Q: What incentives are offered under the REF's Brownfields incentive?

A: The REF's Brownfields incentive offers up-front incentives of $1,000/kW, with a max of $250,000 for direct-ownership projects. For third-party owned projects, the incentive is $800/kW with a max of $175,000.

Q: Did stakeholders provide comments regarding the alignment of an incentive-payment adder pilot with other funding sources? If so, please provide an overview.

A: Yes. First, the DPUC provided SEA with numerous questions regarding additional information relating to potential program rule changes, but did not provide specific recommendations or arguments in conflict with SEA's findings (see DPUC's comments filed in response to SEA's September 10 stakeholder meeting, **SEA Schedule 5**).

Second, RI Energy argued that the PUC's directive to "align improved siting in the Renewable Energy Growth program with other programs and ratepayers' interests" suggests that any "adder pilot should place the Renewable Energy Growth program on a level playing field relative to other compensation programs" (see **SEA Schedule 5**). Based on this interpretation, RI Energy concluded in its comments that "it follows that the Commission's objective would be achieved if the exact same incentive design [as the Renewable Energy Fund], including the cap, were to be available to projects compensated through the Renewable Energy Growth Program." RI Energy further argued that this objective could be achieved if the REF Brownfields Program opened its eligibility to REG projects.

Q: As a reminder, what was the PUC's directive to "parties" in the ordering paragraph of the August 29 Report and Order regarding incentive-payment adders?

A: On p. 33 of the August 29 Report and Order, the PUC orders that, in pertinent part:

> *Parties may file a new pilot proposal at least 105 days prior to the proposed commencement of the pilot. The purpose of the pilot should be* to align improved siting in the Renewable Energy Growth program with other programs and ratepayers' interests. *At a minimum, the proposal shall consider the design of the incentive, the level of compensation, total program size, and* ***alignment with other sources of funding*** *for similar policy outcomes* ***<u>including, but not limited to</u>*** ***[emphasis and <u>underline</u> added]*** *the Renewable Energy Fund's Brownfield incentive, Rhode Island Infrastructure Bank Brownfields Revolving Loan Fund, and DEM's Brownfield Site Preparation and Remediation Grant.*

Q: Under Rhode Island statute, are OER or the DG Board one of the "parties" that are bound by R.I.G.L. § 39-26.6-22 to propose an adder if a series of potential criteria related to benefits are met?

A: Yes, they are.

Q: Does RI Energy's interpretation of the PUC's directive consider the totality of what the PUC ordered OER and the DG Board to do in re-proposing an incentive-payment adder pilot?

A: No. The scope of consideration that the PUC ordered OER and the DG Board must engage in for any re-proposed adder is *clearly* not limited to the specific terms of the REF incentive program, but to generally ensure that any proposed pilot would "align improved siting in the [REG] program with other programs and ratepayer interests" writ large. Furthermore, the PUC concludes the relevant ordering paragraph by saying that *not only* the REF Brownfield incentive *but also* two other programs must be also given equal consideration. In contrast, the logical foundation for RI Energy's assertions rests upon the company's apparent attempt to redefine the verb "align" as "to make identical."

Q: What is OER and the DG Board's understanding of the PUC's directive?

A: OER and the DG Board understanding of the directive to "align" the REG program with other programs is to ensure that all facets of a proposed REG incentive-payment adder pilot program (e.g., incentive format and level) are examined in relation to existing state and federal incentive programs. OER and the DG Board's understanding is that a key aspect of such alignment is the consideration of other state and/or federal incentives that could reasonably be leveraged by REG adder-eligible projects when calculating an adder, such that the adder is developed in alignment with other incentives potentially available to REG-eligible projects.

Q: If, as RI Energy claims, the PUC was certain that it *only* wanted to consider an adder on the precise terms of the REF Brownfield incentive, would it have been redundant for it to have ordered OER and the DG Board to examine (in any re-proposal) the potential contribution of other state brownfield-focused programs to project economics in developing an adder pilot proposal?

A: Yes, it would.

Q: In SEA's expert opinion, what conditions must be met for an incentive-payment adder to be optimal?

A: For an incentive to be optimal, it must cover the incremental revenue requirements introduced by the attribute the adder intends to encourage (e.g., siting on a brownfield requiring remediation) for a typical project such that it ensures the project breaks even from a net-present-value perspective, after accounting for reasonable returns on investment. An optimal incentive-payment adder should not overcompensate a project such that it provides more revenue than is necessary for a typical project to be developed, constructed, and operated.

Q: In SEA's expert opinion, does it believe that adopting an identical incentive as the REF's

Brownfields incentive would yield an optimal incentive, given the parameters in the previous answer?

A: No. The per-project caps in the REF's Brownfields incentive, and the REF in general, are clearly targeted at small commercial projects, typically under 250 kW. As such, the incentives offered under the REF's Brownfields incentive maxes out at 250 kW for direct-owned projects and approximately 220 kW for third-party owned projects. Given this, the incentive's caps were designed with a fundamentally different project scale in mind and would yield insufficient revenue to cover the incremental expenses associated with Large Solar I or II development on a brownfield requiring remediation.

Q: During SEA's discussions with RI Energy regarding their comments, did the company acknowledge that the REF incentive was likely designed with smaller projects in mind than those multi megawatt scale solar projects eligible under the proposed pilot program?

A: Yes, they did.

Q: Did SEA conduct modeling to substantiate the claim that REF incentive levels would be insufficient to cover the incremental costs associated with development on a brownfield requiring remediation for Large Solar I and II REG projects?

A: Yes. SEA utilized the CREST model to calculate the ¢/kWh equivalent of the REF's Brownfields incentives. Our analysis suggests that, for Large Solar I, the maximum award for third-party owned facilities of $175,000 is equivalent to a 0.4 ¢/kWh adder, relative to the 1.3 ¢/kWh incremental revenue requirement for such a project. For Large Solar II, the maximum award for third-party owned facilities of $175,000 was equivalent to a 0.2 ¢/kWh adder, relative to the 1.6 ¢/kWh incremental revenue requirement for such a project.

As such, the REF incentive, assuming its current cap structure, would only cover 31 percent (%) of the 1.3 ¢/kWh necessary to cover the incremental costs associated with development of a Large Solar I project on a brownfield requiring remediation, and only 12.5% of the 1.6 ¢/kWh necessary to cover the incremental costs of a similarly-situated Large Solar II project.

Q: During SEA's discussions with RI Energy regarding their comments, did the company also acknowledge that an incentive offered on the exact terms of the REF incentive levels would likely be insufficient to cover the incremental costs of projects eligible for the proposed pilot program?

A: Yes, they did.

Q: Given the considerations above, what are SEA's conclusions with respect to the applicability of REF incentives to Large Solar I and II REG projects?

A: SEA concludes that the REF's Brownfield incentives were not designed with Large Solar I and II-scale projects in mind, and thus could significantly under-compensate such projects. Given this, drawing conclusions regarding the optimal incentive-payment adder level for brownfield-sited Large Solar I and II REG projects based on REF incentives and project performance is not appropriate.

Q: Do OER and Commerce RI object to the application of REF's funds to REG projects?

A: Yes. As provided in **SEA Schedule 6** the REF program manager expressed significant concerns with the limited pool of funding available under the REF, which is sized to support small commercial projects, being drained by the application of such funds to Large Solar I and II REG projects. In addition, the REF program manager identified timeline and administrative capacity constraints that would make the application of REF funds to REG-eligible projects infeasible in the near-term.

Q: Does SEA believe that the DG Board's proposed incentive-payment adders for a two-year pilot program accomplish the goal of aligning REG incentives with other state and federal funding sources?

A: Yes. The proposed incentive-payment adders ensure optimal incentives for the scale of project the pilot is designed to target and consider the ability for a typical eligible project to realistically leverage other state and federal funding sources.

Q: With respect to the incentive-payment adder format, what were SEA's findings?

A: OER, in consultation with SEA, ultimately determined that a ¢/kWh incentive was the most optimal incentive-payment adder format due to its ease of implementation, predictability, and its ability to tie compensation to project performance. Our findings regarding alternative incentive formats are provided below:

- **Upfront Grants**: Upfront incentives have the potential to reduce the total adder required (due to the operation of the time value of money), but present risks regarding achievement of benefits, as well as the front-loaded nature of the cost to ratepayers. Such benefits did not outweigh the potential risks of an upfront adder.
- **$/Acre Incentives**: Incentives based on the total acreage of land remediated have the potential to align incentives with conservation benefits realized through project development. However, $/Acre incentives do not provide projects with an incentive to maximize the capacity of a project within a given parcel requiring remediation given the incentive would not be tied to project size or energy production. In addition, a $/Acre incentive offers little benefits given that the proposed incentive-payment adder pilot would include provisions adjusting the final adder value based on the percentage of the

project overlapping eligible land. Constraining the application of a ¢/kWh adder to only the portion of a project sited on a parcel requiring remediation achieves the same goal of sizing incentives relative to remediation benefits delivered, while ensuring that incentives are still tied to project performance.

- **Incentives Based on Actual Costs**: Incentives based on a project's actual realized costs have the potential to right-size incentives to project-specific costs. However, administrating such an incentive would be complex and administratively burdensome, as it would require unique CREST model calculations for each project, significant data collection, and data validation. In addition, many project costs would not be known at the time incentives are calculated, such as certain project operating expenses, requiring the use of estimates. Based on SEA's market research, brownfield projects face significant development hurdles that greatly increase the development risk of pursuing such projects. As such, reducing an incentive to only cover realized costs would reduce the incentive to pursue more challenging projects. Lastly, under the proposed ¢/kWh adder, competitive dynamics will allow adder-eligible projects to bid more aggressively for their base compensation, thereby allowing lowest-cost projects.

Q: Did stakeholders provide comments regarding the incentive-payment adder format?

A: Yes. In its comments in response to SEA's September 10 stakeholder session (see **SEA Schedule 5**), the DPUC recommended the adoption of an incentive-payment adder scaled to actual project costs. In addition, the DPUC discussed many of the tradeoffs described by SEA above, but did not explicitly recommend the adoption of a $/kW or $/Acre adder. In its comments in response to SEA's September 10 stakeholder session, RI Energy noted that a ¢/kWh adder would be the simplest for it to administer.

Q: In the absence of adopting an incentive-payment adder scaled to actual project costs, did the DPUC offer an alternative?

A: Yes. In its comments in response to SEA's October 16 stakeholder session (see **SEA Schedule 5**), the DPUC recommended that the pilot program collect sufficient information to "back calculate" the actual required adder based on the actual project costs.

Q: Does OER agree there is merit to information collection regarding actual project costs?

A: Yes. An important goal of the two-year pilot program is to collect information regarding actual project costs. As such, OER proposes that the incentive-payment adder pilot include requirements that RI Energy collect from all adder-eligible program applicants data on expected upfront costs, including the separate reporting of remediation costs, and certain operational costs, including land lease expenses.

Q: Did stakeholders comment upon the cost inputs used in the calculation of the incentive-payment adder?

A: Yes. In its comments in response to SEA's October 16 stakeholder session (see **SEA Schedule 5**), the DPUC argued that land lease costs for brownfields should be lower than the assumed land lease costs for a greenfield project. In addition, RI Energy asked a series of questions regarding SEA's data sources for the calculation of land lease costs, but did not provide any explicit recommendations.

Q: Did the DPUC or any other stakeholder provide SEA with data pertaining to the land lease costs of solar on brownfields?

A: No. The DPUC's assertion that such costs should be lower than land lease costs for solar on greenfields was not accompanied by data.

Q: What is the basis for SEA's current assumption that land lease costs for solar on brownfields are identical to land lease costs for solar on greenfields?

A: During SEA's research process in support of the initial adder program proposed in Docket 23-44-REG, the consulting team interviewed multiple developers active in the development of solar on brownfields in the Northeast to inform inputs used in modeling. These interviews suggested that land lease costs were comparable for either siting case. In addition, these results were benchmarked against data collected by SEA through prior engagements in which SEA surveyed market participants to understand costs associated with solar development on brownfields.

Q: Did stakeholders provide any other comments regarding the proposed incentive-payment adder pilot implementation?

A: Yes. RI Energy recommended that "DEM, as the authority on siting, make all siting determinations, including if a project is on a preferred site requiring remediation, and what percentage of panels are within the preferred site requiring remediation compared to the total project's panels."

Q: Did OER and the DG Board agree with these recommendations?

A: Yes.

Q: Did SEA, on behalf of OER and the DG Board, consult with DEM regarding their ability to act as the authority on siting determinations for an incentive-payment adder pilot?

A: Yes. DEM confirmed they would be able to fulfill this role.

C. <u>Recommended Incentive-Payment Adder Pilot Program</u>

Q: What are the recommended incentive-payment adders for the 2025 through 2026 program year?

A: The recommended incentive-payment adders for the 2025 through 2026 program year are provided below in **SEA Table 4**.

SEA Table 4 - Recommended Brownfield Adder (For 2025-2026 PYs)

Renewable Energy Class/ Project Size	Eligible Project Size (MW_{DC})	Adder Capacity Allocation (MW_{DC})	Final Recommended Brownfield Adder (¢/kWh)
Large Solar I	1-<5 MW	10	1.6
Large Solar II	5-<10 MW	10	

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

A: Overall, the recommended brownfield adders are substantially lower than those adopted in Massachusetts and Connecticut.

- In Massachusetts, the Solar Massachusetts Renewable Target ("SMART") Program, which are approximately 3-4 ¢/kWh, as seen in the SMART Capacity Block, Base Compensation Rate, and Compensation Rate Adder Guideline.[8]
- In Connecticut, the Non-Residential Renewable Energy Solutions ("NRES") policy lever to incent development on previously disturbed sites takes the form of a 20% bid preference, rather than a flat adder, which allows for projects to bid higher in the procurement to reflect increased costs, but still compete with greenfield sites based upon the "evaluated bid price." Projects are paid the as-bid price over the tariff term, i.e. the bid price before the 20% reduction is applied. Details can be found in the NRES Year 3 Program Manual.[9] While the actual value of the bid preference fluctuates depending on the bid price, the weighted average value of the bid price preference in the program among projects that were selected in the procurement is 3.18 ¢/kWh, as seen in the

[8] Available at: https://www.mass.gov/doc/capacity-block-base-compensation-rate-and-compensation-rate-adder-guideline-2/download

[9] Available at: https://www.eversource.com/content/docs/default-source/save-money-energy/nres-year-3-program-manual.pdf?sfvrsn=cc29a16f_1

Eversource and United Illuminating Company NRES procurement results.[10]

Q: Under the proposal, would the adder value change if a project is not fully located on a parcel requiring remediation?

A: Yes. Consistent with the proposed adder approach in Docket 23-44-REG, the adder would be equal to 1.6 cents/kWh multiplied by the percentage of the project that overlaps with a brownfield parcel requiring remediation. As such, the value of the adder would scale based on the proportion of the project overlapping the eligible land type.

Q: What additional requirements are OER and the DG Board recommending as a component of the incentive-payment adder pilot?

A: OER and the DG Board recommend that DEM be required to report any awards for solar projects made through its Brownfields Economic Development and Remediation fund to RI Energy, OER and the DG Board. OER and the DG Board further recommend that RI Energy collect the following information at program application:

- Bidder’s plans to pursue third-party funding (e.g., other state incentives);
- Estimated total project installed cost;
- Estimated costs associated with site remediation; and
- Estimated operating expenses associated with the site in question, including estimated incremental O&M expenses due to the siting on a brownfield and land lease expenses.

Q: Consistent with current practice following the enactment of the 2023 solar siting law, do OER and the DG Board intend that DEM continue to make all siting determinations, including if a project is on a preferred site requiring remediation, as well as what percentage of panels are within the preferred site requiring remediation compared to the total project’s panels?

A: Yes.

Q: Per the PUC’s Docket 4600 framework, is the proposed incentive-payment adder pilot targeted in scope and timing?

A: Yes. The proposed two-year pilot program, which would support the amended REG law to advance REG large solar development on preferred sites, is targeted to Large Solar I and II

---

[10] Eversource results are available at: https://www.eversource.com/content/docs/default-source/save-money-energy/nres-program-summary-data.xlsx?sfvrsn=f8abb379_1
United Illuminating are available at:
https://www.uinet.com/documents/1678076/1703797/NRES+Program+Summary+as+of+Q3+2024_08.27.24.xlsx/67328cd7-f164-bff8-9d80-152bd3e47798?t=1724788075471

projects sited on brownfield parcels requiring remediation, is limited to a total of 10 MW per renewable energy class, and is proposed for a duration of two program years.

Q: Per the PUC's Docket 4600 framework, how will the proposed incentive-payment adder pilot test the feasibility of future programs?

A: The proposed pilot will help assess the optimal incentives and program design based on the level of pilot participation and feedback and data received from pilot participants regarding actual project expenses and the ability to leverage other state or federal funding sources. As such, it will allow stakeholders to continue to test the most effective means of fulfilling the General Assembly's intent to ensure development shifts to preferred sites.

Q: Would SEA be able to provide a status report on the Pilot Program if approved by the Commission?

A: Yes. OER and SEA, in collaboration with RI Energy, would be able to provide a biannual written update on the status of the Pilot Program to the Commission and other intervening parties to this docket if ordered.

V. RECOMMENDED 2025 PROGRAM YEAR MEGAWATT ALLOCATION PLAN

A. Analysis in Support of Megawatt Allocation Plan for 2025 Program Year

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

A: In tasking SEA with developing the Megawatt Allocation Plan, OER directed SEA to carefully consider and balance the objectives of developing a robust plan that would not unduly constrain deployment of distributed renewable energy projects, but also promote healthy competition and limit costs to ratepayers.

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

A: With respect to ratepayer cost mitigation, SEA focused on assessing the relative competitiveness of future solicitations to avoid proposing capacity allocations in which insufficient capacity to produce healthy competition was available in the interconnection queue or in which a high concentration of projects in the interconnection process are sponsored by a single market participant for any given renewable energy class.

Q: Can you please describe how SEA went about ensuring healthy competitive dynamics?

A: Yes. Our team sought data from (and worked closely with) RI Energy to:

- Identify the number of unique developers with projects in the interconnection queue in each renewable energy class, as well as the relative share of capacity owned by each developer;
- Estimate the capacity of projects expected to be able to bid into the 2025 PY, with consideration given to the likelihood a project could bid into the REG 2025 PY based on each project's stage in the interconnection process and its involvement in ASO studies; and
- Identify the ability for net metering projects at various interconnection stages to change course and bid into the REG Open Enrollments.

Q: Did RI Energy provide SEA with project-specific determinations regarding their ability and likeness to qualify for the 2025 PY?

A: Yes. For all Large Solar II and III projects, RI Energy provided SEA with project-specific determinations regarding their ability and likeness to qualify for the 2025 PY which were adopted in SEA's analysis.

Q: For Large Solar I, how did SEA estimate the total capacity of projects that could qualify for the 2025 PY?

A: In coordination with RI Energy, SEA developed assumptions regarding the percentage of Large Solar I projects at each stage of the interconnection process that would qualify for the 2025 PY. As a result, SEA's analysis de-rated the total capacity of projects in the interconnection queue that could potentially be eligible for the 2025 PY based on these probabilities of success assumptions. In addition, these assumptions were combined with project-specific information provided by RI Energy regarding a project's inclusion in ASO studies which resulted in further capacity being excluded from consideration for Plan A (in the case of involvement in any study other than ASO#3) or Plan B (in the case of any ASO study involvement).

Q: Did RI Energy review SEA's analysis regarding the expected volume of projects, and the relative market concentration across unique developers, in each resource class eligible to participate in REG 2025 PY?

A: Yes. A summary of this accounting by size bin is contained in **SEA Table 5** and **SEA Table 6**.

SEA Table 5 - Total Capacity (MW_{AC}) of Solar Projects (Excluding Projects in ASO#3) Likely to be Eligible for REG 2025 PY by Interconnection (IC) Process Milestone and Size Bin

IC Process Milestone	Preapplication	Application	Screening	Supplemental Review	Study	Conditional Approval	Design	Construction	Total
Large Scale IV (15 - <39MW)	[redacted]								
Large Scale III (10 - <15MW)	[redacted]								
Large Scale II (5 - <10MW)	[redacted]								
Large Scale I (1 - <5MW)	[redacted]								
Commercial Scale II (>500 - <1000kW)	[redacted]								
Commercial Scale I (>250 - 500kW)	[redacted]								
Medium Scale (>25 - 250kW)	[redacted]								
Small Scale II (>15 - 25kW)	[redacted]								
Small Scale I (0 - 15kW)	[redacted]								

SEA Table 6 - Total Capacity (MW_{AC}) of Solar Projects (Including Projects in ASO#3) Likely to be Eligible for REG 2025 PY by IC Process Milestone and Size Bin

IC Process Milestone	Preapplication	Application	Screening	Supplemental Review	Study	Conditional Approval	Design	Construction	Total
Large Scale IV (15 - <39MW)	[redacted]								
Large Scale III (10 - <15MW)	[redacted]								
Large Scale II (5 - <10MW)	[redacted]								
Large Scale I (1 - <5MW)	[redacted]								
Commercial Scale II (>500 - <1000kW)	[redacted]								
Commercial Scale I (>250 - 500kW)	[redacted]								
Medium Scale (>25 - 250kW)	[redacted]								
Small Scale II (>15 - 25kW)	[redacted]								
Small Scale I (0 - 15kW)	[redacted]								

Q: In addition, how did SEA account for ongoing interconnection delays in the development of the plan?

A: Though it is our understanding that the most intensive analytical phases of ASO#3 have concluded as of the date of this filing, it is SEA's understanding that any projects choosing to proceed in the interconnection process following the conclusion of the study may be subject to re-study if other projects in the study choose to drop out. To accommodate these potential re-studies, the DG Board recommends that all capacity greater than or equal to 1 MW_{DC} should be offered in the third (and final) Open Enrollment of the 2025 PY procurement cycle. SEA believes that this step is prudent, given that it will maximize the number of potential bidders in that final Open Enrollment, thus maximizing the potential value of the procurement outcome for ratepayers.

In addition, the DG Board recommends that the PUC approve two separate Megawatt Allocation Plans, contingent upon the resolution of any re-studies associated with ASO#3. These specific plans are referred to hereafter as Plan A and Plan B. These specific Plan A and Plan B values are informed by the information in **SEA Table 5** and **SEA Table 6**, and further limited to account for potential over-concentration of market power in the hands of specific potential bidders in specific renewable energy classes.

Q: As proposed by OER and the DG Board, under what conditions would the proposed Plan A or Plan B take effect?

A: Plan A refers to the DG Board's recommended plan in the case that RI Energy *can* finalize ASO#3 results, including any required re-studies, by forty-five (45) days prior to the anticipated opening of the Third Open Enrollment window for the 2025 Program Year. Plan B refers to the DG Board's recommended plan in the case that RI Energy *cannot* finalize ASO#3 results forty-five (45) days prior to the anticipated opening of the Third Open Enrollment window for the 2025 Program Year. Plan B includes reduced capacity in the Large Solar renewable energy classes, reflecting that the availability of eligible projects in such renewable energy classes is contingent on the conclusion of ASO#3.

Q: Are OER and the DG Board requesting that the PUC choose *between* Plan A and Plan B?

A: No. OER and the DG Board are recommending that the PUC approve both Plan A and Plan B, and that *either* Plan A or Plan B take effect based on the timing of the finalization of ASO#3, as reported by RI Energy.

Q: Based on the dataset provided by RI 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: Similar to the approach utilized during the development of the recommended 2024 PY allocation plan, SEA limited its analysis of the interconnection queue for the purpose of recommending (to OER and the Board) 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 RI 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 RI 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 the interconnection of projects, SEA assumes that these projects will emerge from the process on an ongoing basis, and thus does not factor the volume of projects currently in the interconnection queue as significantly into setting a capacity allocation for such renewable energy classes.

Q: Did SEA, on behalf of OER, receive feedback from stakeholders during the 2025 PY Megawatt Allocation Plan development process?

A: Yes. SEA received comments from Solect Energy (a market participant) and RI Energy.

Q: Please summarize the feedback supplied from Solect Energy.

A: Solect recommended that any unused capacity in the Large Solar categories be re-allocated to renewable energy classes for projects less than 1 MW_{DC}.

Q: Is this recommendation included in the recommended Megawatt Allocation Plan alternatives?

A: No, because OER and the DG Board's decision to recommend that RI Energy only offer capacity 1 MW_{DC} and larger in the third and final Open Enrollment precludes the Company's ability to reallocate such capacity during the 2025 PY.

Q: Please summarize the feedback supplied by RI Energy on the Megawatt Allocation Plan.

A: RI Energy recommended the following changes:

- That the Large Solar III allocation under Plan A be reduced from 30 MW to 15 MW due to potential competitiveness concerns; and

- That the capacity allocated to the renewable energy classes for projects less than 1 MW_{DC} be reduced to the statutory minimum of 30 MW_{DC} per year for such projects.

Q: Did the DG Board adopt RI Energy's recommendations?

A: Upon OER's recommendation, the DG Board voted to recommend a Megawatt Allocation Plan to the PUC that incorporated RI Energy's recommended 15 MW_{DC} allocation for Large Solar III. However, the DG Board (also at OER's recommendation) declined to adopt the Company's recommendation to reduce the less than 1 MW_{DC} capacity to allocation to the 30 MW_{DC} statutory minimum.

B. <u>Recommended 2025 Megawatt Allocation Plan</u>

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

A: OER and the DG Board's proposed Megawatt Allocation Plans A and B are shown in **SEA Table 7** below.

SEA Table 7 – DG Board Recommended Megawatt Allocation Plan (2025 Program Years)

Renewable Energy Class	Eligible System Sizes	2024 PUC Approved MW Allocation Plan	"Plan A" MW_{DC} (2025 PY)	"Plan B" MW_{DC} (2025 PY)
Small Solar	<=25 kW_{DC}	9	9	9
Medium Solar	>25-250 kW_{DC}	5	7	7
Commercial Solar I	>250-500 kW_{DC}	7.5	9.5	9.5
Commercial Solar I (CRDG)	>250-500 kW_{DC}	0.5	0.5	0.5
Commercial Solar II	>500 kW-1 MW_{DC}	10.5	11.5	11.5
Commercial Solar II (CRDG)	>500 kW-1 MW_{DC}	1	1	1
Large Solar I	>1-<5 MW_{DC}	15	20	10
Large Solar I (CRDG)	>1-<5 MW_{DC}	5	5	5
Large Solar II	5 MW-<10 MW_{DC}	35	30	0
Large Solar III	10-<15 MW_{DC}	15	15	0
Large Solar IV	15-<39 MW_{DC}	0	0	0
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}			
Total		**107.5**	**112.50**	**57.50**

Q: With the plan shown in SEA Table 7 above, are OER and the DG Board requesting procurement of the full 300 MW per year that is eligible under the amended REG law for the Board to submit to the Commission for consideration?

A: No, they are not. Based on SEA's review and discussions with OER and Rhode Island Energy it would not be prudent to make that recommendation.

Q: Does SEA believe that the recommended Plan accomplishes OER's key objectives?

A: Yes, we do.

Q: Why did OER and the DG Board recommend that it was reasonable to not include any capacity in the Large Solar IV classes during for the 2025 Program Year?

A: As shown in **SEA Table 5** and **SEA Table 6** above, SEA's analysis revealed that there is no capacity in that renewable energy class that is likely to be eligible to bid into the third Open Enrollment of the 2025 PY.

VI. COST-EFFECTIVENESS OF 2025 PROGRAM YEAR MEGAWATT ALLOCATION PLAN AND PROPOSED BROWNFIELD REMEDIATION ADDER PILOT

A. Identification of Benefits Under R.I. Gen. Laws § 39-26.6-22 for the Two-Year Adder Pilot Program,

Q: Did SEA evaluate the benefits and costs of the recommended 2025 REG program plan?

A: Yes, we did.

Q: Could SEA please provide the benefit categories calculated and included in this benefit-cost analysis ("BCA"), a description of these benefits, and the source for the benefit values?

A: Yes, please see **SEA Schedule 7** for this information.

Q: Do any of the benefits shown in SEA Schedule 7 constitute "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) 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 7 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 7 constitute a "conservation benefit" as described in R.I.G.L. § 39-26.6-22?

A: Yes. In the instant analysis, the categories of benefits identifiable as conservation benefits consistent with R.I.G.L. § 39-26.6-22 include the non-carbon value of ecosystem services as well as the social value of brownfield remediation.

The non-carbon value of ecosystem services is associated with water supply, water quality, flood and storm damage mitigation, wildlife habitat and air pollution removal provided by conserved open space.[11] In the instant analysis, they are applied only to projects sited on brownfields, since such parcels are not assumed to provide similar ecosystem services and thus development on such parcels avoids the degradation of ecosystem services were such development to otherwise occur on a greenfield. Next, the social value of brownfield remediation is associated with human health and ecological benefits from brownfields remediation.

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

A: No. As noted in our testimony filed in Docket No. 23-44-REG, 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 the 2023 solar siting law to eliminate most solar development on core forest parcels.

Q: Did SEA revise its approach relating to the accounting of the non-carbon value of ecosystem service benefits?

A: Yes. In response to the PUC's feedback during the Docket 23-44-REG process, SEA determined it was most appropriate to include the value associated with non-carbon value of ecosystem service benefits as a cost for all projects in renewable energy classes over 1 MW assumed cited on a greenfield. As such, the absence of such costs for adder-eligible projects constitutes an incremental benefit.

Q: Per R.I.G.L. § 39-26.6-22, does this analysis justify a finding of the required types of benefits within the load zone of RI 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.

---

[11] 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

B. Detailed Cost-Effectiveness Methodology – 2025 PY Small Solar Ceiling Prices and Megawatt Allocation Plan

Q: What methodology did SEA use to complete the instant BCA?

A: SEA utilized data from the User Interfaces of the Avoided Energy Supply Cost in New England 2024 study (AESC 2024), which is accepted as a high-quality source for benefit-cost analysis data (including as a basis for BCA calculations for RI Energy's various energy efficiency programs). Given the robust approach taken by the Synapse Energy Economics team[12] in completing this analysis, we believe that many well-vetted assumptions are included herein.

Q: Could you please briefly describe AESC 2024?

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 RI Energy), state energy offices and other regulators, as well as select other stakeholders. The most recent completed version was released in May 2024.

Q: Which baseline scenario from AESC 2024 did SEA utilize for the instant BCA, and why?

A: SEA utilized AESC 2024's Counterfactual #5 ("All-In DERs") as the baseline scenario for this analysis. Unlike Counterfactuals #1-#4, Counterfactual #5 not only assumes further deployment of energy efficiency, demand response, and further electrification of transportation and buildings, but also assumes further deployment of DG in the ISO-NE control area. As such, it serves as the best fit for a counterfactual scenario amongst the available scenarios for analyzing the benefits and costs of further DG deployment in Rhode Island under current policy.

Q: In the instant BCA analysis, did SEA utilize the same AESC 2024 inputs as was used in SEA's analysis in Docket 23-44-REG?

A: Yes.

Q: What tests did SEA utilize in its analysis?

A: SEA utilized three specific tests:

---

[12] For full disclosure, SEA participated in the development of the AESC 2024 analysis as a subcontractor to Synapse Energy Economics, providing renewable energy buildout and REC/CEC price estimates.

1. The RI Test (developed by the PUC in Docket No. 4600); and
2. A "Cost of Supply" Test. This test includes all monetizable benefits of the program's incentivized generation to ratepayers in the ISO-NE control area, and was utilized by RI Energy in its supplemental response to PUC Data Request 3-2 in Docket 23-44-REG; and
3. A Rhode Island Ratepayer Test, which includes all monetizable benefits of the program's incentivized generation to ratepayers in Rhode Island.

Q: Is SEA introducing other elements into the BCA relative to the one conducted in Docket No. 23-44-REG?

A: Yes. First, during the Docket 23-44-REG process, SEA presented BCA results in Net Present Value ("NPV") $/MW$_{DC}$ terms. In response to concerns from the PUC regarding total program costs, SEA is now presenting the results of its BCA in total dollar terms based on the proposed Megawatt Allocation. Specifically, SEA is presenting high and low-end cost estimates. To facilitate this, SEA has developed estimates (based on historical data) of the percentages of available capacity that will ultimately be selected, as well as the percentage of selected projects that ultimately reach commercial operation. Our team found that this selection- and commercial operation-adjusted value is, on a historical basis, equivalent to 51% of any given Megawatt Allocation Plan's capacity. Furthermore, our team found that no program year's capacity was both fully subscribed and fully reached commercial operation. Therefore, SEA's low-end BCA estimates assume that 51% of the 2025 PY Megawatt Allocation reaches commercial operation, while our high-end BCA estimate assumes that the entire Plan is fully subscribed and fully reaches commercial operation. Using this range of potential capacity commercial operation and selection rates, SEA was also able to calculate these values on a total NPV basis, instead of an NPV in $/MW basis.

Q: What are the assumed project development timeframes utilized in the BCA 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: Did the BCA consider non-solar renewable energy classes?

A: No.

Q: Do you believe that the limitation in the scope of the BCA to only Solar renewable energy classes 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 that reaches commercial operation.

Q: Which cost categories are utilized under each test in the analysis?

A: For all tests, the total cost is equivalent to the tariff cost for projects assumed to reach commercial operation under the REG program during the 2025 PY.

Q: Which benefit categories are utilized under each test utilized in the analysis?

A: The Rhode Island Test considers benefits monetizable in organized electric and gas markets in New England as well as unmonetized societal benefits (namely, benefits associated with greenhouse gas reduction and benefits associated with the social value of brownfield remediation). The Cost of Supply Test values the same monetizable benefits to ratepayers in organized electric and gas markets in New England but does not consider unmonetized societal benefits. Unlike the Cost of Supply Test, the Rhode Island Ratepayer Test considers only benefits directly accruing to Rhode Island ratepayers (and thus excludes all "rest of pool" (ROP) benefits monetized by ratepayers outside of Rhode Island).

Q: Can you provide a full list of benefits and costs by test utilized in the instant analysis?

A: Yes. The specific benefit and cost categories for each test are shown in **SEA Table 8** below.

SEA Table 8 – Benefits and Costs Analyzed In Each Benefit-Cost Test

Benefit/Cost Category	RI Test	Cost of Supply Test	RI Ratepayer Test
REG Tariff Cost	Cost	Cost	Cost
Avoided Energy	Benefit	Benefit	Benefit
Energy DRIPE - In-State	Benefit	Benefit	Benefit
Energy DRIPE - Rest of Pool (ROP)	Benefit	Benefit	N/A
Avoided Capacity	Benefit	Benefit	Benefit
Capacity DRIPE - In-State	Benefit	Benefit	Benefit
Capacity DRIPE - ROP	Benefit	Benefit	N/A
Avoided Transmission	Benefit	Benefit	Benefit
Avoided Distribution	Benefit	Benefit	Benefit
REC Value	Benefit	Benefit	Benefit
Improved Reliability	Benefit	N/A	N/A
Non-Embedded GHG Emissions	Benefit	N/A	N/A
Economic Development	Benefit	N/A	N/A

Electric-Gas Cross-DRIPE - In-State	Benefit	Benefit	Benefit
Electric-Gas Cross-DRIPE - ROP	Benefit	Benefit	N/A
Electric-Gas-Electric Cross-DRIPE - In-State	Benefit	Benefit	Benefit
Electric-Gas-Electric Cross-DRIPE - ROP	Benefit	Benefit	N/A

Q: During the proceedings in Docket No. 23-44-REG, did PUC staff and the DPUC raise concerns regarding the inclusion of economic development benefits in the BCA in that docket?

A: Yes. Specifically, PUC staff and the DPUC suggested that economic development benefits should be removed from the Rhode Island Test and presented separately, reasoning that such benefits cannot always be cleanly separated from their potential offsetting economic impacts to ratepayers.

Q: Has SEA accounted for this concern in the BCA?

A: Yes. Specifically, the Rhode Island Test results shown later in this Direct Testimony include values with and without economic benefits, as well as the specific economic development values derived from taking the difference between the two cases.

Q: During the public hearings in Docket No. 23-44-REG, did PUC staff raise potential concerns regarding energy DRIPE-related benefit estimates?

A: Yes, they did.

Q: What were those concerns?

A: In short, PUC staff were skeptical that the DRIPE-related benefits identified in our analysis in Docket No. 23-44-REG can be realized by Rhode Island ratepayers if price suppression is functionally a cost to ratepayers under long-term contracts in which RI Energy re-sells the energy,

Q: Did SEA investigate the question of whether such potential outcomes were incorporated into the AESC 2024 modeling by Synapse Energy Economics?

A: Yes, we did. Specifically, we consulted with Jason Gifford, Senior Director and Vice President, who directly contributed to the AESC analysis whether generation operating under long-term contracts (as well as future procurement authority assumed to be utilized) was treated in the analysis as hedged supply. Though we were unable to find a specific instance in which the public AESC documentation stated this outright, our colleagues that worked on this element of the AESC analysis informed us that Synapse *did* count such cost impacts associated with energy re-sale in their estimates of hedged supply.

C. <u>Benefit-Cost Results: 2025 PY Megawatt Allocation Plan</u>

Q: Please summarize the results of the benefit-cost analysis for the Megawatt Allocation Plan options.

A: Our analysis found that under the Rhode Island Test, and regardless of whether economic development benefits are included, the benefits associated with Plan A (regardless of eventual subscription and commercial operation levels) exceed the tariff cost under the Rhode Island Test, and thus provide a net benefit. However, the benefits of Plan B only exceed their costs under the Rhode Island Test if economic development benefits were to be included. Under the Cost of Supply Test, neither the benefits under Plan A nor Plan B exceeded the costs, regardless of eventual subscription and commercial operation levels.

Q: What were the BCA results for the 2025 PY Megawatt Allocation Plan using the Rhode Island Test?

A: As shown in **SEA Table 9,** in the absence of economic development benefits, our BCA found that the net benefits of Plan A, assuming historical subscription levels, would be **$39.2 million**, while the net benefits of a fully-subscribed Plan A would be **$76.1 million**. If economic development benefits are included, our BCA found that the net benefits of Plan A, assuming historical subscription levels, would be **$104.5 million**, while the net benefits of a fully-subscribed Plan A would be **$203.1 million**. For Plan B, as shown in SEA **Table 10**, in the absence of economic development benefits, our analysis found net benefits, assuming historical subscription levels, of **-$3.8 million**, while the net benefits of a fully-subscribed Plan B would be **-**$7.5 million. If economic development benefits are included, our BCA found that the net benefits of Plan B, assuming historical subscription levels, would be **$36.2 million**, while the net benefits of a fully-subscribed Plan B would be **$70.4 million**.

SEA Table 9 - Total MW & Benefits and Costs of 2025 PY Megawatt Allocation Plan A (NPV ($), RI Test, With and Without Econ. Dev. Benefits)

BCA Type	***Historical Subs./ COD Levels (No Econ. Dev)***	***Fully Subscribed (No Econ. Dev.)***	***Historical Subs./ COD Levels (W/ Econ. Dev.)***	***Fully Subscribed & Operational (W/Econ. Dev.)***	***Total Econ Dev. Benefits (Hist. Subs./COD Levels)***	***Total Econ Dev. Benefits (Fully Subscribed)***
Total MW Deployed	55.9	108.5	55.9	108.5	**$65,383,521**	**$127,007,617**
Total Benefits	$213,584,454	$414,888,216	$278,967,975	$541,895,833		
Total Tariff Cost	$174,378,973	$338,731,493	$174,378,973	$338,731,493		
Total Net Benefits (Solar Classes)	**$39,205,481**	**$76,156,722**	**$104,589,002**	**$203,164,339**		
Benefit-Cost Ratio (BCR)	**1.22**		**1.60**			

SEA Table 10 – Total MW & Benefits/Costs of 2025 PY Megawatt Allocation Plan B (NPV ($), RI Test, With and Without Econ. Dev. Benefits)

BCA Type	***Historical Subs./ COD Levels (No Econ. Dev.)***	***Fully Subscribed (No Econ. Dev.)***	***Historical Subs./ COD Levels (W/ Econ. Dev.)***	***Fully Subscribed & Operational (W/Econ. Dev.)***	***Total Econ Dev. Benefits (Hist. Subs./COD Levels)***	***Total Econ Dev. Benefits (Fully Subscribed)***
Total MW Deployed	27.5	53.5	27.5	53.5	**$40,124,056**	**$77,941,056**
Total Benefits by Test	$98,992,181	$192,292,504	$139,116,236	$270,233,560		
Total Tariff Cost	$102,854,786	$199,795,622	$102,854,786	$199,795,622		
Total Net Benefits (Solar Classes)	**($3,862,605)**	**($7,503,118)**	**$36,261,450**	**$70,437,938**		
BCR	**0.96**		**1.35**			

Q: Why are the net benefits under the Rhode Island Test associated with Plan B lower than those associated with Plan A?

A: This is because on a NPV $/MW basis, the Large Solar classes offer more net benefits under the Rhode Island Test than projects less than 1 MW. As a result, the benefits under the Rhode Island Test for Plan B are lower because there is assumed to a smaller share of deployment (and less generation) from Large Solar projects as compared to Plan A.

Q: What were the BCA results for the 2025 PY Megawatt Allocation Plan using the Cost of Supply Test?

A: As shown in **SEA Table** 11, our BCA found that the net benefits of Plan A, assuming historical subscription levels, would be **-$20.8 million**, while the net benefits of a fully-subscribed Plan A would be **-$40.4 million**. For Plan B, as shown in **SEA Table** 12, our analysis found net benefits, assuming historical subscription levels, of **-$33.5 million**, while the net benefits of a fully-subscribed Plan B would be **-$65.2 million**.

SEA Table 11 - Total MW & Benefits/Costs of 2025 PY Megawatt Allocation Plan A (NPV ($), Cost of Supply Test)

BCA Type	***Cost of Supply Test – Hist. Subs./COD Levels***	***Cost of Supply Test - Fully Subscribed & Operational***
Total MW Deployed	55.9	108.5
Total Benefits	$153,569,256	$298,308,578
Total Tariff Cost	$174,378,973	$338,731,493
Total Net Benefits (Solar Classes)	**($20,809,717)**	**($40,422,916)**
BCR	**0.88**	

SEA Table 12 - Total MW & Benefits/Costs of 2025 PY Megawatt Allocation Plan B (NPV ($), Cost of Supply Test)

BCA Type	***Cost of Supply Test – Hist. Subs./COD Levels***	***Cost of Supply Test - Fully Subscribed & Operational***
Total MW Deployed	27.5	53.5
Total Benefits by Test	$69,307,689	$134,630,321
Total Tariff Cost	$102,854,786	$199,795,622
Total Net Benefits (Solar Classes)	**($33,547,097)**	**($65,165,301)**
BCR	**0.67**	

Q: Why are the net benefits under the Cost of Supply Test associated with Plan B lower than those associated with Plan A?

A: As with the results obtained utilizing the Rhode Island Test, this is because on an NPV $/MW basis, the Large Solar classes also offer net monetizable benefits relative to the cost of supply, whereas projects less than 1 MW do not. Therefore (and again, like the Rhode Island Test), the benefits under the Cost of Supply Test are lower because there is assumed to be less deployment of Large Solar projects.

Q: What were the BCA results for the 2025 PY Megawatt Allocation Plan using the Rhode Island Ratepayer Test?

A: As shown in **SEA Table 13**, our BCA found that the net benefits of Plan A, assuming historical subscription levels, would be **-$81.9 million**, while the net benefits of a fully-subscribed Plan A would be **-$159.2 million**. For Plan B, as shown in **SEA Table 14**, our analysis found net benefits, assuming historical subscription levels, of **-$59.2 million**, while the net benefits of a fully-subscribed Plan B would be **-$115.0 million**.

SEA Table 13 - Total MW & Benefits/Costs of 2025 PY Megawatt Allocation Plan B (NPV ($), RI Ratepayer Test)

BCA Type	***RI Ratepayer Test – Hist. Subs./COD Levels***	***RI Ratepayer Test - Fully Subscribed & Operational***
Total MW Deployed	55.9	108.5
Total Benefits	$92,429,171	$179,543,844
Total Tariff Cost	$174,378,973	$338,731,493
Total Net Benefits (Solar Classes)	**($81,949,802)**	**($159,187,649)**
BCR	**0.53**	

SEA Table 14 - Total MW & Benefits/Costs of 2025 PY Megawatt Allocation Plan B (NPV ($), RI Ratepayer Test)

BCA Type	***RI Ratepayer Test – Hist. Subs./COD Levels***	***RI Ratepayer Test - Fully Subscribed & Operational***
Total MW Deployed	27.5	53.5
Total Benefits by Test	$43,644,023	$84,778,600
Total Tariff Cost	$102,854,786	$199,795,622
Total Net Benefits (Solar Classes)	**($59,210,763)**	**($115,017,022)**
BCR	**0.42**	

Q: Why are the net benefits under the Rhode Island Ratepayer Test associated with Plan B higher than those associated with Plan A?

A: Unlike in the Rhode Island Test and Cost of Supply Test, the results obtained utilizing the

Rhode Island Ratepayer Test show a lower cost for Plan B because on an NPV $/MW basis, neither the Large Solar classes nor the classes for projects less than 1 MW offer net monetizable benefits to Rhode Island ratepayers. As a result, the reduced capacity offered under Plan B results in greater net benefits, as all capacity introduces net costs under the Rhode Island Ratepayer Test.

Q: Can SEA provide a detailed breakdown of the benefits and costs of Plan A and Plan B by renewable energy class?

A: Yes, this information is contained in **SEA Schedule 8.**

D. Detailed Benefit-Cost Methodology: Proposed Brownfield Adder Pilot Program

Q: Did SEA undertake an analysis to quantify the benefits and costs associated with the adoption of the proposed brownfield incentive-payment adder pilot program for projects greater than 1 MW_{DC}?

A: Yes, we did.

Q: What are the potential societal benefits from brownfield remediation?

A: As the General Assembly recognized in its enactment of the 2023 solar siting law, brownfield remediation is known to confer numerous potential societal benefits. According to the EPA in its *Handbook on the Benefits, Costs and Impacts of Land Cleanup and Reuse*, brownfield remediation has the potential to provide benefits in the form of human health benefits, ecological benefits, aesthetic improvements, and increased land productivity.[13]

Q: Please describe, at a high level, the methodology utilized to calculate the benefits and costs associated with the proposed pilot program.

A: To quantify these benefits, SEA conducted a literature review to determine appropriate brownfield remediation benefit inputs. Based on that literature review, our team adopted the results of Haninger et al. 2017, a peer-reviewed study published in the Journal of the Association of Environmental and Resource Economists.[14] The study assesses the societal benefits of

[13] Available at: https://www.epa.gov/environmental-economics/handbook-benefits-costs-and-impacts-land-cleanup-and-reuse
[14] Available at: https://www.journals.uchicago.edu/doi/full/10.1086/689743

brownfield remediation by studying changes in property values in parcels within a given radius of remediated brownfields. In other words, the study uses changes in property values as a measure of resident's willingness to pay for the benefits of remediation.

Q: How did SEA adopt the findings of Haninger et al. 2017 in its analysis?

A: Haninger et al. 2017 reports a range of potential benefits based the different experimental methods and samples considered in the study. SEA adopted the values recommended by Haninger et al. 2017 for use in benefit-cost analyses, which represent the lowest estimate of remediation value from the study's range of results. Using this most conservative set of assumptions, Haninger et al. 2017 estimates the average and median value of remediation per brownfield site. SEA adopted the median value for use in its benefit-cost analysis, which is roughly 44% lower than the average value. SEA then translated this value into a per-acre value based on the median size of brownfields included in the study's sample. This per-acre value was then translated to a per-MW value assuming a capacity density of 3.8 acres per MW. Lastly, given that the calculated benefit relates to changes in property values, which can be realized years into the future depending on when such properties are sold, SEA discounted the benefit stream by 10 years using a discount rate of 3%.

Q: At a conceptual level, how does this benefit differ from the property value benefit included in the incentive-payment adder BCA filed by the DG Board in Docket No. 23-44-REG?

A: Though both analyses rely on a study of changes in property value in response to nearby development, they differ in two crucial ways. First, the benefit quantified in the BCA filed by the DG Board in Docket No. 23-44-REG quantified the avoided cost of diverting development from greenfields, which could negatively impact nearby property values, to brownfields. This benefit relied on the counterfactual that, were it not for the adder, development otherwise occurring on brownfields would occur on greenfields. This benefit, at a conceptual level, quantified resident's willingness to pay to avoid living near a solar facility.

The benefit being presented in the updated BCA, on the other hand, does not rely on the absence of a cost in a hypothetical counterfactual, but rather the presence of a benefit due to the direct remediation activity required by the adder. As such, some degree of benefit is guaranteed to be realized if remediation of a site is complete. This benefit, at a conceptual level, quantifies resident's willingness to pay to avoid living near an unremediated brownfield.

Q: Is SEA confident that this approach represents the state of the art for understanding the societal benefits of brownfield remediation?

A: Yes. In fact, using changes in property values as a proxy for the social value of land remediation, as used in the above-described analysis, was endorsed by EPA in its *Handbook on the Benefits, Costs and Impacts of Land Cleanup and Reuse* as "the best prospect for defensible studies of the social benefits of land cleanup and reuse." As such, this benefit is a catch-all for the various benefits associated with brownfield redevelopment and is intended to represent the combined social value of ecological and health improvements from brownfield remediation, as studied through changes in property values.

E. Benefit-Cost Results: Proposed Brownfield Adder Pilot Program

Q: What were the benefit-cost analysis results for the proposed brownfield remediation adder pilot program?

A: Our analysis found that, using the Rhode Island Test and assuming historical subscription and commercial operation levels, the net benefits of the pilot program would be $2.6 million on an NPV basis, while a fully-subscribed and operational capacity allocation would result in net benefits equivalent to $5.1 million. Assuming historical subscription and commercial operation levels, the incremental cost to ratepayers associated with adder payments is equivalent to $1.8 million, while the incremental cost would be $3.7 million if all projects were selected and reached commercial operation.

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- Proposed Brownfield Remediation Adder Pilot Program Totals (MW & NPV)

BCA Type	***Hist. Subs./COD Levels (No Econ. Dev.)***	***Fully Subs./Operational (No Econ. Dev.)***
Total MW Deployed	10.3	20.0
Total Benefits by Test	$4,524,460	$8,788,773
Incremental REG Tariff Cost	$1,884,259	$3,660,178
Total Net Benefits	**$2,640,201**	**$5,128,596**
BCR	**2.40**	

Q: Do the results in SEA Table 15 consider any of the electric system benefits considered in the BCA of the Megawatt Allocation Plan?

A: No. These were not included because the BCA for the adders is intended to capture only the specific incremental benefits associated with brownfield remediation, relative to their specific incremental costs to ratepayers. In other words, projects can be reasonably assumed to confer the same degree of electric system benefits as any other Solar project included in the two Megawatt Allocation Plan options, and that counting the system benefits in a BCA for the adders would constitute double-counting.

Q: Can SEA provide a detailed breakdown of the benefits, by category, applicable to the incentive-payment adders BCA?

A: Yes, this information is contained in both **SEA Table 16**, **SEA Table 17**, and **SEA Schedule 8**.

SEA Table 16 - MW and NPV of Benefits and Costs for Brownfield Remediation Adder Pilot Program (Rhode Island Test, Assuming Historical Subscription and Commercial Operation Rates)

Renewable Energy Class	***Pilot MW_{DC}***	***Per-MW Benefits (NPV)***	***Per-MW Tariff Costs (NPV)***	***Total Benefits (NPV)***	***Total Tariff Costs (NPV)***	***Total Net Benefits (NPV)***	**BCR**
Large Solar I	5.1	$439,439	$181,937	$2,262,230	$936,609	$1,325,621	**2.42**
Large Solar II	5.1	$439,439	$184,081	$2,262,230	$947,650	$1,314,580	**2.39**

SEA Table 17 - MW and NPV of Benefits and Costs for Brownfield Remediation Adder Pilot Program (Rhode Island Test, Assuming All Projects Subscribed and Operating)

Renewable Energy Class	***Pilot MW_{DC}***	***Per-MW Benefits (NPV)***	***Per-MW Tariff Costs (NPV)***	***Total Benefits (NPV)***	***Total Tariff Costs (NPV)***	***Total Net Benefits (NPV)***	**BCR**
Large Solar I	10	$439,439	$181,937	$4,394,387	$1,819,366	$2,575,021	2.42
Large Solar II	10	$439,439	$184,081	$4,394,387	$1,840,812	$2,553,575	2.39

Q: Does SEA believe these results justify adoption of the recommended brownfield incentive-payment adder two-year pilot program?

A: Yes. As discussed above, brownfield projects confer system, reliability and conservation benefits within the State of Rhode Island (and thus the load zone of RI Energy), a 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 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 ratepayer costs of said projects over the proposed 2025 and 2026 Program Year pilot program duration.

Q: Does this conclude your testimony?

A: Yes, it does.

SEA Schedule 1 – Presentation for Public Stakeholder Meeting No. 1 (Sept. 10, 2024)

See file named 'SEA Schedule 1 – Presentation for Public Stakeholder Meeting No. 1 (Sept. 10, 2024).pdf'

SEA Schedule 2 – Presentation for Public Stakeholder Meeting No. 2 (Oct. 16, 2024)

See file named 'SEA Schedule 2 – Presentation for Public Stakeholder Meeting No. 2 (Oct. 16, 2024).pdf'

SEA Schedule 3 – Presentation for DG Board Meeting (Nov. 4, 2024)

See file named 'SEA Schedule 3 – Presentation for DG Board Meeting (Nov. 4, 2024).pdf'

SEA Schedule 4 – Stakeholder Data Request and Survey

See file named 'SEA Schedule 4 – Stakeholder Data Request and Survey.pdf'

SEA Schedule 5 – Stakeholder Comments

See file named 'SEA Schedule 5 – Stakeholder Comments.pdf

SEA Schedule 6 – Commerce RI Letter on REF Brownfields

See file named 'SEA Schedule 6 – Commerce RI Letter on REF Brownfields.pdf'

SEA Schedule 7 – REG 2025 BCA - Benefits Methodology

See file named 'SEA Schedule 7 – REG 2024-2026 BCA - *Benefits Methodology.docx'*

SEA Schedule 8 – REG 2025 BCA - Component Benefit Calculations

See file named 'SEA Schedule 8 – REG 2024-2026 BCA - Component Benefit Calculations.xlsx'